General Notice

ELECTRICITY CONTROL BOARD

No. XXX 2026

TRANSMISSION GRID CODE (1 OF 3 CODE DOCUMENTS): ELECTRICITY ACT, 2007

Under Section 3(4)(a) of the Electricity Act, 2007 (Act No. 4 of 2007), the Electricity Control Board, with the prior approval of the Minister of Industries, Mines and Energy, has made the Transmission Grid Code set out in the Schedule.

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DEPUTY CHAIRPERSON OF THE ELECTRICITY CONTROL BOARD Windhoek,
_____ 2026

SCHEDULE
ARRANGEMENT OF CODES

CHAPTER 1
INTRODUCTORY PROVISIONS
PART 1
DEFINITIONS AND OBJECTIVES

1. Definitions/Interpretation
2. Objectives of Transmission Grid Code
3. Application of Transmission Grid Code

CHAPTER 2
TRANSMISSION POWER SYSTEM GOVERNANCE
PART 1
TRANSMISSION GRID CODE ADMINISTRATIVE AUTHORITY AND CONSTITUTION OF TRANSMISSION GRID CODE ADVISORY COMMITTEE

4. Administrative authority
5. Establishment of Grid Code Advisory Committee
6. Constitution of GCAC
7. Functioning of GCAC
8. Secretariat of GCAC

PART 2
REGISTRATION OF GRID CODE PARTICIPANTS AND GRID CODE AMENDMENT OR EXEMPTION

9. Registration and deregistration of Grid Code participants
10. Transmission Grid Code amendment or exemption process
11. Submissions to GCAC
12. Recommendation to the Board

PART 3
DISPUTE MEDIATION, RESOLUTION AND APPEAL MECHANISM

13. Dispute mediation, resolution and appeal mechanism
14. Complaints about operations of GCAC
15. Disputes about decisions of the Board
16. Complaints among transmission customers and service providers
17. Incident report
18. Non-conformance report

19. Submission of disputes to the Board

PART 4
COMPLIANCE, CODE AUDITS, CONTRACTING AND VERSION CONTROL

20. Compliance
21. Code compliance audits
22. Contracting
23. Version control

CHAPTER 3
TRANSMISSION POWER SYSTEM
PART 1
TRANSMISSION POWER SYSTEM TECHNICAL REQUIREMENTS

24. Purpose of transmission company technical design requirements
25. Equipment design standards
26. Clearances
27. Current transformer (CT) and voltage transformer (VT) ratios and cores
28. Standard busbar arrangements and security criteria
29. Transmission substation standard busbar arrangements
30. Use of bypasses
31. Motorised isolators
32. Earthing isolators and earthing switches
33. Busbar protection current transformers
34. Tele-control
35. Transformer tap change
36. Substation drawings
37. Protection requirements
38. Protection design standards for equipment (feeder protection: 220kV and above)
39. Protection settings for equipment (feeder protection: 220kV and above)
40. Automatic reclosing for equipment (feeder protection: 220kV and above)
41. ARC for equipment (feeder protection: 220kV and above)
42. Single phase automatic reclosing
43. Three phase fast ARC
44. Three phase slow ARC
45. Power swing blocking
46. Design standard: equipment protection requirements (feeder protection: 132kV and below at transmission company substations)
47. Protection settings: equipment protection requirements (feeder protection: 132kV and below at transmission company substations)
48. Automatic reclosing: equipment protection requirements (feeder protection: 132kV and below at transmission company substations)
49. Tele-protection requirements
50. Transformer and reactor protection
51. Transformer inverse definite minimum time earth fault
52. Transformer primary and secondary winding inverse definite minimum time over-current
53. Transformer HV/MV instantaneous over-current
54. Transformer LV (tertiary) inverse definite minimum time /instantaneous over-current
55. Transformer current differential protection
56. Transformer restricted earth fault
57. Transformer thermal overload
58. Transmission power system busbar protection
59. Transmission power system bus coupler and bus section protection
60. Transmission power system shunt capacitor protection
61. Over-voltage protection
62. Ancillary protection functions
63. Breaker fail or bus trip
64. Breaker pole discrepancy
65. Breaker anti-pumping
66. Pantograph isolator discrepancy

67. Latching functionality
68. System protection requirements (under-frequency load shedding)
69. System protection requirements (out of step tripping)
70. System protection requirements (under-voltage load shedding)
71. System protection requirements (sub-synchronous resonance protection)
72. System protection requirements (protection against near 50 Hz resonance)
73. System protection requirements (protection settings impact on system stability (dynamic stability))
74. Protection system performance monitoring
75. Nomenclature

PART 2
TRANSMISSION POWER SYSTEM PLANNING AND DEVELOPMENT

76. Transmission power system planning and development
77. Planning process
78. Identification of need for transmission power system development
79. Forecasting demand
80. Technical limits and targets for planning purposes
81. Voltage limits and targets
82. Other targets for planning purposes
83. Transmission power system lines
84. Transformers
85. Series capacitors
86. Shunt reactive compensation
87. Circuit breakers
88. Secondary automatic reclosing cycle current during single-phase re-closing
89. Reliability criteria for planning purposes
90. Contingency criteria for planning purposes
91. Integration of power stations
92. Power stations of less than 1000 MW
93. Power stations of more than 1000 MW
94. Fault levels
95. Transient stability
96. Busbar arrangements
97. Information required
98. Criteria for system investments
99. Least economic cost criteria
100. Cost reduction investments
101. Statutory or strategic investments
102. Development investigation reports
103. Transmission power system master plan
104. Mitigation of system constraints
105. Interfacing between Grid Code participants
106. Special transmission customer requirements for increased reliability
107. Network maintenance

CHAPTER 4
TRANSMISSION POWER SYSTEM OPERATIONS
PART 1
OPERATIONAL RELATIONS, PROCEDURES, PLANNING, CONDITIONS AND CONTROL

108. Operation of interconnected transmission power system
109. System operator obligations
110. System operation states
111. Transmission power system operation planning
112. Transmission power system reliability and safety
113. Transmission power system security
114. Operational measures
115. Scheduling of generation and ancillary services
116. Ancillary services

117. Operating reserves
118. Operating reserve requirements
119. Instantaneous reserve
120. Regulation reserve
121. 10-minute reserve
122. Fast frequency reserve
123. Supplemental reserve
124. Black start and islanding
125. Reactive power compensation and voltage control from generation units
126. Near 50 Hz resonance control service
127. Operational authority
128. Operating procedures
129. Operational liaison, permission for synchronisation
130. Emergency or contingency planning
131. Transmission power system frequency and area control error control under abnormal frequency or imbalance conditions
132. Description of normal frequency or balancing conditions
133. Operation during abnormal conditions
134. Independent action by Grid Code participants
135. Voltage control
136. Fault reporting and analysis or incident investigation
137. Commissioning
138. Risk of trip

PART 2
MAINTENANCE COORDINATION OR OUTAGE PLANNING AND TELE-CONTROL

139. Maintenance coordination or outage planning
140. Roles and responsibilities of outage requester
141. Roles and responsibilities of transmission company outage scheduler
142. Roles and responsibilities of system operator outage scheduler
143. Outage process
144. Risk-related outages
145. Maintenance planning between transmission company and generators
146. Refusal or cancellation of outages
147. Communication of system conditions, operational information and interconnected power system performance
148. Tele-control
149. Telecommunications

PART 3
TRANSMISSION POWER SYSTEM CONTROL PERSONNEL AND CONTROLLER TRAINING

150. Authority and responsibility
151. Qualifications of the system controller
152. Training requirements of the system controller
153. Training programmes of the system controller
154. Initial system controller training programme
155. Continuous system controller training programme
156. Inter-system operator training
157. Training organization and system controllers' accreditation
158. Basic requirements for dispatcher training simulator

CHAPTER 5
TRANSMISSION POWER SYSTEM METERING

159. Principles of transmission metering
160. Responsibility for metering installations
161. Metering installation components
162. Data validation

163. Meter verification
164. Metering database
165. Testing of metering installations
166. Metering data base inconsistencies
167. Access to metering data
168. Confidentiality

CHAPTER 6
TRANSMISSION POWER SYSTEM INFORMATION EXCHANGE
PART 1
INFORMATION EXCHANGE INTERFACE AND SYSTEM PLANNING INFORMATION

169. Confidentiality of information
170. Information exchange interface
171. System planning information

PART 2
OPERATIONAL INFORMATION

172. Pre-commissioning studies
173. Commissioning and notification
174. General information acquisition requirements
175. Bilateral contract information
176. Generating unit scheduling
177. Energy market schedules
178. Ancillary services market schedules
179. File transfers
180. Inter control centre communication
181. Communication facilities requirements
182. Information exchange tele-control
183. Telephone or mobile phone
184. Electronic mail
185. Access and security of infrastructure at points of supply
186. Time standards for infrastructure at points of supply
187. Integrity of installation
188. Data storage and archiving

PART 3
POST-DISPATCH INFORMATION

189. Market information
190. Generation settlement
191. Ancillary services settlement
192. Hourly demand metering data
193. SAPP information
194. Files used for data transfer
195. Generator performance data
196. Distributor and end-use customer performance
197. System performance information
198. System performance information

PART 4
CYBER SECURITY

199. Cyber Security minimum standards compliance
200. Cyber security working group
201. Cyber security requirements

CHAPTER 7
TRANSMISSION POWER SYSTEM MARKET CODE
PART 1
TRANSMISSION CAPACITY ALLOCATION AND CONGESTION MANAGEMENT

202. Non-discrimination for transmission capacity allocation and congestion management
203. Capacity calculation timeframes
204. Demand data
205. Transmission and generation planned and unplanned outages.
206. Total transfer capacity methodology
207. Transmission reliability margin methodology
208. Operational security limits, contingencies relevant to capacity calculation and allocation of constraints methodology
209. Steady state and dynamic load flow calculations methodology
210. Net Transfer Capacity
211. Available Transfer Capacity
212. Congestion management

PART 2
TRANSMISSION FORWARD CAPACITY ALLOCATION

213. Physical transmission rights
214. Financial transmission rights

ANNEXURES

ANNEXURE 1: TRANSMISSION GRID CODE AMENDMENT OR EXEMPTION APPROVAL PROCESS
ANNEXURE 2: CONTRACTING FRAMEWORK FOR GRID CODE PARTICIPANTS
ANNEXURE 3: VOLTAGE LIMITS AND TARGETS
ANNEXURE 4: SELECTION OF DEAD LINE CHARGING END OF THE LINE
ANNEXURE 5: SAMPLE CONFIDENTIALITY AGREEMENT FOR INFORMATION TRANSFER TO THIRD PARTIES
ANNEXURE 6: DISTRIBUTOR AND END-USE CUSTOMER DATA
ANNEXURE 7: GENERATION PLANNING DATA
ANNEXURE 8: GENERATOR'S MAINTENANCE DATA
ANNEXURE 9: OPERATIONAL DATA
ANNEXURE 10: GENERATOR'S PERFORMANCE DATA
ANNEXURE 11: PLANNING SCHEDULES
ANNEXURE 12: INFORMATION RELATING TO DETAILS SPECIFIED
ANNEXURE 13: MEASUREMENT EQUIPMENT ACCURACY CLASSES
ANNEXURE 14: DAILY 24 HOURS DAY-AHEAD ENERGY SCHEDULE
ANNEXURE 15: FILES TRIGGERED FOR DATA TRANSFER
ANNEXURE 16: TESTING FORMAT FOR UNDER-FREQUENCY LOAD SHEDDING RELAYS
ANNEXURE 17: TRANSMISSION POWER SYSTEM INFORMATION FORMAT FOR PERFORMANCE INDICATORS

CHAPTER 1
INTRODUCTORY PROVISIONS

PART 1
DEFINITIONS AND OBJECTIVES

Definitions/Interpretation

1. (1) In this Code a word or an expression to which a meaning has been given in the Act has that meaning and unless the context otherwise indicates -

“ancillary services” -

(a) mean services supplied to the transmission company by generators, distributors or end-use customers -

(i) for the reliable and secure transport of power from generators to distributors and transmission customers; and

(ii) to support the short-term reliability of the interconnected power system; and

(b) may include -

(i) operating reserves;

(ii) black start and islanding;

(iii) constrained generation;

(iv) reactive power compensation and voltage control from units;

(v) regulation and load following;

(vi) near 50Hz resonance control service; or

(vii) power oscillation damping services,

“AGC” means automatic generation control ;

"ARC” means automatic reclosing;

“area control error” means the mismatch between the instantaneous demand and supply of a control area which combines the frequency error and the tie line schedule error;

“automatic generation control” means the automatic centralised closed loop control of generating units, by means of the computerised energy management system of the system operator, where unit output is controlled by changing the set point on the generator;

“auxiliary supply” means the supply of electricity to auxiliary systems of a unit or substation equipment;

“black start” means the provision of equipment that, following a total system collapse (black out), is able to -

(a) start without an outside electrical supply; and

(b) energise a defined portion of the transmission power system so that it can act as a start-up supply for other capacity to be energised as part of a process of re-energising the transmission power system;

"Board" means the Electricity Control Board established under the Section 2 of the Act;

"busbar" means an electrical conduit at a substation where lines, transformers and other equipment are connected;

"co-generator" means a unit that is part of a specific industrial or production process and is not connected to the transmission power system;

"constrained generation" means the difference between the energy scheduled at the point of connection of the generator under the unconstrained schedule, and the energy scheduled at the point of connection under the constrained schedule derived to accommodate transmission power system constraints;

"control area" means a subset of SAPP that adheres to the minimum requirements for a control area as set out in the SAPP Operating Guidelines;

"control centre" means a person responsible for the operational control of electricity network assets;

"transmission customer" means a person that contracts directly with a transmission company for the provision of transmission services and may include a generator, distributor or end-use customer;

"distribution" means the conveyance of electricity through a distribution power system, but excludes trading;

"distribution power system" means a distribution power system which is used to convey electricity locally and for short distances from a transmission substation or local generator to individual customers;

"disputes" mean unresolved complaints between parties that require intervention;

"distributor" means a licensed person that owns, operates and maintains a distribution power system;

"DTS" means dispatcher training simulator;

"embedded generator" means a unit, other than a co-generator, that is not directly connected to the transmission power system;

"emergency" means a situation where transmission or distribution service providers have an unplanned loss of facilities or another situation beyond their control that impairs or jeopardises their ability to supply their system demand;

"emergency outage" means an outage when plant has to be taken out of service so that repairs can immediately be affected to prevent further damage or loss;

"EMS' means energy management system;

"end-use customer" means users of electricity connected to the transmission power system;

"firm supply" means a supply that enjoys a level of reliability as specified in code 89;

"flicker" means a cyclic voltage fluctuation, normally between 0, 1 Hz and 10 Hz, that causes optical stress to humans;

"forced outage" means an outage that occurs when a component is taken out of service immediately, either automatically or as soon as switching operations can be performed as a direct result of abnormal operating conditions, emergency conditions or human error;

"frequency" means the number of oscillations per second on the AC waveform;

"GCAC" means the Grid Code Advisory Committee established in accordance with code 05(a);

"generating unit" means a device used to produce electrical energy;

"generator" means a person operating a licensed generating unit or power station;

"governing" means a mode of operation where any change in system frequency beyond the allowable frequency dead band will have an immediate effect on the generating unit output according to the governor droop characteristic;

"governor droop characteristic" means the MW or Hz characteristic according to which governing will take place;

"grid code" refers to any code made as a grid code under section 3(4) of the Act;

"Grid Code participant" includes but is not limited to -

(a) a generator with a power station connected to any transmission power system;

(b) a generator whose power station is embedded in any distribution power system connected to any transmission power system;

(c) a distributor whose distribution power system is connected to any transmission power system;

(d) an end-use customer connected to any transmission power system, or the end-use customer's distributor acting on its behalf;

(e) an electricity retailer or market participant required to contract for the use of any transmission power system;

(f) an operator of storage of electricity equipment;

(g) the operator of a transmission power system;

(h) the system operator;

(i) an ancillary services participant; or

(j) the market operator;

"IEC" means the International Electrotechnical Commission, an organisation that prepares and publishes international standards for all electrical, electronic and related technologies;

"imbalance" means the mismatch between the energy scheduled at a point of supply or a generator point of connection and the actual energy metered at that point of supply or generator point of connection over a scheduled period;

"information" means knowledge that can be exchanged and communicated, typically in the form of data, and can be stored and processed either electronically or through other means;

"information owner" means the party to whose system or installation the information pertains;

"interconnected power system" means the transmission power system and any other connected system elements that are likely to have an impact on the electricity supply at a national level, including power stations with a capacity of more than 500 kVA and networks linking such power stations to the transmission power system;

"interruptible load" means the consumer load or a combination of consumer loads that can be contractually interrupted without notice or reduced by remote control or on instruction from the system operator;

"interruption" means an interruption of the flow of power to a point of supply not requested by the

transmission customer;

“island” means a generating unit or a group of generating units and its associated load, which is isolated from the rest of the transmission power system but is capable of generating and maintaining a stable supply of electricity to the transmission customers within the isolated area;

“islanding” means the isolated operation of certain portions of the transmission power system as a result of forced outages or action by the system operator;

“load following” means the provision of generation and load response capability, including capacity, energy, and manoeuvrability, that is dispatched by system operator to match power generation and load demand within a scheduling period;

“load reduction” means the ability to reduce transmission customer demand by load curtailment and load shedding;

“losses” means the technical or resistive energy losses incurred on the transmission power system;

“major incident” means an incident where -

(a) more than 20 system minutes of load was interrupted; or

(b) severe damage to the plant has occurred;

“manual load shedding” means the load reduction obtained by manually shedding load at convenient points on the distribution power system within 10 minutes of the instruction being issued by the system operator;

“market operator” means a person acting as a central buyer of electricity from generators and cross-border electricity providers and responsible for administering transactions in the electricity market and “market operations” have a similar meaning;

“market participant” means the market operator, system operator, eligible generators, contestable transmission customers, traders, importers and exporters;

“metering” means all the equipment employed in measuring the supply together with the apparatus directly associated with it;

“metering installation” means all meters, fittings, equipment, wiring and installations used for measuring the flow of electricity;

“MSB” means the modified single buyer established under the Modified Single Buyer Market Structure, adopted by the Government of the Republic of Namibia, in April 2019;

“national grid authority” means the organization responsible for the operation and supervision of the national electric power grid, also referred to as the system operator;

“planned interruption” means a planned outage that will interrupt transmission customer supply;

“planned outage” means an outage of equipment that is requested, negotiated, scheduled and confirmed a minimum of 21 days prior to maintenance or repairs taking place;

“point of connection” means the electrical node in a transmission substation where the assets of a transmission customer are physically connected to the assets of a transmission company;

“point of supply” means a transmission substation where energy can be supplied to distributors and end-use customers;

“power station” means one or more generating units at the same physical location;

“protection” means the process of clearing a fault on the interconnected power system in order to protect plant and people;

“regulating reserve” means a reserve that is under automatic generation control and has the generation capacity or transmission customer loads to respond within 10 seconds and be fully active within 10 minutes of activation;

“regulation” means the provision of generation and load response capability, including capacity, energy and manoeuvrability that responds to automatic control signals issued by the system operator;

“risk-related outage” means a planned outage where the next credible contingency would result in a loss of load, loss of supply, voltage slide, thermal overload or dynamic stability constraint;

“SAPP” means the Southern Africa Power Pool -

(a) founded in 1995 as a cooperation of national electricity companies in Southern Africa; and

(b) consisting of utilities of SADC member states;

"SCADA” means supervisory control and data acquisition;

“scheduling” means a process to determine which generating unit or equipment will be in operation and at what loading;

“security” means the probability of not having an unwanted operation;

“service provider” means any licensed transmission company;

“speed of operation” means the time taken to clear a fault on the interconnected power system;

“spinning reserve” means the unused capacity which is synchronized to the system and which can be delivered immediately without manual intervention;

“stakeholders” means the persons affected by or having a material interest in the Transmission and Connection Grid Codes including transmission customers and other Grid Code participants, the Board, the market operator and the SAPP;

“storage of electricity” means the receipt of electricity and the storage of electricity, whether electrically, chemically, electro-chemically, mechanically, thermally or in any other manner and the making of the electricity available for use;

“substation” means a site at which switching or transformation equipment is installed;

“synchronous condenser” means a synchronous generator or motor that, when in synchronous condenser operation, can provide reactive power, voltage control and inertis without providing or absorbing significant real power;

“system frequency” means the frequency of the fundamental AC voltage as measured at selected points by the system operator;

“system minutes” mean the normalised performance indicator for interruptions calculated as system minutes interrupted = energy interrupted (MWh) * 60 / system peak demand (MW);

“system operator” means a person responsible for operating the interconnected transmission power system;

“the Act” means the Electricity Act, 2007 (Act No. 4 of 2007);

“this Code” means this Transmission Grid Code;

“trading” means to buy electricity or ancillary services as a commercial activity for the selling of electricity or services to other licensees or transmission customers;

“transmission” means the conveyance of electricity through a transmission power system, but

excludes trading;

"transmission company" means a person that holds a valid transmission licence and depending on the licence conditions may be responsible for -

(a) system operations;

(b) transmission supply business;

(c) transmission wires business;

(d) imports and exports; and

(e) market operator;

"transmission company outage scheduler" means a person appointed by the transmission company to check for multiple requests for an outage of the same system unit;

"transmission equipment" means the equipment that is needed for the purpose of transmission;

"transmission metering administrator" means a licensed transmission company that is responsible for all transmission tariff metering installation, maintenance and operations;

"transmission supply business" means a licensed transmission company that is responsible for supplying energy to transmission customers;

"transmission power system" means a transmission power system which is used to convey electricity in bulk or over long distances from a generator to substations located near demand centres for delivery to transmission customers or distribution licensees;

"transmission wires business" means a licensed transmission company that is responsible to install, operate and maintain transmission equipment; and

"unplanned outage" means an outage that is not requested, negotiated, scheduled and confirmed 21 days before the outage takes place but does not include a forced outage, emergency outage or opportunity maintenance.

(2) Unless specifically defined differently in this Code, any word or expression defined in the Modified Single Buyer Market Rules as published in Government Gazette No 7983 of 19 December 2022, General Notice No 736, and which word or expression is used in this Code has the same meaning as defined in the Modified Single Buyer Market Rules.

(3) This Transmission Grid Code must be read in conjunction with applicable legislation, electricity licences and licence conditions and other codes and rules applicable to the electricity provision industry.

Objectives of Transmission Grid Code

2. (1) The objectives of the Transmission Grid Code are to -

(a) establish the rules and procedures that allow a person to use the transmission power system;

(b) permit the transmission power system to be planned and operated safely, reliably, efficiently and economically;

(c) be objective, transparent, non-discriminatory and consistent with Government policy;

(d) provide for the overall administration and review of the various aspects of -

(i) the Transmission Grid Code; and

(ii) the Distribution Grid Code published in terms of section 3(4)(a) of the Act;

(e) set the -

(i) connection conditions for transmission customers; and

(ii) standards used to plan and develop the transmission power system;

(f) set out the responsibilities and roles of the Grid Code participants as far as the interconnected power system is concerned and more specifically issues related to -

(i) reliability, security and safety of the interconnected power system;

(ii) ancillary services;

(iii) market operation actions required by the system operator;

(iv) independent actions required and allowed by transmission customers;

(v) operation of the interconnected power system under abnormal conditions; and

(vi) field operation, maintenance and maintenance coordination or outage planning;

(g) ensure a metering standard for all current and future Grid Code participants;

(h) specify metering requirements to be adhered to;

(i) clarify levels of responsibility relating to metering requirements contemplated in paragraph (h);

(j) define the obligations of Grid Code participants with regard to the provision of information for the implementation of this Code.

(2) Information exchanged between parties governed by this Code is confidential unless otherwise stated.

(3) The NRS 057:2001 metering specifications must be used as the metering requirements for the Transmission Grid Code.

(4) Despite subcode (3), the Board may in writing approve a deviation of the NRS 057:2001 specifications should it find them inadequate or contrary to CHAPTER 5.

(5) If an aspect is not fully or clearly addressed in the NRS 057:2001 metering specifications or if a conflict arises between the provisions of this Code and the NRS 057:2001 metering specifications, this Code takes precedence over the NRS 057:2001 metering specifications.

Application of Transmission Grid Code

3. (1) This Transmission Grid Code applies to all users of the transmission power system including distributors, embedded generators, end-use customers, electricity retailers, re-sellers and any other persons with equipment connected to the distribution power system.

(2) The provisions of this Transmission Grid Code relating to the transmission power system metering apply to all Grid Code participants in respect of any metering point at the boundary of the transmission power system.

CHAPTER 2
TRANSMISSION POWER SYSTEM GOVERNANCE

PART 1
TRANSMISSION GRID CODE ADMINISTRATIVE AUTHORITY AND CONSTITUTION OF TRANSMISSION GRID CODE ADVISORY COMMITTEE

Administrative authority

4. (1) The Board is the administrative authority for the Transmission Grid Code and must ensure that the Transmission Grid Code is compiled, approved and implemented for the benefit of the electricity industry.

(2) The Board must, in addition to its mandate under subcode (1), publish the Transmission Grid Code or any amendments to the Transmission Grid Code, on its website.

Establishment of Grid Code Advisory Committee

5. (1) The Board must –

(a) establish a Grid Code Advisory Committee; and

(b) ensure the proper functioning of the GCAC contemplated in paragraph (a).

(2) The GCAC is established to –

(a) ensure a consultative stakeholder process is followed in the formulation and review of the Transmission Grid Code;

(b) receive comments, review and make recommendations regarding proposals to amend the Transmission Grid Code;

(c) receive proposals, review and make recommendations regarding exemption to comply with the Transmission Grid Code; and

(d) facilitate the provision of expert technical advice to the Board on matters related to the Transmission Grid Code.

(3) The GCAC is a stakeholder representative panel.

(4) Members of the GCAC must ensure that they consult with their constituencies with respect to issues raised in order to solicit views, evaluate impact and make representations at GCAC meetings.

(5) The Board must annually review the composition of and constituencies represented by the GCAC to ensure that it is at all times reflective of the evolving industry.

(6) The Board may decide to expand the composition of the GCAC as part of the membership review process in consultation with the GCAC.

(7) The Board must ensure that members on the GCAC are able to make meaningful contributions towards the membership review process contemplated in this code.

Constitution of GCAC

6. (1) The GCAC must consist of at least the following members:

(a) one member representing the system operator;

(b) one member representing the market operator;

(c) one member representing transmission companies;

(d) two members representing generators;

(e) one member representing the traders;

(f) three members representing distributors;

(g) three members representing end-use transmission customers; and

(h) two members representing the Board, one to chair the GCAC and the other to assist the secretariat,

subject thereto that a member may have more than one representation where such member represent a constituent which constituent is entitled to membership in more than one of the categories set out above.

(2) The members must be identified as follows:

(a) if an industry association represents the larger part of the constituency, the association will be requested to make the nomination;

(b) if the constituency consists of more than one association or a relatively small number of entities, calls for nominations will be sent to all entities and the Board may -

(i) decide on the member if more than the required number of nominations are received; or

(ii) choose the member if no nominations are received; or

(c) if there is no identifiable entity, a public call for nomination will be sent out by the Board and the Board may decide on the member if more than the required number of nominations are received.

(3) The Board must publish resignations and changes in membership within 14 days of the occurrence, on the website of the Board.

(4) GCAC members must serve a three-year term, after which they are eligible for reappointment.

(5) Despite subcode (4), the -

(a) constituency of a GCAC member may replace that member at any given time but 14 days' written notice must be given to the secretariat of the GCAC and to the Board before the replacement; or

(b) Board may, on the recommendation of the GCAC, request the constituency of a GCAC member to replace that member if that member has not attended three consecutive meetings or is otherwise failing to represent the interests of its constituency.

(6) In the event of subcode (5)(b), the constituents of a GCAC member must nominate an alternative representative and that nomination must be made in writing to the secretariat of the GCAC.

Functioning of GCAC

7. (1) The GCAC must periodically initiate a review of the Transmission Grid Code to align with industry changes and developments, receive proposals for ad hoc review or amendment or exemptions from the Transmission Grid Code.

(2) The GCAC must schedule at least one annual review session and the format of a session

will be determined by the GCAC but should include a work session if proposed changes are of a substantive nature.

(3) Agenda items for a session contemplated in subcode (2) must be circulated at least 14 days in advance of the session.

(4) The GCAC must -

(a) subject to code 6, determine its own meeting procedures and code of conduct; and

(b) publish the meeting procedures and code of conduct, contemplated in paragraph (a), on the website of the Board.

(5) A Board member must chair the GCAC meetings and if that Board member or his or her alternate is unable to attend the GCAC meeting the members of the GCAC who are present must select a chair from amongst them to chair that meeting.

(6) A quorum at GCAC meetings consists of 66 % of GCAC constituent members plus the member of the Board who chair, and the GCAC must take decisions by consensus, failing which by a majority vote of the GCAC constituent members constituted as contemplated in code 06, and if votes are even then the chair has the deciding vote, subject thereto that if a quorum cannot be reached within 30 minutes the meeting must stand over to the same day and time in the ensuing week, or such other date and time as the members may agree, to be no later than the same day and time in the ensuing week. If there is still not a quorum the issue should be referred to the ECB for a decision on how to proceed.

(7) When decisions must be made through voting, each constituent member is allowed only one vote.

(8) The GCAC may make recommendations or take decisions by means of round robin subject thereto that notice is given to all the members and members are given not less than 14 days to respond to such recommendation and such recommendation or decision is supported by at least 66% of the members.

(9) On receipt of a recommendation contemplated in subcode (8), the GCAC members must, within the period set out in the notice, make a decision and the chair must communicate the decision in writing to the secretariat.

(10) The secretariat must keep minutes of every meeting and the recommendations or decisions made at a meeting which minutes must be published on the Board's website.

(11) If a recommendation or decision is voted on as contemplated in subcode (9), the decision must be minuted as confirmed at the next GCAC meeting where a quorum is present.

(12) The secretariat must record all the recommendations and decisions of the GCAC including the dissenting views expressed by GCAC members.

(13) The Board must fund the administrative activities of the GCAC but GCAC members are responsible for their own travel and subsistence expenditure.

(14) The GCAC may -

(a) request for permission and funding to the Board to co-opt experts with the purpose of allowing expert opinion to be obtained regarding complicated submissions;

(b) encourage industry participation and consultation in the activities of the experts contemplated in paragraph (a); or

(c) obtain industry participation and consultation through the activities of the experts contemplated in paragraph (a).

(15) The GCAC must provide the experts contemplated in subcode (14)(a) with a full scope of work and an indication of the urgency of each task referred to them.

Secretariat of GCAC

8. (1) The national grid authority is appointed as the secretariat of the GCAC by the Board and the secretariat is accountable to the GCAC for its activities.

(2) The functions of the secretariat are to -

(a) ensure procedures are developed and published for the review of proposed updates, amendments and exemptions by the GCAC;

(b) provide standard submission forms to Grid Code participants;

(c) assist, when requested, in the preparation of submissions to the GCAC;

(d) prepare amendment and exemption proposals for submission to the Board following review by the GCAC;

(e) manage grid code documentation;

(f) disseminate relevant information;

(g) inform Grid Code participants of the progress with applications for amendments or exemptions;

(h) co-ordinate the activities of the GCAC;

(i) keep and circulate minutes of meetings and documentation of proceedings of the GCAC;

(j) register Grid Code participants as contemplated in code 9; and

(k) function as a formal communication channel for the GCAC.

(3) The Board must ensure that an updated copy of the Transmission Grid Code is published on its website.

(4) The secretariat must make hard copies of the latest version of the Transmission Grid Code available to requesting persons, for which a fee may be charged to recover reproduction costs.

PART 2
REGISTRATION OF GRID CODE PARTICIPANTS AND GRID CODE AMENDMENT OR EXEMPTION

Registration and deregistration of Grid Code participants

9. (1) A Grid Code participant may request the secretariat to register it, and upon such request, the secretariat must register the Grid Code participant.

(2) A Grid Code participant must apply in writing to the secretariat to be registered as contemplated in subcode (1).

(3) Service providers must verify that their transmission customers are registered as Grid Code participants before entering into a contract for licensed services.

(4) A Grid Code participant who intends to deregister must notify the secretariat in writing before the intended date of deregistration and the deregistration must be carried out in accordance with guidelines determined by the Board.

Transmission Grid Code amendment or exemption process

10. (1) A Grid Code participant, a member of the GCAC or the Board -

(a) may in writing to the Board propose amendments to the Transmission Grid Code; and

(b) who proposes amendments pursuant to paragraph (a), must submit the proposed amendments to the secretariat as contemplated in code 11(4).

(2) A Grid Code participant -

(a) may in writing to the Board apply for an exemption from complying with provisions of the Transmission Grid Code; and

(b) who applies for an exemption pursuant to paragraph (a), must submit the application to the secretariat as contemplated in code 11(4).

(3) On receipt of the proposed amendments contemplated in subcode (1) or the application contemplated in subcode (2) -

(a) the secretariat must submit the proposed amendments or the application to the GCAC for review; and

(b) subject to paragraph (a) and code 7, the GCAC must review the proposed amendments and subject to code 12 , make recommendations to the Board.

(4) Subject to code 12(2), the Board -

(a) may approve the amendments proposed under subcode (1) ; or

(b) must approve and grant an exemption applied for under subcode (2), if the exemption is necessary to -

(i) provide for existing equipment that has not been designed with consideration for the provisions of the Transmission Grid Code;

(ii) facilitate transition through interim arrangements; or

(iii) facilitate temporary conditions necessitating exemption,

and deal with such amendment or exemption in accordance with the Act.

(5) The GCAC must keep a register which contains a list of exemptions that have been approved under subcode (4), with the relevant expiry date and the reference number.

(6) The procedure for the amendment of, or exemption from, the Transmission Grid Code as contemplated in subcodes (1) to (4) inclusive, is sketched in Annexure 1.

Submissions to GCAC

11. (1) Submissions may be made to the secretariat at any time for deliberation at scheduled GCAC meetings.

(2) Urgent submissions must be dealt with at *ad hoc* meetings of the GCAC as decided by the chair upon advice from the secretariat.

(3) The secretariat must issue guidelines for submissions to the GCAC and the guidelines must be published on the website of the Board.

(4) An application for an amendment or exemption must be submitted, in accordance with the guidelines, to the secretariat and the applicant must state the relevant clauses of the Transmission Grid

Code and give reasons for the application.

(5) The GCAC must initiate the review process as soon as reasonably possible and must -

(a) if necessary, ensure that the submission is referred to an expert team for detailed assessment, clarification and reformulation of response or recommendation; and

(b) forward the recommendation to the Board for consideration once it has been finalized.

(6) The GCAC must take the complexity and importance of the amendment or exemption into account in deciding on the composition of the expert team that will deal with the submission.

(7) The secretariat must inform the applicant of the expected time frames for dealing with the submission.

(8) Where necessary, the applicant must be allowed to make representation to the expert team or the GCAC prior to the formulation or finalization of the GCAC recommendation to the Board.

Recommendation to the Board

12. (1) Once the GCAC has reviewed submissions, the secretariat must prepare the formal recommendation to the Board on all proposed amendments to, and exemptions from, the Transmission Grid Code.

(2) In the recommendation contemplated in subcode (1), the secretariat must include -

(a) a clear expression of divergent views on the proposed amendments and exemptions if any were received by the GCAC; and

(b) an appropriate implementation date for the proposed amendments or exemptions.

(3) Despite any code to the contrary, a Grid Code participant may, subject to the Act, be granted full or partial exemption from complying with any code in this Transmission Grid Code.

(4) The Board must give written notice to the secretariat of the recommendations or decisions reached by the Board.

(5) The secretariat is responsible for communicating the decisions contemplated in subcode (4) to Grid Code participants.

(6) The secretariat must ensure that the Transmission Grid Code is annotated with the approved amendments as published in the Government Gazette and that a register of exemptions is maintained.

PART 3
DISPUTE MEDIATION, RESOLUTION AND APPEAL MECHANISM

Dispute mediation, resolution and appeal mechanism

13. (1) A registered Grid Code participant must have a documented procedure for handling disputes arising under the Transmission Grid Code, which shall include:

(a) clear guidelines on initiating a dispute resolution process;

(b) timelines and steps for mediation, arbitration, or other applicable methods of resolution;

(c) provisions for involving independent experts or third-party mediators, if necessary;

(d) mechanisms for recording, tracking, and monitoring dispute cases.

(2) The procedure contemplated in subcode (1) must cover the aspects contemplated in code 16 (1).

Complaints about operations of GCAC

14. (1) Any complaint regarding the operations of the GCAC must be addressed in writing to the secretariat who shall forward these to the GCAC.

(2) The GCAC should establish a clear process for addressing complaints, including:

(a) acknowledging receipt of the complaint;

(b) conducting a thorough investigation into the matter;

(c) providing a timely response to the complainant; and

(d) taking appropriate corrective actions, if necessary, to rectify the issue and prevent future occurrences.

(3) If a complaint remains unresolved after review by the GCAC, the matter should be referred to the Board for further consideration and resolution.

Disputes about decisions of the Board

15. Any objection to decisions by the Board must be made in writing to the Board and must be dealt with by the Board in accordance with the Act.

Complaints among transmission customers and service providers

16. (1) The procedure for handling complaints among a transmission customer and a service provider must include the incident report and non-conformance report requirements set out in codes 17 and 18.

(2) The Board must develop and maintain a database of disputes resolved to assist in the resolution of future disputes.

(3) If the outcome of a dispute resolution proceeding requires or implies an amendment to the Transmission Grid Code, the Board must first consult with the GCAC and if an amendment is decided on the provisions of code 7 shall apply with the necessary changes.

Incident report

17. (1) An incident report should be seen as a formal communication of a problem.

(2) A transmission customer may issue an incident report to a service provider on becoming aware of a problem or a possible breach of the Transmission Grid Code.

(3) The service provider contemplated in subcode (2) must provide a reasonable explanation and if appropriate indicate what action it will take to address the problem.

(4) A service provider may issue an incident report to a transmission customer if the transmission customer is suspected of not complying with the Transmission Grid Code requirements and the transmission customer must provide the service provider with a reasonable explanation and where appropriate indicate the measures that the transmission customer will take to address the problem.

(5) A service provider must keep a log of all incident reports received and a log of all incident reports communicated to transmission customers.

(6) Incident reports are operational in nature and generally require action only by technical and transmission customer relations staff.

Non-conformance report

18. (1) A transmission customer may issue a non-conformance report when it is suspected that -

(a) the service provider has -

(i) failed to provide a reasonable explanation;

(ii) wilfully misrepresented the facts concerning an incident; or

(iii) failed to implement the agreed preventative actions within the agreed time frame;

(b) the number of incident reports is excessive in relation to historical performance; or

(c) the actions or undertakings arising from a mediation or arbitration process have not been performed or adhered to.

(2) A service provider may issue a non-conformance report when it is suspected that -

(a) the transmission customer has failed to provide a reasonable explanation;

(b) the transmission customer has wilfully misrepresented the facts concerning an incident;

(c) the transmission customer has failed to implement the agreed preventative actions within the agreed time frame;

(d) the number of incident reports is excessive in relation to historical performance; or

(e) the actions or undertakings arising from a mediation or arbitration process have not been performed or adhered to.

(3) Non-conformance reports are indications of problems that require managerial intervention by the service provider or transmission customer.

(4) In the case where the parties agree with the non-conformance report, recommended action must be agreed upon and both Grid Code participants must implement the recommended action within an agreed time frame.

(5) Service providers must report annually to the Board on the following aspects of the procedure:

(a) number of non-conformance reports for each transmission customer category;

(b) number of closed out non-conformance reports for each transmission customer category; and

(c) number of disputes resolved.

(6) A dispute may be declared when the parties cannot agree on the non-conformance report or the recommendations of the non-conformance report or when the agreed recommendations are not implemented in the agreed time frame.

Submission of disputes to the Board

19. (1) A Transmission Grid Code participant may submit a dispute to the Board in accordance with the Act and the procedures contemplated in codes 14 and 16.

(2) When a dispute is submitted to the Board as contemplated in subcode (1) or referred to the Board as contemplated in code 14(3) the parties must provide the following information:

(a) full history of relevant incident reports;

(b) detailed non-conformance report and accompanying information that gave rise to the dispute; and

(c) written report from each party detailing the reason for not being able to close out the non-conformance report.

(3) When a dispute that has not followed the relevant procedure reaches the Board, the Board must refer the Gride Code participant to the correct process.

(4) The Board must conduct a dispute mediation process and act as the mediator to the dispute in accordance with the Act and applicable dispute procedures.

(5) If the dispute mediation process contemplated in subcode (4) succeeds, the parties must strive to honour their respective undertakings or actions agreed upon to the best of their abilities.

(6) If the dispute mediation process contemplated in subcode (4) does not succeed, the parties should, if the Tribunal under the Act has not been established, preferably agree to refer the dispute for arbitration in accordance with the Namibian Arbitration Act, 1965 (Act No. 42 of 1965) and if such agreement cannot be reached on arbitration then, if deemed appropriate, refer the matter to any court of competent jurisdiction.

PART 4
COMPLIANCE, CODE AUDITS, CONTRACTING AND VERSION CONTROL

Compliance

20. (1) All Grid Code participants must comply with the Transmission Grid Code.

(2) Grid Code participants must inform the Board of any non-conformance report of a material nature that has been submitted to another Grid Code participant as contemplated in code 18.

(3) The Board may require a Grid Code participant to provide the Board with information that the Board considers necessary for the proper administration of the Transmission Grid Code and that information must, on request, be treated as confidential.

(4) Upon a report or suspicion of non-compliance the Board may seek to -

(a) resolve the issue through negotiation;

(b) take action in terms of the procedures for handling licensing contraventions;

(c) consider an application for amendment; or

(d) consider an application for exemption.

(5) Transmission customers may apply for exemption from changes to the Transmission Grid Code as contemplated in code 10.

Code compliance audits

21. (1) Grid Code participants have the right to request from each other any material relevant to assessing compliance with specific codes of the Transmission Grid Code for the purpose of conducting periodic code audits.

(2) A request made under subcode (1) must include the following details:

(a) the nature and scope of the requested information;

(b) the designation of the representative appointed by the requesting Grid Code participant to conduct the audit;

(c) the timeframe for providing the requested information.

(3) The Grid Code participant receiving a request under subcode (1) shall reasonably cooperate and provide the requesting Grid Code participant's representative with access to all pertinent documentation, data, records, including computer systems, as reasonably required for the code audit.

(4) Any information shared under subcode (3) shall be treated as confidential, upon request, to protect sensitive data and maintain the integrity of the audit process.

(5) Transmission Grid Code audits and investigations should be conducted in a manner that minimizes disruption to the business operations of the participating entities while ensuring thorough scrutiny of compliance with the Transmission Grid Code.

Contracting

22. (1) The Transmission Grid Code must comprise one of the standard documents that form part of the contract between Grid Code participants.

(2) Service providers must contract with transmission customers for any services specified in the Transmission Grid Code in accordance with the contracting framework sketched in 0.

(3) Service providers must ensure that a non-discriminatory procedure is developed and implemented for the allocation of quality of supply parameters at the points of common coupling.

(4) Transmission customers must enter into a connection contract and an operating agreement with the service provider in advance of construction of the connection facilities.

(5) Grid Code participants and a service provider must enter into a use-of-system contract before the commencement of energy transactions between them over the transmission power system and an ancillary services contract before the commencement of ancillary service delivery to the service provider.

Version control

23. (1) The Transmission Grid Code will evolve as the electricity distribution industry in Namibia evolves.

(2) The secretariat is responsible for version control.

CHAPTER 3
TRANSMISSION POWER SYSTEM

PART 1
TRANSMISSION POWER SYSTEM TECHNICAL REQUIREMENTS

Purpose of transmission company technical design requirements

24. The purpose of the transmission company technical design requirements contemplated in codes 25 to 36 inclusive, is to document the design and other technical standards that the transmission company must adhere to.

Equipment design standards

25. (1) Primary substation equipment must, subject to subcode (2), comply with IEC specifications.

(2) The application of the specifications contemplated in subcode (1) must cater for local conditions including increased pollution levels and must be determined by or in consultation with the transmission customer.

(3) The transmission company must design, install and maintain equipment in accordance with relevant electricity industry standards.

(4) Transmission customers may require the transmission company to provide documentary proof that their connection facilities complies with all relevant standards, both by design and by testing.

Clearances

26. Clearances must comply with relevant electricity industry standards.

Current transformer (CT) and voltage transformer (VT) ratios and cores

27. Current transformer and voltage transformer ratios and cores must be determined by or in consultation with the transmission company.

Standard busbar arrangements and security criteria

28. Substations on the transmission power system must be configured in accordance with code 29 and 30.

Transmission substation standard busbar arrangements

29. (1) The reliability and availability of the transmission power system is dependent on, but not limited to -

(a) transmission power system lines;

(b) transformers;

(c) other primary and secondary plants; and

(d) the busbar layout.

(2) When planning the transmission power system, the transmission company must prudently

assess the busbar layout contemplated in subcode 29(d) and assess the impact of the busbar layout on the reliability and availability of the supply of the transmission customer.

(3) When planning substation design, the transmission company must base the standard busbar arrangement on providing one busbar zone for every main transformer or line normally supplying that busbar.

(4) A transmission company must consider the local conditions, type of equipment used, type of load supplied and other factors in the assessment of the required busbar redundancy.

(5) The system reliability criteria set out in code 89 must also be adhered to in addition to subcodes (1) to (4).

Use of bypasses

30. (1) Bypasses provide high line availability by allowing circuit breakers to be taken out of service for maintenance and testing without affecting line availability.

(2) The bypass with single busbar selection must be used at 132 kV and 220 kV on single line radial feeds to provide continuity of supply when maintaining the line breakers.

(3) The bypass with double busbar selection must be used on new 400 kV, 330 kV and 220 kV lines where justified in accordance with the planning criteria defined in CHAPTER 2.

Motorised isolators

31. To provide motorised isolators at new substations -

(a) all 400 kV, 330 kV and 220 kV isolators must be motorised at new substations; and

(b) isolators of 132 kV and below must be specified on individual merit, taking into account importance ranking, cost and remoteness.

Earthing isolators and earthing switches

32. Earthing isolators and earthing switches must be provided at new substations where the fault level is designed for 20 kA and above.

Busbar protection current transformers

33. (1) For phase 3 busbar protection schemes, single sets of current transformers, including 3 current transformers instead of 6 current transformers, must be used on bus couplers and bus section breakers to reduce the probability of a double bus zone outage for a current transformer fault on a bus coupler or bus section breaker.

(2) At a power station, overlapped bus zones must be retained to ensure fastest possible clearance of busbar faults.

Tele-control

34. (1) All Grid Code participants shall be permitted to have tele-control equipment in the substations, yards or buildings of the other Grid Code participants, to perform agreed monitoring and control and access must be provided to the tele-control equipment.

(2) At the interface with the transmission power system, distributors must have reliable SCADA facilities including telecommunications, computers and remote terminal units for the distribution power system to provide the necessary response where system conditions require.

Transformer tap change

35. (1) The transmission company must install automatic tap changing facilities on all new transformers.

(2) Transformers used in the transmission power system at 220kV or more are normally not on automatic tap change and transformers supplying a transmission customer are usually on automatic tap change.

(3) Voltage levels, sensitivity and time settings and on or off auto tap changing must be determined by the –

(a) system operator in consultation with the transmission customer; and

(b) transmission company.

Substation drawings

36. The following set of drawings must be made available by the respective asset owners for all points of supply, if required by the other party for the purposes of connection:

(a) station electric diagram;

(b) key plan;

(c) bay layout schedules;

(d) foundation, earth mat and trench layout;

(e) steelwork marking plan;

(f) security fence layout;

(g) terrace, road and drainage layout;

(h) transformer plinth;

(i) general arrangement;

(j) sections;

(k) slack span schedule;

(l) barrier fence layout;

(m) security lighting;

(n) floodlighting parameter sketch;

(o) protection details; and

(p) contour plan.

Protection requirements

37. (1) Codes 38 to 74 specify the minimum protection requirements for a transmission company as well as typical settings, to ensure adequate performance of the transmission power system as experienced by the transmission customers.

(2) The transmission company must at all times install and maintain protection installations

that comply with the provisions of the codes contemplated in subcode (1).

(3) The transmission company must conduct periodic testing of equipment and systems to ensure and demonstrate that the equipment and systems are performing to the design specifications.

(4) Tests procedures must be according to the specifications of the manufacturer.

(5) The transmission company must make available to transmission customers all results of test performed on equipment for reasonable requests.

(6) Protection schemes are generally divided into –

(a) equipment protection; and

(b) system protection.

Protection design standards for equipment (feeder protection: 220kV and above)

38. (1) New feeders must be protected by the Main 1 and Main 2 protection systems.

(2) The Main 1 and Main 2 protection systems must be fully segregated in secondary circuits.

(3) An additional earth fault function must be incorporated in the main protection relays or installed separately to alleviate possible deficiencies of distance relays in the detection of high-resistance faults.

Protection settings for equipment (feeder protection: 220kV and above)

39. (1) The protection relays –

(a) must provide reliable protection against all possible short circuits;

(b) must provide remote or local back up for busbar faults that have not been cleared; and

(c) must not be set to provide overload tripping.

(2) Where specifically required, the feeder protection may be set, if possible, to provide remote back up for other faults as agreed upon with other Grid Code participants.

Automatic reclosing for equipment (feeder protection: 220kV and above)

40. (1) Automatic reclosing facilities must be provided on all feeders.

(2) The system operator must decide on automatic reclosing selection based on real time system behaviour, environmental constraints and consultation with transmission customers, with regard to equipment capabilities and in accordance with codes 41 to 44.

(3) All automatic reclosing settings and methodology must be -

(a) implemented by the transmission company; and

(b) made available by the transmission company to transmission customers on request.

ARC for equipment (feeder protection: 220kV and above)

41. (1) Either of the following two automatic reclosing cycles for single phase faults must be used:

(a) double attempt ARC cycle for persistent fault: 1ph fault – 1ph trip – 1ph ARC – 3ph trip – 3ph ARC – 3ph trip – lockout; or

(b) single attempt ARC cycle for persistent fault: 1ph fault – 1ph trip – 1ph ARC – 3ph trip – lockout.

(2) The ARC cycle for a multiphase (mph) fault must be: mph fault – 3ph trip – 3ph ARC – 3ph trip – lockout.

(3) On some lines the automatic reclosing shall be switched off according to the following operational needs:

(a) sporadically, when a high risk of line fault is recognised, for live line work or to reduce the breaker duty cycle where the condition of the breakers is questionable;

(b) periodically, during a season of high fault frequency;

(c) permanently, on selected lines with the highest fault frequency throughout the year or on the request of the transmission customers; or

(d) whenever an automatic reclosing could initiate a severe power swing or an out-of-step condition in weakly interconnected systems.

Single phase automatic reclosing

42. (1) In most applications, the dead time of single-phase automatic reclosing is selected to one second but may differ for different system requirements.

(2) The closing of the breaker is performed without synchronisation as the synchronism is maintained via remaining phases that are closed during the whole incident.

Three phase fast ARC

43. (1) Fast ARC or the fast closing of the breaker without checking synchronism, is not used on the transmission power system to avoid stress to the rotating machines at the power stations and at the plant of the transmission customer but is available on protection panels and can be selected in case of an emergency such as when as a result of outages disturbance load or generation islands are interconnected via a single line.

(2) Despite subcode (1) the operating practice is to use only single phase ARC (fast by its nature) as a compromise between supply reliability and stress to the equipment.

Three phase slow ARC

44. (1) The dead line charging end is selected in line with Annexure 6 based on the fault level at the connected substations A and B.

(2) In most applications the dead time of slow automatic reclosing is selected to three seconds at the dead line charging end of the line.

(3) At the synchronising end of the line the automatic reclosing dead time is usually selected to four seconds.

(4) The close command will be issued only after synch-check is completed and this may take up to two seconds if synchronising relays are not equipped with direct slip frequency measurement.

(5) The breaker may take longer to close if its mechanism is not ready to close after initial operation at the time when the close command is issued.

(6) On the line between two power stations the dead time at the dead line charging end should be extended to 25 seconds to allow the rotors oscillations of the generator to stabilise.

(7) The dead time on the synchronising end is then extended accordingly to 30 seconds.

(8) The synchronising relays are installed at both ends of the line to enable flexibility in automatic reclosing cycles and during restoration.

Power swing blocking

45. (1) New distance relays on the transmission power system must be equipped with power swing blocking facility.

(2) All unwanted operations of distance relays during power swing conditions must be blocked on the transmission power system.

Design standard: equipment protection requirements (feeder protection: 132kV and below at transmission company substations)

46. (1) The feeders of 1 kV up to 44 kV must be protected by a single protection system, incorporating either distance or differential protection relays, unless otherwise agreed.

(2) The feeders of 44 kV up to and including 132 kV shall be protected by a single or dual protection system, incorporating either distance or differential protection relays, unless otherwise agreed.

(3) Back up must be provided by definite time and inverse definite minimum time (IDMT) over-current and earth fault relays.

(4) The protection must be equipped with automatic reclosing.

(5) Synchronising relays must be provided on feeders that operate in “ring supplies” and are equipped with line voltage transformers.

Protection settings: equipment protection requirements (feeder protection: 132kV and below at transmission company substations)

47. (1) Protection relays –

(a) must provide reliable protection against all possible short circuits;

(b) must provide remote and local back up for un-cleared busbar faults; and

(c) should not be set to provide overload tripping where measurements and alarms are provided on the SCADA system.

(2) In isolated applications where the SCADA system is not available, overload tripping will be provided.

(3) Where overload conditions are alarmed at control centres, it is the responsibility of the control centre to reduce load to an acceptable level as quickly as possible.

Automatic reclosing: equipment protection requirements (feeder protection: 132kV and below at transmission company substations)

48. (1) The transmission customer must determine automatic reclosing requirements.

(2) The system operator may specify additional automatic reclosing requirements for system security reasons, which could extend beyond the transmission company substations.

Tele-protection requirements

49. New distance protection systems must be equipped with tele-protection facilities to enhance the speed of operation.

Transformer and reactor protection

50. (1) The standard schemes for transformer protection comprise a number of systems, each designed to provide the requisite degree of protection for the following fault conditions:

(a) faults within the tank;

(b) faults on transformer connections;

(c) overheating; and

(d) faults external to the transformer.

(2) The transmission company must consider the application and where necessary implement the relays contemplated in, but not limited to, codes 51 to 57 in the design of the protection system.

Transformer inverse definite minimum time earth fault

51. The transformer secondary voltage (MV) earth fault protection is to discriminate with the feeder back-up earth fault protection for feeder faults.

Transformer primary and secondary winding inverse definite minimum time over-current

52. (1) It is a requirement of the system operator that the inverse definite minimum time over-current (IDMT O/C) does not operate for twice transformer full load.

(2) Overloading of the transformer is catered for by the winding and oil temperature protection but system requirements may be such that subcode (1) cannot be applied and amutually agreed philosophy may have to be used.

Transformer HV/MV instantaneous over-current

53. Transformer high voltage medium voltage instantaneous over-current (transformer HV/MV instantaneous over-current) back-up protection caters for flash-overs external to the transformer on the HV side or MV side and should operate for minimum fault conditions (as well as possibly for an Earth Fault condition), subject thereto that the overriding requirement is not to operate for through faults or for magnetising inrush current.

Transformer LV (tertiary) inverse definite minimum time /instantaneous over-current

54. (1) This protection is to operate for external faults between the main delta winding of the transformer and the auxiliary transformer, but not for faults on the secondary side of the auxiliary transformer.

(2) The auxiliary transformer is also protected by Buchholz and oil temperature protection in case of oil immersed auxiliary transformers.

(3) The cable from the secondary winding of the auxiliary transformer shall be protected by a model case circuit breaker (MCCB) with appropriate ratings and fitted with signaling/alarming contact.

Transformer current differential protection

55. (1) Transformer current differential protection is the main transformer protection for earth fault and phase to phase faults.

(2) Maximum sensitivity is required, while ensuring no incorrect operation for load, for through fault conditions or for magnetising inrush current with its attendant decaying offset.

Transformer restricted earth fault

56. Transformer restricted earth fault is an additional protection for the transformer differential relay to cater for earth faults close to the star point of the transformer winding, where phase to phase faults are most unlikely to occur.

Transformer thermal overload

57. Winding temperature and oil temperature relays, supplied by the manufacturer, are used to prevent transformer damage or lifetime reduction due to excessive loading for the ambient temperature or during failure of the cooling system.

Transmission power system busbar protection

58. (1) Busbars must be equipped with appropriate busbar (bus zone) protection systems and where more than one Grid Code participant is affected, the design of the busbar protection is to be agreed upon between affected Grid Code participants.

(2) The protection should be set with every endeavour to maintain stability for any faults outside the protected zone, even with fully saturated current transformers.

Transmission power system bus coupler and bus section protection

59. Bus-coupler and bus-section panels must be equipped with over-current and earth fault protection.

Transmission power system shunt capacitor protection

60. (1) All the new high voltage capacitor banks must be equipped with point on wave (POW) switching relays to limit inrush current during capacitor bank energisation and inrush reactors and damping resistors must also be employed to limit inrush current.

(2) The following protection functions must be provided for all types of protection schemes:

(a) unbalanced protection with alarm and trip stages;

(b) over-current protection with instantaneous and definite time elements;

(c) earth fault protection with instantaneous and definite time sensitive function;

(d) overload protection with inverse definite minimum time characteristic;

(e) over-voltage with definite time;

(f) circuit breaker close inhibit for 300 seconds after de-energisation; and

(g) ancillary functions as indicated below.

Over-voltage protection

61. (1) Primary protection against high transient over-voltages of magnitudes above 140% must be provided by means of surge arrestors.

(2) To curtail dangerous, fast developing over-voltage conditions that may arise as a result of disturbance, additional over-voltage protection must be installed on shunt capacitors and feeders.

(3) Over-voltage protection on shunt capacitors is set to disconnect capacitor above 110% voltage level with a typical delay of 200 milliseconds to avoid unnecessary operations during switching transients.

(4) Over-voltage protection on the feeders is set to trip the local breaker at voltage level of 120% with a delay of one to two seconds.

Ancillary protection functions

62. (1) Protection systems are equipped with auxiliary functions and relays that enable adequate co-ordination between protection devices and with bay equipment.

(2) The transmission company must consider the functions contemplated in codes 63 to 67 inclusive, for all new protection system designs.

Breaker fail or bus trip

63. Each individual protection scheme is equipped with breaker fail or bus trip function to ensure fast fault clearance in case of circuit breaker failure to interrupt fault current.

Breaker pole discrepancy

64. (1) Breaker pole discrepancy protection compares, by means of breaker auxiliary contacts, state (closed or opened) of breaker main contacts on each phase.

(2) When breaker on one phase is in a different position than breakers on remaining phases a trip command is issued after time delay.

Breaker anti-pumping

65. (1) To prevent repetitive closing of the breaker in case of fault in closing circuits the standard protection schemes provide breaker anti-pumping timers.

(2) Circuit breakers are often equipped with their own anti-pumping devices and the anti-pumping function is duplicated.

Pantograph isolator discrepancy

66. The pantograph isolator discrepancy relay operates in the same manner as breaker pole discrepancy and is used to issue local and remote alarm.

Latching functionality

67. (1) Transformer and reactor protection schemes are equipped with latching functionality that requires manual reset before the circuit breaker is enabled to close which may be by use of a master relay or may be integral with the main protection.

(2) If a master relay is used to fulfil subcode (1) it must be operated by unit protection that

indicates the possibility of internal failure.

System protection requirements (under-frequency load shedding)

68. (1) The actions taken on the power system during an under-frequency condition are set out in CHAPTER 3.

(2) Under-frequency load shedding relays must be installed in the interconnected power system as determined by the system operator in consultation with distributors and end-use customers.

(3) An asset owner must pay for the installation and maintenance of the relays referred to in subcode (2).

(4) The system operator must periodically test under-frequency relays.

(5) Distributors and end-use customers must submit to the system operator a written report of each test referred to in subcode (4) within a month of the test being done and in the format specified in code 196 subcode (2).

(6) The test referred to in subcode (4) must be done by isolating all actual tripping circuits, injecting a frequency to simulate a frequency collapse and checking all related functionality.

System protection requirements (out of step tripping)

69. (1) The purpose for the out-of-step tripping protection is to separate the transmission power system in a situation where a loss of synchronous operation takes place between a generating unit or units and the main power system.

(2) In a situation referred to in subcode(1), system separation is desirable to remedy the situation and once the islanded system is stabilised it can be reconnected to the main system.

(3) The system operator must determine and specify the out-of-step tripping functionality to be installed at selected locations by the transmission company.

System protection requirements (under-voltage load shedding)

70. (1) Under-voltage load shedding protection schemes are used to prevent loss of steady-state stability under conditions of large local shortages of reactive power (voltage collapse). Automatic load shedding tripping of suitable loads is carried out to arrest the slide.

(2) The system operator must determine and specify the under-voltage load shedding functionality to be installed at selected locations by the transmission company.

System protection requirements (sub-synchronous resonance protection)

71. (1) The sub-synchronous resonance condition may arise on a power system where a generating unit is connected to the main power system through long series compensated transmission power system lines.

(2) The potential for unstable interaction is sensitive to system topology and is greater with the higher degree of compensation and larger thermal turbo-generators are employed.

(3) The sub-synchronous resonance condition is addressed either through protection or mitigation and if through –

(a) protection –

(i) a suitable relay must be deployed as part of the turbo-generator protection that will

lead to the generating unit disconnection on detection of the sub-synchronous resonance condition; and

(ii) the protection does not reduce or eliminate the torsional vibration, but rather detects it and acts to remove the condition leading to the resonance; or

(b) mitigation, the mitigation –

(i) acts to reduce or eliminate the resonant condition; and

(ii) is needed only under conditions when it is desirable or essential to continue operation when the transmission power system is at or near a resonant condition.

(4) A new generator must liaise with the transmission company regarding sub-synchronous resonance protection studies.

(5) Least-cost solutions must be determined by the transmission company in accordance with code 99 and implemented by the relevant asset owner.

System protection requirements (protection against near 50 Hz resonance)

72. (1) Due to the length of the transmission power system in Namibia and due to the relatively low load conditions, a near 50 Hz resonance may arise on the transmission power system.

(2) Adequate reactive compensation for purposes of subcode (1) need to be installed on the transmission power system and the influence of the system operator and transmission customers on this near 50 Hz resonance needs to be reduced.

(3) The transmission company must ensure that the near 50 Hz resonance is catered for in any old or new networks.

System protection requirements (protection settings impact on system stability (dynamic stability))

73. Minimum clearance times for protection in distributor or end-use customer networks will be determined on a case-by-case basis in order to ensure dynamic stability of the transmission power system.

Protection system performance monitoring

74. (1) To maintain high level of protection performance and long-term sustainability, the transmission company must monitor protection performance.

(2) Each protection operation must be investigated for its correctness based on available information.

(3) The transmission company must provide a report to transmission customers affected by a protection operation when requested to do so.

Nomenclature

75. All safety terminology must comply with the transmission company operating regulations for high voltage systems.

PART 2
TRANSMISSION POWER SYSTEM PLANNING AND DEVELOPMENT

Transmission power system planning and development

76. (1) Codes 77 to 107 set out the -

(a) technical, design and economic criteria and procedures to be applied by the transmission company in the planning and development of the transmission power system and to be taken into account by transmission customers in the planning and development of their own systems; and

(b) information to be supplied by transmission customers to the transmission company, and information to be supplied by the transmission company to transmission customers.

(2) The development of the transmission power system will arise for a number of reasons including, but not limited to -

(a) a development on a transmission customer system already connected to the transmission power system;

(b) the introduction of a new transmission power system substation or point of connection or the modification of an existing connection between a transmission customer and the transmission power system;

(c) the cumulative effect of a number of the developments referred to in paragraphs (a) and (b) by one or more transmission customers; and

(d) the need to reconfigure, decommission or optimise parts of the existing transmission power system.

(3) The development of the transmission power system as contemplated in subcode (2) may involve work -

(a) at a substation where a plant or apparatus of a transmission customer is connected to the transmission power system;

(b) on transmission power system lines or other facilities which join the substation referred to in paragraph (a) to the remainder of the transmission power system; or

(c) on transmission power system lines, transmission power system substations or other facilities at or between points remote from that substation.

(4) The time required for the planning and development of the transmission power system will depend on -

(a) the type and extent of the necessary reinforcement or extension work;

(b) the need or otherwise for statutory planning consent;

(c) the associated possibility of the need for public participation; and

(d) the degree of complexity in undertaking the new work while maintaining satisfactory security and quality of supply on the existing transmission power system.

Planning process

77. The transmission company must follow a planning process divided into major activities as follows:

(a) needs identification;

(b) formulation of alternative options to meet this need;

(c) studying these options to ensure compliance with agreed technical limits, and justifiable reliability and quality of supply standards;

(d) costing these options on the basis of present-day capital costs and using appropriate net discount rates, establish the net present cost of each option;

(e) determining the preferred option;

(f) building a business case for the preferred option using acceptable justification criteria; and

(g) requesting approval of preferred option and initiating execution.

Identification of need for transmission power system development

78. The transmission company must source relevant data from relevant national planning studies, specific transmission customer information, governmental and transmission customer development plans to establish the needs for transmission power system strengthening.

Forecasting demand

79. (1) The transmission company shall annually produce a maximum demand forecast for the next ten years.

(2) The transmission power system demand forecast must be determined for each point of supply.

(3) Generation and import capacity plans must be used to obtain the annual generation patterns.

(4) To forecast the maximum demand megawatt for each transmission power system substation, the transmission company must -

(a) use distributor and end-use customer load forecasts; and

(b) reconcile final loads with data from various sources.

(5) Load forecasts must be adjusted at various levels, by making use of diversity factors determined from measurements and calculations, to line up with the higher-level data.

(6) All distributors and end-use customers must annually, by end October, supply their ten year ahead load forecast data to the transmission company as detailed in CHAPTER 3.

Technical limits and targets for planning purposes

80. (1) The limits and targets against which proposed options are checked by the transmission company must include technical and statutory limits which must be observed and other targets which indicate that the system is reaching a point where problems may occur.

(2) If technical or statutory limits are not achieved, alternative options shall be evaluated.

(3) If targets are not achieved, some options may be still acceptable as per the investment criteria.

Voltage limits and targets

81. (1) The technical and statutory voltage limits are as set out in Table 1 of Annexure 3.

(2) The standard voltage levels are as set out in Table 1 of Annexure 3.

(3) The target voltages for planning purposes are as set out in Table 3 of Annexure 3.

Other targets for planning purposes

82. The other targets for planning purposes are as set out in codes 83 to 88 inclusive.

Transmission power system lines

83. (1) Thermal ratings of standard transmission power system lines must be determined and updated from time to time.

(2) The thermal ratings must be used as an initial check of line overloading.

(3) If the limits of the thermal ratings are exceeded the situation must be investigated as it may be possible to defer strengthening depending on the actual line and on local conditions.

Transformers

84. (1) Standard transformer ratings must be determined and updated from time to time using IEC specifications.

(2) The permissible overload of a specific transformer depends on load cycle, ambient temperature and other factors.

(3) If target loads are exceeded, the specific situation must be assessed as it may be possible to defer adding extra transformers, depending on the actual transformer and on load conditions.

Series capacitors

85. (1) With the system healthy, the maximum steady state current should not exceed the rated current of the series capacitor.

(2) IEC 143 standards call for cyclic overload capabilities as follows:

(a) 8 hours in a 12-hour period, 1.1 times rated current;

(b) ½ hour in a 6 hour period, 1.35 times rated current; and

(c) 10 minutes in a 2 hour period, 1.5 times rated current.

(3) Despite subcode (2) the transmission company may require an occasional over-current rating of two hours once per year 1.3 times rated current.

(4) The particular rating to be used must match the duration of the contingency with the required overload capability.

(5) Duration of contingency will depend on ability to pick up generation or shed load and the load profile.

(6) If a transmission company intends to install a new series capacitor or modify the size of an existing series capacitor, the transmission company must at its own expense and according to its requirements, arrange for sub synchronous resonance, harmonic and protection coordination studies to be

conducted to ensure that sub synchronous resonance will not be excited in any generating unit.

Shunt reactive compensation

86. (1) Shunt capacitors must be able to operate at 30 percent above their nominal rated current at Un to allow for harmonics and voltages up to Um.

(2) Reactive compensation, whether new or modified, may cause harmonic resonance problems.

(3) A Grid Code participant wishing to install or modify reactive power compensation must at its expense arrange for harmonic resonance studies to be conducted.

(4) If the studies referred to in subcode (3) indicate possible harmonic resonance conditions which could impact on the transmission power system, the Grid Code participant must inform the system operator before proceeding with the installation or modification.

Circuit breakers

87. (1) Normal and fault current ratings for standard switchgear are determined and updated from time to time.

(2) The ratings contemplated in subcode (1) and the following limits specified for circuit breakers must not be exceeded:

(a) Single-phase breaking current, 1.15 times three phase fault current; or

(b) Peak making current, 2.55 times three phase rms fault current.

Secondary automatic reclosing cycle current during single-phase re-closing

88. The secondary automatic reclosing cycle current must not exceed:

(a) 20 amps rms with recovery voltage of 0.4 pu; or

(b) 40 amps rms with recovery voltage of 0.25 pu.

Reliability criteria for planning purposes

89. (1) The security and reliability of the transmission power system should be maintained in the event of the loss of any single element (n-1) of the system such as a generating unit, a transmission circuit, section of busbar, transformer or reactive compensation device.

(2) A transmission power system cannot be made 100% reliable as planned, forced outages of components will occur and multiple outages are always possible, despite having a very low probability of occurrence.

(3) From an economic point of view, optimum reliability is obtained when the cost involved in reducing the load not supplied by one kW is just equal to the value of this unsupplied kW to the economy or to the specific transmission customer involved.

(4) The appropriate degree of reliability depends on the probability of loss of supply and the probable amount of load not supplied when an outage does occur.

(5) The transmission company must formulate long-term plans for expanding or strengthening the transmission power system on the basis of the justifiable redundancy.

Contingency criteria for planning purposes

90. (1) A system meeting the n-1 or n-2 contingency criterion must comply with the limits referred to in code 81.

(2) For contingencies under various loading conditions, it must be assumed that appropriate, normally-used generating unit is in service to meet the load and provide spinning reserve.

(3) The availability of the Ruacana Power Station will be taken into account for all load flow studies.

(4) A generation condition at the Ruacana Power Station will not be one of the base cases used in planning studies.

(5) For the more probable n-1 system contingency, the most unfavourable generation pattern within the limitations referred to in subcodes (1) to (4) must be assumed, while for the less probable n-2 system contingency an average pattern must be used.

(6) More details of load and generation assumptions for load flow studies are set out in code 91.

(7) The generation assumptions for the n-1 and n-2 system contingencies do not affect the final justification to proceed with investments, but merely check that the backbone of the system is still sufficient to meet an n-1 or n-2 contingency.

Integration of power stations

91. When planning the integration of power stations the criteria contemplated in codes 92 to 97 inclusive, apply.

Power stations of less than 1000 MW

92. (1) With all connecting lines healthy, it must be possible to transmit the total output of the power station to the transmission power system for any system load condition.

(2) If the local area depends on the power station for voltage support, connection must be done with a minimum of two lines.

(3) Transient stability must be maintained following a successfully cleared single phase fault where economically justifiable.

(4) If only a single line is used to connect generators in category C2 as defined in the Connection Code, it must be able to be selected to alternative busbars and be able to go on to bypass at each end of the line.

Power stations of more than 1000 MW

93. (1) With one connecting line out of service (n-1) it must be possible to transmit the total output of the power station to the transmission power system for any system load condition

(2) With the two most onerous line outages (n-2) it must be possible to transmit 83% of the total output of the power station to the transmission power system

Fault levels

94. (1) The expansion of the transmission power system will take into account the need to limit fault levels to within the fault current rating of the installed equipment.

(2) A transmission company will conduct fault level calculations for the peak load case to confirm the adequacy of existing switchgear ratings, or specify the ratings of new switchgear.

(3) For fault calculations, the voltages will be set to unity when there is maximum generation in service and transmission companies shall refer to IEC standard 6909.

(4) A transmission company shall determine both three-phase and single-phase fault currents, both of which should be within the rupture capacity of switchgear.

(5) When specifying the ratings of new switchgear and other equipment, a transmission company should consider the impact on fault levels of future transmission power system developments, such as new generation or additional lines or transformers, to ensure as far as practicable that new equipment will be adequately rated for its expected service life.

Transient stability

95. (1) Transient stability must be retained for the following conditions -

(a) a three-phase, line or busbar fault, cleared in normal protection times, with the transmission power system healthy and the most onerous power station loading condition;

(b) a single phase fault cleared in bus trip times, with the transmission power system healthy and the most onerous power station loading condition; or

(c) a single-phase fault, cleared in normal protection times, with any one line out of service and the power station loaded to average availability.

(2) The conditions contemplated in subcode (1) apply only to power stations larger than 1000 MW and for power stations smaller than 1000 MW, the conditions will only apply where it is economically justifiable.

(3) A transmission company bears the cost to ensure transient stability and must recover the costs as per the approved tariff methodology and its schedule of approved tariffs.

(4) Despite subcode (3), a generator bears the cost to ensure transient stability if the optimum solution, as determined by the transmission company, results in generating unit or power station equipment to be installed.

Busbar arrangements

96. Busbar layouts must allow for selection to alternative busbars and the ability to go on to bypass, and not more than 1000 MW of generation must be connected to any bus section, even with one bus section out of service.

Information required

97. To enable the transmission company to successfully integrate new power stations, detailed information is required per generation unit and power station, as contemplated in CHAPTER 6.

Criteria for system investments

98. (1) The planning limits, targets and criteria form the basis for evaluation of the long-term development of the transmission power system.

(2) The transmission company must -

(a) only invest in the transmission power system when the required development meets the approved investment criteria specified in subcode (5), or if the investment is required to

facilitate the connection of a transmission customer's generation or load to the transmission power system and the cost of the investment is recoverable from the transmission customer as a connection charge; and

(b) invest as contemplated in paragraph (a) if the development meets the approved criteria, but the transmission company may agree with affected transmission customers to waiver certain investments.

(3) Any one of the investment criteria set out in subcodes (4) and (5), each applicable under different circumstances, can be applied.

(4) Calculations will assume a typical project life expectancy of 25 years except where otherwise dictated by power station life or project life expectancy.

(5) The following key economic parameters must have a Board approved process of being established:

(a) discount rate;

(b) Cost of unserved energy; and

(c) Other parameters as specified by the Board.

Least economic cost criteria

99. (1) The least economic cost criteria may be used -

(a) when investments are made in terms of improved supply reliability or quality; or

(b) to determine or verify the desired level of system or equipment redundancy.

(2) The least economic cost criteria requires -

(a) the determination of the cost of poor transmission power system services including the cost of interruptions, load shedding, system constraints and poor quality of supply; and

(b) statistical analysis of system outages.

(3) The least-cost investment criterion equation to be satisfied can be expressed as: value of improved quality of supply to transmission customers > cost to the service provider to provide improved quality of supply.

(4) If a project is proposed and pursuant to subcode1(a) a service provider uses the equation in subcode (2), the service provider should not invest in the proposed project if the value of the improved quality of supply to the transmission customer is less than the cost to the service provider to improve the quality of supply.

(5) The equation above can be stated differently as: cost of unserved energy annual value (N$/kWh) x reduction in expected energy not served to transmission consumers (kWh) > annual cost to the service provider to reduce expected energy not served (N$).

(6) For purposes of subcode (4) -

(a) the reduction in expected energy not served is calculated on a probabilistic basis based on the improvements derived from the investments; and

(b) the cost of unserved energy is a function of -

(i) the type of load;

(ii) the duration and frequency of the interruptions;

(iii) the time of the day the interruptions referred to in subparagraph (ii) occur;

(iv) whether notice is given of the impending interruption;

(v) the indirect damage caused;

(vi) the start-up costs incurred by the consumers;

(vii) the availability of transmission customer back-up generation; and

(viii) any other relevant factors.

Cost reduction investments

100. (1) Proposed expenditure which is intended to reduce the costs -

(a) to service providers, of but not limited to -

(i) shunt capacitor installations;

(ii) telecommunication projects and telecommunication replacement equipment which reduce costs; and

(iii) external telephone service expenses and maintenance costs; or

(b) of losses or other ancillary services,

should be evaluated in the manner set out in subcode (2).

(2) For purposes of the evaluation contemplated in subcode (1) -

(a) it is necessary to calculate the net present value of the proposed investment using the discounted cash flow method;

(b) the calculation referred to in paragraph (a) should be done by considering all cost reductions including savings in losses, as positive cash flows off-setting the required capital expenditure;

(c) sensitivity analysis is required with respect to the -

(i) amount of capital expenditure, including estimated contingency amount;

(ii) annual average incremental cost of generation, where appropriate; and

(iii) future load growth scenarios; and

(d) if the calculation under paragraphs (a) and (b) or the sensitivity analysis under paragraph (c) results in a positive net present value, the investment is justified over the expected life of the proposed new transmission power system asset.

Statutory or strategic investments

101. (1) Decisions on statutory or strategic investments need to be taken in order to encourage development in Namibia.

(2) Projects relating to statutory or strategic investments include the following:

(a) investments formally requested by government, including investments that will allow Namibia to become more self-sufficient in electricity supply and issues pertaining to the electrification of Namibia;

(b) increased connection with neighbouring countries and SAPP requirements to allow the electricity industry of Namibian access to other markets;

(c) projects necessary to meet environmental legislation, for example the construction of oil containment dams;

(d) expenditure to satisfy the requirements of the Labour Act, 2007 (Act No. 11 of 2007) and specifically the Regulations relating to Health and Safety of Employees at Work published under Government Notice No. 1617 of 1 August 1997;

(e) possible compulsory contractual commitments; or

(f) servitude acquisition.

(3) Subcode (2)(d) is intended to ensure the safety of operating and maintenance personnel who are exposed to possible danger when busy with activities related to electricity transmission.

(4) Subcode (2) must not be used for justifying projects that are not of economic benefit.

Development investigation reports

102. (1) The transmission company must compile, before any development of the transmission power system is approved, a detailed development investigation report.

(2) The report referred to in subcode (1) must be used as the basis for making the investment decision and must as a minimum contain the following elements:

(a) a description of the problem or request;

(b) alternatives considered, including non-transmission or capital;

(c) an evaluation of the long-term costs or benefits of each alternative contemplated in paragraph (b); and

(d) detailed techno-economic justification of the selected alternative according to the approved investment criteria.

Transmission power system master plan

103. (1) The transmission company must annually publish a five year ahead transmission power system expansion plan, indicating the major capital investments planned and the opportunities for connecting to and using the transmission power system in each year.

(2) The transmission company must base the transmission power system expansion plan contemplated in subcode (1) on -

(a) all transmission customer requests received at the time of planning;

(b) transmission power system load forecasting; and

(c) projects initiated by the transmission company.

Mitigation of system constraints

104. (1) A transmission company must regularly review and resolve transmission power system constraints.

(2) A transmission company must put in place around each constraint economically optimal plans involving investment, the purchase of the constrained generation as an ancillary service or other

solutions.

Interfacing between Grid Code participants

105. A transmission company must ensure regular interfacing with transmission customers, regarding transmission power system development, with the objective to achieve overall optimal plans that ensure economically efficient investment.

Special transmission customer requirements for increased reliability

106. (1) If a transmission customer requires a more reliable connection than the one provided by the transmission company and the transmission customer is willing to pay the total cost of providing the increased reliability, the transmission company must meet the requirements at the lowest overall cost.

(2) The transmission company must include details regarding recovery of direct costs in its connection agreement with its transmission customers, distributors or end-use customers.

Network maintenance

107. (1) A Grid Code participant -

(a) must operate and maintain the equipment owned by the Grid Code participant; and

(b) bears the costs of the operation and maintenance contemplated in paragraph (a) unless the Grid Code participant proves that the equipment referred to in that paragraph was damaged by the negligent act or omission of another Grid Code participant or a Grid Code participant who is not -

(i) the owner of the equipment; or

(ii) an agent or employee of the owner referred to in subparagraph (i),

in which case the Grid Code participant who is responsible for the damage is liable for the costs of repairing the damage.

(2) Grid Code participants must monitor the performance of their plant and take appropriate action where deteriorating trends are detected.

CHAPTER 4
TRANSMISSION POWER SYSTEM OPERATIONS

PART 1
OPERATIONAL RELATIONS, PROCEDURES, PLANNING, CONDITIONS AND CONTROL

Operation of interconnected transmission power system

108. (1) The system operator is responsible for the safe and efficient operation of the interconnected transmission power system.

(2) The system operator must operate the interconnected transmission power system in accordance with the provisions of this code.

(3) All Grid Code participants must co-operate in setting up operational procedures under the direction of the system operator to ensure proper operation of the interconnected transmission power system.

(4) The system operator has ultimate authority and accountability for the operation of the interconnected transmission power system.

(5) SAPP and other international tie-line operations shall be governed by the SAPP and related agreements.

System operator obligations

109. The system operator is responsible for the -

(a) system reliability and safety contemplated in code 112;

(b) system security contemplated in code 113; and

(c) operational measures contemplated in code 114.

System operation states

110. (1) Normal conditions state, where in a normal condition, the interconnected transmission power system is operating within its technical parameters and has sufficient generation reserves, all transmission elements are operating within limits, and voltage and frequency are normal.

(2) In the event of identifying a risk of insecure operation, the system operator, may issue a single contingency warning or an emergency situation warning in real-time.

(3) These warnings shall be issued to all users, to the SAPP coordination centre and any adjacent system which may be affected by the risk.

(4) Any warning issued by the system operator may be applied to the whole or part of the interconnected transmission power system.

(5) The SAPP coordination centre may also issue warnings to parties when in its view there is a serious risk to the whole SAPP interconnected transmission power system.

(6) An abnormal condition -

(a) is where in an abnormal condition, a contingency has occurred but the interconnected transmission power system is stable and all operational reserves for both transmission and generation balance have been committed; and

(b) the system operator may be uncertain as to when the interconnected transmission power system can be returned to its normal condition due to system constraints and or low operating reserves and the situation is potentially dangerous.

(7) An emergency condition is where in an emergency situation, the interconnected transmission power system is in an unstable condition and phenomena such as cascade tripping, low frequency and or voltage, loss of synchronism, loss of supplies, whether partial or total, and islanding may occur and the security of the interconnected power system is endangered.

(8) In the event of subcode (7), exceptional actions such as load shedding may be necessary to limit the spread of the dangerous phenomena and prevent the collapse of part of or the whole interconnected transmission power system.

(9) In such an emergency situation, the interconnected transmission power system passes rapidly towards dangerous conditions of operation with system parameters outside the limits fixed for secure operation.

Transmission power system operation planning

111. (1) The system operator shall have a long-term operations plan for the next three years, a rolling month-ahead plan and a rolling day-ahead plan and in this regard -

(a) the three-year ahead plan shall be updated annually;

(b) the rolling month-ahead plan shall be updated daily;

(c) The day-ahead plan shall be continuously updated to take into account the evolving system operation and grid information.

(2) The models for the operations plans shall be compliant with the requirements set out in code 171.

(3) The models for the operational plans shall be consistent with the models used for planning studies.

Transmission power system reliability and safety

112. (1) The interconnected transmission power system must be operated to achieve the highest degree of reliability practicable and appropriate remedial action must be taken promptly to relieve any abnormal condition that may jeopardise reliable operation.

(2) Power transfers as determined by the energy market or scheduling arrangements, and other transfers as far as feasible, must be adjusted as required to achieve or restore reliable interconnected transmission power system operation.

(3) Voltage control, operating on the interconnected transmission power system and security monitoring must be co-ordinated on a system-wide basis in order to ensure safe, reliable, and economic operation of the interconnected transmission power system.

(4) During or after a transmission power system disturbance high priority must be given to keeping all synchronized generating units -

(a) running and connected to the interconnected power system; or

(b) islanded on their own auxiliaries, in order to facilitate system restoration.

(5) Black start services must be provided as available from generating units.

(6) The system operator must make all reasonable endeavours to retain international interconnections unless it becomes evident that continued parallel operation of the affected parts of the

interconnected transmission power system would jeopardise the remaining part of system or damage equipment.

(7) Should it become unsafe to operate generating units in parallel with the interconnected transmission power system when critical levels of frequency and voltage result on the interconnected transmission power system from a disturbance, the separation or safe shut down of generating units must be done in such a way as to minimize the time required to resynchronise and restore the system to normal.

(8) In the event of an interconnected transmission power system separation the system operator must ensure that the part of the interconnected transmission power system with a generation deficit must automatically remove sufficient load to permit early recovery of voltage and frequency so that system integrity may be re-established.

(9) Transmission customer load must be shed for a reasonable period of time rather than risking the possibility of a cascading failure or operating at abnormally low frequency or voltage for an extended period of time.

(10) A system operator of an interconnected transmission power system in SAPP may request that the Namibian system operator takes any available action to increase or decrease the active power transfer into or out of the Namibian power system by the way of emergency assistance.

Transmission power system security

113. (1) The interconnected transmission power system must be operated as far as practical so that instability, uncontrolled separation or cascading outages do not occur as a result of the most severe double contingency.

(2) Multiple outages of a credible nature must be examined and whenever practical the interconnected transmission power system must be operated to protect the interconnected transmission power system against instability, uncontrolled separation and cascading outages.

(3) The system operator is responsible for efficient restoration of the transmission power system after supply interruptions.

(4) The system operator must operate and maintain primary and emergency control centres and facilities to ensure continuous operation of the interconnected transmission power system.

Operational measures

114. (1) Operating instructions, procedures, standards and guidelines must be established to cover the operation of the interconnected transmission power system under all system conditions.

(2) The interconnected transmission power system must be operated within defined technical standards and equipment ratings.

(3) The system operator shall be control area or be a part of a control area and if the system operator is a control area it shall abide by the SADC regional grid code and SAPP rules for a control area.

(4) The system operator must manage constraints on the transmission power system through the determination of operational limits and the purchase of the constrained generation as an ancillary service.

(5) To achieve a high degree of service reliability, the system operator must ensure adequate and reliable communications between all control centres, power stations and substations.

(6) Communication facilities to be provided and maintained by transmission customers are specified in code183.

(7) The system operator is responsible for the determination of the transmission power system protection philosophy, as contrasted to equipment protection, by means of applicable analytical studies.

(8) The system operator must determine, and review on a regular basis, relay settings for main and back-up protection on the interconnected transmission power system.

Scheduling of generation and ancillary services

115. (1) The system operator must provide a day-ahead demand forecast for the interconnected transmission power system to the MSB market operator.

(2) The MSB market operator must provide the interconnected transmission power system operator with the daily 24 hours day-ahead energy schedule from 16:00 CAT each day.

(3) Should a deviation exist between the scheduled and actual load conditions the system operator is responsible for taking remedial action.

(4) A system operator is responsible for executing the energy schedule.

(5) A market operator is responsible for scheduling ancillary services in the energy market.

(6) A system operator is responsible for executing ancillary services.

(7) Rescheduling of generation and ancillary services during unplanned events must be undertaken by the system operator in real-time on the basis of rules provided by the market operator.

Ancillary services

116. (1) The system operator is responsible for the technical specification and execution of all short term reliability services for the interconnected transmission power system.

(2) The short-term reliability services referred to in subcode (1) include -

(a) restoration;

(b) the balancing of supply and demand;

(c) the provision of quality voltages; and

(d) the management of the real-time technical risk.

(3) Suitable ancillary service levels for the following year must be calculated annually.

(4) Reliability targets must be selected to minimise the sum of the cost to the transmission company of providing the reliability plus the cost to the transmission customer of limited reliability.

(5) The system operator is responsible for procuring the required ancillary services that are economically efficient and needed to provide the required reliability.

(6) The acquisition of ancillary services must take place on a non-discriminatory basis.

Operating reserves

117. (1) Operating reserves are required to secure capacity that will be available for reliable and secure balancing of supply and demand.

(2) Operating reserves consist of the following:

(a) Instantaneous reserve;

(b) Regulating reserve (control area requirement only);

(c) Ten-minute reserve;

(d) Fast frequency reserve; and

(e) Supplemental reserve.

(3) Ancillary services can be procured from other system operators and control areas, where there is sufficient transmission capacity to allow activation of the ancillary service.

Operating reserve requirements

118. (1) The system operator is responsible for the technical specification and execution of all short-term reliability services for the interconnected transmission power system.

(2) The system operator shall operate its active power resources to ensure a level of operating reserve sufficient to account for such considerations as errors in forecasting, generation or transmission equipment unavailability, loss of generating units, forced outages, maintenance schedules, variable renewable energy intermittency, inertia requirements, regulating requirements and load diversity between system operators and control areas.

Instantaneous reserve (IR)

119. (1) Instantaneous reserve is the automatic response by synchronised generating units to a rise or fall in the frequency of the synchronous area requiring changes in the generating unit's active power output, to restore the frequency to within operational limits.

(2) Demand side also participates in instantaneous reserve through the self-regulating effect of frequency-sensitive loads such as induction motors or the action of under frequency relays that disconnect some demand at given frequency thresholds.

(3) The minimum technical requirements for instantaneous reserve are:

(a) the maximum dead band for providers of instantaneous reserve shall be 0.15Hz and in this regard no response is required between 49.85 Hz and 50.15 Hz;

(b) the real power response to a change in transmission power system frequency shall be fully available within 10 seconds of the frequency change and be sustainable for a further 10 minutes;

(c) instantaneous reserve shall be fully activated with a frequency deviation of 0.1 Hz from the allowable dead band.

(4) The minimum contribution required for the system operator as initial instantaneous reserve shall be determined by SAPP.

(5) The system operator can provide additional instantaneous reserve, as long as, the provision of the additional reserve is not detrimental to the synchronous area.

Regulation reserve

120. (1) If the system operator is a control area, then the system operator shall have sufficient regulation reserve (generating units on AGC) to meet the control area requirements in section OC5.1 of the SADC regional grid code.

(2) Regulating reserve is reserve that is under AGC and can respond within 10 seconds and be fully active within 10 minutes of activation, this reserve is used for second-by-second balancing of supply and demand and regulating reserve is also used to restore instantaneous reserve within 10 minutes of the disturbance.

(3) The control areas shall meet the performance standards in section OC7.4 of the SADC regional grid code.

10-minute reserve

121. (1) 10-minute reserve is required to balance supply and demand for changes in real time requirements (for example, due to load forecast errors and unit unreliability).

(2) 10-minute reserve shall be fully activated, on request, within 10 minutes and must be sustainable for two hours.

(3) 10-minute reserve shall be activated to restore instantaneous reserve and regulating reserve following a disturbance within 10 minutes of the disturbance.

(4) The system operator shall meet the performance standards in section OC7.5 of the SADC regional grid code.

Fast frequency reserve

122. (1) Fast frequency reserve shall be the combination of system inertia provided automatically by synchronously connected generating units and the response of fast frequency reserve Grid Code participants to a change in frequency in the first one second to reduce the rate of change of frequency and sustained for at least 10 seconds to allow the full activation of instantaneous reserve.

(2) Fast frequency reserve shall be sufficient to ensure the rate of change of frequency is maintained below the limits specified in SADC regional grid code section OC5.7 for at least the loss of the largest power station in SAPP or import in the synchronous area.

(3) The system operator shall coordinate with all system operators of the synchronous area to determine the fast frequency reserve requirements for the synchronous area and the minimum share of fast frequency reserve to be provided by the system operator to meet the rate of change of frequency requirements specified in SADC regional grid code section OC5.7.

Supplemental reserve

123. (1) Supplemental reserve is required to cater for the uncertainty in generation availability, renewable energy capacity and demand forecasts.

(2) Supplemental reserve can be obtained from both generation and demand resources.

(3) The system operator shall ensure they have sufficient supplemental reserves to balance the transmission power system they are responsible for and to maintain system security for the remainder of the day.

Black start and islanding

124. (1) Islanded generating units must be capable of running in the islanded state for at least 2 hours and of re-connecting to the transmission power system.

(2) Generating units capable of islanding must -

(a) offer such ancillary service to the system operator; and

(b) be certified by the system operator and entitled to payment for these ancillary service referred to in paragraph (a).

(3) To ensure optimal operation of the interconnected transmission power system, the system operator may deploy network islanding schemes on the system, including an out-of-step tripping scheme.

(4) The system operator shall have two reliable sources of black start which are capable restoring the transmission power system.

(5) The system operator must determine the minimum requirements for each black start supplier and ensure that the contracted suppliers are capable of providing this ancillary service.

(6) Black start ancillary services facilities shall be tested every 5 years unless these facilities were used for an actual system restoration within the last 7 years and these tests shall include, where possible, the restoration of some portion of load and the starting of another power station.

(7) Where a physical test contemplated in subcode (6) is not possible, then simulation tests should be performed to demonstrate the black start and system restoration capability.

Reactive power compensation and voltage control from generation units

125. (1) Voltage control and the supply or consumption of reactive power is inter- related in the sense that the voltage is affected by changes in the reactive power flow.

(2) System stability depends on the voltage profile across the system.

(3) In view of subcodes (125 and (2), it is necessary from time to time to employ certain generating units to supply or consume reactive power whether or not they are producing active power, for the purpose of voltage control.

(4) In the case of subcode (3), the generation unit must be able to provide reactive power without having to produce or consume a large quantity of real power.

(5) The amount of reactive power must be controlled by the system operator through the energy management system or by telephone.

(6) When a generation unit is generating or pumping in the case of a pump storage unit, reactive power supply is mandatory in the full operating range as specified in code 20 of the Connection Code.

Near 50 Hz resonance control service

126. (1) Some power stations may be required to run in synchronous condenser mode in order to add fault level to the transmission power system to mainly assist with the shifting of the near 50Hz resonance in the Namibian power network upwards from 50Hz.

(2) The near 50Hz resonance control service is an additional risk mitigation option for the Auas Static VAR Compensator.

(3) Generators are rewarded financially for the supply of a near 50Hz resonance control service as an ancillary service.

Operational authority

127. (1) The system operator has operational authority over the transmission power system.

(2) Operational authority for other systems lies with the respective asset owners.

(3) Normal control of the various networks must be in accordance with the operating procedures agreed between the Grid Code participants.

(4) Unless otherwise provided in this Code, a Grid Code participant may not be permitted to operate the equipment of another Grid Code participant without the permission of that other Grid Code participant.

(5) Before a Grid Code participant is permitted to operate the equipment of another Grid Code

participant the asset owner has the right to test and authorise the operating staff in accordance with its own standards before the permission is granted.

(6) Despite subcode (1), Grid Code participants retain the right to safeguard the safety of their equipment.

Operating procedures

128. (1) The system operator must develop and maintain operating procedures for -

(a) the safe operating of the transmission power system; and

(b) assets connected to the transmission power system.

(2) The operating procedures referred to in subcode (1) must be adhered to by Grid Code participants when operating equipment on the transmission power system or connected to the transmission power system.

(3) Each transmission connected customer is responsible for its own safety rules and procedures.

(4) The system operator must ensure the compatibility with regard to the safety rules and procedures of all Grid Code participants but if a dispute affecting the interpretation or application of safety rules and procedures should arise, the dispute must be resolved in accordance with the procedures specified by the system operator.

(5) The SAPP operating agreements and the SADC regional grid code apply in the case of operational liaison with all international power systems connected to the transmission power system.

Operational liaison, permission for synchronisation

129. (1) The system operator must sanction the switching, including shutting down and synchronising, of generating units and changing over of auxiliaries on all generating units.

(2) If a Grid Code participant experiences an emergency, the other Grid Code participants must assist to an extent as may be necessary to ensure that the emergency does not jeopardise the operation of electricity systems or power stations.

(3) A transmission customer must enter into an operating agreement with the system operator if it is physically possible to transfer load or embedded power stations from one point of supply to another by performing switching operations on the electricity system of the transmission customer.

(4) The operating agreement under subcode (3) must cover at least the operational communication and notice period requirements and switching procedures for load transfers.

Emergency or contingency planning

130. (1) The system operator must develop and maintain contingency plans to manage transmission power system contingencies and emergencies that are relevant to the performance of the interconnected transmission power system.

(2) The contingency plans under subcode (1) must -

(a) be developed in consultation with all Grid Code participants;

(b) be consistent with internationally acceptable utility practices; and

(c) include -

(i) under-frequency load shedding;

(ii) meeting disaster management requirements including the necessary minimum load requirements;

(iii) forced outages at all points of interface; and

(iv) supply restoration.

(3) Emergency plans must allow for quick and orderly recovery from a partial or complete transmission power system collapse, with minimum impact on transmission customers.

(4) Emergency plans must comply with SAPP agreements and the SADC regional grid code.

(5) All contingency or emergency plans must be periodically verified by actual tests to the greatest practical extent, as agreed by the Grid Code participants, without causing undue risk or undue cost.

(6) The costs of the tests referred to in subcode (5) must be borne by the respective asset owners.

(7) The system operator, in consultation with all affected Grid Code participants, must ensure the coordination of the tests referred to in subcode (5).

(8) The system operator must specify minimum emergency requirements for distributor control centres, power station local control centres and substations to ensure continuous operation of their control, recording, enunciator and communication facilities.

(9) Other Grid Code participants must comply with the requirements of the system operator for contingency or emergency plans.

(10) Automatic and manual load shedding schemes must be made available under the direction of the system operator.

(11) The system operator must be responsible for determining all operational limits on the transmission power system by means of the applicable analytical studies.

(12) Load flow studies must be conducted regularly to determine the effect that various component failures would have on the reliability of the interconnected transmission power system.

(13) At the request of the system operator, distributors must perform related load flow studies on their part of the distribution power system and make the results available to the system operator.

Transmission power system frequency and area control error control under abnormal frequency or imbalance conditions

131. The system operator is responsible for the balancing of supply and demand in real time through the implementation of the energy schedules and utilisation of ancillary services.

Description of normal frequency or balancing conditions

132. (1) The control area is considered to be under normal frequency conditions when -

(a) the immediate demand can be met with the available scheduled resources, including any expensive contingency resources;

(b) the SAPP control performance criteria are not consecutively violated;

(c) the frequency is within the range 49,5 to 50,5 Hz;

(d) the interconnection is intact; and

(e) there are no security and safety issues.

(2) The control area is considered to be under abnormal conditions if it is not in a normal condition as contemplated in subcode (1).

Operation during abnormal conditions

133. (1) When abnormal conditions occur, corrective action must be taken by the control area with assistance from the system operator until the abnormal condition is corrected.

(2) The corrective action referred to in subcode (1) includes both supply-side and demand-side options.

(3) Where possible, warnings must be issued by the system operator on expected utilisation of any contingency resources.

(4) The system operator must have a designated person to refer to in periods of abnormal operation, particularly during emergencies.

(5) The order in which emergency resources are to be used may change from time to time.

(6) An updated list must be issued by the system operator.

(7) Termination of the use of emergency resources must occur as the power station shortage situation improves and after frequency has returned to normal.

(8) Automatic under-frequency systems must be kept armed at all times.

Independent action by Grid Code participants

134. (1) Each Grid Code participant must have the right to reduce or disconnect a point of connection under emergency conditions if it is necessary for the protection of life or equipment.

(2) If a Grid Code participant considers it necessary to reduce or disconnect a point of connection as contemplated in subcode (1) the Grid Code participant must give advance notice of the intended reduction or disconnection where possible and no financial penalties apply.

(3) During emergencies that require load shedding, the request to shed load must be initiated in accordance with agreed procedures.

(4) Following emergency operations necessary to protect the integrity of the interconnected transmission power system or the safety of equipment and human life, the Grid Code participants must work diligently towards removing the cause of the emergency and the supply must be reconnected immediately after the emergency conditions have passed.

Voltage control

135. (1) The system operator is responsible for the voltage control of the transmission power system, at transmission level voltages as well as at the interface between the transmission company and its transmission customers.

(2) Electricity must be supplied at three phase alternating current which must have a nominal voltage between phases and range, at the points of supply, as agreed between the Grid Code participants.

(3) Transmission power system voltages must be controlled during normal operation to be at least within statutory limits at the points of supply.

Fault reporting and analysis or incident investigation

136. (1) The generators of category C power stations as defined in the Connection Code must report loss of output and tripping of generating units and governing to the system operator within 15 minutes of the event occurring.

(2) Distributors and end-use customers must –

(a) report the loss of major loads (>5MVA) to the system operator within 15 minutes of the event occurring; and

(b) give warning of the reconnection of the loads referred to in paragraph (a) with at least 15 minutes advance notice.

(3) Incidents on the interconnected transmission power system involving sabotage or suspected sabotage, as well as threats of sabotage must be reported to the system operator.

(4) Interruptions of supply, disconnections, under or over voltage incidents, quality of supply contraventions or any incident that materially affected the quality of the service to another Grid Code participant must be formally investigated.

(5) A preliminary incident report must be available after three working days and a final report within three months.

(6) The system operator must -

(a) initiate the investigation contemplated in subcode (4);

(b) arrange for the writing of the report; and

(c) involve all affected Grid Code participants.

(7) The Grid Code participants referred to in subcode (6)(c) must make all relevant required information available to the system operator.

(8) A major incident must have the following additional requirements:

(a) any Grid Code participant must have a right to request an independent audit of the report, at its own cost, if they are not satisfied with it; and

(b) recommendations must be implemented by the Grid Code participants within the time frames specified.

(9) Incidents must also be reported to the Board as defined in the licence conditions.

(10) The system operator is responsible for developing and maintaining an adequate system of fault statistics.

Commissioning

137. (1) The system operator must verify commissioning or maintenance programmes concerning operating at major substations as far as is needed to ensure adequate co-ordination and reliability of the interconnected transmission power system.

(2) All aspects of commissioning, by transmission customers, of new equipment associated with the transmission connection, or re-commissioning of such existing equipment, must be agreed with the system operator in writing before such commissioning starts.

(3) The aspects referred to in subcode (2) include, but are not be limited to the following:

(a) commissioning procedures and programmes;

(b) documents and drawings required;

(c) proof of compliance with standards;

(d) documentary proof of the completion of all required tests;

(e) SCADA information to be available and tested before commissioning; and

(f) site responsibilities and authorities.

(4) A minimum notice period of one month applies from the date of receipt of the request for all commissioning or re-commissioning.

(5) When commissioning equipment at the connection point, the transmission company must liaise with the affected transmission customers on all aspects that could potentially affect the operation of these transmission customers.

(6) The transmission company and transmission customers must perform all commissioning tests required in order to confirm that the transmission company and the plant and equipment of transmission customers meets all the requirements of the Transmission Grid Code before going on-line.

(7) Where commissioning is likely to involve a requirement for dispatch or operating for test purposes, the transmission customer must, as soon as possible, notify the system operator of the requirement including reasonable details as to the duration and type of testing required.

Risk of trip

138. (1) Generators must identify and report all tripping risks to the system operator.

(2) Grid Code participants must minimise the risk of tripping or loss of output on their own plant and equipment, associated with their operation and maintenance.

(3) Special care must be taken by Grid Code participants when planning or executing work on protection panels.

(4) The normal outage process set out in code 139 must be followed.

(5) The work referred to in subcode (3) must be treated as risk-related outages by the system operator.

(6) When a risk of trip of equipment or loss of output with an impact exceeding 5 MW could occur on any part of the interconnected transmission power system, owing to an operation or maintenance contemplated in subcode (2) and (3), the affected Grid Code participants must be consulted as to who must accept the risk before work may commence.

(7) The system operator must always be informed of the operations and maintenance contemplated in subcode (2) and must in general coordinate the information and accept the risks.

(8) The affected Grid Code participants must be informed when the risk has been removed.

PART 2
MAINTENANCE COORDINATION OR OUTAGE PLANNING AND TELE-CONTROL

Maintenance coordination or outage planning

139. (1) Optimal reliability of the interconnected transmission power system must be achieved by co-ordinating scheduled outages of generation, the transmission company, distributor, end-use customer, metering, communication and control facilities affecting interconnected transmission power system operation.

(2) The maintenance coordination or outage planning must be done in collaboration with relevant Grid Code participants and any other relevant stakeholders.

Roles and responsibilities of outage requester

140. (1) An outage requester must be a formally nominated employee or agent of a distributor, generator, end-use customer or a transmission company.

(2) The responsibilities of an outage requester are to request an outage on a generating unit/s -

(a) for planned maintenance, repairs, auditing, emergency repairs, construction, refurbishment, inspection, testing; or

(b) to provide safety clearance for other activities such as servitude clearance, line crossings and underpasses.

Roles and responsibilities of transmission company outage scheduler

141. (1) The transmission company outage scheduler must check for multiple requests for an outage of the same portion of the network.

(2) If the transmission company outage scheduler notices -

(a) another outage request for the same bay, the transmission company outage scheduler must request the parties involved to combine their requests into a single outage; or

(b) conflicting outages, the transmission company outage scheduler must consider the priority and relative urgency of the requests and reflect the consideration against the validated request.

(3) The transmission company outage scheduler is responsible for ensuring that negotiations of risk-related outages have taken place.

Roles and responsibilities of system operator outage scheduler

142. (1) The system operator outage scheduler is appointed to assess the viability of a scheduled outage request and to confirm or turn down the request.

(2) The system operator outage scheduler must optimise plant utilisation by evaluating network load capabilities, different system configurations and risk factors.

(3) It is also the responsibility of the system operator outage scheduler to co-ordinate and schedule power stations that affects international transmission customers.

Outage process

143. (1) The system operator controller on shift at the time of the outage is responsible for finally sanctioning or alternatively refusing the outage and ensuring that the relevant operating instructions are issued.

(2) The system operator must develop and maintain an electronic transmission maintenance scheduling system for the coordination of all transmission power system outages.

(3) The transmission company must inform all transmission customers of the name and contact details of the respective transmission company outage schedulers in the different geographic parts of the Namibia.

(4) The system operator must make available to transmission customers an outage schedule of all planned outages on the transmission power system.

(5) The outage schedule referred to in subcode (4) must cover a period of one year rolling and must indicate whether the status of the outage is confirmed or not.

(6) When the need for an outage is first identified and -

(a) the outage requester has access to the transmission maintenance scheduling system, the outage requester must enter the outage into the transmission maintenance scheduling system referred to in subcode (2) as a requested outage with planned outage dates, times, reason, type of maintenance and request urgency assigned to it; or

(b) the outage requester does not have access to the transmission maintenance scheduling system, the outage requester must contact the relevant transmission company outage scheduler or the system operator outage scheduler to enter the outage as contemplated in paragraph (a).

(7) When the transmission company outage scheduler is satisfied with the request referred to in subcode (6)(b) and, in the case of a calculated risk, has ensured that negotiation has taken place with the relevant Grid Code participants the scheduler must mark the outage as a scheduled outage.

(8) When the outage is marked as contemplated in subcode (7), the system operator outage scheduler must confirm the scheduled outage if the scheduled outage satisfies all the necessary requirements.

(9) If the scheduled outage is confirmed as contemplated in subcode (7), the transmission company outage scheduler must change the request referred to in subcode (6)(b) to a confirmed booking in the transmission maintenance scheduling system referred to in subcode (2).

(10) If the confirmed booking referred to in subcode (8) is subject to the outcome of another booking, the confirmed booking under subcode (8) must reflect that it is linked to another booking.

(11) If the request referred to in subcode (6)(b) cannot be accommodated, it must be marked as refused, with a reason or an alternative suggestion, in the transmission maintenance scheduling system referred to in subcode (2).

(12) When it is time for the confirmed booking referred to in subcode (8) to be executed or the outage becomes effective, the status must be changed or taken by the system operator controller who is on shift if sanctioning the outage.

(13) While an outage is in progress the responsible Grid Code participants may report the actual state of the progress to the system operator controller who is on shift, who must enter the actual state into the transmission maintenance scheduling system referred to in subcode (2) so that the progress of the outage may be monitored by the outage requester and other Grid Code participants who may be affected by the requested outage.

(14) When the outage is completed and power is restored, the system operator shift controller must change the status of the outage to complete.

(15) When an outage is cancelled it is the responsibility of the person cancelling the outage to furnish the reasons for the cancellation to the system operator.

(16) The system receiving the cancellation contemplated in subcode (14) must enter the cancellation into the transmission maintenance scheduling system referred to in subcode (2) and change the status to cancelled.

(17) Subcodes (14) and (15) also apply to outages that are postponed.

Risk-related outages

144. (1) All risk-related outages must be scheduled a minimum of 14 days in advance with an executable contingency plan in place.

(2) The compilation of the contingency plan referred to in subcode (1) is the responsibility of the relevant transmission company.

(3) The contingency plan referred to in subcode (1) -

(a) is, in some cases, of a permanent nature and in force every time the same transmission power system conditions occur; and

(b) may only be prepared once and comes into force again, with minimal changes if needed, when the same outage is scheduled.

(4) The contingency plan referred to in subcode (144 consists of the following five parts:

(a) security linking prior to the outage, to ensure minimal risk to transmission customers;

(b) returning the plant that is on outage back to service as soon as possible;

(c) restoring supply to transmission customers by utilising by-pass schemes;

(d) load shedding if necessary and load profiles must be made available by the transmission customer; and

(e) list of contact persons.

(5) When a transmission company compiles a contingency plan in accordance with this code –

(a) the system operator is responsible for identifying risk-related outages;

(b) the system operator and transmission customer control centres are responsible for the security linking contemplated in subcode (4)(a);

(c) the transmission company is responsible for supplying the information relating to returning the plant to service;

(d) the transmission company must develop by-pass schemes with assistance from the system operator and the transmission customer control centres; and

(e) the system operator and transmission customer control centres are responsible for identifying the load at risk and load shedding in the contingency plan.

(6) If the contingency plan referred to in subcode (1)indicates that load shedding must take place, the contingency plan must include -

(a) the total amount of load to be shed in relation to the load profile; and

(b) the point at which load of transmission customers must be shed for optimal results.

(7) The transmission customer control centre must confirm that it is possible to execute the contingency plan successfully.

(8) The outage scheduler must contact the control centre a day prior to the outage to ensure that the control centre is in possession and aware of the contingency plan.

(9) Negotiation of all risk-related outages must take place with affected transmission customers a minimum of 14 days prior to the outage being executed unless otherwise agreed.

(10) Where a request for a risk related outage comes from a generator with a requirement for 28 days prior notice of the risk related outage, the time period must be complied with by the parties.

(11) The service provider must involve transmission customers in the planning phase of projects and -

(a) outages that will affect them;

(b) subcodes (1) to (11) apply also to all outages affecting international transmission customers.

(12) The transmission company must give distributors and end-use customers at least 14 days prior notice of planned interruptions.

Maintenance planning between transmission company and generators

145. (1) Each generator must provide the system operator with the following documents in the pro-forma format set out in ANNEXURE 10 to enable the system operator to execute short-term power system reliability inclusive of -

(a) a 52 weeks-ahead outage plan per power station, showing planned outage and return dates and other known generation constraints, updated weekly by 15:00 every Monday or the first working day of the week;

(b) an annual maintenance or outage plan per power station, for five years ahead, showing planned outage and return dates and other known generation constraints, and issued by 31 December of each year; or

(c) a monthly variance report, explaining the differences between the plan contemplated in paragraph (a) or (b).

(2) Each generator must invite the transmission company to provide inputs into the compiling of the annual maintenance or outage plan referred to in subcode 145(b), on the basis of ensuring system reliability, and must not unreasonably reject the inputs.

(3) If a generator rejects the inputs contemplated in subcode (2) the generator must substantiate the rejection as reasonable by providing the transmission company with documentary proof of the reasons for the rejection.

(4) Power station versus system risks must be carefully weighed up by the affected Grid Code participants under all circumstances.

(5) Joint risk assessments must be undertaken and joint contingency plans under these outage conditions must be prepared by the affected Grid Code participants.

(6) Each generator must ensure the absolute minimum deviation from its annual outage plan and each deviation must be negotiated with the system operator.

(7) The system operator must coordinate system outages affecting generating unit output with related generating unit outages to the maximum possible extent.

(8) The objectives to be used by the system operator in this maintenance coordination -

(a) maintaining adequate reserve levels at all times;

(b) ensuring reliability where transmission power system constraints exist; and

(c) maintaining acceptable and consistent real-time technical risk levels.

Refusal or cancellation of outages

146. (1) A Grid Code participant may not unreasonably refuse or cancel a confirmed outage.

(2) If a Grid Code participant unreasonably refuses or cancels a confirmed outage the Grid Code participant is liable for the risks associated with that refusal or cancellation.

(3) In the case of the system operator cancelling the request owing to system conditions, the outage requester must bear the cost of such cancellation.

Communication of system conditions, operational information and interconnected power system performance

147. (1) The system operator must -

(a) determine system conditions; and

(b) communicate the system conditions determined under paragraph (a) to all Grid Code participants.

(2) The system conditions contemplated in subcode (1)147(a) are –

(a) Based on a steady state and dynamic simulation of the interconnected transmission power system; and

(b) include measures that will enhance reliability.

(3) The system operator must provide Grid Code participants with operational information as may be agreed from time to time and as contemplated in CHAPTER 6.

(4) The operational information under subcode (3) includes information regarding planned and forced outages on the interconnected transmission power system as determined by the market rules.

(5) The system operator must report on both technical and energy aspects of interconnected transmission power system performance monthly and annually.

(6) The reporting pursuant to subcode (5) includes information on daily demands, energies, losses, interruptions and codes 195, 196, 197 and 198.

(7) The system operator must, on request by a Grid Code participant, make available the information contemplated in subcode (6).

Tele-control

148. Where tele-control facilities are shared between Grid Code participants, operating procedures must be agreed.

Telecommunications

149. (1) The system operator shall be equipped with adequate and reliable telecommunication facilities internally and with other system operators and control area operators to ensure the exchange of information necessary to maintain the reliability of the interconnected transmission power system and when possible, redundant facilities using alternative routes and medium, shall be provided.

(2) Dedicated telecommunication channels shall be provided between a control centre and the control centre of each adjacent electricity system.

(3) All dedicated telecommunication channels should not require intermediate switching to establish communication.

(4) Alternate and physically independent telecommunication channels should be provided for emergency use to back up the circuits used for critical data and voice communications.

(5) Restoration services on critical telecommunications channels should be available 24 hours per day, every day of the year.

(6) Each control centre should be able to take control of any telecommunication channel for system controller use when necessary.

(7) The system shall have inter-control center communications protocol running over internet

protocol connection to the SAPP coordination centre.

(8) All telecommunications shall meet the cyber security requirements as defined in code201.

PART 3
TRANSMISSION POWER SYSTEM CONTROL PERSONNEL AND CONTROLLER TRAINING

Authority and responsibility

150. (1) Each system controller shall be delegated sufficient status and authority by the system operator to take any action necessary to ensure that the interconnected transmission power system is operated in a stable and reliable manner.

(2) The system operator shall provide to the system controllers a clear definition of their authority and responsibilities.

(3) System controllers shall be empowered to conduct real time trading.

Qualifications of the system controller

151. (1) Personnel selected as system controllers shall be capable of directing other operating personnel in their own system, and, at the same time, working efficiently with their counterparts in other control centres.

(2) A system controller shall have:

(a) a high level of intellectual ability and above-average reasoning capability especially when under stress;

(b) reasonable mechanical, electrical and mathematical aptitudes, communication, supervision and decision-making skills;

(c) field experience related to protection systems, field power system operations and power generation systems.

(3) System controllers shall also be proficient in the procedural activities necessary for smooth management of the control centre.

Training requirements of the system controller

152. (1) The system operator shall train the system controller in accordance with SAPP guidelines and procedures.

(2) The system operator shall ensure the appropriate qualification of the personnel to cope with any kind of unforeseen events and emergency situation within the interconnected transmission power system.

(3) The training of system operators is based on the system operator operating procedures.

(4) Such training must include feedback about the quality of these procedures and the skills of the system controllers, especially in case of procedures in real time operation that are not frequently used.

Training programmes of the system controller

153. (1) The system operator shall provide system controllers with a structured training programme that is designed to develop and improve their skills.

(2) The training has to be permanently adapted to the evolution of system operational conditions and all the issues addressed by the training have to be regularly checked and updated.

(3) A training programme is a planned, organized sequence of activities designed to prepare individuals and teams to perform their jobs and to maintain or improve their performance on the job.

(4) The training programme consists of an initial programme and a continuous programme and organizes the training process based on the qualifications to be awarded (such as selection, activities, training requirements,).

(5) The initial programme is an important stage of the general structured basic training of operating personnel with respect to the critical contribution of their role to the safe and reliable operation of transmission power system.

(6) The aim of the initial programme is to prepare personnel to take the system controller position and must provide an adequate necessary level of professional knowledge in order to obtain the required qualifications.

(7) The main aim of the continuous programme is to keep and extend the system controllers knowledge and competences.

(8) On-the-job training is the integration of previously acquired knowledge related to routines and skills in practice under the supervision of a qualified on-the-job instructor in a live system situation.

(9) The initial and continuous programmes have to consider the relevant parts of the interconnected transmission power system and mutual agreements between system operators.

(10) The system operator is required to define specific requirements for the initial programme and the continuous programme and their duration.

(11) The system controllers in contact with adjacent system operators shall have sufficient knowledge of English and operations technical terms to carry out their tasks and being immediately understood, ensuring the safe and smooth flow of information in an international environment.

(12) The above knowledge shall provide the system controller with the ability to produce clear messages in unusual situations including the ability to communicate in plain language even under stress.

(13) The system operator shall make available a reference list of operations technical terms in English with translation to the first language of system controllers for operation and for training and this reference list shall be based on the SADC regional grid code definitions and glossary.

Initial system controller training programme

154. (1) The initial programme shall last at least six months for trainees without any experience in power system operation, either in real time or in operational planning, including a minimum of three months for on-the-job and simulator training.

(2) The initial programme shall include at least knowledge of components of the power system, the operation of the power system, the tools for operation at the control centre and relevant on-the-job practice.

(3) The initial programme consists of a theoretical part and an on-the-job part complemented by simulator sessions.

(4) A prerequisite to the initial training programme shall be the successful completion of relevant system operator’s safety code.

(5) The structure of the theoretical part of the initial programme shall provide a first level of competencies on the following main topic categories of power system components, operation of the transmission power system and knowledge of operational tools:

(a) transmission power system components shall include a general description and analysis of all system components including national and international technical specifications, as follows:

(i) types of overhead lines, underground and submarine cables with their components;

(ii) different types of HV and EHV substations, HVDC converters, with their entire components as types of breakers, isolator-ground switches, power transformers, measurement-protection transformers, tap changers, reactors, capacitors, phase shifter transformers, other electronic regulators (such SVCs and FACTS), telecommunication systems, protection relays and other auxiliaries;

(iii) types of power stations (fossil fuel, nuclear, oil, gas turbine, combined cycle gas turbine, hydro, wind, renewable sources and the like) and their components such as turbines and generators with respect to their operational characteristics such as response times;

(b) operation of the transmission power system shall include all relevant domestic and international regulations and market rules as well as the knowledge and analysis of the necessary conditions for safe and reliable operation (such as under normal, emergency situation, blackout and restoration conditions) and this category may include courses on the following aspects:

(i) Transmission power system behaviour and system operation (power flows and system frequency);

(ii) basics of transmission power system protection;

(iii) voltage and reactive power control;

(iv) balancing, ancillary services, automatic generation control, organization and operation;

(v) other internal rules (namely relevant market rules, organizational and technical) described by each system operator;

(vi) introduction to SAPP and other system operator organizations;

(vii) the SAPP regional grid code and other international regulations;

(viii) crisis management;

(ix) manual or automatic remedial actions in emergency situations (for example load shedding);

(x) restoration actions after black-out;

(xi) basic methods in network calculation (on-off line), state estimation, load flows and the like;

(xii) limiting short-circuit levels to the maximum capacity of the transmission power system components;

(xiii) special phenomena such as frequency oscillations (slow = sub-synchronous, higher-order harmonics = over-synchronous) in the national and SAPP systems;

(xiv) special phenomena such as local (in the national networks) and global (in the synchronous area) collapses (voltage, frequency, angular) and the like;

(6) The system controllers shall be trained in the knowledge of operational tools including:

(i) collecting, transferring data signals, computers configuration, SCADA systems and the like;

(ii) remote control technology;

(iii) implemented models for state estimation, for transmission power system topology, for contingency analysis, for offer-demand balancing, for automatic generation control, for load forecast and the like;

(iv) interpretation of calculation results;

(v) operator's MMI (man machine interface) and the like;

(vi) other internal operational tools (for example scheduling system).

(7) The theoretical part of the initial programme shall be supported by practical experience, which plays crucial role in the education process and acquisition of prudent utility practice.

(8) On-the-job sessions as well as additional simulator sessions with enough frequency and duration shall be compulsory.

(9) On-the-job training shall consider the future position and responsibilities of the candidate and should cover all relevant operational aspects related to this position.

(10) The on-the-job training shall put into practice all the professional actions required in real time operation, using appropriate tools.

(11) The trainees shall be guided by personnel experienced in the respective positions for which they are being trained.

(12) On-the-job education shall take into account the theoretical aspects of all the relevant topics.

(13) On-simulator sessions shall be provided during which the trainees experience normal and insecure system situations.

Continuous system controller training programme

155. (1) The continuous programme shall be imposed to all system controllers as soon as they are certified and nominated to a system controller position and the main aim of the continuous programme is to keep and extend the system controllers' knowledge and competences.

(2) The continuous programme has to focus on theoretical and practical aspects of system operation as well as on boundary conditions at the borders with adjacent systems.

(3) The inter-system operator training as defined in code 156 is part of the continuous training.

(4) The continuous programme is established to complement the initial programme with:

(a) advanced theoretical parts;

(b) learning of new rules and procedures;

(c) additional simulator sessions.

(5) The system operator shall define a continuous programme designed to cover theoretical knowledge, simulator sessions and stress management techniques.

(6) The theoretical part of the continuous programme shall provide advanced knowledge on the following main topics:

(a) analysis of disturbances and "almost" disturbances;

(b) technical knowledge (recapitulation of important aspects of network operation in normal,

emergency situation and black-out conditions);

(c) information about new conditions affecting network operation (for example new system elements and new power stations and generating units);

(d) information about new rules and procedures following changes in general framework; and

(e) human behaviour aspects (analysis of human factors).

(7) The simulator session shall be provided on a DTS.

(8) The DTS shall simulate situations with insecure and emergency scenarios, complemented by the restoration of the network after disturbances and blackouts and shall also include inter-system operator disturbances.

(9) The system controllers shall be informed on methods to manage the stress associated with the system controller's tasks.

Inter-system operator training

156. (1) The system operator can sign bilateral and multilateral agreements of cooperation for common training.

(2) The content of inter-system operator training programme shall include:

(a) a necessary knowledge of the adjacent system operators' systems;

(b) awareness of coordinated actions in normal operational conditions in order to ensure the best operational conditions of the common system area;

(c) awareness of coordinated remedial actions in case of security violations, in order to avoid the deterioration of the operational conditions towards emergency situations;

(d) awareness of remedial actions in case of emergency situation and restoration after black-out conditions.

(3) The system operator shall implement at least one of the following four actions to improve communication and coordinated measures between system controllers of its adjacent system operator and the actions taken have to be chosen depending on the mutual level of risks for secure system operation with the first (or further) adjacent system operator(s):

(a) cross visits between adjacent system operators' system controllers in which the characteristics of the system and operational constraints of a system operator organization are presented and a cross visit intends to give the opportunity to operators, who have frequent contacts, to get to know each other on a personal level and introduce a more collaborative atmosphere between the system controllers, and to provide a global overview of the adjacent system operator system to system operators' system controllers;

(b) common training workshops where Grid Code participants are informed about the specific items, problems, evolutions and the like in the different networks and they can exchange experience on system operation at boundaries and such workshops aim at providing the same set of information (common knowledge) to all involved system controllers, with a view to better understanding the problems of the adjacent systems and the content of existing procedures in normal and abnormal system states and during the workshops, exercises can be carried out (for example tests of communication procedures on borders, where detailed arrangements between system operators exist);

(c) on-shift cross periods, meaning visits by adjacent system controllers for spending full real-time shifts at the hosting system operator where during on-shift cross periods in the respective control rooms, the system controllers will enhance their mutual knowledge of the adjacent operational environment and the on-shift cross periods aim at improving in-depth

understanding and interpersonal communication between adjacent system operators' system controllers and at reinforcing the knowledge level of the adjacent system operators' systems;

(d) common DTS training sessions, to ensure better coordination of adjacent system controllers actions in normal and abnormal conditions which can be organized on a bilateral or multilateral level and the main focus of the sessions should be the training of inter- system operator disturbances with the goal that the system operator's system controllers act in a coordinated way in stressful conditions (for example to exchange efficient information, to apply relevant rules and procedures, to order cross-border actions after mutual evaluation or to take any remedial actions).

Training organization and system controllers' accreditation

157. (1) All system controllers shall be accredited and in this regard accreditation means a written endorsement of the proven qualifications of a person for the position of a system controller.

(2) The accreditation validity shall be subject to the system controller successfully completing continuous training required in code 155.

(3) The system operator shall appoint a training coordination manager responsible for the organization of training, including designing, following-up and updating the full training process.

(4) The training coordination manager shall determine appropriate procedures for the organization of training which procedures shall cover:

(a) a description of the system controllers' required qualifications (knowledge and skills);

(b) a reference list of topics for training programmes linked to the system controllers' required qualifications;

(c) the processes for the initial and continuous programmes including scripts and documents for the theoretical sessions, time-schedules, supervision, tools, support for trainees, evaluation and validation and continuous improvement of the programmes and the process of system controllers accreditation;

(d) selection and training of trainers.

(5) The system operator has to determine the profile of trainers with regard to their respective tasks and responsibilities in the training programmes.

(6) Trainers may be selected internally (experienced system controllers) or from external sources.

(7) Training of trainers shall be provided depending on their education and previous experience and an individual training programme shall be defined for each trainer and can be provided by internal sessions or by outsourced training sessions.

(8) Training for trainers shall be provided for trainers to be qualified to hold lectures for the trainees to conduct oral examinations or provide personal coaching.

(9) The essential training is to be able to:

(a) lead a training session;

(b) lead a debriefing;

(c) evaluate of a training session; and

(d) teach management of system controllers' stress.

(10) The initial programme has to be completed by an evaluation in which the knowledge and

capabilities of a candidate to perform a system controller job are tested and this evaluation is performed by the trainers for which a relevant document is forwarded to the manager of the candidate.

(11) The system operator shall provide a first accreditation to the system controller candidates that authorises them to perform their job in the control room.

(12) The first accreditation is attributed according to defined criteria for a duration decided by the system operator based on the following criteria:

(a) content of the evaluation document;

(b) on-the-job session reports;

(c) simulator session reports, where these exist;

(d) assessment of the system controller's capabilities through an interview at the end of the initial training programme.

(13) The renewal of accreditation shall be based on following criteria:

(a) confirmation of attendance at the theoretical part of the continuous programme;

(b) simulator sessions reports;

(c) assessment of the system controller capabilities through an interview.

(14) The validity duration of the system controller's accreditation is two years and any system controller not on active duty for more than six months shall be required to renew their accreditation.

Basic requirements for dispatcher training simulator

158. (1) A DTS is required which is based on the EMS in the dispatching centre or on a dedicated modelling of the real time network.

(2) An external DTS, which is an independent simulator and could be used for joint extended training including multi areas, is optional.

(3) The DTS shall include a comprehensive database with respective data from adjacent networks at a sufficient level and including a (n-1) security analysis and the DTS shall also provide an adequate realistic control room environment.

(4) The DTS shall have the functionality to provide training to system controllers to learn to solve situations that occur in the power system operation, including:

(a) operation during the normal state;

(b) defence of the system against a serious disturbance; and

(c) restoration of the transmission power system starting after a blackout.

(5) The DTS should also be able to provide:

(a) training in SCADA and in other power applications of the dispatching tool (EMS);

(b) training in the man machine interface of the local dispatching tool (EMS) in case of integrated DTS;

(c) testing of the EMS sub-applications, for example SCADA and AGC (case of integrated DTS);

(d) training in local switching procedures for maintenance activities in the network;

(e) training in n-1 calculation software; and

(f) analysing the past events through simulations.

(6) The minimum functional requirements of DTS are:

(a) efficient data input, data accessibility and data handling;

(b) modelling of all the transmission power system components in the operational areas, including low and high voltages, over-current and multi-island-operation;

(c) optional modelling of (sub)transient behaviour of the system;

(d) monitoring and control options for the trainee and trainer to influence the process, through the MMI;

(e) MMI functions to prepare and apply base cases and training scenarios for the trainer;

(f) providing reports after a training session with the view of evaluation;

(g) restoration of the simulated system; and

(h) combining sets of data of the different control areas.

CHAPTER 5
TRANSMISSION POWER SYSTEM METERING

Principles of transmission metering

159. (1) The following points must have a metering installation:

(a) each point of supply connecting a distributor or end-use customer to the transmission power system;

(b) each point of connection between a category B and C generating unit as defined in the connection code and a distributor or the transmission power system;

(c) each point of connection between a generating unit, end-use customer and a distributor providing an ancillary service and

(d) each point connecting the networks of Namibia to a neighbouring country.

(2) The type of metering installation at each metering point as contemplated in subcode (1)must comply with the NRS 057:2005 metering specifications.

(3) Transmission customers with a maximum demand of 5 MVA or more, category B and C generating units as defined in the connection code and connections to neighbouring countries must have main and check metering and there must be separate main and check current transformer cores but one dedicated voltage transformer must be allowed.

(4) A metering point may be located at a point other than the point of connection or the point of supply by mutual agreement between the Grid Code participants.

(5) Transmission customers may request the installation of their own separate check meters and any extra costs must paid for by the requesting party and the transmission metering administrator must install and control the check meters.

Responsibility for metering installations

160. (1) For the purposes of this Chapter, the transmission company is the transmission metering administrator and owner of the meter.

(2) The transmission company is responsible for ensuring that all points identified as metering points under code 167 have metering installations.

(3) The transmission metering administrator is responsible for managing and collecting metering information.

(4) Grid Code participants connected to or wanting to connect to the transmission power system must provide the transmission metering administrator with all information considered necessary to enable the transmission metering administrator to perform metering duties.

(5) In the event of a metering installation being positioned between two distributors -

(a) both distributors are responsible for installing and maintaining the metering installation in accordance with the requirements of this Chapter;

(b) all costs related to the metering installation must be paid for by both distributors; and

(c) the distributors must ensure that the transmission metering administrator is given remote or electronic access to the metering installation where appropriate and if access to the metering installation compromises the security of the installation, then metering data must be supplied to the transmission metering administrator on a daily basis in an appropriate format if required.

Metering installation components

161. (1) The following principles apply to all metering installations:

(a) the meter or recorder must be able to store data in memory for 35 days or more;

(b) data stored in either a meter or a recorder must be remotely and locally retrievable;

(c) a meter must be remotely interrogated on a daily basis where possible or as mutually agreed by the affected Grid Code participants;

(d) a meter must be visible and accessible but access is restricted to authorised staff members only;

(e) data for transmission customers must be historical data situated on a secure server and, as and when required, metering impulses must be provided;

(f) a telecommunications medium must be connected by the relevant transmission supply business or distributer to the meter or recorder contemplated in paragraph (a) where possible;

(g) the meter data retrieval process must be a secure process whereby meters or recorders are directly interrogated to retrieve billing information from their memories;

(h) the accuracy of meters and recorders shall be class 0.2 or better;

(i) commissioning of the metering installation and metering data supporting systems must take place in accordance with the requirements of NRS 057:2005 metering specifications;

(j) both active and reactive energy must be measurable without compromising any requirements of this Chapter;

(k) the meters must measure both active and reactive energy flow in both directions;

(l) the meters must be configured to store or record metering data in half-hourly integration periods.

(2) If a metering installation is used for purposes other than metering data -

(a) the use must not in any way obstruct metering data collection and accuracy requirements;

(b) the secondary use must be communicated to all Grid Code participants who may be affected by the secondary use of the installation; and

(c) no secondary user must interfere with voltage transformer or current transformer circuitry.

(3) Metering installations must be audited in accordance with NRS 057:2005 metering specifications or equivalent.

Data validation

162. (1) Data validation must be carried out in accordance with NRS 057:2005 metering specifications.

(2) In the event of -

(a) electronic access to the meters not being possible;

(b) an emergency bypass or other scheme having no metering system; or

(c) metering data not being available any of the following may be resorted to by the distributor,

the transmission metering administrator may resort to -

(i) manual meter data downloading;

(ii) estimation or substitution subject to mutual agreement between the affected parties;

(iii) profiling; or

(iv) reading of the meter at scheduled intervals.

(3) In the event of an estimation having to be made -

(a) a monthly report must be produced for all estimations made; and

(b) the estimation may not be made on three or more consecutive time slots but if that estimation is made the transmission metering administrator must ensure that the meters are downloaded for the billing cycle.

(4) Not more than 10 slots may be estimated per meter point per month but if that estimation is made the transmission metering administrator must ensure that the meters are downloaded for the billing cycle.

Meter verification

163. In addition to the NRS 057:2005 metering specifications verification requirements, meter readings must be compared with the metering data base at least once a year.

Metering database

164. (1) The transmission metering administrator must create, maintain and administer a metering database containing the following information:

(a) name and unique identifier of the metering installation;

(b) the date on which the metering installation was commissioned;

(c) the connecting parties at the metering installation;

(d) maintenance history schedules for each metering installation;

(e) telephone numbers used to retrieve information from the metering installation;

(f) type and form of the meter at the metering installation;

(g) fault history of a metering installation; and

(h) commissioning documents for all metering installations.

(2) Information relating to raw and official values as indicated in section 4.2 of the NRS 057:2005 metering specifications must form part of the metering database and must be retained for at least five years for audit trail purposes.

Testing of metering installations

165. (1) Commissioning, auditing and testing of metering installations must be done in accordance with the NRS 057:2001 metering specifications.

(2) New or replacement components of a metering installation shall be individually calibrated by an accredited calibration laboratory or the Namibian Standards Institution before their installation.

(3) Recalibration and testing of meter installations shall be performed by an accredited calibration laboratory or the Namibian Standards Institution.

(4) A Grid Code participant may request the Board to have the testing of a metering installation carried out and that request may not be unreasonably refused but the costs of the testing must be for the account of -

(a) the requesting Grid Code participant if the meter is found to be accurate; or

(b) the account of the transmission metering administrator if the meter is found to be inaccurate.

Metering data base inconsistencies

166. In the event of testing revealing that data in the metering database is inconsistent with the data in the meter, the transmission metering administrator must inform all affected Grid Code participants and make corrections to the official metering data.

Access to metering data

167. (1) Metering data must be accessed through a central database that stores all transmission customer information.

(2) The transmission metering administrator must control access to all metering installations.

(3) Electronic access to the meters may not be granted to the transmission customer or any other party unless special permission has been granted by the Board.

(4) Schedules for accessing metering data from the central database must be administered by the transmission metering administrator in line with section 4.2.3 of the NRS 057:2005 metering specifications.

(5) All security requirements for metering data must be as specified in NRS 057:2005 metering specifications.

Confidentiality

168. Metering data and passwords are confidential information.

CHAPTER 6
TRANSMISSION POWER SYSTEM INFORMATION EXCHANGE

PART 1
INFORMATION EXCHANGE INTERFACE AND SYSTEM PLANNING INFORMATION

Confidentiality of information

169. (1) Information exchanged between parties governed by this Chapter is confidential unless otherwise stated or the information is defined as being in the public domain.

(2) Confidential information may not be transferred to a third party without the written consent of the information owner.

(3) Parties must observe the proprietary rights to information of third parties for the purposes of this Chapter.

(4) Parties receiving information must use the information only for the purpose for which it was supplied.

(5) Parties must maintain confidentiality of information after termination of agreements or severance of relationships between the Parties.

(6) The information owner may request the receiver of information to enter into a confidentiality agreement with the information owner before the information owner provides confidential information.

(7) A pro forma confidentiality agreement is set out in ANNEXURE 7.

(8) Parties must -

(a) take all reasonable measures to control unauthorised access to information and to ensure secure information exchange; and

(b) must report any violation of information security to the information owner.

Information exchange interface

170. (1) The parties must identify the following for each type of information exchange:

(a) the names and contact details of the persons designated by the information owner as responsible for the provision of information;

(b) the names and contact details of the parties represented by persons requesting the information; and

(c) the purpose for which the information is required.

(2) The parties must agree on appropriate confirmation procedures for the transfer of information.

(3) Access to information must be provided by the relevant parties with reasonable motivation and notice.

System planning information

171. (1) Transmission customers must -

(a) provide to the transmission company, without unreasonable delay, information requested by the transmission company on a regular basis for purposes of -

(i) planning and developing the transmission power system;

(ii) monitoring current and future transmission power system adequacy and performance; or

(iii) fulfilling statutory or regulatory obligations; and

(b) submit to the transmission company the information listed in ANNEXURE 11 and -

(i) ANNEXURE 6, for distributors or end-use customers; or

(ii) ANNEXURE 7, for generators.

(2) The transmission company must keep an updated technical database of the interconnected transmission power system for purposes of modelling and studying the behaviour of the interconnected transmission power system.

(3) The transmission company must provide transmission customers or potential transmission customers, upon request, with any relevant information that they require to properly plan and design their own systems or installations or comply with their other obligations in terms of the Transmission Grid Code.

(4) The transmission company must make available all the relevant information related to transmission power system planning as contemplated in CHAPTER 3 PART 2.

(5) Transmission customers must, upon request to upgrade an existing connection or when applying for a new connection, provide the transmission company with information relating to the details specified in ANNEXURE 12.

(6) The transmission company may estimate any transmission power system planning information not provided by the transmission customer as contemplated in ANNEXURE 6 or ANNEXURE 7.

(7) The service provider must indicate to the transmission customer any data items that have been estimated and the estimated data items are deemed to have been provided by the transmission customer.

(8) Generators must submit to the relevant service provider all the information set out in 0 with regard to each generating unit at each power station.

PART 2
OPERATIONAL INFORMATION

Pre-commissioning studies

172. (1) Transmission customers must meet all system planning information requirements before the commissioning test date.

(2) The system planning information requirements under subcode (1) include -

(a) confirming any estimated values assumed for planning purposes; or

(b) where practical, replacing the estimated values contemplated in paragraph (a) with validated actual values and with updated estimates for the future.

(3) The system operator must perform pre-commissioning studies prior to -

(a) sanctioning the final connection of new or modified plant to the transmission power system; and

(b) user data for exciter, turbine governor, high voltage direct current systems, flexible alternating current transmission power systems device parameters and settings supplied by transmission customers.

(4) To verify that all control systems are correctly tuned and planning criteria have been satisfied and in this regard the system operator may request adjustments prior to commissioning should tuning adjustments be found to be necessary by the system operator.

(5) Grid Code participants must ensure that exciter, turbine governor, flexible alternating current transmission power systems and high voltage direct current control system settings are as finally recorded by the system operator prior to commissioning.

Commissioning and notification

173. (1) Grid Code participants must give the system operator reasonable advance notice referred to in code 137, of the time at which the commissioning tests will be carried out.

(2) The system operator and the Grid Code participant must agree on the timeous provision of operational data items set out in ANNEXURE 9.

(3) Grid Code participants must jointly verify all measurements and indications for functionality and accuracy once every three years so as to achieve overall accuracy of operational measurements within the limits agreed.

(4) Records of commissioning must be -

(a) maintained for reference by the system operator for the operational life of the plant; and

(b) made available, within a reasonable time, to authorised Grid Code participants upon request.

(5) A transmission customer connected to the transmission power system must ensure that measurement equipment complies with the accuracy classes set out in ANNEXURE 13.

General information acquisition requirements

174. (1) Transmission customers and the transmission company must supply measurements and indications, including the standards set out in ANNEXURE 9, to the system operator.

(2) Where required signals become unavailable or do not comply with applicable standards for reasons within the control of the provider of the information supplied in terms of subcode (1) the provider of the information must report and restore or correct the signals and indications as soon as reasonable.

(3) The measurements and indications contemplated in subcode (1) must be presented to the system operator in a form nominated by the system operator.

(4) The system operator must give notice to a Grid Code participant if the system operator determines that additional measurements or indications in relation to a plant or equipment of the Grid Code participant are needed to meet a transmission power system requirement.

(5) The costs related to a modification to the transmission power system are for the account of the provider of information referred to in subcode (2).

(6) On receipt of the notice contemplated in subcode (4) a Grid Code participant must promptly ensure that the measurements or indications are made available at the remote terminal unit.

(7) The data formats to be used and the fields of information to be supplied to the system operator by the various Grid Code participants are set out in ANNEXURE 9.

Bilateral contract information

175. (1) The system operator shall provide the market operator with the available transmission capability in accordance with CHAPTER 3.

(2) The market operator shall provide the system operator with sufficient information to evaluate proposed bilateral trades and ensure there is sufficient available transmission capacity.

(3) The market operator shall provide approved bilateral energy trades to the system operator for the system operator to update and publish the updated available transmission capability.

Generating unit scheduling

176. The market operator must provide the data set out in in energy market rules to the system operator.

Energy market schedules

177. The market operator must provide the system operator energy market schedules and associated information in accordance with the energy market rules.

Ancillary services market schedules

178. (1) The market operator must provide the system operator with ancillary service market schedules and associated information in accordance with the energy market rules.

(2) All information exchange requirements for ancillary services that are contracted annually must be included in the contract between the parties.

File transfers

179. (1) The format of the file used for data transfer through file transfers must be negotiated with the system operator.

(2) The data must be made available in a common electronically protected directory.

(3) All file transfer data must be collected by the system operator in line with the file format set out in ANNEXURE 14.

Inter control centre communication

180. (1) All transmission customer control centres must provide the system operator with network information that is considered reasonable for the security and integrity of the transmission power system on request.

(2) The system operator must communicate network information as requested to the transmission customer control centres, as required for safe and reliable operation.

(3) The information exchange between control centres must be electronic and paper-based within the timeframe agreed upon.

Communication facilities requirements

181. The minimum communication facilities for voice and data that are to be installed and maintained between the system operator and Grid Code participants must -

(a) comply with the applicable IEC standards for Supervisory Control and Data Acquisition and communications equipment; and

(b) meet the standards set by the system operator in advance of the design of communication facilities.

Information exchange tele-control

182. (1) The information exchange must support data acquisition from remote terminal units.

(2) The system operator must be able to monitor the state of the interconnected transmission power system via telemetry from the remote terminal unit connected to the plant of a Grid Code participant.

(3) The signals and indications required by the system operator are set out in ANNEXURE 7, together with other information the system operator may from time to time reasonably require by notice to the Grid Code participant.

(4) Grid Code participants must interface via the standard digital interfaces as specified by the system operator.

(5) Interface cabinets must be installed in the plant and equipment room of a Grid Code participant if required by the system operator.

(6) A Grid Code participant is responsible for providing and maintaining the signalling from the plant and equipment of the Grid Code participant to the interface cable.

(7) A Grid Code participant must provide the capability -

(a) for the system operator to deactivate and reactivate the scanning of a given remote terminal unit; and

(b) of monitoring the availability of all remote terminal units centrally.

(8) A Grid Code participant must comply with the tele-control requirements -

(a) applicable to the primary control centre; and

(b) reasonably required for the emergency control centre, of the system operator.

Telephone or mobile phone

183. (1) A transmission customer is responsible for the provision and maintenance of no less than one telephone and one mobile phone that must be reserved for operational purposes only and must be continuously attended to and answered without undue delay.

(2) The system operator must use a voice recorder for historical recording of all operational voice communication with Grid Code participants.

(3) The voice recordings contemplated in subcode (2) must be available for at least three months.

(4) The system operator must make the voice records of an identified incident in dispute available within a reasonable time period upon request by a Grid Code participant or the Board.

Electronic mail

184. (1) Grid Code participants must provide the system operator with the electronic mailing address of the contact person and the system operator must provide Grid Code participants with

the mailing address of the contact person of the system operator.

(2) The service provider must be selected to meet the real-time operational requirements of the system operator.

Access and security of infrastructure at points of supply

185. (1) The system operator must agree with Grid Code participants on the procedures governing security and access to the SCADA, computer and communications equipment of the Grid Code participants.

(2) The procedures under subcode (1) must allow for adequate access to the equipment and information by the system operator for purposes of maintenance, repair, testing and the taking of readings.

(3) A Grid Code participant must -

(a) designate a person to perform the duties of the information owner in respect of the granting of access to information to third parties; and

(b) disclose the name and contact details of the person designated pursuant to paragraph to the Board.

(4) A Grid Code participant may, pursuant to subcode (3)(a), designate more than one person.

Time standards for infrastructure at points of supply

186. All information exchange shall use GPS time stamping for all signals at the remote terminal unit, gateway or plant controller level which will be propagated to the SCADA master station with date and time to 1 millisecond accuracy, as defined in the IEC 60870-5-101/104 protocol.

Integrity of installation

187. (1) A Grid Code participant is responsible for optimising the reliability and security of the facilities to comply with the system operator equipment and the original equipment manufacturer minimum requirements.

(2) The optimising of reliability and security contemplated in subcode (1) includes the provision, at no charge to the system operator, of an uninterruptible power supply with an eight-hour standby capacity.

Data storage and archiving

188. (1) An information owner must store and archive data.

(2) A Grid Code participant -

(a) must have a system for storing data and information to be used by the Grid Code participant ; and

(b) is responsible for own choice, and the costs, of the system contemplated in paragraph (a).

(3) A system contemplated in subcode (2) must -

(a) be auditable by a person authorised to audit the system;

(b) provide for clear and accessible audit trails on all relevant operational transactions.

(4) All requests that require an audit on a system contemplated in subcode (2) must be

undertaken with reasonable notice to the Grid Code participants.

(5) The information owner must keep all information for a period of at least five years from the date the information was created, unless otherwise specified in the this Code.

(6) The Grid Code participants must ensure reasonable security against unauthorised access, use and loss of information of the systems that contain the information.

PART 3
POST-DISPATCH INFORMATION

Market information

189. (1) The system operator and the transmission metering administrator must provide Grid Code participants, including the market operator, with the information contemplated in codes 176, 177and 178.

(2) Before the finalisation of the information referred to in subcode (1) the information must be provided in accordance with codes 190 to192.

Generation settlement

190. (1) The market operator must request all data required for settlement of the energy market from the transmission company.

(2) On a request pursuant to subcode(1), the transmission company must make the data available to the market operator within an agreed time period and acknowledge that the data is confidential.

Ancillary services settlement

191. (1) The market operator must request all data required for settlement of the ancillary services market from the transmission company.

(2) The transmission company must make this information available, within an agreed time period, with acknowledgement of the confidentiality of the data requested.

Hourly demand metering data

192. The transmission metering administrator must provide Grid Code participants with hourly metered data pertaining to their installations.

SAPP information

193. The system operator shall provide post-dispatch information to SAPP Coordination Centre and relevant SAPP members as required by the SAPP rules and SADC regional grid code.

Files used for data transfer

194. (1) The format of the files used for data transfer must be negotiated and defined by the supplier and receiver of the information.

(2) The file transfer media must be negotiated and defined by both parties involved.

(3) The parties must keep the agreed number of files for backup purposes so as to enable the recovery of information in the case of communication failures.

(4) The files that may be triggered in the transmission power system and the frequency of the occurrence of the events that trigger the files are set out and described in ANNEXURE 15.

Generator performance data

195. Generators must provide the system operator monthly with official performance indicators in relation to each generating unit at each power station in respect of availability or reliability as detailed in ANNEXURE 10.

Distributor and end-use customer performance

196. (1) The performance measurement of all distributors and end-use customers must be in accordance with the quality of supply requirements as contemplated in code 90 of the Connection Code.

(2) Periodic testing of under-frequency load shedding relays must be reported in the format set out in ANNEXURE 16.

System performance information

197. (1) The transmission company must make available monthly the performance indicators for the transmission power system, in the format set out in, to the Board, transmission customers and the market operator.

(2) The transmission company must contract point of supply performance with each transmission customer.

(3) The point of supply performance under subcode (2) includes performance reporting requirements.

System performance information

198. The following interconnected transmission power system operational information must be made available by system operator -

(a) daily:

(i) the hourly actual demands of the previous day (MW); and

(ii) the reserve amounts over the morning and evening peaks of the previous day (MW); and

(b) annually:

(i) the annual peak (MW), date and hour; and

(ii) the annual minimum MW, date and hour.

PART 4
CYBER SECURITY

Cyber Security minimum standards compliance

199. (1) Grid Code participants shall comply to IEC 62351 “Power systems management and associated information exchange - Data and communications security”.

(2) The market operator shall ensure compliance to Part 503: Market data exchanges

guidelines for the IEC 62325 or agreed equivalent standard for ensuring all market communications between the market participants, the system operator and the SAPP market operator is secure.

(3) Grid Code participants shall establish, implement, maintain and continually improve an information security management system in compliance to IEC 27001.

(4) The information technologies security controls and techniques of the Grid Code participants shall be in compliance to IEC 27002.

(5) Grid Code participants shall establish a risk management system for risk identification, analysis, evaluation and treatment in compliance to IEC 27005.

(6) The security of industrial automation and control systems of the Grid Code participants shall be in compliance to IEC 62443.

(7) The information security for power system control operations of the Grid Code participants and other relevant parties shall be in compliance to IEC 62351.

Cyber security working group

200. (1) The system operator shall be responsible for coordinating a cyber security working group, which shall meet at least once a year.

(2) The cyber security working group shall made up from cyber security experts from Grid Code participants, government agencies and industry experts.

(3) The cyber security working group shall assist the system operator and Namibian security agencies responsible for security assessments in cyber security risk assessments, including at least the following:

(a) development of the cyber security risk assessment methodologies;

(b) development of the methodology to determine the high-impact and critical-impact perimeters;

(c) development of a risk assessment report every two years to Grid Code participants and the relevant authorities in Namibia;

(d) development of cyber security risk assessments which shall identify, analyse, and evaluate the risks of cyber-attacks affecting the operational security of the transmission power system and disrupting cross-border electricity flows but the cyber security risk assessments shall not consider the legal, financial or reputational damage of cyber-attacks;

(e) development of a cyber security risk treatment plans including minimum security controls to be included;

(f) identification of high-impact and critical-impact business processes where a possible risk of a cyber-attack can impact regional electricity; and

(g) coordinate with the SAPP cyber security team for identifying SAPP wide cyber security risks and mitigation plans.

(4) The cyber security risk assessment methodologies shall include at the least the following elements:

(a) quantitative metrics to measure the consequences of cyber-attacks to cross-border electricity flows taking into account safety, operational security, frequency quality and the efficient use of the interconnected transmission power system and resources;

(b) a list of threats to consider, including at least the following supply chain threats:

(i) a severe and unexpected corruption of the supply chain;

(ii) the unavailability of products or services from the supply chain;

(iii) attacks through actors of the supply chain;

(iv) supply chain tracking or infiltration;

(c) criteria to evaluate the consequences and cyber security risks as high or critical using a defined threshold for consequences and likelihood;

(d) rules for the definition of the electricity cyber security impact index and high-impact and critical-impact thresholds; and

(e) an approach to analyse the cyber security risks coming from legacy system, the cascading effects of electricity incidents and the real-time nature of systems operating the transmission grid.

(5) The electricity cyber security risk assessment report shall include at least the following:

(a) list of system-wide high-impact and critical-impact business processes identified in the regional risk assessment including risk of a cyber-attack;

(b) list of assets that have the highest impact on system security and potential risk of a cyber-attack;

(c) current threats, with a specific focus on emerging threats and risks for the electricity system; and

(d) cyber security incidents that have occurred in the reporting period and corrective actions taken.

Cyber security requirements

201. (1) Grid Code participants with a demand or power station greater than 2.5 MW shall be IEC 27001 certified.

(2) When performing cyber security risk assessments, Grid Code participants shall use the methodologies developed by the cyber security working group.

(3) Grid Code participants shall implement all cyber security risk treatment plans recommended by the cyber security working group in its report or any individual recommendation.

(4) Grid Code participants shall report to the cyber security working group any cyber security incident that has a risk to the stability, operability, and reliability of the transmission power system, as promptly as reasonably practicable in the circumstances of the incident.

(5) Grid Code participants shall have a recovery plan to recover from a cyber security incident to ensure the continuous stability, operability, and reliability of the transmission power system.

(6) The recovery plan shall be tested on a regular way with all interested Grid Code participants.

(7) Grid Code participants shall identify and protect power stations and substations and their associated primary control centres that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or cascading within of the transmission power system and interconnections to SAPP.

CHAPTER 7
TRANSMISSION POWER SYSTEM MARKET CODE

PART 1
TRANSMISSION CAPACITY ALLOCATION AND CONGESTION MANAGEMENT

Non-discrimination for transmission capacity allocation and congestion management

202. (1) The system operator shall ensure transmission capacity allocation and congestion management for the transmission power system is provided on a non-discriminatory basis in accordance with the rules below.

(2) The processes and procedures developed by the system operator to ensure non-discriminatory transmission capacity allocation and congestion management for the transmission power system shall be approved by the Board.

(3) The available transmission capacity shall be calculated for all transmission substations and transmission zones.

(4) The system operator shall define the transmission zones to ensure there is no congestion between main bulk supply and demand points in Namibia and at the border to neighboring countries.

Capacity calculation timeframes

203. (1) The system operator shall calculate available transmission capacity for all transmission substations and transmission zones for at least the following timeframes:

(a) long term transmission capacity which includes all MSB bilateral trades which are trades that are longer than a year up to 20 years ahead;

(b) rolling year ahead hourly available transmission capacity including all short-term bilateral trades and including future day-ahead, intraday and balancing markets.

(2) Long-term bilateral trades capacity calculation shall be calculated on an ad-hoc basis by the system operator when requests are received from MSB market participants.

(3) The system operator shall annually calculate minimum monthly available transmission capacity (ATC) information specific to each transmission substation for the 20 year-ahead forecast.

(4) The available transmission capacity shall be calculated for at least the predicted peak hour, midday and the predicted off-peak hour in the month and the minimum available transmission capacity shall be calculated for both import to and export from each transmission substation and transmission zones.

(5) Long-term bilateral trades capacity calculation shall be calculated on an ad-hoc basis by the system operator when requests are received from MSB market participants.

(6) The system operator shall enter into discussions with the MSB market participant should the bilateral trade exceed the available transmission and agree the possible revised bilateral trade.

(7) The system operator shall notify the market operator and the relevant MSB market participant long term bilateral trades doesn’t result in congestion.

(8) The market operator shall provide the system operator with approved long term bilateral trades and the system operator upon receipt of such a bilateral trade, immediately update the minimum monthly available transmission capacity information specific to transmission substation for the 20 year-ahead forecast.

(9) The minimum available transmission capacity shall be calculated for both import to and export from each transmission substation.

(10) MSB market participants must confirm their short term bilateral contracts to the MSB at least by 09:00 the day before real-time. Bilateral contracts not confirmed will be deemed to still be valid. The MSB market operator in accordance with market rules.

(11) The market operator shall provide the system operator with any changes to bilateral contracts by 10:00 of each day and the system operator shall immediately update the available transmission capacity for all transmission substations and transmission zones.

(12) The market operator shall ensure day-ahead, intraday and balancing markets trades schedules do not exceed the transmission available capacity published by the system operator.

(13) For rolling year ahead, the hourly capacity calculation shall be immediately updated each time there is an energy trade approved by the system operator including approved energy trades resulting from clearing of various market platforms and the available transmission capacity shall be calculated for both import to and export from each transmission substation and transmission zones.

(14) The system operator shall provide the SAPP Coordination Centre the available transmission capacity to SAPP members in accordance with the SAPP regional grid code and SAPP market rules.

Demand data

204. (1) All distribution consumers who do not have bilateral contracts for their energy with distributors, distributors and transmission connected end-use customers shall provide the system operator with a rolling year ahead hourly demand forecast after internally contracted embedded generation has been considered.

(2) The distribution consumers who do not have bilateral contracts for their energy with distributors, distributors and transmission connected end-use customers shall provide the system operator with an updated the rolling year ahead hourly demand forecast every Monday by 09:00.

Transmission and generation planned and unplanned outages.

205. (1) Planned transmission and generation outages shall be considered in the calculation of the available transmission capacity.

(2) The available transmission capacity shall be updated when there is unplanned transmission and generation outages.

(3) The system operator shall inform the market operator of any reduction in available transmission capacity due to unplanned outages and within the timeframes specified in the MSB market rules and the system operator shall in the include the time the capacity is expected to return to normal.

(4) The market operator shall acknowledge the receipt of the available transmission reduction in capacity due to an unplanned outage and inform the system operator the time from which the capacity reduction will be considered in the market schedules.

(5) The system operator shall be responsible for ensuring that the capacity reduction is managed in real-time until the market schedules have been updated by the market operator.

Total transfer capacity methodology

206. (1) The total transfer capacity (TTC) is the maximum transfer capability to and from each transmission substation and between two zones taking into account security standards.

(2) The total transfer capacity methodology for preparing the inputs to capacity calculation, which shall include the following parameters:

(a) the methodologies for determining operational security limits, contingencies relevant to

capacity calculation and allocation constraints; and

(a) the methodology for determining the steady state and dynamic load flow calculations.

(3) The transmission capacity calculation methodology shall include a fallback procedure for the case where the initial capacity calculation does not lead to any results.

Transmission reliability margin methodology

207. (1) The transmission reliability margin (TRM) is a security margin that shall cover the uncertainties on the computed total transfer capacity values arising from:

(a) unintentional deviations of physical flows during operation due to the physical system in real time;

(b) emergency power flows including to neighbouring countries to cope with unexpected unbalanced situations in real-time; and

(c) inaccuracies, e.g. in data collection and effective measurements.

(2) The system operator shall determine the transmission reliability margin methodology and the methodology shall be approved by the Board.

(3) The transmission reliability margin shall consider at least the following:

(a) the transmission reliability margin must at least cater for instantaneous reserve activation;

(b) the transmission reliability margin shall be at least 0.5% of TTC to cover measurement errors; and

(c) the transmission reliability margin shall consider historical power system flow errors and uncertainties.

Operational security limits, contingencies relevant to capacity calculation and allocation of constraints methodology

208. (1) The methodology for determining operational security limits, contingencies relevant to capacity calculation and allocation constraints shall include at least the following:

(a) loss of load expectation;

(b) loss of load probability;

(c) embedded variable renewable energy (VRE) penetration probability; and

(d) deterministic risk-analysis studies.

(2) Operational security limits shall be the same as the ones used for the long-term planning as defined in CHAPTER 3 PART 2.

(3) The steady-state contingencies to be considered shall include at least the following:

(a) loss of any transmission line having an impact on the loading of the tie-lines;

(b) loss of the largest reactive power source; and

(c) evaluation of the danger of voltage collapse.

(4) The transient contingencies to be considered shall include at least the following:

(a) critical transformer in the transmission power system;

(b) loss of one or several generating units due to a common cause;

(c) tripping of one large power station;

(d) evaluation of the auto-reclose policy on any transmission line that will have an impact on the transmission power system; and

(e) loss of any transmission line that could have an impact on the transmission power system.

Steady state and dynamic load flow calculations methodology

209. (1) The system operator shall develop the steady state and dynamic load flow calculations methodology.

(2) The steady state and dynamic load flow calculations methodology shall include at least the following:

(a) method to determine which power stations are in service and the marginal (swing) power stations for determining transmission capacity calculation;

(b) the determination of cases to be studied, including:

(i) peak case;

(ii) off-peak case; and

(iii) probable maximum VRE penetration

(c) method to determine which faults are to be studied.

Net Transfer Capacity

210. The net transfer capacity (NTC) is the maximum transfer capability at transmission substations and between zones taking into account security standards and technical uncertainties and the Net Transfer Capacity is calculated as follows:

NTC = TTC – TRM

Available Transfer Capacity

211. The available transfer capacity (ATC) is the remaining transfer capability at transmission substations and between zones after considering already allocated capacity (AAC) to approved bilateral agreements and the available transfer capacity is calculated as follows:

ATC = NTC – AAC

Congestion management

212. The congestion management shall be according with rule 11 of the MSB market rules.

Physical transmission rights

213. (1) The system operator shall allocate transmission capacity hourly to the MSB market participants by with approved firm bilateral energy contracts in the form of physical transmission rights.

(2) The system operator shall allocate transmission capacity to the MSB market participants in the order of time of approval of their bilateral energy contracts, having the oldest dated bilateral contracts first benefiting from allocated transmission capacity up to the volume mentioned in the bilateral energy contracts.

(3) Proposed bilateral energy contracts shall not be approved by the system operator should there not be sufficient transmission capacity.

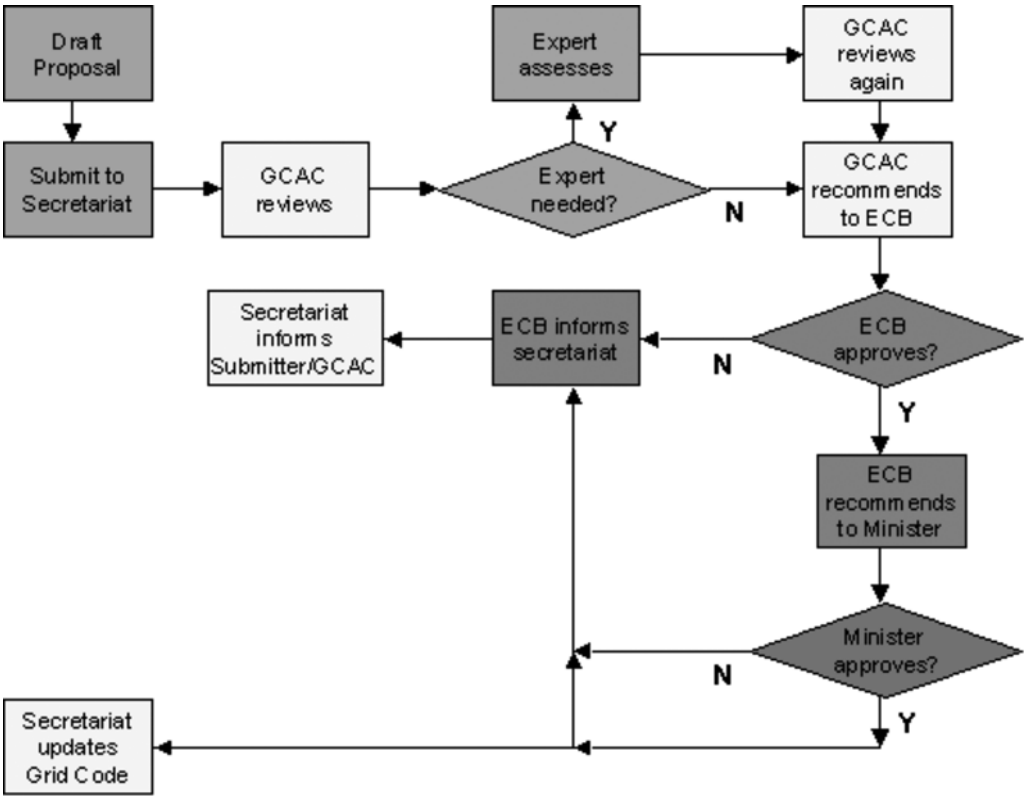
(4) Should the transmission capacity be reduced due to unforeseen circumstances, the last approved bilateral energy contracts shall be cancelled until sufficient capacity is available for safe and secure operation of the transmission power system.

Financial transmission rights

214. (1) Physical transmission rights can be converted into financial transmission rights according to the provisions of the MSB electricity market rules, if any.

(2) The system operator shall be responsible for the auctioning of transmission capacity according to the provisions of the MSB electricity market rules, if any.

ANNEXURE 1: TRANSMISSION GRID CODE AMENDMENT OR EXEMPTION APPROVAL PROCESS



ANNEXURE 2: CONTRACTING FRAMEWORK FOR GRID CODE PARTICIPANTS

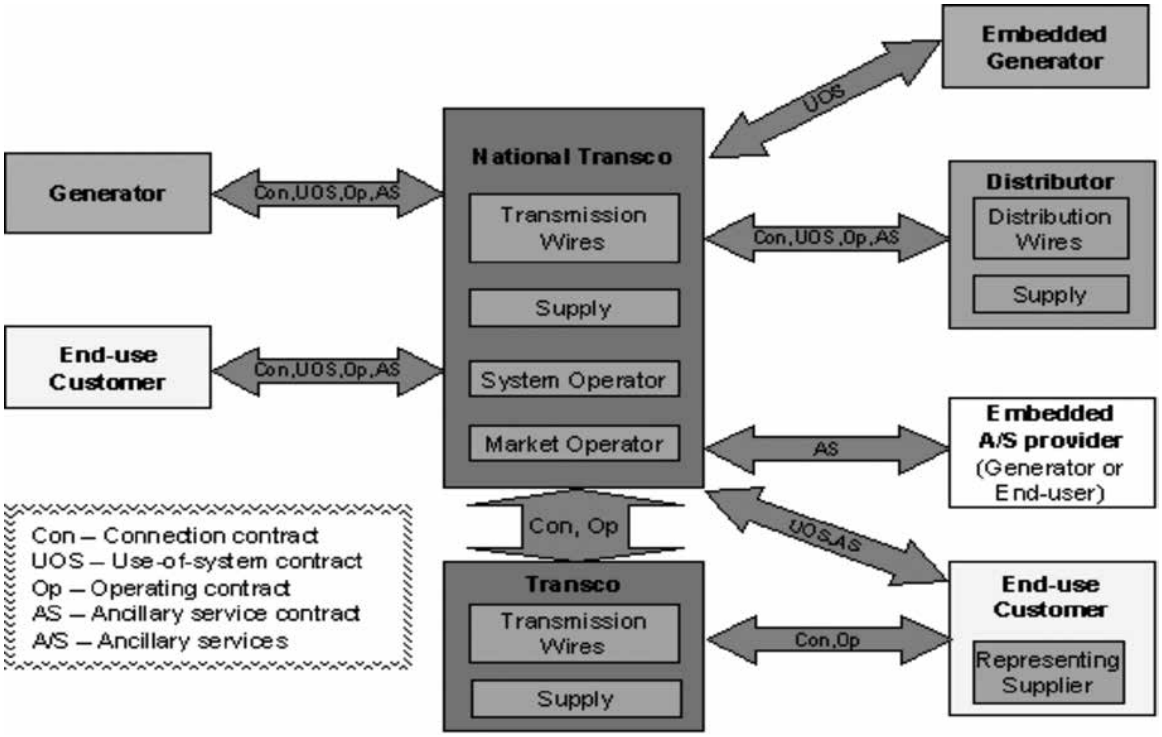


Table 1: Technical and Statutory Voltage Limits

Nominal continuous operating voltage on any bus for which equipment is designed	*UN*
Maximum continuous voltage on any bus for which equipment is designed Note: To ensure voltages never exceed *Um*, the highest voltage used at sending-end *busbars* in planning studies should not exceed 0.98 *Um*	*UM*
Minimum voltage on Point of Common Coupling (*PCC*) during motor starting	0.85 *UN*
Maximum voltage change when switching lines, capacitors, reactors, etc.: Maximum Fault Level Minimum Fault Level	 0.03 *UN* 0.075 *UN*
Statutory voltage on bus supplying *transmission customer* for any period longer than 10 consecutive minutes (unless otherwise agreed in Supply Agreement)	*UN* + OR - 5%

Table 2:Standard Voltage Levels (Phase to phase RMS) as defined in IEC 60038

Un (kV)	Um (kV)	(Um-Un)/Un %
400	420	5,00
330	346.5	5,00
220	245	11,36
132	145	9,85
66	72,5	9,85
33	36	9,09
22	24	9,09
11	12	9,09

Table 3: Target Voltages for Planning Purposes

Minimum steady state voltage on any bus not supplying a *transmission customer* System Healthy: After designed contingency:	 0.95 *UN* 0.90 *UN*
Maximum harmonic voltage caused by *transmission customer* at *PCC*:	ACCORDING TO NRS 048-4 (2009)
Maximum unbalance caused by *transmission customer* at *PCC*:	ACCORDING TO NRS 048-4 (2009)
Maximum voltage change due to load varying N times per hour:	(4.5 $LOG_{10}N$)% OF *UN*
Maximum voltage decrease for a 5% increase in MW at receiving end of system (without adjustment):	0.05 *UN*

ANNEXURE 4: SELECTION OF DEAD LINE CHARGING END OF THE LINE

End A End B	*Substation* FL<10kA	*Substation* FL>10kA	*Power Station*
Substation FL<10kA	*Substation* with higher FL	*Substation* A	*Substation* B
Substation FL>10kA	*Substation* B	*Substation* with lower FL	*Substation* B
Power Station	*Substation* A	*Substation* A	*Power Station* with lower FL

ANNEXURE 5: SAMPLE CONFIDENTIALITY AGREEMENT FOR INFORMATION TRANSFER TO THIRD PARTIES

CONFIDENTIALITY AGREEMENT
BETWEEN

.....
(HEREINAFTER REFERRED TO AS THE INFORMATION OWNER)
AND

.....
(HEREINAFTER REFERRED TO AS THE RECIPIENT)

IN RESPECT OF INFORMATION SUPPLIED TO PERFORM THE FOLLOWING WORK:

.....

.....

(HEREINAFTER REFERRED TO AS THE WORK)

ON BEHALF OF

.....
(HEREINAFTER REFERRED TO AS THE CLIENT).

(1) The Recipient agrees to treat all information (hereinafter referred to as the Information) received from the Information Owner, whether in hard copy or electronic format, as strictly confidential.

(2) The Recipient agrees to disclose the Information only to persons who are in his or her permanent employ, and who require access to the Information to perform their duties in respect of the Work on behalf of the Client.

(3) Persons other than those described in Clause 2 above, including but not restricted to temporary employees, subcontractors, and sub-consultants, shall enter into separate Confidentiality Agreements with the Information Owner prior to receiving the Information.

(4) The Recipient undertakes to use the Information only to perform the Work on behalf of the Client, and for no other purpose whatsoever.

(5) On completion of the Work, the Recipient shall at his or her own expense return to the Information Owner all hard copy material and computer disks containing the Information supplied to him or her by the Information Owner. The Recipient shall furthermore ensure that all duplicate copies of the Information in his or her, or his or her employees', possession (electronic as well as hard copy format) are destroyed.

(6) The Recipient shall take all reasonable measures to protect the security and integrity of the Information.

(7) If requested to do so by the Information Owner, the Recipient shall forthwith at his or her expense return to the Information Owner all hard copy material and computer disks containing the Information supplied to him by the Information Owner. The Recipient shall furthermore ensure that all duplicate copies of the Information in his or her, or his or her employees', possession (electronic as well as hard copy format) are destroyed.

(8) The Recipient shall report any leak of the Information, howsoever caused, to the Information Owner as soon as practicable after he becomes aware of the leak, and shall provide to the Information Owner with all reasonable assistance to ensure its recovery or destruction (as

deemed appropriate by the Information Owner).

Signed at ..... on this the ..... *day* of ..... by (full name) .... in his/her capacity as ..... on behalf of ...., the Information Owner

.....

Signed at ..... on this the ..... *day* of ..... by (full name) .... in his/her capacity as ..... on behalf of ...., the Recipient

.....

ANNEXURE 6: DISTRIBUTOR AND END-USE CUSTOMER DATA

Unless otherwise indicated, the following information shall be supplied to the transmission company, prior to connection and then updated as and when changes occur.

1. Demand data

Connection capacity	Connection capacity required (MW)
Measured and forecast data (annually)	For each Point of Supply, the information required is as follows: • A 5-year demand forecast. (See Annexure 11). • A description setting out the basis for the forecast. • The season of peak demand • Quantification of the estimated impact of embedded generation. (See Annexure 11) • A 10-year demand estimate
User network data	• Electrical single-line diagram of user network to a level of detail to be agreed with the service- providers, including the electrical characteristics of circuits and equipment (R, X, B, R0, X0, B0, continuous and probabilistic ratings). • Contribution from transmission customer network to a three-phase short circuit at Point of Connection. • Connection details of all transmission customer transformers, shunt capacitors, shunt reactors etc. connected to the secondary voltage levels of the transmission customer connected the TS. (the requirement here is for data pertaining to the network connecting shunt capacitors, harmonic filters, reactors, SVCs, etc. to the Point of Supply for purposes of conducting harmonic resonance studies.) • Electrical characteristics of all circuits and equipment at a voltage lower than secondary voltage levels of the transmission customer connected the TS that may form a closed tie between two connection points on the TS.
Standby supply data (annually)	The following information is required for each distributor and end-use customer that can take supply from more than one supply point: • Source of standby supply (alternative supply point(s)) • Standby capacity required (MW)
General information	For each new connection from a distributor or end-use customer, the following information is required: • Number and type of switch bays required • Load build-up curve (in the case of new end-user plant) • Supply date (start of load build-up) • Temporary construction supply requirements • Load type (e.g. ARC furnaces, rectifiers, rolling mills, residential, commercial, etc.) • Annual load factor • Power factor (including details of harmonic filters and power factor correction capacitors) Special requirements (e.g. quality of supply) Other information reasonably required by the service providers to provide the transmission customer with an appropriate supply (e.g. pollution emission levels for insulation design)
Disturbing loads	Description of any load on the power system that could adversely affect the System Operator target conditions for power quality and the variation in the power quality that can be expected at the point connected to the TS. (The areas of concern here are, firstly, motors with starting currents referred back to the nominal voltage at the Point of Supply exceeding 5% of the fault level at the Point of Supply and secondly, ARC furnaces likely to produce flicker levels at the Point of Supply in excess of the limits specified in NRS048. The size limit for ARC furnaces is subject to local conditions in respect of fault level at the Point of Supply and background flicker produced by other ARC furnaces.)

2. Transmission power system connected transformer data

	Symbol	Units
Number of windings		
Vector group		
Rated current of each winding		A
Transformer rating		MVA_{Trans}
Transformer tertiary rating		MVA
Transformer nominal LV voltage		kV
Transformer nominal tertiary voltage		kV
Transformer nominal HV voltage		kV
Tapped winding		HV/MV/LV/None (Delete what is not applicable)
Transformer ratio at all transformer taps		
Transformer Impedance (resistance R and reactance X) at all taps	R+jX	% on rating MVA_{Trans}
For three-winding transformers, where there are external connections to all three windings, the impedance (resistance R and reactance X) between each pair of windings is required, measured with the third set of terminals open-circuit.	Z_{HVMV}, Z_{HVLV}, & Z_{MVLV}	% on rating MVA_{Trans} % on rating MVA_{Trans} % on rating MVA_{Trans}
Transformer zero sequence impedances at nominal tap		
Zero phase sequence impedance measured between the HV terminals (shorted) and the neutral terminal, with the LV terminals open-circuit.	$Z_{HT\ 0}$	Ohm
Zero phase sequence impedance measured between the HV terminals (shorted) and the neutral terminal, with the LV terminals short-circuited to the neutral.	$Z_{HL\ 0}$	Ohm
Zero phase sequence impedance measured between the LV terminals (shorted) and the neutral terminal, with the HV terminals open-circuit.	$Z_{LT\ 0}$	Ohm
Zero phase sequence impedance measured between the LV terminals (shorted) and the neutral terminal, with the HV terminals short-circuited to the neutral.	$Z_{LH\ 0}$	Ohm
Zero phase sequence leakage impedance measured between the HV terminals (shorted) and the LV terminals (shorted), with the Delta winding closed.	$Z_{L\ 0}$	Ohm
Earthing arrangement, including LV neutral earthing resistance and reactance core construction (number of limbs, shell or core type)		
Open circuit characteristic		Graph

Transformer test certificates, from which actual technical detail can be extracted as required, are to be supplied on request.

3. Shunt capacitor or reactor data requirements

(l) For each shunt capacitor or reactor or power factor correction equipment or harmonic filters with a rating in excess of 1 MVAr connected to or capable of being connected to a transmission customer network, the transmission customer shall inform the transmission company and, if required, shall provide the transmission company with the specific shunt capacitor or reactor data as well as network details necessary to perform primarily harmonic resonance studies. The transmission customer shall inform the transmission company of its intention to extend or modify this equipment.

(2) If any Grid Code participant finds that a capacitor bank of 1MVAr or less is likely to cause harmonic resonance problems on the TS, he shall inform the transmission company. The 1MVAr minimum size limit shall thereafter be waived in respect of the affected network for information reporting purposes in respect of this code, and the transmission company shall inform the affected Grid Code participants of this fact and request the additional data. If the affected network is modified or reinforced to the extent that capacitor banks of 1 MVAr or less no longer cause harmonic resonance problems on the TS, the transmission company shall inform the affected Grid Code participants that information reporting requirements have returned to normal.

(3) A Grid Code participant investigating a complaint about harmonic distortion, shall have the right to request such additional information (including, but not restricted to, data from harmonic distortion measuring devices) from parties in the vicinity of the source of the complaint as may reasonably be required to complete the investigation.

Shunt capacitor or reactor rating	Rating (MVAr)
Reactor/capacitor/harmonic filter	(delete what is not applicable)
Location (station name)	
Voltage rating	kV
Resistance/reactance/susceptance of all components of the capacitor or reactor bank	
Fixed or switched	
If switched	Control details (manual, time, load, voltage, etc.)
If automatic control	Details of settings. If under FACTS device control (e.g. SVC), which device?

4. Series capacitor or reactor data requirements

(1) Series capacitors are installed in long transmission lines to increase load transfer capability.

(2) Series reactors are installed to limit fault levels, or to balance load sharing between circuits operated in parallel that would otherwise not share load equitably, or to balance load sharing on an interconnected network.

Reactor/capacitor	**(Delete what is not applicable)**
Location (specify substation bay where applicable)	
Voltage rating	kV
Impedance rating	Ohm or MVAr
Current rating (continuous and emergency, maximum times for emergency ratings)	Continuous: A Hours A Hours A Hours A

(3) Note: if a series capacitor or reactor is located in a dedicated reactor or capacitor station (i.e. a substation built to hold only the series reactor or capacitor), the lines or cables linking it to each remote end substation must be specified as separate circuits under line or cable data.

5. FACTS devices and HVDC data

5.1 FACTS devices

(1) FACTS devices enable system parameters (voltage, current, power flow) to be accurately controlled in real time. Because of their cost, they are generally used only if cheaper, more conventional, solutions cannot deliver the required functionality.

(2) Applications requiring rapid control capability include the following:

(a) Voltage regulation following loss of a system component, generation, large load, or HVDC link disturbance;

(b) Automatic reclosing cycle furnace voltage flicker mitigation;

(c) Negative phase sequence voltage compensation;

(d) Sub-Synchronous Resonance (SSR) damping;

(e) Machine transient stability enhancement;

(f) System load transfer capability enhancement; and

(g) Load sharing control in interconnected, deregulated, networks.

(3) The most commonly used FACTS device is the SVC (static Var compensator). Other FACTS devices made possible by advances in power electronics and control systems include STATCON (static condenser), TCSC (thyristor controlled series capacitor), thyristor controlled tap changer, thyristor controlled phase shifter, BES (battery energy storage), and UPFC (unified power controller). The common factor is rapid control capability.

(4) Because FACTS devices are purpose-designed for their specific applications, the following data is required:

Name	**Station, HV voltage, device number**
Type	(SVC, STATCON, TCSC, etc.)
Configuration: Provide a single line diagram showing all HV components and their MVA/ MVAr and voltage ratings, with all controlled components identified as such.	
Control system: Provide a block diagram of the control system suitable for dynamics modelling.	
Primary control mode	Voltage control, automatic reclosing cycle furnace flicker mitigation, negative phase sequence voltage control, etc.

(5) Transmission customers are required to perform, or cause to be performed, harmonic studies to ensure that their installation does not excite harmonic resonance, and that harmonic distortion levels at the PCC with the TS do not exceed the limits specified in NRS048.

5.2 HVDC

(1) Strictly speaking, HVDC is a form of FACTS device because of the rapid control capabilities. However, HVDC is treated separately because its primary function is the transmission of real power.

HVDC is used to connect two systems that are not necessarily interconnected via the AC network (and thus in synchronism), or even at the same nominal frequency.

(2) Transmission customers wishing to connect HVDC systems to the TS shall supply a single line diagram showing all HV plant (including valve bridges) forming part of the HVDC system, plus additional HV plant required for its proper operation, e.g. harmonic filters, synchronous condensers, FACTS devices, etc. Transmission customers and the transmission company shall cooperate in performing, or causing to be performed, studies to determine network strengthening requirements needed to accommodate the HVDC system without violating the planning criteria specified in CHAPTER 3. In addition, transmission customers shall thereafter perform, or cause to be performed, studies to demonstrate that the proposed HVDC system does not cause exceedance of QOS parameters specified in NRS048, and where applicable shall specify what additional HV plant will be required to ensure compliance with NRS048.

6. Information on transmission customer networks

(1) If a transmission customer will have two or more points of supply from the TS, including the one applied for, the transmission customer shall specify the amount of load to be transferred from existing points of supply to the new one under normal conditions as well as under contingencies. The same requirement applies to any embedded generator within the transmission customer's network, since they affect fault levels as well as net load on the system.

(2) The transmission customer shall also specify whether it intends to interconnect two or more transmission points of supply via its network. In such circumstances the transmission customer shall provide detailed information on the lines and cables used.

(3) Where a circuit consists of two or more segments of different characteristics (different overhead line tower and/or conductor bundle types and/or underground cable types), each section shall be specified separately.

7. Overhead line data

	Units
Line description	Name ("from" Busbar, "to" Busbar, circuit number and, where applicable, line section number numbered from the "from" bus end)
Line voltage (specify separately for dual voltage multi-circuit lines)	kV
Single / double / multiple circuit	
Standard suspension tower information (to confirm impedance): Supply copy of tower drawing, or sketch drawing showing co-ordinates of shield wire and phase conductor bundle attachment points relative to tower centre line and ground level at nominal tower height.	
Phase sub-conductor type (per circuit)	
Number of sub-conductors per phase conductor bundle	
Sub-conductor spacing, if applicable (supply sketch showing phase conductor bundle geometry and attachment point)	mm
Number of earth wires	
Earth wire description	
Line length	km
Conductor parameters (R, X, B, R0, X0, B0)	Ohmic values or P.U. on 100MVA base (specify)
Conductor normal and emergency ratings	Ampere or 3 phase MVA at nominal voltage

8. Cable data

Cable description	**Name** ("from" Busbar, "to" Busbar, circuit number, and where applicable, line section number numbered from the "from" bus end)
Voltage rating	kV
Type (copper/aluminium)	(Delete what is not applicable)
Size	mm^2
Impedance (R, X, B, R_0,X_0,B_0)	Ohms or P.U. on 100MVA base (specify)
Length	km
Continuous and (where applicable) emergency current rating and time limit	Amp or MVA at nominal voltage (specify), hours maximum at emergency rating

Generator's planning data

Unless otherwise indicated, the following information shall be provided to the transmission company prior to connection and then updated as and when changes occur.

1. Power station data

Generator name	
Power Station name	
Number of generating units	
Primary fuel type / prime mover	For example gas, hydro, fossil or nuclear
Secondary fuel type	For example oil
Capacity requirement	Generation sent-out connection capacity required (MW)
"Restart after station blackout" capacity	Provide a document containing the following: Start-up time for the first generating unit (time from restart initiation to synchronize) and each of the following generating units assuming that restarting of generating units will be staggered.
Black starting capacity	A document stating the number of generating units that can be black started at the same time, preparation time for the first generating unit black starting restarting time for the first generating unit, and restating time for the rest of the generating units.
Partial load rejection capability	A description of the amount of load the generating unit can automatically govern back, without any restrictions, as a function of the load at the point of governing initiation.
Multiple generating unit tripping (MUT) risks	A document outlining all systems common to more than one generating unit that is likely to cause a MUT. Discuss the measures taken to reduce the risk of MUT.

2. Generating unit data

Generating Unit number	
Capacity	Generating Unit capacity (MW)

	Units
Normal maximum continuous generation capacity:	MW
Normal maximum continuous sent out capacity	MW
Generating Unit auxiliary active load	MW
Generating Unit auxiliary reactive load	MVAr
Maximum (EL1) generating capacity	MW
Maximum (EL2) sent out capacity	MW
Normal minimum continuous generating capacity	MW
Normal minimum continuous sent out capacity	MW
Generator rating (Mbase)	MVA
Normal maximum lagging power factor	MVAr
Normal maximum leading power factor	MVAr
Governor droop	
Forbidden loading zones	MW
Terminal voltage adjustment range	kV
Short circuit ratio	
Rated stator current	Amp

Time to synchronise from warm	Hour
Time to synchronise from cold	Hour
Minimum up-time	Hour
Minimum down-time	Hour
Normal loading rate	MW/min
Normal de-loading rate	MW/min
Can the generating unit start on each fuel?	
Ability to change fuels on-load	
Available modes (lean burn etc.)	
Time to change modes on-load	
Control range for secondary frequency regulation operation	MW
Partial load rejection capability	% MW name plate rating
Minimum time generating unit operates in island mode	Hour
Maximum time generating unit operates in island mode	Hour

Description	**Data**
Capability chart showing full range of operating capability of the generating unit, including thermal and excitation limits	Diagram
Systems that are common and can cause a multiple generating unit trip	Description
Open circuit magnetisation curves	Graph
Short circuit characteristic	Graph
Zero power factor curve	Graph
V curves	Diagram

Documents	**Description**
Protection setting document	A document agreed and signed by the system operator containing the following: • A section defining the base values and per generating unit values to beused • A single line diagram showing all the protection functions and sources of current and voltage signals • A protection tripping diagram(s) showing all the protection functions and associated tripping logic and tripping functions • A detailed description of setting calculation for each protection setting, discussion on protection function stability calculations, and detailed dial settings on the protection relay in order to achieve the required setting • A section containing a summary of all protection settings on a per generating unit basis • A section containing a summary for each of the protection relay dial settings/ programming details • An annex containing plant information data (e.g. OEM data) on which the settings are based • An annex containing OEM information sheets or documents describing how the protection relays function

Excitation setting document	A document agreed and signed by the system operator containing the following: • A section defining the base values and per generating unit values to be used • A single line diagram showing all the excitation system functions and all the related protection tripping functions • An excitation system transfer function block diagram in accordance with IEEE or IEC standard models • A detailed description of setting calculation for each of the excitation system functions, discussion on function stability calculations, and detailed dial settings on the excitation system in order to achieve the required setting • A section containing a summary of all settings on a per generating unit basis • A section containing a summary for each of the excitation system dial settings/ programming details. • An annex containing plant information data (e.g. OEM data) on which the settings are based • An annex containing OEM information sheets or documents describing the performance of the overall excitation system and each excitation function for which a setting is derived
Governor setting document	A document agreed and signed by the system operator containing the following: • A section defining the base values and per generating unit values to be used • A single line diagram showing all the excitation system functions and all the related protection tripping functions • An excitation system transfer function block diagram in accordance with IEEE standard models • A detailed description of setting calculation for each of the governor system functions, discussion on function stability calculations, and detailed dial settings on the governor system in order to achieve the required setting • A section containing a summary of all settings on a per generating unit basis • A section containing a summary for each of the governor system dial settings/ programming details • An annex containing plant information data (e.g. OEM data) on which the settings are based • An annex containing OEM information sheets or documents describing the performance of the overall governor system and each governor function for which a setting is derived

3. Reserve capability

The generator shall provide the system operator with the reserve capability of each generating unit at each power station. The reserve capability shall be indicated as per each reserve category: instantaneous reserve, regulating reserve, emergency reserve, 10-minute reserve and supplemental reserve.

4. Generating unit parameters

	Symbol	Units
Direct axis synchronous reactance	X_d	% on rating
Direct axis transient reactance saturated	$X'_{d_{sat}}$	% on rating
Direct axis transient reactance unsaturated	$X'_{d_{unsat}}$	% on rating
Sub-transient reactance unsaturated	$X''_d = X''_q$	% on rating
Quad axis synchronous reactance	X_q	% on rating

Quad axis transient reactance unsaturated	$X'_{q_{unsat}}$	% on rating
Negative phase sequence synchronous reactance	X_2	% on rating
Zero phase sequence reactance	X_{0q}	% on rating
Generating unit inertia constant for entire rotating mass	H	*MW* s/*MVA*
Stator resistance	Ra	% on rating
Stator leakage reactance	X_L	% on rating
Poiter reactance	X_P	% on rating
Generating units generator time constants: · Direct axis open-circuit transient · Direct axis open-circuit sub-transient · Quad axis open-circuit transient · Quad axis open-circuit sub-transient · Direct axis short-circuit transient · Direct axis short-circuit sub-transient · Quad axis short-circuit transient · Quad axis short-circuit sub-transient	 Tdo' Tdo'' Tqo' Tqo'' Td' Td'' Tq' Tq''	 sec sec sec sec sec sec sec sec
Speed damping	D	
Saturation ratio at 1 pu terminal voltage	S(1.0)	
Saturation ratio at 1.2 pu terminal voltage	S(1.2)	

5. Excitation system

(l) The generator shall fill in the following parameters or supply a Laplace-domain control block diagram in accordance with IEEE or IEC standard excitation models (or as otherwise agreed with the system operator) completely specifying all time constants and gains to fully explain the transfer function from the compensator or generating unit terminal voltage and field current to generating unit field voltage. Transmission customers shall perform, or cause to be performed, small signal dynamic studies to ensure that the proposed excitation system and turbine governor do not cause dynamic instability. Where applicable, a PSS (power system stabiliser) shall be included in the excitation system to ensure proper tuning of the excitation system for stability purposes.

	Symbol	**Units**
Excitation system type (*AC* or *DC*)		Text
Excitation feeding arrangement (solid or shunt)		Text
Excitation system filter time constant	Tr	sec
Excitation system lead time constant	Tc	sec
Excitation system lag time constant	Tb	sec
Excitation system controller gain	Ka	
Excitation system controller lag time constant	Ta	sec
Excitation system maximum controller output	Vmax	P.U.
Excitation system minimum controller output	Vmin	P.U.
Excitation system regulation factor	Kc	
Excitation system rate feedback gain	Kf	
Excitation system rate feedback time constant	Tf	sec

6. Speed governor system, turbine and boiler models

The generator shall supply a Laplace domain control block diagram in accordance with IEEE standard prime mover models for thermal and hydro generating units (or as otherwise agreed

with the transmission company), fully specifying all time constants and gains to fully explain the transfer function for the governor, turbine, penstocks and control systems in relation to frequency deviations and set-point operation.

7. Control devices and protection relays

The generator should supply any additional Laplace domain control diagrams for any outstanding control devices (including power system stabilisers) or special protection relays in the generating unit that automatically impinge on its operating characteristics within 30 seconds following a system disturbance and that have a minimum time constant of at least 0,02 seconds.

8. Pumped storage

	Symbol	**Units**
Reservoir capacity		MWh pumping
Max pumping capacity		MW
Min pumping capacity		MW
Efficiency (generating/pumping ratio)		%

9. Generating unit step-up transformer

	Symbol	**Units**
Number of windings		
Vector group		
Rated current of each winding		Amps
Transformer rating		MVA_{Trans}
Transformer nominal LV voltage		kV
Transformer nominal HV voltage		kV
Tapped winding		
Transformer ratio at all transformer taps		
Transformer impedance at all taps (For three winding transformers the HV/LV1, HV/LV2 and LV1/ LV2 impedances together with associated bases shall be provided)		% on rating MVA_{Trans}
Transformer zero sequence impedance at nominal tap	Z_0	Ohm
Earthing arrangement, including neutral earthing resistance and reactance		
Core construction (number of limbs, shell or core type)		
Open circuit characteristic		Graph

10. Generating unit forecast data

The generator shall provide the transmission company with expected maintenance requirements, in weeks per annum, for each generating unit at a power station.

11. Mothballing of generating units or power station

Mothballing of generating units or a power station is the withdrawal of plant from commercial service for six months or longer, with the intention of returning it to commercial service at a later date. Mothballing can have a profound impact on the operation and integrity of the TS. Transmission customers wishing to mothball generating plant shall supply the transmission company with the following information:

Generator name	
Power station name	
Generating unit number	
Date withdrawn	Date generating unit is to be withdrawn from commercial service
Return to commercial service	Envisaged return to service date (re-commissioning tests completed and generating unit available for commercial service)
Auxiliary power requirements	

12. Return to service of mothballed generating unit or power station

Once the transmission customer has decided to return mothballed generating unit or power station to service, the transmission company requires the information specified for new connections.

13. Decommissioning of a power station

Decommissioning of plant is the permanent withdrawal from service of a power station. The transmission company requires the following with a one-year notice period:

Generator name	
Power station name	
Generating unit number	
Date to be removed from commercial service	
Auxiliary supplies required for dismantling and demolition	kVA, point at which supply is require, duration

ANNEXURE 8: GENERATOR'S MAINTENANCE DATA

Generator's maintenance data

(1) The 52-weeks-ahead outage plan per week per power station shall be supplied weekly to the system operator.

Generator:					
DATE (week starting)					
WEEK NUMBER:		n	n+1	…	n+51
MAINTENANCE (MW)					
WEEKEND OUTAGES		0	0	0	0
Power station 1		0	0	0	0
Power station 2		0	0	0	0
Power station 3		0	0	0	0
Power station n		0	0	0	0
TOTAL MAINTENANCE					
FUTURE KNOWN UNPLANNED:		0	0	0	0
		MAJOR CHANGES SINCE LAST WEEK:			
Notes:					
FUTURE KNOWN UNPLANNED :	a)				
	b)				

(2) The annual maintenance/outage plan per power station, looking five years ahead, shall be supplied to the system operator.

(3) The format shall be as per the 52-weeks-ahead outage plan per week per power station but extending for five years.

(4) A monthly variance report, explaining the differences between the above two reports, shall be supplied to the system operator.

Variance Report Template							
Power station and	**MW**	**Start-Date**	**Outage Completion-Date**				
Outage Code	**Cap**	**Official**	**Official**	**Revised**	**Urg**	**Outage Description**	**Reason for Difference**

Operational data

(1) This Annexure specifies the data format to be used by the SCADA system for the mapping of RTU data into the SCADA database. The data base has a definition for each electrical configuration (ELC) or electrical object in the station. Each ELC definition specifies a different ELC type, e.g. transformers, generating units, feeders, etc, and is accompanied by a picture showing the ELC and all its associated devices as they would be indicated on the system operator operational one-line displays. In each instance, the picture defines the primary devices and is followed by the points belonging to each device.

(2) Description of table column headings used in this section:

Device	01_State	10_State	Category	Type	Control

Device Gives the name of the device and acts as a collector of all point information belonging to the device. Each binary status point can be mapped to one or two binary bits. In the case of a breaker or isolator, the state is reported via two bits. In the case of single-bit alarm points, only one bit is used to report the state of the indication.

01_state This is the **alarm** state of the point.
10_state This is the **normal** state of the point.
In the table below the TYPE column indicates the number of bits used to report the state of the point in question.

For single-bit points please ignore the left-hand 0 or 1 value in the headings "01-State" and "10-State".

Where an indication uses two bits to report the state, the right-hand bit is used report that the state is OPEN and the left-hand bit to report the state when it is CLOSED. Thus an open condition will be "01" and a closed state will be "10".

It is thus illogical for a device to have a permanent value of either "00" or "11". However, if the device is in transit between "01" and "10" then a temporary value of "00" is possible. The SCADA system reports a state of "00" as "In transit", which will normally only be seen on slow-moving devices such as isolators.

Category Defines the category the point belongs to: health, main protection, back-up protection or information.
Classical alarm systems attempt to set priorities on alarm points. However, the priority of a point changes as the system changes, which means having a fixed priority is not useful. As an alternative, the approach used here is to assign the point to the area that is affected by the indication. In this case we have four areas, namely:

Health	All alarm indications that refer to the health of the primary or secondary plant are assigned to this category.
Main protection	All protection activity that is triggered by the main 1 protection circuits is assigned to this category.
Backup protection	Where back-up protection is installed, such as on transformers, or where main 2 protection is used, these alarms are assigned to this category.
Information	Pure state change data such the state of a breaker or isolator are assigned to this category. As such, no alarming is associated with these points – the data presented is pure information.

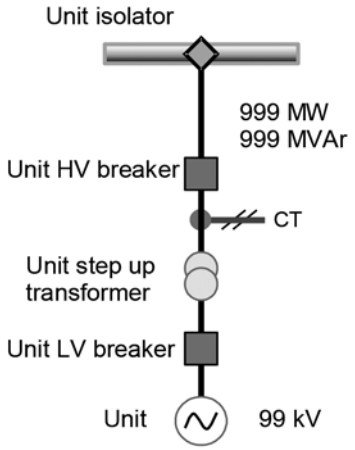
Type Indicates the type of point – single-bit, double-bit, analogue or binary change detection.

Control Indicates if there is a supervisory control associated with the point

1. Generator

The generator shall install operational measurements to specification from the system operator so as to provide continuous operational information for both real time and recording purposes in relation to each generating unit at each power station in respect of the following:

(1) Gas turbines



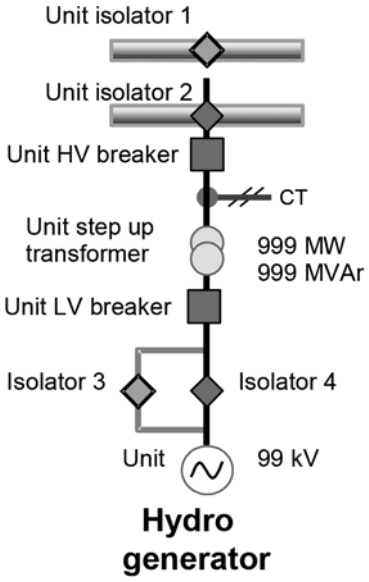
Gas turbine

Generating unit isolator	01_State	10_State	Category	Type	Control
Pole	Disagree	Normal	Health	Single	False
Generating unit isolator state	Open	Closed	Info	Double	False
Generating unit HV Breaker	01_State	10_State	Category	Type	Control
Breaker failed to trip	Alarm	Normal	Main	Single	False
Bus zone trip	Alarm	Normal	Info	Single	False
Earth applied	Alarm	Normal	Health	Single	False
Pole	Disagree	Normal	Health	Single	False
Protection abnormal	Alarm	Normal	Health	Single	False
Protection operated	Alarm	Normal	Main	Single	False
Protection unhealthy	Alarm	Normal	Health	Single	False
Breaker gas critical	Alarm	Normal	Health	Single	False
Breaker non-urgent	Alarm	Normal	Info	Single	False
Generating unit breaker state	Closed	Tripped	Info	Double	False
Current transformer	01_State	10_State	Category	Type	Control
SF6 gas critical (CT)	Alarm	Normal	Health	Single	False
SF6 non-critical (CT)	Alarm	Normal	Health	Single	False
Generating unit Step Up Transformer	01_State	10_State	Category	Type	Control

Reactive power			Info	Analogue	False
Active power			Info	Analogue	False
Generating unit LV Breaker	01_State	10_State	Category	Type	Control
Breaker failed to trip	Alarm	Normal	Main	Single	False
Earth applied	Alarm	Normal	Health	Single	False
Pole	Disagree	Normal	Health	Single	False
Breaker gas critical	Alarm	Normal	Health	Single	False

Breaker non-urgent	Alarm	Normal	Info	Single	False
Generating unit breaker state	Closed	Tripped	Info	Double	False
Generating unit	01_State	10_State	Category	Type	Control
Engine A	Ready	Not ready	Health	Single	False
Engine B	Ready	Not ready	Health	Single	False
Frequency			Info	Analogue	False
Generating unit start not ready	Alarm	Normal	Health	Single	False
Remote control	On	Off	Info	Single	True
SCO start not ready	Alarm	Normal	Health	Single	False
Sequence starting	Auto	Manual	Info	Single	False
Stator voltage			Info	Analogue	False
Supervisory	Isolated	Off	Info	Single	False
Under-frequency start	Armed	Off	Health	Single	False
Generating unit at standstill	Yes	Normal	Info	Single	True
Generating unit auto load to base	Yes	No	Info	Single	True
Generating unit auto load to minimum	Yes	No	Info	Single	True
Generating unit auto load to peak	Yes	No	Info	Single	True
Generating unit failed to start	Alarm	Normal	Health	Single	False
Generating unit voltage			Info	Analogue	False
Generating unit in generation mode	Yes	No	Info	Single	True
Generating unit in SCO mode	Yes	No	Info	Single	True
Generating unit load rate	Fast	Slow	Info	Single	True
Generating unit loading mode	Auto	Manual	Info	Single	False
Generating unit reactive power generated			Info	Analogue	False
Generating unit reactive power sent out			Info	Analogue	False
Generating unit active power generated			Info	Analogue	False
Generating unit active power sent out			Info	Analogue	False
Generating unit tripped and locked out	Alarm	Normal	Info	Single	False
Generating unit under frequency start	Initiate	No	Info	Single	False

(2) Hydro generating units



Generating unit isolator 1	01_State	10_State	Category	Type	Control
Pole	Disagree	Normal	Health	Single	False
Generating unit isolator state	Open	Closed	Info	Double	False
Generating unit isolator 2	01_State	10_State	Category	Type	Control
Pole	Disagree	Normal	Health	Single	False
Generating unit isolator state	Open	Closed	Info	Double	False
Generating unit HV breaker	01_State	10_State	Category	Type	Control
Breaker failed to trip	Alarm	Normal	Main	Single	False
Bus zone trip	Alarm	Normal	Info	Single	False
Earth applied	Alarm	Normal	Health	Single	False
Pole	Disagree	Normal	Health	Single	False
Protection abnormal	Alarm	Normal	Health	Single	False
Protection operated	Alarm	Normal	Main	Single	False
Protection unhealthy	Alarm	Normal	Health	Single	False
Breaker gas critical	Alarm	Normal	Health	Single	False
Breaker non-urgent	Alarm	Normal	Info	Single	False
Generating unit breaker state	Closed	Tripped	Info	Double	False
Current transformer	01_State	10_State	Category	Type	Control
SF6 gas critical (CT)	Alarm	Normal	Health	Single	False
SF6 non-critical (CT)	Alarm	Normal	Health	Single	False
Generating unit LV Breaker	01_State	10_State	Category	Type	Control
Breaker failed to trip	Alarm	Normal	Main	Single	False
Earth applied	Alarm	Normal	Health	Single	False
Pole	Disagree	Normal	Health	Single	False
Breaker gas critical	Alarm	Normal	Health	Single	False
Breaker non-urgent	Alarm	Normal	Info	Single	False
Generating unit breaker state	Closed	Tripped	Info	Double	False
Generating unit step up transformer	01_State	10_State	Category	Type	Control
Reactive power			Info	Analogue	False
Active power			Info	Analogue	False

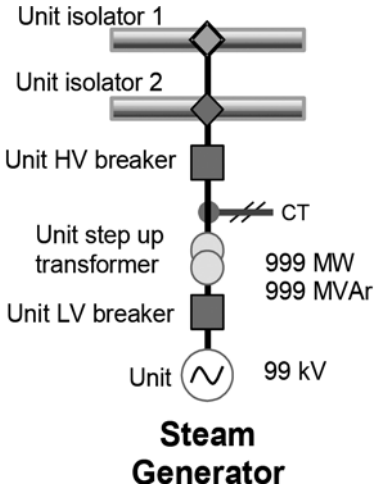
Isolator 3	01_State	10_State	Category	Type	Control
Pole	Disagree	Normal	Health	Single	False
Generating unit isolator state	Open	Closed	Info	Double	False
Isolator 4	01_State	10_State	Category	Type	Control
Pole	Disagree	Normal	Health	Single	False
Generating unit isolator state	Open	Closed	Info	Double	False
Generating unit	01_State	10_State	Category	Type	Control
Frequency			Info	Analogue	False
Auto load	Active	Normal	Info	Single	True
Automatic power factor regulator	Operated	Normal	Health	Single	True
Emergency trip	Operated	Normal	Main	Single	True
Generating unit start not ready	Alarm	Normal	Health	Single	False
Generating unit to pump mode	Active	Off	Info	Single	True
Generating unit to SCO mode	Active	Off	Info	Single	True
Pump start not ready	Alarm	Normal	Health	Single	False
Pump to generation mode	Active	Off	Info	Single	True
Pump to SCO mode	Active	Off	Info	Single	True
SCO start not ready	Alarm	Normal	Health	Single	False
SCO to generation mode	Active	Off	Info	Single	True
SCO to pump mode	Active	Normal	Info	Single	True
Sequence starting	Auto	Manual	Info	Single	False
Stator voltage	Info	Analogue	Log_only	No	
Under-frequency start	Armed	Off	Health	Single	False
Generating unit AGC – high limit	High	Normal	Health	Single	False
Generating unit AGC – high regulating limit	Health	Analogue	Panel	No	
Generating unit AGC – low limit	Low	Normal	Health	Single	False
Generating unit AGC – low regulating limit			Health	Analogue	False
Generating unit AGC – raise/ lower blocking	Off	Normal	Info	Single	False
Generating unit AGC – ramp rate			Info	Analogue	False
Generating unit AGC – set-point active power			Info	Analogue	True
Generating unit AGC – status	On	Off	Info	Single	False
Generating unit at standstill	Yes	Normal	Info	Single	True
Generating unit voltage			Info	Analogue	False
Generating unit guide vane			Info	Analogue	True
Generating unit in generation mode	Yes	No	Info	Single	True
Generating unit in pump mode	Yes	No	Info	Single	True

Generating unit in SCO mode	Yes	No	Info	Single	True
Generating unit load limiter			Info	Analogue	True
Generating unit reactive power generated			Info	Analogue	False
Generating unit reactive power sent out			Info	Analogue	False
Generating unit active power generated			Info	Analogue	False
Generating unit active power sent out			Info	Analogue	False
Generating unit synchronising	Yes	No	Info	Single	False
Generating unit turning in generation direction	Yes	No	Info	Single	False
Generating unit turning in motor direction	Yes	No	Info	Single	False

Breaker non-urgent	Alarm	Normal	Info	Single	False
Generating unit breaker state **current transformer**	Closed **01_State**	Tripped **10_State**	Info **Category**	Double **Type**	False **Control**
SF6 gas critical (CT)	Alarm	Normal	Health	Single	False
SF6 non-critical (CT) **Generating unit step up transformer**	Alarm **01_State**	Normal **10_State**	Health **Category**	Single **Type**	False **Control**
Reactive power			Info	Analogue	False
Active power **Generating unit LV breaker**	 **01_State**	 **10_State**	Info **Category**	Analogue **Type**	False **Control**
Breaker failed to trip	Alarm	Normal	Main	Single	False
Earth applied	Alarm	Normal	Health	Single	False
Pole	Disagree	Normal	Health	Single	False
Breaker gas critical	Alarm	Normal	Health	Single	False
Breaker non-urgent	Alarm	Normal	Info	Single	False
Generating unit breaker state **steam generating unit**	Closed **01_State**	Tripped **10_State**	Info **Category**	Double **Type**	False **Control**
Generating unit AGC – high limit	High	Normal	Health	Single	False
Generating unit AGC – high regulating limit			Health	Analogue	False
Generating unit AGC – low limit	Low	Normal	Health	Single	False
Generating unit AGC – low regulating limit			Health	Analogue	False
Generating unit AGC – raise/ lower blocking	Off	Normal	Info	Single	False
Generating unit AGC – ramp rate			Info	Analogue	False
Generating unit AGC – set-point active power			Info	Analogue	True
Generating unit AGC – status	On	Off	Info	Single	False
Generating unit voltage			Info	Analogue	False
Generating unit islanded	Alarm	No	Health	Single	False

Generating unit reactive power generated			Info	Analogue	False
Generating unit reactive power sent out			Info	Analogue	False
Generating unit active power generated			Info	Analogue	False
Generating unit active power sent out			Info	Analogue	False

(3) Steam generating units



Generating unit isolator 1	**01_State**	**10_State**	**Category**	**Type**	**Control**
Pole	Disagree	Normal	Health	Single	False
Generating unit isolator state	Open	Closed	Info	Double	False
Generating unit isolator 2	**01_State**	**10_State**	**Category**	**Type**	**Control**
Pole	Disagree	Normal	Health	Single	False
Generating unit isolator state	Open	Closed	Info	Double	False
Generating unit HV breaker	**01_State**	**10_State**	**Category**	**Type**	**Control**
Breaker failed to trip	Alarm	Normal	Main	Single	False
Bus zone trip	Alarm	Normal	Info	Single	False
Earth applied	Alarm	Normal	Health	Single	False
Pole	Disagree	Normal	Health	Single	False
Protection abnormal	Alarm	Normal	Health	Single	False
Protection operated	Alarm	Normal	Main	Single	False
Protection unhealthy	Alarm	Normal	Health	Single	False
Breaker gas critical	Alarm	Normal	Health	Single	False

Generators contributing to regulating reserve shall provide indications for emergency generation and maximum generation for rescheduling.

2. Distributor and end-use customer

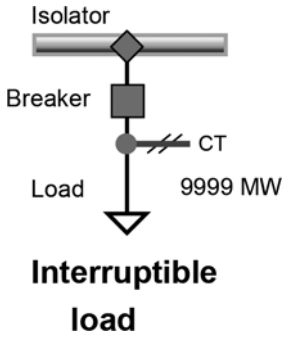
2.1 Transmission equipment

The transmission customer shall provide operational information for both real time and recording purposes in relation to each feeder, transformer and compensation device at each substation required for the full functionality of a SVC, as well as full control by the system operator.

2.2 Interruptible load

(1) All interruptible loads shall meet the minimum requirements. The system operator shall negotiate and integrate the conditions as presented in bilateral agreements and additional contracts without reducing the requirements as defined in this Code.

(2) The interruptible load shall install operational measurements to specification so as to provide operational information for both real time and recording purposes in relation to each controllable energy block in respect of the following minimum requirements for operation and control of an interruptible load:



Isolator	**01_State**	**10_State**	**Category**	**Type**	**Control**
Pole	Disagree	Normal	Health	Single	False
Isolator state	Closed	Open	Info	Double	False
Breaker	**01_State**	**10_State**	**Category**	**Type**	**Control**
Generating unit breaker state	Closed	Tripped	Info	Double	True
Current transformer	**01_State**	**10_State**	**Category**	**Type**	**Control**
SF6 gas critical (CT)	Alarm	Normal	Health	Single	False
SF6 non-critical (CT)	Alarm	Normal	Health	Single	False
Load	**01_State**	**10_State**	**Category**	**Type**	**Control**
Load reduction acknowledged	No	Yes	Info	Single	True
Load interrupt acknowledged	No	Yes	Info	Single	True
Block load reduction acknowledged	No	Yes	Info	Single	True
Return to service acknowledged	No	Yes	Info	Single	True
Load active power			Info	Analogue	False

(3) The availability of the interruptible load shall be integrated into the ancillary service schedules by the market operator before the transfer to the system operator.

ANNEXURE 10: GENERATOR'S PERFORMANCE DATA

1. Measurement of availability

(1) The Unipede/Eurelectric standard for the measurement of power station availability must be used. Availability is measured with the use of an indicator known as "energy availability factor" (EAF).

(2) EAF represents the network point-of-view.

(3) The "energy availability factor" has the same conceptual content as the "equivalent availability factor" used by USA operators, for example the NERC-GADS data bank.

(4) Energy availability factor is defined as the ratio of the available energy generation over a given time period (PH) to the reference energy generation over the same period, expressed as a percentage. Both of these energy generation terms are determined relative to reference ambient conditions.

(5) Available energy generation (b) for the purpose of calculating EAF is the energy that could have been produced under reference ambient conditions considering limitations within and beyond the control of the plant management.

$$b = Pd \times PH$$

(6) Reference energy generation (Y) is the energy that could be produced during a given time period if the generating unit were operated continuously at reference generating unit power (PM) under reference ambient conditions throughout the period.

$$Y = PM \times PH$$

(7) Reference ambient conditions are environmental conditions representative of the annual mean (or typical) ambient conditions for the generating unit.

(8) Alternative definition: The "energy availability factor" (f), over a specified period, is the ratio of energy (b) that the available capacity (Pd) could have produced during this period to the energy (Y) that the net maximum electrical capacity (PM) could have produced during the same period.

(b) The energy produced (b) (or capable of being produced) by the available capacity

$$f = \frac{b}{Y} = \frac{Y - c \times 100\%}{Y}$$

(Pd) may also be calculated as the difference between the energy (Y) (the maximum electrical capacity –PM – that could have been produced) and the unavailable energy (which was not produced or not able to be produced) by the total unavailable

Note: For the transmission company reporting systems (c) is calculated from a summation of unavailable MWh due to outages and restrictions (planned, unplanned, external and non-engineering) occurring throughout the period from *MW* capacity loss x duration (hr) of the loss.

$$f = \frac{b}{Y} = \frac{Y - c \times 100\%}{Y}$$

2. Components of the energy availability factor (EAF) (GCR1.1)

$$EAF = UCF - OCLF$$

(1) Unplanned capability loss factor (*UCLF*) (GCR1.2)

The purpose of this indicator is to monitor industry progress in minimising outage

time and power reductions that result from unplanned equipment failures or other conditions. This indicator reflects the effectiveness of power station programmes and practices in maintaining systems available for safe electrical generation.

(2) Other capability loss factor (OCLF) (*GCR* 1.3)

Other capability loss factor is an indicator to monitor outage time and power reductions due to causes beyond the control of power station management.

(3) Planned capability loss factor (*PCLF*) (GCR1.4)

Planned capability loss factor is defined as the ratio of the planned energy losses during a given period of time to the reference energy generation expressed as a percentage.

Planned energy loss is energy that was not produced during the period because of planned shutdowns or load reductions due to causes under power station management control. Energy losses are considered to be planned if they are scheduled at least four weeks in advance.

(4) Generating unit capability factor (UCF)

Note: UCF represents the generator's point of view
The purpose of this indicator is to monitor progress in attaining high generating unit and industry energy production availability. This indicator reflects effectiveness of power station programmes and practices in maximising available electrical generation and provides an overall indication of how well plants are operated and maintained.

3. Measurement of availability reliability

(1) The Unipede/Eurelectric standard for the measurement of power station reliability must be used.

(2) Reliability is measured with the use of two specific indicators, namely unplanned automatic grid separations (UAGS) and successful start-up rate.

4. Unplanned automatic grid separations per 7 000 operating hours (UAGS/7000h)

(1) The purpose of this indicator is to enable monitoring of an important aspect of the reliability of service supplied to the transmission power system. It takes into account success in improving reliability by reducing the number of turbo power station trips. It also provides an indication of power station operation and maintenance performance.

(2) Taking account of the number of operating hours when the turbo generator set is connected to transmission power system enables assessment of required reserves. Furthermore, using a common standard for all grid separation data for each generating unit provides a uniform basis for comparison among generating units with values for the industry as a whole.

(3) Intentional (manual) grid separations are not taken into account since operators should not be discouraged from taking action to protect equipment.

(4) This indicator may be defined as corresponding to the number of unplanned (unintentional) automatic grid separations of internal origin that occur per 7 000 operating hours. This definition can be clarified as follows:

"Unplanned" means that grid separation is not an anticipated part of a planned test, nor part of an operating programme designed to adjust output to demand

(e.g. a controlled shutdown). Controlled shutdowns of generating units where the line circuit breaker is manually or automatically opened at loads equal to or below the first automatic synchronising load should not be considered when computing this indicator.

(5) "Grid separation" means the opening of the generator breaker or HV yard breaker where no power station breaker exists. This could be an opening signal actuated by overshooting of a safety threshold, or a spurious trip. Grid separation can only occur during grid service of the generating units. Grid service is obtained when the start-up is successful for requested start-ups or when loads in excess of the first synchronising load are reached for "contracted" or "other start-ups" (i.e. house or block load as programmed into the automatic synchronising equipment).

(6) "Automatic" (unintentional) means that the grid separation is not the result of an action by the operator either on one of the switches to trigger a generating unit trip or grid separation or to simulate operation of a protection system.

(7) Trips caused by the operator in error, e.g. opening the wrong switch leading to a trip, are excluded from the "manual" category. Controlled shutdowns of generating units where the line circuit breaker is manually or automatically opened at loads equal to or below the first automatic synchronising load should not be considered when computing this indicator.

(8) "Operating" means that the turbo generator set is connected to the off-site grid (transmission of generated power) even if the alternator is operating in synchronous motor mode owing to exceptional circumstances.

(9) "Of internal origin" means that the trip is due to an unspecified internal installation failure resulting in a loss of reliability – even if the initial event can be traced to an off-site cause. The signal that triggered grid separation must originate from one of the sensors (or protection logic) for monitoring generating unit parameters (turbo generator set and power transmission, up to and including the power station transformer HV breaker, and boiler). Grid separations actuated by protection systems for the physical parameters of the transmission power system are not included unless they were incorrectly controlled.

(10) The selected figure of 7 000 hours represents the typical number of on-line hours for most power stations operating at base load or semi-base load. The indicator thus represents an approximate value of the actual number of grid separations occurring in one year.

(11) The following data are required to determine the value for this indicator -

(a) the number of unplanned automatic grid separations (U) with the generating unit circuit breaker (or HV breaker where no generating unit breaker exists) in initially closed position; and

(b) the number of operating hours (OPH).

(12) All automatic trips are counted for the UAGS indicator, including those auto trips occurring within +30 minutes of all requested start-ups that comply with the

±15-minute time limit for synchronization.

$$\frac{UAGS}{7000h} = \frac{U \times 7000}{OPH}$$

(13) Data for new generating units is included in the calculation of industry values beginning 1 January of the first calendar year following the start of commercial operation. However, in order to be included in the industry value, the generating unit must have at least 1 000 operating hours per year. This minimum operating period

requirement reduces the effects of plants that are shut down for long periods of time and for which limited data may not be statistically valid.

(14) Summarised definition of UAGS per 7 000 hours: This indicator tracks the average grid separation rate per 7 000 operating hours (approximately one year of operation) for generating units having at least 1 000 operating hours during the year. Only trips of internal origin to the installation are included and trips for the physical parameters of the transmission power system are not included unless they were incorrectly controlled.

5. Successful Start-up Rate (GCR2.2)

(1) The "successful start-up rate" is the ratio of the number of successful start-ups to the number of contracted start-ups over a given period of time. It measures the reliability of the service that is rendered to the *transmission customers*.

$$SSR = \frac{NumberOfSuccessfulStartUps \times 100\%}{NumberOfContractedStartUps}$$

(2) Start-up comprises the set of operations that enable the generating unit to be connected to the off-site transmission power system for the production of electrical energy according to requirements issued by the system operator. Connection of the generating unit to the transmission power system (closing the line circuit breaker) is the purpose of the first start-up phase, before loading and stabilisation at the required power level. Only this initial start-up phase, the success of which results in sustained connection to the transmission power system, is considered here.

(3) The contracted start-up refers to an agreement between the system operator (through any medium, i.e. verbally, telephonically, etc.) and the power station, following a request from the system operator or the power station. This forms part of a transmission power system management schedule (hereafter referred to as the 'real' National Control programme) for the full range of power generation resources (excluding tests). The request for a start- up in advance of the synchronising time corresponds to the technical delay due to equipment start-up times. This delay time can be reduced to almost zero in the case of start-up of peak-supply gas turbines with centralised, automatic control systems. For any given start-up contract, a precise time for transmission power system connection and an implementation schedule are required (except for peak-load gas turbines). In the event of a sudden modification by the system operator of the transmission power system connection contract time, within the start-up capabilities of the generating unit, a new contract needs to be entered into.

(4) The following indicators are still under development:

(a) protection management;

(b) ability to island;

(c) excitation system management;

(d) reactive capabilities;

(e) multiple-generating unit trip risks;

(f) governing requirements;

(g) restart after power station blackout capability;

(h) black start capability;

(i) intermediate load capability;

(j) external supply disturbance withstand capability;

(k) loading rates; and

(l) on-load tap changing for generating set-up transformers.

Planning schedules

Schedule 1: Ten-year demand forecast

	Demand = Total Demand + Distribution *Losses* – Embedded Generation					
			Maximum demand		**Expected minimum demand**	
Year		**GWh**	***MW***	**MVAr**	***MW***	**MVAr**
Measured (year 0)						
Year 1						
Year 2						
Year 3						
Year 4						
Year 5						
Year 6						
Year 7						
Year 8						
Year 9						
Year 10						

S	**Generation net sent out contribution at peak**	**Year 9**	
		Year 8	
		Year 7	
		Year 6	
		Year 5	
		Year 4	
		Year 3	
		Year 2	
		Year 1	
	Net sent out	**Peak**	
		Normal	
	On-site usage	**Peak**	
		Normal	

Power station	
Tx Substation name at closest connection point	
Operating power factor	
Installed capacity (MW)	
Plant type	

ANNEXURE 12: INFORMATION RELATING TO DETAILS SPECIFIED

No.	Detail	Specification
1.	Commissioning	Projected or target commissioning test date
2.	Operating	Target operational or on-line date
3.	Reliability of connection requested	Number of connecting circuits e.g. one or two feeders, or firm/ non-firm supply required (subject to this code and MSB market requirements)
4.	Location map.	Upgrades: Name of existing point of supply to be upgraded and supply voltage. New connections: Provide a 1:50 000 or other agreed scale location map, with the location of the facility clearly marked. In addition, please specify the co-ordinates of the point of connection.
5.	Site plan	Provide a plan of the site (1:200 or 1:500) of the proposed facility, with the proposed point of supply, and where applicable, the transmission line route from the facility boundary to the point of supply, clearly marked.
6.	Electrical single-line diagram	Provide an electrical single-line diagram of the transmission customer intake substation.

ANNEXURE 13: MEASUREMENT EQUIPMENT ACCURACY CLASSES

Measurement equipment	**Accuracy class**
Current transformer (CT)	0,2%
Voltage transformer (VT)	0,2%
Transducer	0,2%
Analogue to digital conversion, i.e. RTU	0,01%

ANNEXURE 14: DAILY 24 HOURS DAY-AHEAD ENERGY SCHEDULE

File	Description	Trigger event	Frequency
Dispatch schedule	The combined 24-hour day-ahead energy and ancillary services schedules. Hourly day-ahead contracts for different market categories that identify the generating unit with the next 24 hourly values for it.	Generation dispatch schedule	Daily
Daily price curve	Daily price curve with incremental prices and corresponding volumes.	Generation dispatch schedule	Daily

ANNEXURE 15: FILES TRIGGERED FOR DATA TRANSFER

File	Description	Trigger Event	Frequency
AGC pulses	The total pulses sent to a generating unit by the AGC system to move the set point up or down	Ongoing, file created at end of hour	Hourly
NERC	A list of the total NERC "A1" and "A2" criteria violations in the system over an hour	Ongoing, file appended at end of hour	Daily
System near real-time data	Historic near real-time system data files on readings as required for post-dispatch	Communication failure	To be agreed
Generating unit near real-time data	Historic near real-time generating unit data files on readings as required for post-dispatch	Communication failure	To be agreed

ANNEXURE 16: TESTING FORMAT FOR UNDER-FREQUENCY LOAD SHEDDING RELAYS

Distributor : Date: Substation: Fed from Transmission Substation (directly or indirectly):				
	Activating frequency		**Timer setting**	
	Required	**As tested**	**Required**	**As tested**
Stage 1				
Stage 2				
Stage 3				
Stage 4				
	Feeders selected (Required)		**Feeders selected (As tested)**	
Stage 1				
Stage 2				
Stage 3				
Stage 4				

ANNEXURE 17: TRANSMISSION POWER SYSTEM INFORMATION FORMAT FOR PERFORMANCE INDICATORS

Indicator	**Month**	**Year to date**	**12 MMI**	**Unit**
System minutes lost				minutes
No. of interruptions				
No. of statutory voltage transgressions				
Mandatory under-frequency load shedding				
Transmission customer voluntary load shedding				
Transmission power system losses				%