GOVERNMENT GAZETTE

OF THE

REPUBLIC OF NAMIBIA

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ELECTRICITY CONTROL BOARD

No. 560 2018

DISTRIBUTION GRID CODE: 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, has made the distribution grid code set out in the Schedule.

G. HINDA
CHAIRPERSON
BY ORDER OF THE BOARD

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CHAPTER 1
INTRODUCTORY PROVISIONS

PART 1
DEFINITIONS AND OBJECTIVES

Definitions

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

“administrative losses” means meter reading errors and any unbilled energy resulting from billing system operational errors;

“applicant” means a potential user intending to connect to the electricity distribution system;

“calibrate” means to establish the relationship between the values indicated by a measuring system and the corresponding values of a quality realised by a reference standard or a working standard;

“capacity” means the potential load that an electrical equipment or network can transfer;

“connection agreement” means an agreement detailing the conditions under which the distributor intends to connect a customer;

“connection charges” means fees recouped from a customer for the cost of providing new or additional capacity;

"connection fee" means an upfront fee payable by the customer for the cost of the connection;

"control and operating facility" means a facility of the distributor which is responsible for the operational control of electricity distribution network assets;

"cost of supply study" means a study for deriving and allocating costs for the design of tariffs excluding the determining of the connection charge;

"cross-subsidy" means the over-recovery of revenue from customers in some tariff classes in order to balance the under-recovery of revenue from customers in other tariff classes as informed by the cost of supply study;

"customer" means a person that has entered into an agreement with the distributor for the provision of distribution services;

"customer connection information guide" means a document prepared and published by the distributor which contains all information regarding an application to connect to the relevant distributor network;

"customer interruption cost" means the cost in Namibia Dollars per kWh to customers due to interruptions of supply;

"customer dedicated assets" means assets created for the sole use of a customer, to meet the technical specifications of the customer, and are unlikely to be shared in the planning horizon of the distributor by any other customer;

"dedicated assets" means the portion of the network which is dedicated to a specific customer;

"demand side management" means technologies or programmes that encourage the customers to modify patterns of electricity usage including timing, level of consumption, conservation, interruptability and load shifting;

"distribution charges" means charges applicable for the use of the distribution system including connection charges;

"distribution network" means the network owned and operated by a distributor;

"distribution system" means a system which consists wholly or mainly of medium and low voltage networks through which electricity is conveyed to a customer;

"distribution system impact assessment studies" means studies to model and assess the impact of connecting a customer load or an embedded generator on the distribution system;

"distribution use of system charges" means unbundled regulated tariffs charged to distribution network services customers for making capacity available to and for use of the distribution system and transmission connected customers for their fair contribution to distribution subsidies;

"distributor" means a person who holds a license issued under the Act for the distribution of electricity as contemplated under section 17(1)(e) of the Act;

"distributor cost" means the investment cost incurred by the distributor;

"domestic supply" means the supply taken by a customer occupying a residential dwelling;

"economic cost" means the total cost of the electricity related investment to both the distributor and the customer;

"economic evaluation" means evaluating the economic benefits and returns from the point of view of the distributor and the affected customer related to electricity infrastructure;

"embedded generator" means a legal entity that -

(a) operates a generating unit that is connected to the distribution system; or

(b) desires to connect a generating unit to the distribution system;

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

"energy charges" means charges designed to recover the costs of electrical energy and levied on the basis of energy consumed;

"excluded services" means the services requested by customers that are excluded from the regulated activities and funded directly by the customer requesting the service;

"financial evaluation" means evaluating the financial benefits and returns from the point of view of the electricity distribution industry;

"firm supply" means a distribution supply that can withstand any single (n-1) contingency within the distribution network;

"forced outage" 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;

"high voltage" means nominal voltage levels greater than 33 kV;

"information" means knowledge that can be exchanged and always expressed by some type of data stored and processed either electronically or otherwise;

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

"international customers" means customers who are situated outside the borders of the Republic of Namibia and supplied by the distributor;

"interruption of supply" means an interruption of the flow of power to a point of supply not requested by the customer for a period exceeding three seconds;

"islanding" means the capability of generating units to settle down at nominal speed, supplying own auxiliary load after separation from the grid, at up to full load pre-trip conditions;

"least economic cost" means least life cycle cost to both the distributor and the customer related to the electricity infrastructure;

"least life cycle cost" means the sum of all cost categories from installation to decommissioning when evaluating different investment alternatives;

"least life cycle distributor cost" means the least life cycle cost to the distributor;

"losses" means energy for which the distributor does not recover revenue and includes technical losses, non-technical losses and administrative losses.

"low voltage" means nominal voltage levels up to and including 1 kV;

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

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

"metering service provider" means a legal entity contracted by the distributor to provide metering services;

"medium voltage" means the nominal voltage levels greater than 1 kV up to and including 33kV;

"network" means the electrical infrastructure over which electrical energy is transported from source to point of consumption;

"network charges" means the charges, designed to recover costs associated with the provision of network capacity required by and reserved for the customer, which include the costs of capital, operations, maintenance and refurbishment;

"network service customers" means customers receiving only a network service from a distributor;

"non-technical losses" means losses due to theft of electrical energy, meter error or inaccurate meter reading;

"normal operating conditions" means operating conditions where the system frequency, voltage and equipment loading are within their statutory, contractual and design limits and no network component on the relevant part of the distribution system is out of service due to a forced outage or due to a planned outage;

"NRS" means a National Rationalised Standard;

"offer to connect" means a quotation issued by the distributor to the applicant indicating the technical and commercial conditions upon which a connection agreement can be entered into;

"participant" means a legal entity registered with or licensed by the Board in terms of the Act and includes embedded generators, traders, distribution licensees, transmission network service providers and the system operator;

"planned outage" means an outage of equipment that is requested, negotiated, scheduled and confirmed a minimum of 14 days prior to maintenance or repairs taking place;

"point of common coupling" means the electrical node where more than one customer is connected;

"point of connection" means the electrical node on a distribution system where the assets of a customer are physically connected to the assets of a distributor;

"point of supply" means the physical point on the electrical network where electricity is supplied or deemed to be supplied to a customer and at which the supply is metered;

"power factor" means the ratio of kW to kVA measured over the same integrating period;

"premium supply" means the requirements of the customer exceed the specifications of a standard supply premium connection;

"quality of supply" means the technical parameters that describe the electricity supplied to customers;

"reliability" means a measurement of the continuity of supply;

"service provider" means a -

(a) licensee as defined under section 1 of the Act; or

(b) legal entity licensed as contemplated under section 17(1)(d) or (e) of the Act;

"micro renewable in-feed" means a non-commercial renewable energy based generator with a peak output capacity -

(a) not exceeding 5kW; or

(b) meeting the specification contained in relevant rules published under the Act,

embedded within an installation of the customer which is operated and maintained by the customer;

"shared network investment" means -

(a) investment on shared infrastructure, non-dedicated, assets;

(b) investment required to provide adequate upstream network capacity;

(c) investment required to maintain or enhance supply reliability and quality to attain the limits or targets, determined in the Namibia Quality of Supply Standards, on existing network assets; and

(d) the refurbishment of existing standard dedicated connection assets;

"standard connection charge" means the connection charge associated with the costs of providing a standard supply;

"standard connection" means the lowest life-cycle cost design that meets the specifications in terms of the Namibia Quality of Supply and Service Standards for a technically acceptable solution and "standard supply" has a corresponding meaning;

"system operator" means the entity responsible for short-term reliability of the interconnected power system, which is in charge of controlling and operating the transmission system and dispatching generation, or balancing the supply and demand, in real time;

"tariff" means the combination of monthly charges each at a particular rate that is applied to recover revenue for measured quantities such as consumption and capacity costs and unmeasured quantities such as service costs;

"tariff structures" contains all the components of price and its relationship to consumption and demand;

"technical losses" means conductor losses, transformer losses and metering accuracy losses, energy consumed by the meter itself;

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

"trader" means a legal entity licensed or registered to engage in the wholesale buying and selling of electricity as a commercial activity;

"transmission company" means the Namibian legal entity, licensed to execute the national transmission responsibility, which consists of a system operator and a national transmission network service provider;

“transmission network service provider” means a legal entity that is licensed to own and maintain a network on the transmission system;

“unit” means a turbine alternator and all the related equipment, including the step-up transformer, operated together to produce electricity; and

“user” means customer as contemplated in section 1 of the Act.

Objectives of code

2. (1) The objectives of the code are to -

(a) establish the rules and procedures that allow a person to use the power system and to permit the power system to be planned and operated safely, reliably, efficiently and economically;

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

(c) define the obligations and accountabilities of all the parties;

(d) specify minimum technical requirements for the distribution system;

(e) ensure that relevant information is made available;

(f) ensure that a service provider operates -

(i) according to the license conditions imposed by the Minister on the recommendation of the Board as contemplated in section 24(1) of the Act;

(ii) transparently and provides non-discriminatory access to its defined services; and

(g) ensure that a customer honours its mutual obligations under this code and that there is industry agreement on the mutual obligations.

(h) set the basic rules of connecting to the distribution system;

(i) ensure that all users of the distribution system are treated in a non-discriminatory manner;

(j) specify the technical requirements to ensure the safety and reliability of the distribution system;

(k) set out the responsibilities and roles of the participants as far as the operation of the distribution system is concerned and more specifically issues related to -

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

(ii) operational authority, communication, emergency and contingency planning of the distribution system;

(iii) operation of the distribution system under abnormal conditions; and

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

(l) specify safety coordination and management criteria to be applied by a distributor to meet the distribution conditions and obligations;

(m) specify demand and voltage control strategies and methods used for the control of distribution system parameters;

(n) ensure a metering standard for all current and future participants;

(o) specify metering requirements to be adhered to;

(p) clarify levels of responsibility relating to metering requirements contemplated in paragraph (o);

(q) define the reciprocal obligations of participants with regard to the provision and exchange of planning, operational and maintenance information for the implementation of the code.

(2) Information exchanged between parties governed by the code is not confidential unless otherwise stated.

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

(4) Despite subcode (3), the Board may override some sections of the NRS specifications should it find them inadequate or divergent from the principles of the code.

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

PART 2
APPLICATION OF DISTRIBUTION GRID CODE

Application of code provisions relating to distribution network

3. The provisions of the code relating to distribution network apply to all users of the distribution system including distributors, embedded generators, end-use customers, retailers, re-sellers and any other entities with equipment connected to the distribution system.

Application of code provisions relating to distribution operations

4. The provisions of the code relating to distribution operations apply to all users of the distribution system including distributors, embedded generators, end-use customers and any other entities with equipment connected to the distribution system.

Application of code provisions relating to distribution metering

5. (1) The provisions of the code relating to distribution metering apply to all participants in respect of a metering point at the boundary of the distribution system.

(2) A metering point relating to a generator which will sell its output to a trader and not to a distributor must be governed by the relevant provisions of the Transmission Grid Code.

(3) The provisions of the code relating to distribution metering set out provisions relating to -

(a) main metering installations and check metering installations used for the measurement of active and reactive energy;

(b) the collection of metering data;

(c) the provision, installation and maintenance of equipment;

(d) the accuracy of all equipment used in the process of electricity metering;

(e) testing procedures to be adhered to;

(f) storage requirements for metering data;

(g) competencies and standards of performance; and

(h) the relationship of entities involved in the electricity metering industry.

Application of code provisions relating to distribution information exchange

6. (1) The provisions of the code relating to distribution information exchange apply to distributors, retailers, embedded generators, end-use customers and resellers.

(2) The information requirements specified in the code are supplementary to the provisions relating to distribution information exchange therefore in the event of inconsistencies between a provision of the code and a provision relating to distribution information exchange with regard to information exchange, the requirements of the provisions relating to distribution information exchange take preference.

CHAPTER 2
DISTRIBUTION NETWORK

PART 1
DISTRIBUTION SYSTEM CONNECTION PROCESS AND PROCEDURES

Connection arrangement

7. (1) A customer seeking a new connection to the distribution system must apply in writing using the application form referred to in subcode (2) or (3) to connect to the distribution system with the relevant distributor.

(2) The application form for embedded generators is attached to this code as Annexure 1.

(3) A distributor must develop its own application form which at minimum must require the applicant seeking a new connection to the distribution system to provide the -

(a) type, capacity, voltage and requested date for the proposed connection;

(b) location of the proposed connection;

(c) test and commissioning results;

(d) safety coordination;

(e) electrical diagrams and connection point diagrams; and

(f) any additional information the distributor may require to adequately assess the application to connect.

(4) A customer applying for medium and high voltage supplies should provide additional information on fluctuating loads, capacitor banks and reactors that could affect the performance of the distribution system.

(5) On receiving the application for connection the distributor must comply with all other requirements relevant to the connection process specified in this code.

Application for connection

8. (1) On receipt of the application contemplated in code 7 the distributor must determine whether the applicant can be connected to the existing system or what technical improvements are required to enable the new connection.

(2) If the distributor determines that transmission system works are required to connect the customer, the distributor must -

(a) notify the relevant transmission licensee of the application contemplated in subcode (1) without delay;

(b) enter into consultations with the transmission licensee regarding -

(i) the best manner in economic and technical terms for connecting that new customer to the grid; or

(ii) whether the new customer should be connected and supplied by the transmission or supply licensee.

(3) The consultations contemplated in subcode (2)(b) must -

(a) seek a cost effective and technically sound manner to connect the new customer; and

(b) consider the potential to supply other existing and future customers of the distribution or supply licensee or the transmission licensee at or near the location of the new customer.

(4) If the distribution or supply licensee can connect other existing or potential customers at or near to the proposed location of the new customer, then the distribution or supply licensee must connect and supply the new customer and enter into corresponding agreements with the transmission licensee.

(5) If the condition contemplated in subcode (4) is not met then the transmission or supply licensee must connect and supply the new customer unless the transmission licensee and the distribution licensee agree otherwise which agreement is subject to approval by the Board.

(6) The distributor must provide an offer to connect and if accepted by the customer, both parties must enter into a connection agreement.

(7) The connection agreement referred to in subcode (6) must include information such as project planning data, inspection, testing and commissioning programs, electrical diagrams and any other information the distributor may deem necessary to proceed with the processing of the application for connection.

(8) If the application for connection has been declined by the distributor, the distributor must advise the customer on the alternative options available for connection to make the connection successful.

(9) If the customer and the distributor cannot reach an agreement on the proposed connection, the dispute resolution process outlined in Chapter 2 of the Transmission Grid Code must be followed by the parties.

(10) The distributor must prepare an offer to connect and provide that offer to the customer within the period specified in the Namibia Quality of Supply and Service Standards, unless otherwise agreed by the participants.

(11) The offer to connect supplied by the distributor must be fair and reasonable and may contain alternative options available to the customer.

(12) Negotiations taking place between the parties must be conducted in good faith and information provided must be treated in a confidential manner by both parties.

Responsibilities of distributor

9. (1) The distributor -

(a) must make capacity available on its networks and provide open and non-discriminatory access for the use of that capacity to all customers including embedded generators; and

(b) in exchange for making capacity available and providing access for the use of that capacity as contemplated in paragraph (a), is entitled to a fair compensation through electricity tariffs as approved by the Board under section 27 of the Act.

(2) A distributor must make available to the customers the Customer Connection Information Guide which must cover -

(a) the process to follow when applying for connection and supply at that distributor;

(b) information requirements of the distributor from the customer to effect an appropriate connection; and

(c) the process and related timeframes which follow the application.

(3) The distributor must respond to the request of a customer to connect within the period specified in the Namibia Quality of Supply and Service Standards.

(4) The distributor must enter into a connection agreement with the customer prior to the actual connection to the distribution system.

(5) The distributor must advise potential users of the expected reliability of its network.

(6) The distributor may participate in the final inspection and testing of customer equipment and facilities to be connected to its network.

(7) The distributor must maintain its distribution system in accordance with good industry practice and its License conditions.

(8) The distributor must maintain the clearances to its live equipment in accordance with the Electricity Act, any other applicable legislation, relevant standards and good practice. The distributor must be responsible for the planning, design and engineering specifications of the work required on the distribution system for connection or expansion.

(9) The distributor must conduct distribution system impact assessment studies to evaluate the impact of additional large loads or major modification to the distribution system.

(10) The assessment studies contemplated in subcode (9) must include the following:

(a) voltage impact studies;

(b) impact on network loading;

(c) fault currents;

(d) coordination of protection systems;

(e) impact on the quality of supply of the system;

(f) environmental impact assessment; and

(g) line or equipment upgrades.

(11) A distributor must not connect a facility which the Distribution Impact Assessment studies indicate will have a deleterious effect, exceeding the parameters laid down in the Namibia Quality of Supply and Service Standards, when connected to the network.

(12) A distributor may request the customer to submit design information, drawings or other relevant information to the distributor if the distributor believes any proposed installation or modification has the potential to adversely or materially affect the performance of the distribution system.

(13) Should the results of the distribution system impact assessment studies of proposed new or altered equipment owned, operated or controlled by the distributor indicate that there will be a material effect at the point of connection the distributor must notify all affected customers prior to commissioning.

(14) A distributor must connect an embedded generator in accordance with the requirements of code 28.

(15) The employees of a distributor or its agents entering the customer premises must comply with the safety requirements of the customer.

Responsibilities of customers and users

10. (1) A customer must provide safe access to the employees of a distributor to carry out the installation, operation and maintenance of the electrical equipment of the distributor on the premises of the customer.

(2) A customer must ensure that during system contingencies there is no unnecessary delay to access to the equipment of the distributor.

(3) A customer is responsible for the removal and reinstallation of privately owned equipment for the distributor to perform the installation work that the customer has requested.

(4) A customer other than a customer for domestic supplies must -

(a) prior to commissioning, attempt to identify if new or altered equipment owned, operated or controlled by the customer could have a deleterious effect at the point of connection; and

(b) must advise the distributor if the deleterious effect contemplated in paragraph (a) is identified.

(5) A customer must maintain the clearances to its live equipment in accordance with the Act, any other applicable legislation, relevant standards and good practice.

(6) If a customer believes the present or proposed distributor installation has the potential to adversely or materially affect the performance of the plant of the customer, the customer may request the distributor to submit design information, drawings or other relevant information.

(7) A customer must comply with the reasonable additional requirements specified by the relevant distributor in respect of the technical and design requirements of equipment proposed to be connected to the distribution system.

PART 2
DISTRIBUTION SYSTEM TECHNICAL REQUIREMENTS

Protection requirements

11. (1) The protection system of a distributor must be appropriately designed and maintained to ensure -

(a) that the protection system is able to detect an electrical fault within a specific zone of the electrical network and to trip only the appropriate or relevant sections of the network in order to clear that fault with minimum disturbance to the rest of the network;

(b) safety and minimum interruptions to customers.

(2) A customer must install and maintain protection, which is compatible with the existing distribution system protection.

(3) The protection settings of a customer must ensure coordination with the protection of the distributor.

(4) A customer must provide the distributor with test certificates, prior to commissioning, of the protection system that is installed at the point of interface with the distributor.

(5) The protection system of a participant or customer must, where applicable, make provisions to safeguard the equipment of that participant or customer from faults occurring on the distribution system including loss of one or two phases of the three phase supply, low voltages on the phases and any auto-reclosing or sequential switching features that may exist on the distribution system.

(6) Where equipment or protection schemes are shared the participants must provide the necessary equipment and interconnections to the equipment of the other party.

Quality of supply

12. Distributors, participants and customers must comply with the Namibia Quality of Supply and Service Standards regarding the following parameters:

(a) voltage harmonics and inter-harmonics;

(b) voltage flicker;

(c) voltage unbalance;

(d) voltage dips;

(e) interruptions;

(f) voltage regulation;

(g) frequency; and

(h) voltage surges and switching disturbances.

Load power factor

13. (1) A customer with a maximum demand meter must ensure that the power factor must not be less than 0.9 lagging and it must not go leading unless otherwise agreed to with the relevant distributor.

(2) If the power factor goes beyond these limits, the customer must take corrective action within a reasonable timeframe to remedy the situation.

(3) A participant or customer intending to install shunt capacitors or other equipment for the purpose of complying with the power factor requirements must obtain the approval of the relevant distributor in writing prior to the installation of that equipment.

Earthing requirements

14. (1) A distributor must advise customers about the neutral earthing methods used in the distribution system.

(2) The method of neutral earthing used on those portions of installations of a customer that are physically connected to the distribution system must comply with the applicable earthing standards of the distributor.

(3) Protective earthing of equipment must be done in accordance with the applicable national standards and reasonable requirements of the distributor.

(4) In cases where the calculated ground potential rise exceeds 5kV as per Institute of Electrical and Electronic Engineering (IEEE) 80, the responsible party must inform the affected participants.

(5) Minimum lightning protection requirements must be applied to the distribution system and switching yards.

(6) A distributor must earth the last overhead line tower to the substation switch yard earth.

Distribution network interruption performance indices

15. (1) The Board is responsible for setting the indicators to be reported on as part of the distribution reliability indices.

(2) Before the end of each fiscal year a distributor must publish its targets for reliability of supply for the following year.

(3) The Board must annually evaluate the distribution system reliability indices to compare actual performance of each distributor with the unique targets of the distributor set by the distributor and the Board must publish these comparative results.

Losses in distribution system

16. (1) A loss in the distribution system must be classified into either a category of -

(a) technical losses;

(b) non-technical losses; or

(c) administrative losses.

(2) The Board must set targets for acceptable levels of the types of losses in consultation with distributors.

(3) Distributors must report annually to the Board on their losses.

(4) The Board must monitor trends in the development of losses for distributors.

Equipment Requirements

17. (1) Equipment at the connection point must comply with the -

(a) prescribed standards of the distributor; and

(b) national standards prevailing at the time.

(2) A distributor must provide the customer with the necessary information to enable the customer to install equipment with the required rating and capacity.

(3) A participant must ensure that all equipment at the connection point is maintained at least in accordance with the specifications of the manufacturer or an alternate industry recognised practice.

(4) A participant or customer with demand meters must retain the test results and maintenance records relating to the equipment at the connection point and make this information available if requested.

PART 3
DISTRIBUTION SYSTEM PLANNING AND DEVELOPMENT

Framework for distribution network planning and development

18. (1) A distributor must source relevant data from various sources including the following sources:

(a) National Integrated Resource Plan;

(b) Local Integrated Resource Plan;

(c) Integrated Development Plan;

(d) Rural Electricity Distribution Master Plan;

(e) customer information;

(f) system performance statistics;

(g) distribution network load forecast; or

(h) government and customer development plans,

to establish the need for network strengthening.

(2) A distributor must annually compile a five year load forecast at the incoming points of supply of the distributor including the cross-boundary connections of the distributor.

(3) A distributor must be responsible for compiling network development plans with a minimum window period of five years.

(4) The network development plans contemplated in subcode (3) must be reviewed at least every three years.

(5) The aim of network development plans is to ensure a capable network and may therefore include all relevant activities such as electrification and refurbishment.

(6) The network development plans may be drawn up taking into account only available information and unexpected loads or customer requests can be retrospectively added to the plans.

(7) The network development plans and post release changes must be submitted to the Board on request to do so.

(8) The network development plans must be made available to a participant on request to do so.

Network investment criteria - introduction

19. (1) Distribution tariffs should be sufficient to allow the necessary investments in the networks to be carried out to ensure the long term viability of the networks.

(2) A distributor must invest in the distribution system when the required development meets the technical and investment criteria specified under code 20.

(3) The need to invest must first be decided on technical grounds and an investment must be a technically acceptable solution.

(4) To be a technically acceptable solution as contemplated in subcode (3) the investment must provide for standard supply minimum -

(a) quality requirements in terms of Namibia Quality of Supply and Service Standards; and

(b) reliability and operational requirements as determined by this code and by the Board.

(5) The investment choice must be justified by considering technical alternatives on a least life cycle cost approach where the least life cycle cost is the discounted least cost option over the lifetime of the equipment, taking into account the technical alternatives for investment, operating expenses and maintenance.

(6) Calculations to justify investment must assume a typical project life expectancy of 25 years, except where otherwise dictated by plant life or project life expectancy.

(7) The following key economic and financial parameters must be determined by a Board approved process:

(a) discount rate;

(b) customer interruption cost or cost of unserved energy; and

(c) other parameters, such as tariffs and additional economic parameters.

General investment criteria

20. (1) Investments should be justified as a least life-cycle cost solution after taking into account alternatives that consider the following:

(a) the investment that will minimise the cost of the energy supplied and the customer interruption cost;

(b) current and projected demand on the network;

(c) reduction of life-cycle costs including reduction of technical losses, operating and maintenance costs and telecommunication projects;

(d) current condition of assets and refurbishment and maintenance requirements;

(e) demand and supply options; and

(f) any associated risks.

(2) General shared network investments must be evaluated on the least life-cycle economic cost, where the economic cost will consider the least life cycle total cost of the electricity related investment to both the distributor and the customer.

(3) Investments made by the distributor dedicated to a particular customer must be evaluated on a least life-cycle distributor cost and distributor cost will consider only the least-life cycle investment cost to the distributor.

(4) The distributor must evaluate investments in terms of the following categories:

(a) shared network investments;

(b) dedicated customer connections;

(c) statutory investments; and

(d) international connections.

Least economic cost criteria for shared network investments

21. Shared network investments are to be justified on least economic cost and in determining the least economic cost for shared network investments the investment must be justified to minimise the cost to the electricity industry and not just to the distributor.

Least life cycle cost criteria for standard dedicated customer connections

22. (1) A standard connection will be charged for at standardised rates.

(2) A dedicated connection investment must be justified on the technically acceptable least life-cycle costs.

(3) If a dedicated connection investment is justified on the least life-cycle cost as contemplated in subcode (2), the customer must be required to pay a standard connection charge as provided for in the connection charge policy.

(4) For customer groupings approved by the Board, the dedicated connection investments must be justified collectively as per customer grouping and not per customer.

Investment criteria for premium customer connections

23. (1) Where a customer has technical specifications that cause investment above the least distributor life-cycle costs, this will be considered a premium connection.

(2) A distributor must investigate these additional requirements and will provide a least life cycle-cost solution.

(3) If the customer agrees to the solution, all costs to meet the customer requirement in excess of what is considered the least life-cycle cost investment are payable as a premium connection charge by the customer.

(4) The costs contemplated in subcode (3) must be appropriately prorated, if a portion of the investment can be justified based on improved reliability or reduction of costs.

(5) Investment costs for the refurbishment or replacement of identified premium connection assets, at the time when the equipment is no longer reliable or safe for operations, will be evaluated using the least economic cost solution.

(6) Refurbishment costs for premium supplies in excess of least economic cost are for the account of the customer.

(7) The least economic cost for refurbishment or replacement of premium assets must be considered as the least life-cycle cost for the distributor required to provide a standard supply plus, if applicable, the estimated cost to the customer to change any of the equipment of the customer to comply with the refurbishment or replacement of the asset using the least life cycle cost solution.

Statutory or strategic investments

24. (1) A distributor must make statutory investments as contemplated in subcode (3).

(2) Statutory and strategic investments must be motivated on a least economic cost basis as contemplated in code 20.

(3) Strategic and statutory projects include the following:

(a) investments formally requested in terms of published government policy but not considered customer dedicated assets;

(b) projects necessary to meet environmental legislation including the construction of oil containment dams;

(c) expenditure to satisfy the requirements on the distributor to comply with its license conditions and safety legislation;

(d) possible compulsory contractual commitments; and

(e) servitude acquisition.

Investment criteria for international connections

25. The investment for international customers must be in terms of the criteria set out for a dedicated connection, but the distributor must charge a connection charge that ensures that there is no cross border subsidy.

Excluded services

26. (1) Excluded services may be competitive or provided by the distributor as a monopoly service.

(2) Monopoly services are those mandatory services to ensure a standard of work that meets quality of supply, reliability and safety standards.

(3) Excluded services include the following:

(a) design and construction of dedicated customer connections;

(b) recoverable works such as inspection and maintenance of non-Distributor owned installations, line relocation and other requested recoverable works; and

(c) the construction and maintenance of public lighting assets.

(4) For excluded services, customers may choose a contractor other than the distributor, provided that an agreement is reached between the distributor and the customer prior to the project being undertaken detailing the conditions.

(5) The conditions contemplated in subcode (4) must set out -

(a) the assets the customer may work on or not work on;

(b) the terms and conditions for the approval of the network design;

(c) the terms and conditions for the inspection and the work done prior to any agreement to take over and commission the supply;

(d) the charges to be raised by the distributor for monopoly related services; and

(e) the fees charged by the distributor for excluded services.

PART 4
MICRO RENEWABLE INFEED AND EMBEDDED GENERATORS
CONNECTION CONDITIONS

Micro Renewable Infeed connection conditions

27. (1) Micro renewable infeeds -

(a) are subject to connection conditions imposed on customers and to subcodes (2) to (5) inclusive; and

(b) are not subject to the same connection conditions imposed on larger embedded generators.

(2) A customer wishing to make a micro renewable infeed into the distribution system must -

(a) notify the distributor in writing of the intention to do so; and

(b) apply for the provision of appropriate metering equipment.

(3) A distributor must maintain a database of all micro renewable infeeds connected to the distribution system.

(4) A customer installing a micro renewable infeed must demonstrate to the distributor that the equipment contemplated in subcode (5) has been installed and is functioning as required.

(5) Micro renewable infeeds must be connected to the distribution system using an automatic connect and disconnect facility and that facility must -

(a) automatically disconnect the generation source from the distribution system in case of a network failure on the distribution system lasting longer than five seconds;

(b) automatically reconnect and synchronise the generation source to the distribution system within five minutes when supply is restored after a supply failure on the distribution system; and

(c) include a fail safe facility designed to disconnect the micro renewable infeed from the distribution system in case of failure of the automatic disconnection equipment.

Embedded generators connection conditions

28. (1) Embedded generators must apply in writing, for connection to the distribution system to the distributor, on the application form attached to this code as Annexure 1.

(2) A distributor must develop and publish its own application form for connecting embedded generators.

Responsibilities of embedded generators to distributors

29. (1) An embedded generator must -

(a) enter into a connection agreement with the distributor before connecting to the distribution system;

(b) ensure that the reliability and quality of supply comply with the terms of the connection agreement;

(c) be responsible for the cost of installation of the metering equipment to measure active and reactive energy flowing out of the generation facility to the distribution system; and

(d) comply with the protection requirement guide of the distributor and as well as protection of own plant against abnormalities, which could arise on the Distribution System.

(2) An embedded generator is responsible for any dedicated connection costs incurred on the transmission system or distribution system as a result of connection of the embedded generation facility to the distribution system.

Responsibilities of distributors to embedded generators

30. (1) If requested by the embedded generator the distributor must provide information relating to the distribution system capacity and loading to enable the embedded generator to identify and evaluate opportunities for connecting to the distribution system.

(2) A distributor may charge the embedded generator a reasonable fee for the information contemplated in subcode (1).

(3) A distributor must treat all applications for connection to the distribution system by potential embedded generators in an open and transparent manner that ensures equal treatment for all applicants.

(4) A distributor is responsible for the installation of the metering equipment to measure power, active and reactive energy flowing from the distribution system into the generation facility of the embedded generator.

(5) A distributor must develop the protection requirement guide for connecting embedded generators to the distribution system to ensure safe and reliable operation of the distribution system.

Provision of planning information

31. (1) Before entering into a connection agreement the embedded generator must provide to the distributor information relating to the generator plant data, location and time scale, capacity and standby requirements as detailed in the application form attached to these code as Annexure 1.

(2) A distributor must provide the embedded generator with any information necessary for the embedded generator to properly design the connection to the distribution system.

(3) Embedded generators must specify, with all relevant details, in their application for connection if the generator facility to be connected must have black-start and quick start capabilities.

Connection point technical requirements for embedded generators

32. (1) An embedded generator must be responsible for the design, construction, maintenance and operation of the equipment on the generation side of the connection point.

(2) An embedded generator is responsible for the provision of the site required for the installation of the distributor equipment required for connecting the generation facility.

(3) The technical specifications of the connection must be agreed upon by the participants based on the distribution system impact assessment studies.

(4) A circuit breaker and visible isolation must be installed at the connection point to provide the means of electrically isolating the distribution system from the generation facility.

(5) The location of the circuit breaker and visible isolation must be decided upon by the participants.

(6) The embedded generator must pay for any expenses incurred by the distributor on behalf of the embedded generator.

General protection requirement for embedded generators

33. (1) The protection for embedded generators must comply with the requirements of this code and with code 27 of the Transmission Grid Code for the respective generator sizes.

(2) Additional features including inter-tripping and generator plant status to be agreed upon by the participants.

(3) The protection schemes used by the embedded generator must incorporate adequate facilities for testing and maintenance.

(4) The protection schemes must be submitted by the embedded generator for approval by the distributor or the transmission company.

(5) Time delays associated with the tripping times must be in accordance with the requirements of the distributor.

Phase and earth fault protection requirement for embedded generators

34. (1) An embedded generator must install a protection system capable of detecting and isolating the generation facility from the distribution system in the event of ground fault.

(2) The protection system of the embedded generator must fully coordinate with the protective relays of the distribution system.

(3) The embedded generator is responsible for the purchasing, setting, testing, operating and maintaining of all interconnection protection relays.

(4) The embedded generator must calculate the protective relay settings and submit the relay characteristics to the distributor for review and approval.

(5) The distributor may require some protective relaying to be duplicated to ensure reliable protection of the embedded generator.

Over-voltage and under-voltage protection requirement for embedded generators

35. An embedded generator must install the over-voltage and under-voltage protection relays to trip the circuit breaker when the phase to ground voltage exceeds the limits specified by the distributor.

Overfrequency and underfrequency protection requirement for embedded generators

36. The embedded generator must install the frequency relays to disconnect the generator form the distribution system for abnormal frequency variations.

Faults on distribution system protection requirement for embedded generators

37. The embedded generator is responsible for protecting its generation facility in the event of a fault arising on the distribution system.

Islanding protection requirement for embedded generators

38. (1) The distributor must specify whether the embedded generator may remain connected if the section of the distribution system is isolated from the rest of the network.

(2) The embedded generation facility must be equipped with a dead-line detection protection system to prevent the generator from being connected to a de-energised distribution system.

(3) The distributor must take reasonable steps to prevent closing circuit breakers onto an islanded network.

(4) For unintentional islanding the embedded generator must cease to operate within the time limit specified by the distributor.

Excitation control system requirements

39. (1) Embedded generators must, where capable, provide voltage support to the Distribution network within the reactive power design limits of the generator.

(2) The settings of the generator excitation system must be determined in consultation with the distributor and the system operator where applicable.

(3) The excitation system must be equipped with load angle limiter and flux limiter as described in IEC60034- 16-1 or any other internationally applicable standard.

PART 5
QUALITY OF SUPPLY REQUIREMENTS AND TELEMETRY

Frequency variations

40. (1) The embedded generation facility must remain synchronised to the distribution system while the network frequency remains within the agreed frequency limitations.

(2) The frequency capability requirements contemplated in codes 28 to 72 of the Transmission Grid Code apply to the embedded generation facility contemplated in subcode (1) unless a different requirement has been agreed between the distributor and the embedded generator.

Power factor

41. The power factor at the connection point must be maintained at the limits agreed upon by the participants.

Fault levels

42. The embedded generator must ensure that the contractually agreed fault level contribution from the generation facility must not be exceeded.

Telemetry

43. The embedded generator must have the means to remotely report to the control centre of the distributor or appointed person any status change of any critical function that may negatively impact on the safety, security, quality of supply and system operation on the distribution system.

CHAPTER 3
DISTRIBUTION SYSTEM OPERATIONS

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

Operational responsibilities of distributors

44. (1) The distributor must operate the distribution system 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) The distributor must co-ordinate voltage control, operating on the distribution system and security monitoring on a system-wide basis in order to ensure safe, reliable and economic operation of the distribution system.

(3) In the event of an embedded generator having to shut-down or island plant because of a disturbance on the distribution system, the distributor must carry out network restoration to minimise the time required to resynchronise the shed embedded generating units.

(4) The distributor may shed customer load to maintain system integrity and the distributor must restore customer load as soon as possible with due consideration of the possibility of cascading failure or operating at abnormally low frequency or voltage for an extended period of time.

(5) The distributor must operate the distribution system in such a way as to minimise adverse effects of disturbances on customers.

(6) The distributor must operate the distribution system as far as practical so that instability, uncontrolled separation or cascading outages do not occur as a result of the most severe double contingency.

(7) Multiple distribution outages of a credible nature must be examined and, whenever practical, the distributor must operate the distribution system to protect it against instability, uncontrolled separation and cascading outages.

(8) The distributor is responsible for efficient restoration of the distribution system after supply interruptions.

(9) The distributor must operate and maintain primary and emergency control centres and facilities to ensure continuous operation of the distribution system.

(10) The distributor must -

(a) establish and implement operating instructions, procedures, standards and guidelines to cover the operation of the distribution system under normal and abnormal system conditions; and

(b) maintain a database with version control of all the documents, relating to the establishment and implementation contemplated in paragraph (a), which are in compliance with license conditions.

(11) The distributor must operate the distribution system, as far as reasonably possible, within defined technical standards and equipment ratings.

(12) The distributor must manage constraints on the distribution system through the determination of operational limits.

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

(14) The distributor is responsible for the ongoing determination of the distribution system protection philosophy, as contrasted to equipment protection.

(15) The distributor must determine and review on a regular basis the relay settings for main and backup protection on the distribution system.

(16) The distributor must develop and publish procedures for load shedding.

(17) The distributor must ensure adequate and reliable communications to all major users of the distribution system.

Operational responsibilities of embedded generators and customers

45. (1) When conditions on the distribution system under normal or abnormal conditions may jeopardise plant or personnel of customers, customers must immediately disconnect from the distribution system.

(2) The embedded generator must ensure that its generating unit is operated within the capabilities defined in the connection agreement entered into with the distributor.

(3) The embedded generator is responsible for the provision of the operational information contemplated in Part B of Chapter 5.

(4) The embedded generator must reasonably cooperate with the distributor in executing all the operational activities during an emergency generation condition.

(5) Customers must assist the distributor in correcting quality of supply problems caused by the equipment of a customer connected to the distribution system.

(6) Customers must ensure that their equipment connected to the distribution system does not cause any degradation or operational adversity to the distribution system.

(7) Customers must operate their equipment so as to ensure that the customers comply with the conditions specified in connection agreement of the customers.

(8) Customers must -

(a) declare any co-generating plant whether licensed or not; and

(b) specify the interlocking mechanism,

to prevent inadvertent parallel operation with the distribution system.

(9) Embedded generators must have the required protection to trip in the event of a momentary supply loss causing an island condition to prevent paralleling out of synchronism due to auto-reclose functionality on the network of the distributor.

Operational authority

46. (1) The distributor must have the authority to instruct operating on the distribution system but operational authority for other networks must lie with the respective asset owners.

(2) Network control, as it affects the interface between the distributor and a customer, must be in accordance with the operating agreements between the participants.

(3) A participant may not operate the equipment of another participant without the permission of that other participant.

(4) Despite subcode (3), the asset owner has the right to test a participant who intends to operate the equipment of another participant before permitting that participant to operate that equipment.

Operating procedures

47. (1) The distributor must develop and maintain operating procedures for the safe operating of the distribution system and for assets connected to the distribution system.

(2) The operating procedures contemplated in subcode (1) must be adhered to by participants when operating equipment on the distribution system or connected to the distribution system.

(3) A customer must -

(a) have safety rules and procedures; and

(b) ensure that safety rules and procedures contemplated in paragraph (a), comply with the law and the National Electricity Safety Code.

(4) Customers must ensure that the rules and procedures contemplated in subcode (3) are compatible with the operating procedures contemplated in subcode (1).

(5) Customers and licensees must enter into operating agreements as defined in the licenses of licensees.

(6) For standard customers the operating agreements contemplated in subcode (5) may form part of the connection agreement or general conditions of supply.

Operational Liaison

48. (1) The participants -

(a) are responsible for the nomination of personnel with sufficient expertise to operate the distribution system; and

(b) must establish direct communication channels amongst themselves to ensure the flow of information exchange between the participants.

(2) If a participant experiences an emergency that participant must notify other participants and -

(a) the other participants must assist to an extent necessary to ensure that the emergency does not jeopardise the operation of the distribution system or health of plant; and

(b) that participant must ensure that the emergency notification contains sufficient details in describing the event including the cause, timing and recording of the event to assist the recipient in assessing the risk and implications to the distribution system or the equipment of the customer.

(3) For planned events which may have an operational effect on the distribution system or on the equipment of a customer connected to the distribution system, the participants must notify each other on whose equipment the operational event may have an effect.

(4) In the event that it is physically possible for a customer to transfer load or embedded generators from one point of supply to another by performing switching operations on the network of a customer the operating agreement must cover at least the operational communication and notice period requirements and switching procedures for such load transfers.

(5) The embedded generator must in consultation with a specific distributor compile both a comprehensive maintenance philosophy and a test and inspection plan for all equipment, systems and protection schemes installed at the connection point addressing concerns from both parties.

(6) The distributor and customers must agree on the bus bar configuration at each point of supply during normal and emergency conditions and the details of the configuration must be included in the operating agreement between the participants.

Emergency and contingency planning

49. (1) The distributor must develop and maintain a distribution system emergency procedures manual to manage the system contingencies and emergencies that are relevant to the performance of the distribution system and the interconnected power system.

(2) A contingency plan in accordance with subcode (1) must be developed in consultation with all participants and must be consistent with internationally acceptable utility practices and must include -

(a) under-frequency load shedding;

(b) prevention of voltage slide and collapse;

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

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

(e) supply restoration.

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

(3) Contingency or emergency plans must be periodically tested with simulations or other approved methodologies and the results must be appropriately documented.

(4) If the tests contemplated in subcode (3) cause undue risk or undue cost to a participant, the distributor must take that risk or cost into consideration when deciding whether to conduct the test.

(5) The tests contemplated in subcode (3) must be carried out at a time that is least disruptive to the participants and the costs of the tests must be paid for by the respective asset owners.

(6) The distributor must ensure the co-ordination of the tests contemplated in subcode (3) in consultation with all affected participants.

(7) The distributor must, in consultation with the transmission company and system operator, set the requirements and implement:

(a) automatic and manual under frequency load shedding in accordance with the requirements of the system operator;

(b) automatic and manual under voltage load shedding to prevent voltage collapse; and

(c) manual load shedding to maintain network integrity.

(8) Participants must make available loads and schemes to comply with these requirements.

(9) The distributor is responsible for -

(a) determining emergency operational limits on the distribution system;

(b) updating the emergency operational limits contemplated in paragraph (a) periodically; and

(c) making the emergency operational limits contemplated in paragraph (a) available to the participants.

(10) The distributor must conduct network studies which may include but not be limited to load flow, fault level, stability and resonance studies to determine the effect that various component failures would have on the reliability of the distribution system.

Operation during abnormal conditions

50. (1) Operation under abnormal operating conditions must comprise all conditions deviating from normal operation.

(2) During abnormal operating conditions the distributor must be obliged to take necessary precautionary measures to prevent network disturbance from spreading and to restore supply to customers.

(3) The distributor must cooperate with the transmission network service provider in taking corrective measures in the event of abnormal conditions on the distribution system.

(4) The corrective measures must include both supply-side and demand-side options and where possible warnings must be issued by the distributor on expected utilisation of any contingency resources.

(5) The distributor must be entitled to disrupt some sections of the network in the event of a prolonged disturbance resulting from unsuccessful corrective measures undertaken.

(6) Termination of the use of emergency resources must occur with the order of return being determined by the most critical loads, first in terms of safety and then plant.

(7) During emergencies that require load shedding, the request to shed load must be initiated in accordance with agreed procedures prepared and published by the distributor.

Independent action by participants

51. (1) A participant has the right to reduce supply or demand or disconnect a point of connection under emergency conditions if the reducing of supply or demand or the disconnection of a point of connection is necessary for the protection of life or equipment.

(2) A participant must give advance notice of the action contemplated in subcode (1) if possible for, amongst other emergency conditions, hot connections, solid breakers and malfunctioning protection.

(3) During customer emergencies that require load shedding, the request to shed load must be initiated in accordance with agreed procedures prepared and published by the distributor.

Demand and voltage control

52. (1) The distributor must implement demand control measures when -

(a) instructed to do so by the system operator;

(b) abnormal conditions exist on the distribution system;

(c) multiple outage contingency exists resulting in island grid operation; or

(d) any other operational event exists which the distributor considers to warrant the implementation of demand control measures for the safe operation of the distribution system.

(2) Demand control must include but is not limited to -

(a) customer demand management;

(b) customer disconnection;

(c) automatic low frequency disconnection;

(d) emergency manual disconnection;

(e) voluntary load curtailment; and

(f) manual load dropping.

(3) The distributor must develop load reduction procedures to reduce load in a controlled manner by reducing or disconnecting certain customer loads.

(4) The distributor must coordinate all the demand control measures undertaken with affected customers.

(5) Distribution system voltages must be controlled during normal operation to be at least within statutory limits at the points of supply and otherwise as agreed with customers.

(6) The distributor is responsible for maintaining reactive power management including all facilities for reactive power compensation on the distribution system and the other connected generating units to ensure compliance with the agreed specified limits, operational voltage parameters and power factor parameters.

Fault reporting and analysis or incident investigation

53. (1) The distributor and end-use customers must report the loss of major loads (>2.5MW) to the transmission system operator within 15 minutes of the event occurring and warning of the reconnection of the loads must similarly be given with at least 15 minutes advance notice.

(2) The participants must report to the control centre of the distributor or appointed person all major incidents occurring on the participants' installation or incidents occurring on the distribution system that would potentially affect the overall performance and reliability of the distribution system including but not limited to -

(a) voltage or frequency outside statutory limits;

(b) deviations from load drawn from the distribution system; or

(c) major breakdowns of equipment supplying power to the customers.

(3) Despite subcode (2) the distributor must -

(a) investigate any incident that materially affected the quality of the service to another participant including interruptions of supply, disconnections, under or over voltage or frequency incidents and quality of supply contraventions;

(b) avail a preliminary incident report after three working days and a final report within three months; and

(c) initiate and co-ordinate the investigation contemplated in paragraph (a) and arrange for the writing of the report contemplated in paragraph (b) and involve all affected participants.

(4) The participants contemplated in subcode (3)(c) must make all relevant information available to the distributor and participate where reasonably required and the distributor must make the report contemplated in subcode (3)(b) available to any requesting participant within the confidentiality constraints.

(5) The report contemplated in subcode (3)(b) must include at a minimum, the -

(a) date and time of the incident;

(b) location of the incident;

(c) duration of the incident;

(d) equipment involved;

(e) description of the incident;

(f) demand control measures undertaken;

(g) embedded generation interrupted;

(h) frequency response achieved;

(i) estimated date and time of return to normal service;

(j) customer load tripped in MW and energy lost when incident occurred or as a direct result of incident not including any demand control measures taken; and

(k) estimated number of customers having lost supply.

(6) A participant may request an independent audit of the report contemplated in subcode (3)(b) at own cost and if the audit findings disagree with the report, the participant may follow the dispute resolution mechanism but if the audit findings agree with the report the report recommendations must stand.

(7) Recommendations that require a change in the Distribution Grid Code must -

(a) be submitted to the review process contemplated in codes 10, 11 and 12 of the Transmission Grid Code; and

(b) only be implemented upon approval of the amendment.

(8) All other recommendations must be implemented by the participant within a time frame of -

(a) three working days for the preliminary incident report under subcode (3)(b); and

(b) three months for the final report under subcode (3)(b).

Distributor maintenance program

54. (1) A distributor must have a maintenance philosophy against which their maintenance practices and programs are compiled and documented in accordance with good practice and any rules, standards or guidelines of the Board that may apply.

(2) The documented maintenance programs contemplated in subcode (1) must be auditable.

(3) The distributor must compile an annual maintenance plan in line with the budget period and provide for sufficient budget to execute that plan.

(4) Accurate records of maintenance done must be kept for a period of five years.

(5) Scheduling of planned outages must coincide with the maintenance requirements of other participants connected to the affected network.

(6) A distributor must, at least five days in advance of a planned outage, inform participants that may be affected by that planned outage.

Testing and monitoring

55. (1) The distributor must reserve the right to test and monitor any equipment or customer installation connected to the distribution system to ensure that the customers are not operating outside the technical parameters specified in any part of the Distribution Grid Code and other applicable standards which the customers are required to comply with.

(2) Despite subcode (1), the distributor must inform the customer about any routine test and monitoring the distributor intends to undertake on the installation of the customer.

(3) A customer found to be operating outside the technical parameters must within such time agreed upon by the participants involved remedy the situation or disconnect from its network the equipment causing problems.

Safety coordination

56. (1) The distributor must in accordance with the relevant legislation governing health and safety in the workplace establish health and safety management guidelines to ensure the health and safety of personnel working on the distribution system or any equipment connected to the distribution system.

(2) The health and safety management guidelines contemplated in subcode (1) must have a set of rules and instructions for implementing safety precautions on Medium Voltage and High Voltage equipment and the participants must adopt these rules and any work done on the distribution system or on the installation of the customer must be governed by these rules.

(3) Despite subcode (2), the health and safety management guidelines must contain details of, but not be limited to -

(a) safety coordination procedures;

(b) appointment of safety coordinators or authorised safety personnel;

(c) safety logs and record of safety precautions;

(d) location of safety precautions;

(e) implementation of safety precautions;

(f) environmental safety issues; and

(g) documentation control.

(4) The participants must coordinate the appointment of safety personnel and must agree on the duties to be carried by the appointed persons.

Disconnection and reconnection

57. (1) The distributor may disconnect supply to the supply address of the customer if the customer fails to comply with the written notice of non-compliance issued by the distributor or any arrangement entered into by the distributor and the customer which the customer has failed to comply with including non-compliance with the applicable standards of the distributor.

(2) The distributor may interrupt or disconnect supply if a threat of injury or material damage is anticipated as a result of the malfunctioning of the electrical installation equipment on the premises of the customer or on the distribution system which may result in any of the following:

(a) planned or unplanned maintenance on the distribution system or customers installation;

(b) load shedding;

(c) installation of new supply or restoration of supply to other customers; or

(d) instruction from the transmission network service provider.

(3) The distributor may disconnect immediately without notice the supply to the supply address of the customer if:

(a) the supply of electricity to a customer is used anywhere else other than at the premises of the customer as specified in the connection agreement.

(b) a customer takes, at the supply address of the customer, electricity supplied to another customer.

(c) a customer tampers with or permits tampering with the meter and associated components.

(d) a customer causes or allows electricity supply to the supply address of the customer to bypass the meter.

(4) A customer, with demand meter, must give written notice to the distributor of any intended voluntary disconnection.

(5) The distributor must reconnect supply to the customer on request by the customer or retailer on behalf of the customer subject to compliance with the relevant provisions of the Distribution Grid Code and other distributor applicable standards including the timing of reconnection and any reconnection charge imposed by the distributor.

Commissioning

58. (1) All aspects of commissioning, by participants, of new equipment associated with the distribution system connection, or re-commissioning of such existing equipment, must be agreed in writing with the distributor, acting reasonably, before such commissioning starts.

(2) The said aspects must include, but 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.

(3) Participants must give minimum notice of one month, unless otherwise agreed, from the date of receipt of the request for all commissioning or re-commissioning.

(4) Where commissioning is likely to involve a requirement for dispatch or operating for test purposes, the participant must notify the distributor of that requirement and of reasonable details as to the duration and type of testing required.

(4) When commissioning equipment at the point of connection, the distributor must liaise with the affected participants on all aspects that could potentially affect the participants' operation.

(5) The distributor and participants must perform all commissioning tests required in order to confirm that the plant and equipment, of that distributor and the participants, meet all the requirements of the Distribution Grid Code that have to be met before going on-line.

PART 2
MAINTENANCE COORDINATION OR OUTAGE PLANNING AND TELE-CONTROL

Responsibilities of distributor

59. (1) The distributor must, with reference to the outage plans of the relevant network service provider and the outage plans of the relevant generator, compile the daily outage schedule which must -

(a) endeavour to cater for the planned maintenance and commissioning of new equipment;

(b) describe the planned outage;

(c) identify the risks and impact on network performance in accordance with the relevant quality of supply and service standard;

(d) describe the practical contingency plans devised to counter risks; and

(e) define the roles and responsibilities of the personnel designated to manage and minimise the impact of these outages on the distribution system and its users.

(2) The distributor must co-ordinate relevant outages with the system operator.

(3) The distributor may require from the customers information regarding major plant and associated equipment which may affect the performance of the distribution system and may require additional resources to be committed during the outage planning process.

(4) Customers with own generation and embedded generators with a capacity greater than 1MW and not subject to central dispatch must furnish to the distributor information on planned outages in order for the distributor to properly plan, and coordinate its control, maintenance and operation activities.

(5) The distribution outage plans must be adjusted to coordinate with the transmission outage plan which must further be coordinated with the generation outage plan.

(6) The distributor, transmission company and generation services must meet regularly on dates agreed upon by the participants to revise, discuss and produce a coordinated outage plan.

(7) The distribution outage plan must be submitted to the Board upon request.

Risk-related outages

60. (1) All risk-related outages must be scheduled with an executable contingency plan in place and the compilation of the contingency plan is the responsibility of the relevant distributor.

(2) A contingency plan contemplated in subcode (1) must address the -

(a) safety of personnel;

(b) security and rating of equipment; and

(c) continuity of supply.

(3) The relevant control centres must confirm that it is possible to execute the contingency plan contemplated in subcode (1) successfully.

Refusal or cancellation of outages

61. (1) A participant may not unreasonably refuse or cancel a confirmed outage and a participant may not unreasonably postpone or cancel a previously accepted outage.

(2) The direct costs related to the cancellation or postponement of an outage must be borne by the respective asset owners.

Communication of system conditions, operational information and distribution system performance

62. (1) The distributor is responsible for providing participants with operational information as may be agreed which must include information regarding planned and forced outages on the distributor.

(2) The distributor must inform participants of any network condition that is likely to impact the short and long-term operation of that participant.

(3) The distributor must -

(a) record the operational information as specified in code 82; and

(b) avail the information recorded as contemplated in paragraph (a) to a participant if the participant requests for that information.

Unplanned interruptions or outages

63. (1) In case of unplanned interruptions or outages the distributor may require a customer to comply with reasonable and appropriate instructions from the distributor and may further -

(a) require the customer to provide the distributor emergency access to customer owned distribution equipment normally operated by the distributor or distributor owned equipment on the property of the customer;

(b) interrupt supply to the customer to effect repairs to the distribution system; and

(c) require customers with permanently connected back up facilities to notify the distributor regarding the presence of such equipment.

(2) The distributor must make arrangements to notify the participants about the expected duration and other details of the unplanned interruptions contemplated in subcode (1).

Planned interruptions or outages

64. For planned interruptions or outages, the distributor must provide the affected customers with information relating to the expected date of the outage, time and duration of the outage and must establish reasonable means of communication to the customers for outage related enquiries.

Tele-Control

65. Where tele-control facilities are shared between the distributor and other participants, the distributor must ensure that operating procedures are established in consultation with the participants.

CHAPTER 4
DISTRIBUTION SYSTEM METERING

Principles of distribution metering

66. (1) The following points must have a metering installation -

(a) each point of supply connecting an end-use customer to the distribution system;

(b) each point of connection between a generator and the distribution system; and

(c) each point connecting the distribution systems 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 metering specifications.

(3) Customers with a maximum demand of 5 MVA or more and generators and connections to neighbouring countries must have main and check metering and there must be separate main and check CT cores but one dedicated VT 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 participants.

(5) Customers may request the installation of their own separate check meters and any extra costs must be paid for by the requesting customer and the distributor must install and control the check meters.

(6) For a customer wishing to make a micro renewable infeed into the distribution system -

(a) the installation must not be metered using a pre-paid meter;

(b) the installation must have a meter capable of measuring active power flow in both directions;

(c) unless the distributor has a small scale infeed tariff approved by the Board the energy supplied by the customer into the distribution system must be compensated by the distributor at the same energy rate as payable by the customer to the distributor for energy supplied to the customer; and

(d) the installation must, where applicable, comply with net metering rules made by the Board under section 3(4)(f) of the Act.

Responsibility for metering installations

67. (1) For the purposes of this code, the distributor must be the owner of the meter and metering installation.

(2) Metering equipment owned by the licensee, retailer or metering service provider but installed on the premises of the customer must remain the property of the service provider.

(3) Except with written consent by the owner, access by customers or customer representatives to meters, metering circuits and metering data must be restricted to ensure that the integrity of the metering device, metering installation and meter data are not at risk.

(4) Unless prior written approval has been obtained customers or customer representatives may not have direct physical access to meters including access gained by downloading the metering information from the meter directly through the digital communication interface or remotely through any communication media such as a modem.

(5) Despite subcode (4) requests from customers to read their own meters must not be unreasonably refused.

(6) Except with written consent by the owner, customers or customer representatives may not install any metering or other equipment integrated into the licensees CT and VT metering circuits, test blocks, terminals or any portion forming part of the electrical metering installation.

(7) A customer on whose premises metering equipment is installed but owned and operated by the licensee, metering service provider or retailer must provide reasonable access to the metering equipment but an official identification must be produced on request.

(8) Where a metering installation is situated in a restricted area the procedures stated in NRS047, applicable legislation or agreed on by the parties must be followed to gain access to the equipment.

(9) If a customer or his representative requires real time energy pulses (kWh & kVArh) at a metering installation, the licensee must provide the real-time energy pulses through mutual agreement and the customer must pay the costs of installation in that event.

(10) Any changes that may affect the authorised and safe access of the parties to the metering equipment must be reported as soon as it is brought to the attention any of the parties.

(11) Customers must not tamper or permit tampering with metering equipment owned by the licensee.

(12) The distributor is responsible for ensuring that all points identified as metering points in accordance with the principles of the previous sections have metering installations.

(13) The distributor is responsible for managing and collecting metering information.

(14) Participants connected to or wanting to connect to the distribution system must provide the distributor with all information considered necessary to enable performance of its metering duties.

(15) 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 code;

(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

68. (1) The following principles apply to all metering installations for customers with a maximum demand of 5 MVA or more and to generators and connections to neighbouring countries:

(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 participants;

(d) a meter must be visible and accessible, but the access must be restricted to only persons authorised by the distributor;

(e) data for customers must be historical data situated on a secure server and when required by a customer metering impulses must be provided by a distributor to the customer;

(f) a telecommunications medium must be connected to the meter or recorder contemplated in paragraph (a) where possible; and

(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.

(2) The following principles apply to all metering installations:

(a) the accuracy of meters and recorders must be in accordance with the minimum requirements of NRS 057-2;

(b) commissioning of the metering installation and metering data supporting systems must take place in accordance with the requirements of NRS 057;

(c) both active and reactive energy must be measurable without compromising any requirements of this code where applicable;

(d) the meters must measure both active and reactive energy flow in both directions where applicable; and

(e) the meters must be configured to store or record metering data in half-hourly integration periods.

(3) 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 participants who may be affected by the secondary use of the installation; and

(c) no secondary user must interfere with VT or CT circuitry.

(4) Metering installations must be audited in accordance with NRS 057 or equivalent.

Data validation

69. (1) Data validation must be carried out in accordance with NRS 057.

(2) In the event of -

(a) electronic access to the meters not being possible;

(b) an emergency bypass or other schemes having no metering system; or

(c) metering data not being available, the distributor 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 distributor 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 distributor must ensure that the meters are downloaded for the billing cycle.

Data verification

70. In addition to the NRS 057 verification requirements meter readings must be compared with the metering data base at least once a year.

Metering database

71. (1) The distributor 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 057-4 must form part of the metering database and must be retained for at least five years for audit trail purposes.

Testing of metering installations

72. (1) Commissioning, auditing and testing of metering installations must be done in accordance with the NRS 057-4 specification.

(2) A participant may request the Board that testing of a metering installation be performed and that request may not be unreasonably refused but the costs of the testing must be for the account of -

(a) the requesting participant if the meter is found to be accurate; or

(b) the account of the distributor if the meter is found to be inaccurate.

Metering database inconsistencies

73. In the event of testing revealing that data in the metering database is inconsistent with the data in the meter, the distributor must inform all affected participants and corrections must be made to the official metering data and the associated billing to an extent as reasonably agreed between the parties.

Access to metering data

74. (1) Metering data must be accessed through a central database that stores all customer information and is maintained by the distributor.

(2) The distributor must control access to all metering installations.

(3) Electronic access to the meters may not be granted to the 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 distributor in line with section 4.2.3 of the NRS 057-4.

(5) All security requirements for metering data must be as specified in NRS 057.

(6) Official metering data must be made available by the licensee on request by the customer in a format agreed on by the parties and the distributor may levy a charge for the provision of that data which is in relation to the cost of providing the data.

Confidentiality

75. Metering data and passwords are confidential information.

CHAPTER 5
DISTRIBUTION SYSTEM INFORMATION EXCHANGE

PART A
INFORMATION EXCHANGE INTERFACE AND PROVISION AND EXCHANGE OF INFORMATION DURING PLANNING AND CONNECTION PROCESS

Information exchange interface

76. (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 procedures for the transfer of information.

(3) Participants with demand meters must exchange information, prior to commissioning, of new or altered equipment connected at the point of connection or changes to the operational regimes that could have an adverse effect on the distribution system to enable proper modifications to any affected participants networks and related systems.

Provision and exchange of information during planning and connection process

77. (1) Each distributor must have a supply application form which must request at minimum the information stipulated in this code.

(2) Customers requesting supply at low voltage must provide the distributor with the information relating to:

(a) new or change in connected loads;

(b) type of load to be connected to the distribution system;

(c) requested connection date;

(d) requested supply capacity in ampere or kVA and number of phases; and

(e) proposed network connection point address.

(3) Customers requesting supply at medium or high voltage must in addition to the information exchange contemplated in code 76 provide the distributor with the following information:

(a) requested supply voltage;

(b) expected or projected maximum demand (in kVA);

(c) expected load power factor;

(d) switched customer capacitor banks and reactors, which could affect the distribution system;

(e) whether the load is capable of producing harmonics as specified by equipment manufacturers;

(f) the nature and type of process the supply is requested for;

(g) minimum required fault levels;

(h) start-up requirements; and

(i) whether the customer has any standby generator.

(4) The distributor may request customers to provide information on the proposed installation of the customer and equipment at the point of connection.

(5) Participants must exchange information relating to the protection of distribution system and customer equipment protection coordination at the point of connection.

(6) Upon any reasonable request the distributor must provide customers or potential customers with any relevant information that they require to properly plan and design their own networks or installations which may include but not limited to:

(a) nominal voltage at which connection will be made;

(b) method of connection, extension and reinforcement details;

(c) the maximum and minimum fault levels;

(d) method of earthing;

(e) maximum installed capacity at the point of supply;

(f) specification of any accommodation of equipment requirement;

(g) individual customer limits relating to:

(i) harmonic distortion;

(ii) voltage flicker;

(iii) voltage unbalance;

(h) expected lead time of providing connection, following formal acceptance of terms for supply;

(i) an indication of network single contingency capability;

(j) an indication of current network performance and power quality;

(k) cost of connection; and

(l) range of current approved tariff structures.

PART B
OPERATIONAL AND CONFIDENTIALITY INFORMATION

Commissioning and notification

78. (1) Customers must confirm that all information given in the application for supply and additional information subsequently requested by the distributor is correct before the commissioning.

(2) The commissioning dates must be negotiated between the parties.

(3) Participants will agree on the type of operational data to be submitted prior to commissioning which must include test and commissioning report.

(4) A distributor or customer who is the asset owner must -

(a) ensure that all equipment records that affect the integrity of the distribution system or relevant to the interconnection are maintained for reference for the duration of the operational life of the plant; and

(b) on request from the distributor, make information available within a reasonable time.

(5) The distributor must indicate to the customer what information is relevant in terms of this code.

Sharing of assets and resources

79. Distributors sharing assets and resources must enter into agreements for the provision and sharing of their assets, resources, services and information.

Additional information requirements

80. (1) Should one participant, acting reasonably, determine that additional measurements or indications are needed in relation to another participant's plant and equipment, that participant must consult with the affected participants to agree on the manner in which the need may be met.

(2) The costs related to the modifications for the additional measurements or indications must be for the account of the causal participant.

Communication and liaison

81. (1) Participants must establish a communication channel for exchange of information required for distribution operations which may include the installation of SCADA equipment of the distributor at the customer or installation of the distributor to facilitate the flow of information and data to and from the distribution or transmission control facilities.

(2) A participant -

(a) must designate a person with delegated authority to perform the duties of information owner in respect of the granting of access to information covered in this code to third parties; and

(b) may designate more than one person to perform the duties contemplated in paragraph (a).

(3) The distributor must take reasonable steps to exchange information with the affected customers of a distributor for distribution and transmission system outages.

(4) Customers must exchange information with the distributor within an agreed lead time on all operations on their installations which may have an adverse effect on the distribution system including any planned activities such as plant shutdown or scheduled maintenance.

(5) The communication facilities standards must be set and documented by the distributor.

(6) Any changes to communication facilities standards impacting on participant equipment must be brought to the attention of the participant well in advance of the proposed change.

(7) Any back up or emergency communication channels established by the distributor and deemed necessary for the safe operation of the distribution system must be agreed upon by the distributor and the participant affected.

Data storage and archiving

82. (1) An information owner must store and archive data.

(2) The systems that store the data to be used by the parties must be of their own choice and for their own cost.

(3) All data storage systems must -

(a) be able to be audited by the Board; and

(b) provide for clear and accessible audit trails on all relevant operational transactions.

(4) All requests that require an audit on a system must be undertaken with reasonable notice to the parties.

(5) The information owner must keep all information, except voice recorded information, in its original format for a period of at least five years, unless otherwise specified in the Distribution Grid Code, commencing from the date the information was created.

(6) Parties must ensure reasonable security against unauthorised access, use and loss of information for the systems that contain the information.

(7) Distributors must -

(a) use a voice recorder for historical recording of all operational voice communication with participants which must be available for at least three months except where there is an incident involved in which case the requirements of any applicable legislation must apply; and

(b) make the voice records of an identified incident in dispute available within a reasonable time period after a request to do so from a participant or the Board.

(8) Customers with own MV or HV networks must keep proper written or voice recorded records of all operations on their MV and HV networks.

(9) An audit trail of all changes made to archived data must -

(a) be maintained;

(b) identify every change made and the time and date of the change; and

(c) include both pre and post values of all content and structure changes.

Confidentiality of information

83. (1) Information exchanged between parties governed by this code is confidential unless otherwise stated.

(2) Parties receiving information must use the information only for the purpose for which it was supplied.

(3) The information owner may request the receiver of information to enter into a confidentiality agreement before information established to be confidential is provided.

(4) A pro forma agreement for purposes contemplated in subcode (3) is annexed to the code as Annexure 2.

(5) Confidential information may not be transferred to a third party without the written consent of the information owner.

(6) Parties must observe the proprietary rights of third parties for the purposes of this code but access to confidential information within the organisations of parties must be provided as reasonably required.

(7) The parties must take all reasonable measures to control unauthorised access to confidential information and to ensure secure information exchange.

(8) Parties must report any leak of information that is governed by a confidentiality agreement as soon as practicable after they become aware of the leak and must provide the information owner with all reasonable assistance to ensure its recovery or destruction, as considered appropriate by the information owner.

ANNEXURE 1
EMBEDDED GENERATOR CONNECTION APPLICATION FORM

Note: This form is to be completed in full and returned to the Distributor together with requested information for review and concurrence

Date:	
Applicant Particulars	
Name of Applicant:	
Address:	
Telephone:	
Facsimile:	
Email:	
Project Details	
Project Name:	
Project Location:	
Project Contact Name & Telephone Number:	
Facsimile:	
Project Type: (co generation, combined cycle, hy-draulic etc)	
Construction Schedule	
Projected Start-up of Construction:	
Construction Power Requirements:	
Projected In-Service Date of Embedded Generator:	
Site Plan	
Site plan to show scaled mapping of existing lot lines, road crossing etc	
Preliminary design	
Design to show generators, transformer, proposed connection point, isolating devices, protection schemes etc	
Generator Specifications	
Manufacturer:	
Fuel type:	
Rated MVA:	
Rated MW:	
Rated Voltage:	
Rated Power Factor:	
Inertial Constant:	
Maximum MVAR Limit:	
Neutral Ground Resistance in Ohms:	
Xd – Synchronous reactance in p.u:	
X'd - Direct Axis transient reactance in p.u:	
X"d – Direct axis sub-transient reactance in p.u:	
X2 – Negative sequence reactance in p.u:	
X0 – Zero sequence reactance in p.u	
Power Transformer Specifications	
Voltage and power ratings:	
Windings configuration:	
Neutral earth resistors or reactors:	

Positive and zero sequence impedances in p.u:	
R1:	
X1:	
RO:	
XO:	
Motor Specifications	
Motor type:	
Rating in kW:	
Power factor:	
Transient reactance in p.u:	
Sub-transient reactance in p.u:	
Expected Generator Consumption	
Generator Output	
Site Sales	
Site Purchases	
kWh	
Peak kWh	
kWh	
Peak kWh	
kWh	
Peak kWh	
January	
February	
March	
April	
May	
June	
July	
August	
September	
October	
November	
December	
Future Site Developments	
Proposed Plant Design	
Technical personnel to be employed:	
Operating characteristics :	
Any other additional information :	

I request the *Distributor* to proceed with a preliminary review of this embedded generation interconnection application and I agree to pay the cost associated with completing this review.

ANNEXURE 2
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).

(i) 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.

(ii) The Recipient agrees to disclose the *Information* only to persons who are in his permanent employ, and who require access to the *Information* to perform their duties in respect of the Work on behalf of the Client.

(iii) 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*.

(iv) The Recipient undertakes to use the *Information* only to perform the Work on behalf of the Client, and for no other purpose whatsoever.

(v) On completion of the Work, the Recipient shall at his 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 his employees' possession (electronic as well as hard copy format) are destroyed.

(vi) The Recipient shall take all reasonable measures to protect the *Security* and integrity of the *Information*.

(vii) If requested to do so by the *Information Owner*, the Recipient shall forthwith at his 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 his employees' possession (electronic as well as hard copy format) are destroyed.

(viii) 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