The South African Wholesale Electricity Market (SAWEM) Market Code

Rev 1.0 – April 2024

Table of Contents

Contents

1 INTRODUCTION

1.1 Purpose

(1) This Market Code provides for the purchase and sale of electrical energy by participating Generators, Retailers and Traders as well as the physical delivery and consumption of electricity on a short term basis, within a framework of medium and long term security of supply.

(2) This Market Code sets out the trading and settlement rules and procedures for participation in the competitive electricity market of South Africa including the required supporting functions and regulations.

(3) It is a condition of the Market Operator Licence that the Market Operator shall enter into and at all times administer and maintain in force a Market Code and rules which:

(a) set out the terms of the trading and settlement arrangements for the sale and purchase of wholesale electricity in the South African Wholesale Electricity Market (SAWEM);

(b) are designed to facilitate the achievement of the objectives set out in chapter 2.4 below; and

(c) contain modification procedures which provide that any major modifications to the Market Code must be subject to a transparent governance process that afford participants and stakeholders to propose changes to the Market Code.

(4) The rules in this Market Code give effect to the requirements for an open market platform that allows for competitive electricity trading as established in the Electricity Regulation Act;

(5) Paragraphs 1 to 4 of this Section 1 are for information only and, without prejudice to the rights, duties and obligations set out in the Licences and legislation referred to therein, are not intended of themselves and should not be construed so as to create legally binding obligations as between or impose rights and duties on the Parties.

2 GENERAL

2.1 Definitions

(1) **"10 Minute Reserve"** shall have the meaning as defined in the System Operation Code;

(2) **"10 Minute Reserve Availability Indicator"** has the meaning of section 9.4 of the Market Code;

(3) **"Accession fee"** shall have the meaning as defined in section 6.2 in this Market Code;

(4) **"Act"** means the Electricity Regulation Act (Act 4 of 2006), as amended, and the

regulations made thereunder;

(5) **“Applicable Laws”** means any legislation, statutory instrument, regulation, directive, decision, instruction, direction, order as is applicable to a Party;

(6) **“Applicant”** shall have the meaning as defined in section 6.2 in this Market Code;

(7) **“Availability”** means a Trading Unit's capability in MW to deliver Active Power or a Trading Unit’s capability of reducing the Active Power consumed on the Trading Facility;

(8) **“Balance Responsible Party”** means a Generator, Supplier or its chosen representative that takes physical and financial responsibility for maintaining real-time balancing at specified metering points, by submitting forecasts day ahead. The BRP will be accountable through the Imbalance settlement for the cost of any imbalances;

(9) **“Balancing”** means ensuring that supply and demand on the NIPS are in balance in real-time;

(10) **“Balancing Agreements”** means the defined agreements under the South African Grid Code;

(11) **“Balancing Buying Stack”** has the same meaning as defined in section 13.8 of the Market Code;

(12) **“Balancing Energy Sold”** has the same meaning as defined in section 13.1 of the Market Code;

(13) **“Balancing Energy Bought”** has the same meaning as defined in section 13.1 of the Market Code;

(14) **“Balancing Penalty Factor”** means the ratio of the day-ahead System Marginal Price applied to ensure a minimum balancing penalty in the Balancing Mechanism;

(15) **“Balancing Selling Stack”** has the same meaning as defined in section 13.7 of the Market Code;

(16) **“Balancing Service Provider”** is defined as a BRP that is offering balancing services to the TSO through the Balancing Market or Balancing Mechanism.

(17) **“Bank”** means a holder of a relevant banking license or authorization issued under the Banks Act 94 of 1990 or the Mutual Banks Act 124 of 1993;

(18) **“Billing Period”** has the same meaning as defined in section 15.3.2 of the Market Code;

(19) **“Capacity Qualifying”** has the same meaning as defined in section 9.9.4 of the Market Code;

(20) **“Central Purchasing Agency”** means an entity assigned to fulfil the role of the wholesale buyer to maintain system integrity during the transition to a competitive electricity market;

(21) **"Code"** means the South African Distribution Code, the South African Grid Code or any other Code, published by NERSA, as applicable and as amended from time to time;

(22) **"Cold Start-up",** means restarting of the generator after 36 hours following shutdown.

(23) **"Collateral Reserve Account"** has the same meaning as defined in section 15.2 of the Market Code;

(24) **"Commencement Date"** means the date established by the NERSA for the commencement of this Code;

(25) **"Competent Authority"** means the National Energy Regulator of South Africa and the Competition Commission

(26) **"Control Area"** means an electrical system with borders defined by points of Interconnection and capable of maintaining continuous balance between the generation under its control, the consumption of electricity within the electrical system and the scheduled interchanges with other Control Areas;

(27) **"Controllability"** means the direct means to vary or instruct the output of a device either via telephonic instruction or similar means in the case of a local operator controlled device or via a remote link to the device's output controller.

(28) **"Constrained Schedule"** has the same meaning as defined in section 9.6 of the Market Code;

(29) **"Cost above Energy Market"** means the compensation due to a trading unit as a result of providing Regulating Down Reserve Capacity where the trading unit is scheduled to produce more than the optimum energy solution.

(30) **"Cost above Energy Market for Regulating Down Reserve Capacity"** has the same meaning as defined in section 9.7.2 of the Market Code;

(31) **"Cost Increment"** has the same meaning as defined in section 9.4 of the Market Code;

(32) **"Cost of Lost Opportunity"** means the forgone opportunity (or profit) in the Energy market as a result of providing Instantaneous, Regulating Up Reserve Capacity, and/or Ten-Minute Reserve Capacity;

(33) **"Cost of Lost Opportunity for Instantaneous Reserve Capacity**" has the same meaning as defined in section 9.7.3 of the Market Code;

(34) **"Cost of Lost Opportunity for Regulating Up Reserve Capacity**" has the same meaning as defined in section 9.7.1 of the Market Code;

(35) **"Cost of Lost Opportunity for Ten-minute Reserve Capacity"** has the same meaning as defined in section 9.7.4 of the Market Code;

(36) **"Court"** means the South African courts;

(37) **"Creditors"** means the counterparts to any outstanding payments or Unsecured Bad Debt arising from the SAWEM;

(38) **“Credit Call”** means the drawing down of a Participant's Credit Cover from its Credit Cover Provider;

(39) **“Credit Cover”** means the credit cover required of and provided by a Participant in a form which meets the requirements of the Market Code;

(40) **“Credit Cover Provider”** means a financial institution which is registered under applicable Law to carry on the business in South Africa, and holds a credit rating of i) at least one investment grade long-term unsecured local currency debt rating by a rating agency which is at or better than ‘BBB-’ (as determined by Standard and Poor’s Rating Group or Fitch Ratings), ‘Baa3’ (as determined by Moody's Investor Services, Inc.); or (ii) long-term unsecured local currency debt rating not worse than the highest South Africa’s sovereign local currency debt rating; or (iii) South African Long-term National Scale Rating no worse than ‘zaA-’ (as determined by Standard & Poor’s) or ‘A-(zaf)’ (as determined by Fitch Ratings) or ‘A3.za’ (as determined by Moody's Investor Services, Inc.) or (iv) equivalent rating to any of the above ratings;

(41) **“Curtailment”** means that the amount of Active Power that the generating unit, the power station or the generating facility is permitted to generate is restricted by the SO, TNSP or other Network Operator due to network or system constraints;

(42) **“Data Verification Period”** means the period when Market Participants have the opportunity to query any data included on the Indicative Settlement Statements;

(43) **“Data Query”** means any query made by a Market Participant in relation to one or more Settlement Items in an Indicative Settlement Statement;

(44) **“Day Ahead Market”** means the platform for the trading of electrical energy which operates day-ahead, i.e. Ex Ante, with participants submitting bids and offers for energy, and the Market Operator clearing contracts between participants;

(45) **“Declared Available Capacity”** shall have the meaning as defined in section 9.4 of the Market Code;

(46) **“Declared Maximum Consumption”** shall have the meaning as defined in section 9.4 of the Market Code;

(47) **“Default”** means any default by a Party to the Market Code;

(48) **“Default Notice”** shall have the meaning as defined in section 6.3.1 of the Market Code;

(49) **“Defaulting Party”** means a Party that is in Default;

(50) **“De Minimis Threshold”** shall have the meaning as defined in section 7.2 of the Market Code;

(51) **“Deregisteration”** means the process whereby a Trading Unit (or parts thereof) of a Market Participant, or, in the case of de-registration of all of it Trading Units, a Market Participant ceases to be registered for the purposes of the Market

Code;

(52) **“Dispatch Day”** means the day of real-time operation;

(53) **"Dispatch instruction"** means the instruction from the SO to a generator or demand-side resource to effect a change in output (for the generator) or consumption (for the demand-side resource) or reserve capacity (for both generators and demand-side resources) either in real-time or in a predetermined time. These instructions may be:

(a) **Automatic,** in that the SO control system issues the instruction to the generator or demand-side resource without operator intervention; or

(b) **Manual,** in that the SO issues the instruction either telephonically, via electronic mail or other mechanism requiring operator intervention;

(54) **"Dispatchable"** means the SO is authorised to influence the dispatch of the generator or demand-side resource and the generator or demand-side resource is able to respond to automatic or manual SO dispatch instructions;

(55) **“Dispute”** has the meaning as defined in section 5 of this Market Code;

(56) **“Dispute Resolution Board”** means a board appointed in accordance with this Market Code to resolve disputes between Disputing Parties;

(57) **“Dispute Resolution Process”** means the process of resolving Disputes as specified in the Market Code;

(58) **“Disputed Event”** means the earliest date of any event, circumstance, claim, difference, Default, assertion of right or entitlement, or denial of right or entitlement in relation to which a Party seeks to raise a Dispute;

(59) **“Disputing Parties”** means any Party to a Dispute;

(60) **“Distributor”** has the same meaning as in the South African Distribution Code;

(61) **"Distribution Network"** means the network owned and operated by a Distributor;

(62) **"Distribution System"** means the network infrastructure operating at nominal voltages of 132kV and below;

(63) **"Effective Available Capacity"** means the actual available capacity of a generator or demand-side resource at any instant taking into account actual events, in particular outages, constraints or load losses;

(64) **"Electrical System Collapse"** means the situation existing when all generation has ceased in part of the Transmission System and there is no electricity supply such that Black Start procedures as set out in the South African Grid Code are initiated;

(65) **“Eligible Customer”** means the demand-side entity that this allowed to participate in the market;

(66) **"Embedded Generator"** means a legal entity controlling one or more generating

units, connected specifically to the DS;

(67) **“Emergency Level 1”** has the same meaning as defined in section 9.4 of the Market Code;

(68) **“EL1 Cost”** has the same meaning as defined in section 9.4 of the Market Code;

(69) **"Emergency Operating Condition"** means a situation where generators, transmission or distribution service providers have an unplanned loss of facilities, or another situation beyond their control, that impairs or jeopardises the integrity of the NIPS and compromises safety of personnel, plant and equipment;

(70) **“Emergency Reserve”** has the same meaning as in the System Operation Code;

(71) **“End-use Customer”** means users of electricity connected to the DS or the TS;

(72) **"Energy"** means the electricity produced, flowing or supplied by an electric circuit over a particular time interval, being the integral with respect to time of the instantaneous power, measured in units of watt-hours (Wh) or standard multiples thereof, i.e.:

(a) 1000 Wh = 1 kWh

(b) 1000 kWh = 1 MWh

(c) 1000 MWh = 1 GWh

(d) 1000 GWh = 1 TWh.

(73) **“Energy Limit”** means an upper limit on the amount of energy that can be generated by a Generator Unit;

(74) **“Excess Participant”** has the meaning as defined in section 15.3.4 (11) in the Market Code;

(75) **“Export License”** means the license granted by NERSA to entities allowed to export power from South Africa;

(76) **“Final Modification Recommendation”** means A recommendation by the MRAC in relation to a Modification Proposal which is submitted to NERSA for approval as part of a Modification Recommendation Report;

(77) **"Flexible"** means that the trading unit can be scheduled or dispatched in that Trading Period according to the economic merit order determined in the dispatch algorithm;

(78) **“Flexible Indicator”** shall have the meaning as defined in section 9.4 of the Market Code;

(79) **“Force Majeure Event”** means, in relation to a person, any event or circumstance, or combination of events or circumstances: that is beyond the reasonable control of the person; that adversely affects the performance by the person of its obligations under this Market Code, a market manual or the system

operation manual; and the adverse effects of which could not have been foreseen and prevented, overcome, remedied or mitigated in whole or in part by the person through the exercise of diligence and reasonable care, and includes, but is not limited to: acts of war (whether declared or undeclared), invasion, armed conflict or act of a foreign enemy, blockade, embargo, revolution, riot, insurrection, civil disobedience or disturbances, vandalism or act of terrorism; strikes, lockouts, restrictive work practices or other labour disturbances; unlawful arrests or restraints by governments or governmental, administrative or regulatory agencies or authorities; orders, regulations or restrictions imposed by governments or governmental, administrative or regulatory agencies or authorities unless the result of a violation by the person of a permit, licence or other authorisation or of any applicable law; epidemics or pandemics; and acts of God including lightning, earthquake, fire, flood, landslide, unusually heavy or prolonged rain or lack of water arising from weather or environmental problems;

(80) **"Generating Unit"** means an independently controllable generating set, especially an alternator and all related equipment including the generation transformer that can be connected to the NIPS. In the case of wind generation the generating unit can refer to the generating facility rather than to the individual generating sets;

(81) **"Generator Suspension Delay Period"** means the time period it will take to make a Suspension Order effective for a Generation Unit;

(82) **"Generating Facility"** means any apparatus which is licensed to produce electricity, including both synchronous and nonsynchronous apparatus (such as solar plant) in a single physical location;

(83) **"Generator"** has the same meaning as defined in the Market Code. For the purpose of these rules, reference to generators shall also include all qualifying generators;

(84) **"High Materiality"** means an amount over R100.000 in respect of a single Market Participant;

(85) **"Hot Start-up"** means restarting of the generator within 8 hours after the shutdown;

(86) **"Imbalance Energy Bought"** has the same meaning as defined in section 13.2 of the Market Code;

(87) **"Imbalance Energy Sold"** has the same meaning as defined in section 13.2 of the Market Code;

(88) **"Incremental Cost of Production"** means the additional cost of production associated with each additional unit of output;

(89) **"Indicative Settlement Statements"** means the Settlement Statement sent to Market Participants before the Initial Settlement Statements are calculated, to allow the Market Participants to quality check the data that is going to be used in the calculation of the Initial Settlement Statements;

(90) **"Initial Settlement Statements"** means the Settlement Statements that are issued for invoicing;

(91) **"Inflexible"** means that the generating unit cannot be scheduled or dispatched at any level other than the indicated available capacity for that Trading Period;

(92) **"Installed Generation Capacity"** means total net maximum capacity (MW) of all qualifying generators;

(93) **"Instantaneous Reserve"** has the same meaning as in the System Operation Code;

(94) **"Instantaneous Reserve Availability Indicator**" has the meaning in section 9.4 of the Market Code;

(95) **"Instructed Energy"** has the meaning in section 11.4 of the Market Code;

(96) **"Intellectual Property Rights"** means the legal rights given to the inventor or creator to protect his invention or creation for a certain period of time;

(97) **"Interconnection / Interconnector"** means facilities that connect two adjacent systems or control areas;

(98) **"International Trader"** means a legal entity licensed to trade electricity across the borders of South Africa (either exports or imports);

(99) **"Invoice"** means the statement of the payments required to be made to the Market Operator by a Market Participant in respect of the trading activities of that Participant in the SAWEM;

(100) **"Legal requirements"** means any requirement under a License or Applicable Laws or rule of any Competent Authority;

(101) **"Load Forecast"** has the same meaning as defined in section 13.6 of the Market Code;

(102) **"Load Forecast Error"** has the same meaning as defined in section 13.6 of the Market Code;

(103) **"Low Materiality"** means an amount below R100.000 in respect of a single Market Participant;

(104) **"Market Assessment"** means an investigation conducted by NERSA into conditions of market power and effective trading in the SAWEM which may be conducted at any time but with the requirement that at least one Market Assessment is concluded before four years from the Commencement Date;

(105) **"Market Auditor"** means the person at any time appointed to performing the Market Audit of the SAWEM;

(106) **"Market Bank"** means the Bank appointed by the Market Operator to fulfil its banking;

(107) **"Market Code"** means this document including any appendices;

(108) **Market Code Advisory Committee** means the committee defined in section 3.5 of the Market Code;

(109) **"Market Code Objectives"** has the meaning as defined in section 2.4 of this Market Code;

(110) **"Market Code Secretariat"** means the committee defined in section 4.1 (5) of the Market Code;

(111) **"Market Conduct Rules"** has the same meaning as defined in appendix **I** in this Market Code;

(112) **"Market Operator"** means organisation responsible for the tasks as defined in section 3.3 of the Market Code;

(113) **"Market Operator License"** means the License granted to the Market Operator specifying its obligations to operate the SAWEM under the Market Code;

(114) **"Market Participant"** means Parties responsible for the tasks as defined in section 3.4of the Market Code;

(115) **"Market Participant Agreement"** means an agreement between the Market Operator and a Market Participant regulating the participation of the Market Participant in the SAWEM;

(116) **"Market Price Cap"** means the maximum price for the System Marginal Price;

(117) **"Market Surveillance Panel"** shall have the meaning as defined in section 4.2 of the Market Code.

(118) **"Market Surveillance Unit"** shall have the meaning as defined in section 4.3 of the Market Code.

(119) **"Maximum Continuous Rating"** means the Sent-Out capacity that a trading unit or trading facility is rated to produce continuously under normal conditions;

(120) **"Minimum of the Capacity Contracted for Regulating up Reserve"** has the same meaning as defined in section 9.9.4 of the Market Code;

(121) **"Meter Data Provider(s)"** means the licensed person with responsibility for submitting Meter Data to the Market Operator in the form and under the timelines specified in the Market Code, and facilitating Data Queries, Settlement Queries and Disputes to the standards indicated in the South African Grid Code as appropriate;

(122) **"Metering Accuracy Band (MAB)"** means the allowance in terms of actual metered sent-out or consumption to cater for metering inaccuracy. Deviations from contracted positions within the Metering Accuracy Band shall not attract balancing penalties;

(123) **"Minimum Consumption Point"** shall have the meaning as defined in section 9.4 of the Market Code;

(124) **"Minimum Stable Generation"** means the minimum stable generation level, in MW, which the Trading Unit is capable of producing;

(125) **"Minimum Stable Generation Point"** means the minimum sent-out level of a generating unit or generating facility without experiencing stability problems

(such as with the associated boiler);

(126) **"Modification process"** means the process of assessing and accepting or rejecting Modification Proposals in accordance with the Market Code;

(127) **"Modification proposal"** means any proposal to modify the Market Code through a proposal which is submitted to the MRAC;

(128) **Modification Recommendation Report** shall have the meaning as defined in section 4.15, point (3) in this Market Code;

(129) **"National Integrated Power System"** means the electrical network comprising components that have a measurable influence on each other as they are operating as one system. This includes:

(a) the TS;

(b) the DS;

(c) assets connected to the TS or DS;

(d) power stations connected to the TS or DS;

(e) international interconnectors;

(f) the control area for which the SO is responsible.

(130) **"Net Export Curve"** has the meaning as in section 8.4 of the Market Code;

(131) **"Net System Demand"** has the same meaning as defined in section 13.6 of the Market Code;

(132) **"NERSA"** means the legal entity established in terms of the National Energy Regulator Act, 2004 (Act 40 of 2004), as amended;

(133) **"Network Constraint Area"** means a zone established by the SO as a subset of the NIPS network structure within which trading facilities may be established. For the avoidance of doubt, trading facilities may not be aggregated across more than one network constraint area;

(134) **"Normal Operating Condition"** means an operating condition which is not an emergency operating condition;

(135) **"Non-dispatchable"** means that the generator makes the dispatch decision for the generating unit or facility or demand-side resource under normal operating conditions;

(136) **"Notice of Dispute"** means a notice specifying what is disputed, when the Dispute commences, and the Parties of the Dispute;

(137) **"Notice of Dissatisfaction"** means a notice produced by one of the disputing Parties in respect of a Dispute;

(138) **"Out of Merit Energy"** means the allowance for capacity utilised by the System Operator for real-time balancing but not included in the calculation of balancing prices.

(139) **“Offer Data”** means one or more orders from a Market Participant to buy or sell power in the SAWEM;

(140) **“Party”** means a Market Participant, Transmission Network Service Provider, Distributor, System Operator, Market Operator or any other person governed by this Market Code;

(141) **“Power Station”** means one or more generating units or generating facilities at the same location;

(142) **“Product”** means a tradable product defined in the different market segments of SAWEM;

(143) **“Proposal Notice”** means the notice of a Modification Proposal to be published by the Market Operator based on a Modification Proposal submitted to the MRAC;

(144) **“Posted Credit Cover”** means the actual Credit Cover that is posted by a given Participant;

(145) **“Pumped-storage Cycle Efficiency”** means the ratio of the energy extracted from water in generating power to the energy put into the same quantity of water to pump the water back into the top reservoir in a pumped-storage system;

(146) **“Qualifying Generator”** means a generator required to provide the information to the Market Operator and/or System Operator as per these rules and the Market Code. The rules governing when a generator becomes a qualifying generator shall be set as per these rules from time to time;

Note: By default the following generator categories shall be regarded as qualifying generators:

(a) A generator operating a generating unit or facility connected directly to the TS.

(b) An embedded generator or a co-generator operating a generating unit or facility with an MCR greater than 10 MW.

(c) An embedded generator or a co-generator operating a generating unit or facility with an MCR greater than 1 MW but less than 10MW. These generator categories shall only comply with the requirements of this Market Code;

(147) **“Real-time Dispatch Schedule”** means the actual schedule for a Trading Unit;

(148) **“Registry”** means the registry defined in section 7.1 of the Market Code;

(149) **“Referral Notice”** means a Notice from a Party to the Dispute Resolution Board;

(150) **“Regulation Reserve”** has the meaning as defined in the Systems Operations Code;

(151) **“Regulating Reserve Availability Indicator”** has the same meaning as defined in section 9.4 of the Market Code;

(152) **"Required Credit Cover"** means the security posted for each Market Participant that is intended to cover the expected potential unpaid payment commitments to the Market Operator over the Settlement Risk Period;

(153) **"Reserve Resource"** means a Trading Unit that is capable of providing different types of Reserves as outlined in the definition of these Services;

(154) **"Revenue Authority"** means the South African Revenue Service, established in terms of the South African Revenue Service Act 34 of 1997;

(155) **"SAPP Market Book of Rules"** means the rules with appendices and operational guidelines that governs the regional markets established under the Southern African Power Pool;

(156) **"Self-Dispatch"** refers to an operating regime where a generating unit or facility output is determined by the generator under normal system conditions except where curtailment rules apply.

(157) **"Self Billing Invoices"** means an arrangement between the Market Operator and a supplier. The Market Operator prepares an invoice and sends the copy to the supplier along with the payment;

(158) **"Sent-out"** means the power or energy actually injected into the IPS by a generating unit or generating facility.

(159) **"Settlement Calendar"** has the same meaning as defined in section 15.3.3 of the Market Code;

(160) **"Settlement Day"** has the same meaning as defined in section 15.3.1 of the Market Code;

(161) **"Settlement Dispute"** means any Dispute which arises out of a failure to resolve a Settlement Query;

(162) **"Settlement Query"** means when the result of the Initial Settlement is claimed to be wrong by a Party. They may be escalated to a Settlement Dispute if not resolved.

(163) **"Settlement Period"** means Billing Period or Capacity Period or both of them as the context may require;

(164) **"Settlement Recalculation Threshold"** means a percentage of change in Metered Generation or market schedule in a Settlement Day that results from an Upheld Dispute or the settlement of a Data Query or a Settlement Query which will result in the Market Operator re-running the SAWEM. The Settlement Recalculation Threshold shall be proposed by the Market Operator from time to time and approved by NERSA;

(165) **"Settlement Reruns"** means a rerun of Settlement for a given Billing or Capacity Period when new data are available;

(166) **"Settlement Risk Period"** means the Settlement timeline from the beginning of the Billing and Capacity Period until the cash is available on the Market Operator's account and the time added needed to remedy in the event that a Market Participant is Suspended defines the Settlement Risk Period;

(167) **“Settlement Statements”** means a defined data set that incorporates a set of variables used to calculate all payments and charges to a Market Participant in respect of its Trading Units for a given Billing or Capacity Period.

(168) **“Shortfall”** has the meaning as defined in section 15.3.4 (11) in the Market Code;

(169) **“South African Market Participant with a Capacity Payment”** means a Market Participant that receives a Capacity Payment from the CPA, System Operator and/or Market Operator;

(170) **“South African Market Participant without a Capacity Payment”** means a Market Participant that does not receive a Capacity Payment from the CPA, System Operator and/or Market Operator;

(171) **“South African Wholesale Electricity Market”** means the markets and products covered by this Market Code;

(172) **“South African Distribution Code”** means the Distribution code approved by NERSA, as amended;

(173) **“South African Grid Code”** means the Grid Code approved by NERSA, as amended;

(174) **“Southern African Power Pool”** means the regional power pool established under the Southern African Development Community in 1995 with its registered office in Harare, Zimbabwe;

(175) **“Supplemental Reserve”** has the meaning as defined in the System Operation Code;

(176) **“Supplier of Last Resort”** has the meaning as defined in the South African Grid Code;

(177) **“Supplier Suspension Delay Period”** means the time period it will take to make a Suspension Order effective for a Supplier Unit;

(178) **“Supplier Unit”** means a resource which receives electrical energy for its own use, excluding System Operator and Transmission Network Service Providers and Distribution Network Service Providers;

(179) **“Suspension Order”** means an order issued suspending all or part of the rights of a Market Participant to participate in the SAWEM;

(180) **“Synchronous Condenser Operation”** has the meaning as defined in the System Operation Code;

(181) **“System Marginal Price”** means the price for energy determined by the incremental price of the marginal unit scheduled to run in the Unconstrained Schedule in a scheduling period;

(182) **“System Operator”** means the legal entity licensed to be responsible for short-term reliability of the NIPS, which is in charge of controlling and operating the Transmission System and dispatching generation (or balancing the supply and demand) in real time;

(183) **"System Operation Code"** means the subset of the South African Grid Code covering the system operations;

(184) **"Terminated Party"** means a Party whose participation has been terminated either as a Party or as a Market Participant in respect of some or all of its Trading Units;

(185) **"Termination Order"** means an order from the Market Operator to a Party of its intent to discontinue that Party or its participation in respect of any or all of its registered Trading Units;

(186) **"Trader"** means a person that holds a trading license issued by NERSA;

(187) **"Trading Clearing Account"** means the account that a Market Participant has established in a Bank to participate in the SAWEM;

(188) **"Trading Day"** means a period from midnight to the following midnight;

(189) **"Trading Facility"** means one or more sites (for electricity generation or consumption as the case may be) that are aggregated within a network constraint area set but the SO;

(190) **"Trading Period"** means one hour;

(191) **"Trading Unit"** means a component of the trading facility which is an aggregated construct of production and/or consumption components established by the market participant with the following conditions:

(a) A Trading Facility may comprise one or more trading units, but a Trading Unit (and components) may only apply to one Trading Facility;

(b) The Trading Unit cannot be greater than 930 MW unless approved by the SO;

(c) The metering configuration of the Trading Unit must encompass all the energy production and consumption of the Trading Unit.

(192) **"Transition period"** means the period starting on the Commencement Date and continuing for five years, or a later date as determined by NERSA following a Market Assessment;

(193) **"Transmission System"** means the network infrastructure operating at nominal voltages of above 132kV;

(194) **"Transmission Asset Owners"** means, at any given time, the Transmission System owner licensed by NERSA;

(195) **"Transmission System Operator"** means the Transmission System Operator SOC Limited which is responsible for the functions as defined in Section 34A (2) of the Act;

(196) **"Unconstrained Schedule"** has the same meaning as defined in section 9.6 of the Market Code;

(197) **"Unsecured Bad Debt"** means a debt which arises as a result of the events set

out in section 15.3.4 in the Market Code. For the avoidance of doubt, this definition applies only for the purposes of the Market Code, and is not intended to imply that any particular sum is a "bad debt" within the meaning of this expression in any financial or accounting definition, standard or practice;

(198) **"Upheld Dispute"** means a Dispute becomes an Upheld Dispute when the Dispute Resolution Board has resolved the Dispute in accordance with the Dispute Resolution Process and has determined that Settlement Items have changed as a result of the Dispute.

(199) **"Urgent"** means a Modifications Proposal which is designated to be Urgent will be therefore treated with a fast-track Modifications Process;

(200) **"Vesting Contract"** means a contract between the Central Purchasing Agency and an Eskom generator or a distribution licensee, for the sale of a specified amount of electricity at a specified price as a mechanism to facilitate the transition to a competitive market;

(201) **"Virtual Power Station"** means a load that can be dispatched in the dispatch algorithm;

(202) **"Voluntary Termination"** means when a Party voluntary decides to discontinue being a Party or deregister its Trading Units and is permitted to do so in accordance with the Market Code. Such voluntary termination will take effect from the Voluntary Termination Date;

(203) **"Voluntary Termination Consent Order"** means the order defining the Voluntary Termination by a Party under the Market Code;

(204) **"Warm Start-up"** means restarting of the generator between 8 and 36 hours after the shutdown.

(205) **"Warning Limit"** has the same meaning as defined in section 15.10.2(4) of the Market Code;

(206) **"Warning Notice"** has the same meaning as defined in section 15.10.2 of the Market Code;

(207) **"Water Authority"** means the Department of Water and Sanitation;

(208) **"Wholesale Tariff"** has the same meaning as defined in section 9.8.1 of the Market Code;

(209) **"Working Day"** means 8am-5pm period on a weekday which is not a public holiday or bank holiday;

2.2 Acronyms and Abbreviations

AGC	Automatic Generation Control
BM	Balancing Market, meaning the regional SAPP balancing market
BRP	Balance Responsible Party
CPA	Central Purchasing Agency

DAM	Day-ahead Market
DS	Distribution System
EL1	Emergency Level 1
EFT	Electronic Fund Transfer
ESI	Electricity Supply Industry
FPM	Forward Physical Market
IDM	Intra-Day Market
IPS	Interconnected Power System
MAB	Metering Accuracy Band
MCAC	Market Code Advisory Committee
MCPR	Maximum Continuous Pump Rating
MCR	Maximum Continuous Rating
Mingen	Minimum Stable Generation
MO	Market Operator
MSP	Market Surveillance Panel
MSU	Market Surveillance Unit
NEC	Net Export Curve
NIPS	National Integrated Power System
SAPP	Southern African Power Pool
SAWEM	South African Wholesale Electricity Market
SCO	Synchronous Condenser Operation
SMP	System Marginal Price (or Day-ahead clearing price)
SO	System Operator
TNSP	Transmission Network Service Provider
TS	Transmission System
TSO	Transmission System Operator

2.3 Interpretation

(1) In this Market Code, notwithstanding the definitions set out in the Act and the Code(s):

(a) a natural person includes a juristic person and vice versa;

(b) a word in the singular includes the plural, and vice versa;

(c) a Generator refers to generators connecting to the TS or the DS (thus including Embedded Generators).

(2) Unless the context indicates a contrary intention, words and expressions defined in the Market Code shall bear the meanings assigned to them throughout the Market Code and cognate expressions bear corresponding meanings;

(a) reference to "days" shall be construed as calendar days unless qualified by the word "business", in which instance a "business day" will be any day other than a Saturday, Sunday or public holiday as gazetted by the government of the Republic of South Africa from time to time. Any reference to "business hours" shall be construed as being the hours starting at 08h00 and ending at 17h00 on any business day;

(b) unless specifically otherwise provided, any number of days prescribed shall be determined by excluding the first and including the last day, or, where the last day falls on a day that is not a business day, the next succeeding business day; and

(c) the words “include” and “including” mean “include without limitation” and “including without limitation”. The use of the words “include” and “including” followed by a specific example or examples shall not be construed as limiting the meaning of the general wording preceding it.

(d) the table of contents, and any index and headings in this Market Code, are for ease of reference only and do not form part of the contents of this Market Code and do not and shall not affect its interpretation;

(e) any reference to any legislation, primary or secondary, in this Market Code includes any statutory interpretation, amendment, modification, re-enactment or consolidation of any such legislation and any regulations or orders made thereunder and any general reference to any legislation includes any regulations or orders made thereunder;

(f) any references to chapters or sections are references to chapters or sections of this Market Code as amended or modified from time to time in accordance with the provisions of this Market Code;

(g) any reference to another agreement or document, or any deed or other instrument is to be construed as a reference to that other agreement, or document, deed or other instrument as lawfully amended, modified, supplemented, substituted, assigned or novated from time to time;

(h) where any obligation is imposed on any Party pursuant to this Market Code and is expressed to require performance within a specified time limit that obligation shall, where appropriate, continue to be binding and enforceable after that time limit if the Party fails to perform that obligation within that time limit (but without prejudice to all rights and remedies available against that person by reason of that person’s failure to perform that obligation within the time limit);

(i) zero is to be treated as a positive, whole number;

(j) capitalised words and phrases, acronyms, abbreviations and subscripts have the meaning given to them in the Definitions;

(k) where a specified number of days is expressed to elapse or expire from or after the giving of a notice or the issue or making available of a document before an action may be taken or by which an action is required to be taken then, unless explicitly stated otherwise, the day on which the notice is given or issued or the document is made available shall not be counted in the reckoning of the period;

(l) a reference to a “person” includes any individual, partnership, firm, company, corporation (statutory or otherwise), joint venture, trust, association, organisation or other entity, whether or not having separate legal personality;

(m) where this Market Code requires data to be published by the Market Operator, it shall be made publicly available (which, for the avoidance of doubt means available to all members of the public and not only to Parties) in a format that readily lends itself to processing by standard computer and analysis tools, through an easily accessible public interface and the terms “publish”, “publication” and “published” shall be construed accordingly;

(n) where this Market Code requires the Market Operator to publish information and no timeline is specified for such publication, it shall be required to publish such information as soon as reasonably practicable;

(o) in the event of any conflict between algebraic formulae and English language text, the algebraic formula shall apply, save in the case of manifest error in the algebraic formula;

(p) where no timeframe for performance is specified in respect of any obligation to be performed by a Party, then such obligation shall be performed within a reasonable time; and

(q) payments or charges may be either positive or negative in accordance with their calculated value except where otherwise stated.

(r) Where any provision of this Market Code provides that NERSA shall determine or approve certain values which are required for the performance of calculations under the Market Code and which apply for a specific period, and on expiry of such period no replacement values have been determined by NERSA, or NERSA have not communicated such determination to the Market Operator, then the values applicable immediately prior to the expiry of the relevant period shall continue to apply until NERSA have determined or approved new values and this has been communicated to the Market Operator in accordance with the Market Code.

2.4 Objectives

(1) The objectives of the Market Code are:

(a) to facilitate the efficient discharge by the Market Operator of the obligations imposed upon it by its Market Operator Licence;

(b) to facilitate the efficient, economic and coordinated operation, administration and development of the South African Wholesale Electricity Market in a financially secure manner;

(c) to facilitate the participation of electricity undertakings engaged in the generation, supply or sale of electricity in the trading arrangements under the South African Wholesale Electricity Market;

(d) to promote competition in the single electricity wholesale market in South Africa;

(e) to provide transparency in the operation of the South African Wholesale Electricity Market;

(f) to ensure no undue discrimination between persons who are parties to the Market Code;

(g) to promote the short-term and long-term interests of consumers of electricity in South Africa with respect to price, quality, reliability, and security of supply of electricity;

(h) to set out roles, responsibilities, and process for the trading of electrical energy and reserves; to set out the roles, responsibilities and process for the scheduling and dispatch of generation and demand-side resources in meeting the electricity demand; and

(i) to ensure fair and equitable treatment of all market participants connected to the NIPS.

2.5 Application

(1) The Market Code applies to all qualifying Generators, Traders, Distributors and Supplier Units connected to the NIPS as well as International Traders.

(2) The Market Code shall provide rules for the trading environment of the ESI and be aligned with the South African Grid Code and the South African Distribution Code.

2.6 Publication of the Market Code

(1) The applicable version of the Market Code shall be made publicly available both on the NERSA website as well as the Market Operator.

2.7 Governing law

(1) This Market Code and any disputes arising under, out of, or in relation to the Market Code shall be interpreted, construed and governed in accordance with the laws of South Africa.

2.8 Jurisdiction

(1) Subject to the provisions relating to the Dispute Resolution Process, the Parties hereby submit to the exclusive jurisdiction of the Courts of South Africa for all disputes arising under, out of, or in relation to the Market Code.

2.9 Term

(1) The Market Code shall commence on the Commencement Date and shall have no fixed duration.

2.10 Priority

(1) In the event of any conflict between any Party's obligation pursuant to any Legal Requirements and the Market Code, such conflict shall be resolved according to the following order of priority:

(a) requirements under Applicable Laws;

(b) any applicable requirement, direction, determination, decision, instruction or rule of any Competent Authority;

(c) applicable Licence;

(d) South African Grid Code applicable to the relevant Trading Unit concerned;

(e) South African Metering Code applicable to the relevant Trading Unit concerned; and

(f) this Market Code.

(2) If and for so long as a Party complies with the relevant Legal Requirements, it shall be relieved of its obligations under the Market Code to the extent that and for so long as the performance of such obligations is in conflict with any of the relevant Legal Requirements taking priority over the Market Code, provided that such conflict does not arise as a result of a failure of the relevant Party to procure, comply with or maintain any consent, permission or Licence.

(3) A Party shall only be relieved of its obligations for so long as and to the extent that resolution of the conflict is not within the reasonable control of the relevant Party.

(4) Until such time as such conflict is resolved through the Modifications Process or otherwise, the applicable obligations under the Legal Requirements shall prevail over the provisions of the Market Code for each Party or Trading Unit in relation to which they are in conflict.

(5) It is not intended that there be any inconsistency or conflict between any provision of any of the sections or appendices of the Market Code. However, in the event of any inconsistency or conflict, such inconsistency or conflict shall be resolved by NERSA or a Dispute Resolution Board as required.

3 ROLES AND RESPONSIBILITIES

3.1 NERSA

(1) NERSA is the administrative authority for the Market Code in terms of section 34A of the Act, as amended. NERSA shall ensure that the Market Code is compiled, implemented and complied with for the benefit of the industry.

(2) NERSA shall perform the following functions:

(a) constitute the MCAC and review its membership on an annual basis;

(b) constitute the MSP and review its membership on an annual basis;

(c) consider and respond to MCAC submissions within three months after the matter has been referred to them for approval;

(d) certify Balance Responsible Parties, and decertify if a Balance Responsible Party fails to adhere to Market Code requirements or the MSP recommends such action;

(e) establish conditions for approval of Market participation in the voluntary Market by the Market Operator;

(f) publish Market Code documentation;

(g) chair all MCAC meetings in line with the requirement of this code; and

(h) fund the administrative activities of the MCAC and MSP.

3.2 The System Operator

(1) The SO shall with respect to this Market Code:

(a) apply the Market Code;

(b) Schedule and Dispatch Generation and Supplier Units based on the economic merit order provided by the MO whilst maintaining the prescribed system security;

(c) provide regular reports to NERSA regarding the scheduling and dispatch of the NIPS;

(d) maintain data for the auditing of the dispatch function; and

(e) disclose to participants upon request the reasons for Dispatch Instructions;

(2) In the event that generation capacity and Supplier Units are insufficient to meet the demand, the SO may take mitigating actions that may not be in line with the Market Code but in accordance with its functions in terms of the System Operation Code.

(3) Under normal operating conditions any contractual requirements that restrict dispatch instructions from the SO shall apply. Under Emergency Operating Conditions the SO may override these contractual requirements and enforce dispatch instructions on all Generators, provided that the Generator is able to comply with SO Dispatch Instruction within statutory limits.

3.3 The Market Operator

(1) The MO shall:

(a) apply the Market Code;

(b) provide market platforms to enable trade between market participants;

(c) register NERSA certified Balance Responsible Parties and conclude Balancing Agreements as per the South African Grid Code to facilitate trade;

(d) approve applications for market participation under conditions established by NERSA and conclude Market Participation Agreements to facilitate trade;

(e) clear the market(s) and timeously settle clearing accounts to ensure the integrity of the markets;

(f) provide regular reports to NERSA regarding the clearing and settlement of the markets;

(g) maintain data for the auditing of the market clearing and settlement functions; and

(h) monitor compliance of all Parties to the Market Code.

3.4 Market Participants

(1) Each Balance Responsible Party shall:

(a) adhere to Market Code obligations, taking into consideration all prevailing constraints, technical and/or economic, prior to submitting information required under the Market Code;

(b) conclude Balancing Agreement with the Market Operator to facilitate Balance Responsibility;

(2) Each Market Participant shall:

(a) adhere to Market Code obligations, taking into consideration all prevailing constraints, technical and/or economic, prior to submitting information required under the Market Code;

(b) conclude Market Participation Agreement with the Market Operator to facilitate trade.

3.5 Market Code Advisory Committee

(1) NERSA shall constitute the Market Code Advisory Committee (MCAC). Subsequent to its constitution NERSA shall ensure the proper functioning of the MCAC.

(2) The MCAC is established to:

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

(b) review and make recommendations regarding proposals to amend the Market Code;

(c) review and make recommendations regarding proposals for exemption to comply with the Market Code;

(d) review and make recommendations regarding proposals for derogation from the requirements of the Market Code;

(e) review and make recommendations regarding updating of the Market Code to facilitate and align with the changing ESI in South Africa; and

(f) facilitate the provision of expert technical advice to NERSA on matters related to the Market Code.

(3) The functions of the MCAC are to facilitate the Modifications Process by:

(a) co-ordinating the resources of Parties to facilitate the development and processing of a Modification Proposal;

(b) assessing Modification Proposals and the impact of any Modification

Proposals for the Market having regard to the Market Code Objectives;

(c) further developing Modification Proposals which are not rejected as being spurious;

(d) working up the detail of Modification Proposals;

(e) consulting on Modification Proposals as required; and

(f) compiling reports and making recommendations on Modification Proposals to the NERSA.

(3) The members of the MCAC shall be appointed by the NERSA board with no more than 20 members.

(4) A member elected or appointed to represent a particular type of Party shall represent the interests of the type of Party it is elected or appointed to represent.

(5) The MCAC shall have a chairperson and vice-chairperson who shall be elected from the voting members of the MCAC by the voting members of the MCAC. In the event of a tie for the election of the chairperson or vice-chairperson, a subsequent ballot or ballots shall take place until a chairperson and vice-chairperson are elected.

(6) The term of appointment for the chairperson and the vice-chairperson shall be two years.

(7) The chairperson will chair meetings of the MCAC and seek to ensure the efficient organisation and conduct of the functions of the MCAC pursuant to the Market Code.

4 MARKET GOVERNANCE

4.1 Market Code modification process

(1) The Market Code Advisory Committee (MCAC) will act as the committee governing all modifications to the Market Code as per the rules in section 3.5 above.

(2) Modifications shall be processed in accordance with this section of the Market Code.

(3) The objective of the MCAC is to progress Modification Proposals with a view to better facilitating the achievement by the Market Code of the Market Code Objectives.

(4) Save as expressly provided otherwise, only members appointed or elected to shall be entitled to vote at any meeting and those members shall have one vote each.

(5) The Market Operator shall make available to the MCAC a Market Code Secretariat. None of the Secretariat's personnel shall be a member of the MCAC.

(6) The Market Operator shall be responsible for the performance by the Secretariat of its functions necessary for the proper functioning of the Modifications Process under the Market Code.

(7) The chairperson will chair meetings of the MCAC and seek to ensure the efficient organisation and conduct of the functions of the Modifications Committee pursuant to the Market Code.

(8) The MCAC shall have a meeting at least once every two months.

(9) The MCAC acting through the Market Code Secretariat, shall set the date of each meeting and, where possible, shall publish such date at least two weeks in advance.

(10) Any person may attend meetings of the MCAC in an observatory capacity where that person has informed the Market Code Secretariat to the MCAC in advance and the Market Code Secretariat has confirmed that person's attendance. Where space is limited, and with the agreement of the chairperson of the MCAC, attendance of non-members may be limited on a first come first served basis.

(11) The costs of the Market Code Secretariat, meetings and all other costs of the MCAC shall be included as costs and expenses of the Market Operator for the purposes of the Market Code.

(12) Members of the MCAC shall not be entitled to remuneration or expenses.

(13) Modification Proposals to the Market Code can be proposed by any person including the Market Operator and NERSA. Any Modification Proposal shall be submitted to the Market Code Secretariat.

(14) Any person raising a Modification Proposal shall ensure that their proposal is clear and substantiated with appropriate detail, including how it furthers the Market Code Objectives, to enable it to be considered by the MCAC.

(15) Each Modification Proposal shall include draft text of the relevant provision of the Market Code as amended by the Modification Proposal.

4.1.1 Modification Recommendation Report timeline

(1) Save as expressly provided otherwise, the MCAC shall produce a Modification Recommendation Report in respect of each Modification Proposal.

(2) The Modification Recommendation Report shall be submitted to NERSA within eight months of receipt of a Modification Proposal unless such period is extended with the consent of NERSA.

4.1.2 Procedure for Developing Proposals

(1) The Market Code Secretariat shall, as soon as practicable after receipt of a Modification Proposal, publish a notice containing the relevant Modification Proposal ("Proposal Notice").

(2) A Modification Proposal shall be considered by the MCAC at the next appropriate meeting.

(3) The person making a Modification Proposal or its representative shall be entitled to present the Modification Proposal at the meeting at which it is to be initially considered.

(4) At the meeting where it first considers a Modification Proposal, the MCAC shall first determine whether the Modification Proposal is spurious as per the definition in section 4.1.3.

(5) The MCAC may decide to modify or combine Modification Proposals. These modified or combined Modification Proposals shall reference the original Modification Proposals.

(6) The MCAC may specifically invite appropriate persons, such as Market Participants, the Market Operator, the System Operator, industry groups, customer representatives or other persons to express their opinions on any Modification Proposal, including providing an impact analysis.

(7) Parties invited to assist the MCAC will make available reasonable resources to respond to such request by the MCAC.

(8) The MCAC may hold a public consultation in relation to a Modification Proposal. Where there is a public consultation, a minimum consultation period of ten business days from the date of publication of the relevant consultation paper shall be provided.

(9) In working up the detail of a Modification Proposal, the MCAC shall have due regard to comments and submissions received during the consultation process.

(10) The MCAC may contract consultants, experts or advisers at reasonable cost to advise the MCAC regarding any Modification Proposal, including the preparation of an impact analysis report. Any reasonable costs incurred by MCAC in connection with this shall form part of the costs of the Market Code Secretariat.

4.1.3 Spurious Proposals

(1) A Modification Proposal shall be deemed to be spurious if, inter alia, it is clearly contrary to the Market Code Objectives or does not further the Market Code Objectives. If the MCAC reasonably considers a Modification Proposal to be spurious, it shall reject such Modification Proposal.

(2) Any decision of the MCAC to reject a Modification Proposal must set out the reasons for the decision in writing and provide them to the person making the Modification Proposal and NERSA.

(3) NERSA reserve the right to veto any decision of the MCAC that a proposal is spurious and in such event, the relevant Modification Proposal must be processed by the MCAC in accordance with the Market Code.

4.1.4 Urgent Modifications

(1) Any person submitting a Modification Proposal may mark it as “Urgent”. A person submitting a Modification Proposal marked “Urgent” shall submit the Modification Proposal to the Market Code Secretariat and to NERSA.

(2) The Market Code Secretariat shall, as soon as possible on receipt of a Modification Proposal which is marked “Urgent”, contact NERSA which shall determine whether or not it shall be treated as Urgent.

(3) A Modification Proposal shall be determined to be Urgent by NERSA where, if not made, it can reasonably be anticipated that the event or circumstance with which the Modification Proposal is concerned would imminently:

(a) threaten or prejudice safety, security or reliability of supply of electricity; or

(b) unduly interfere with, disrupt or threaten the operation of the Market; or

(c) if a Modification is required to correct an obviously material error; or

(d) inconsistency in the Market Code.

(4) If NERSA determine that a Modification Proposal is Urgent, the MCAC shall convene an Emergency Meeting.

(5) If the Secretariat or the MCAC considers that any of the apply in respect of any Modification Proposal that has not been marked “Urgent” by the person submitting the Modification Proposal, the Secretariat shall promptly submit the Modification Proposal to NERSA for consideration.

(6) In the event that a Modification Proposal is deemed to be Urgent, the MCAC shall propose the procedure and timetable to be followed in making a recommendation in respect of the Urgent Modification which may fast-track the normal processes provided for in this Market Code. NERSA shall have the right to veto or direct amendments to the procedure and timetable proposed by the MCAC within two business days of any such proposal by the MCAC.

4.1.5 Alternative Proposals

(1) If any person does not agree with a Modification Proposal to the Market Code, it may propose an alternative Modification Proposal, which if received in sufficient time to be considered within the MCAC’s plans for progressing the initial original Modification Proposal may be considered in conjunction with, or in substitution for, the initial Modification Proposal.

4.1.6 Final Modification Recommendation & Report

(1) The MCAC shall make the determination for the Final Modification Recommendation by majority vote of voting members of the MCAC. The MCAC shall send the Final Modification Recommendation as part of the Modification Recommendation Report in relation to the Modification Proposal to NERSA as soon as practicable after the determination.

(2) The MCAC shall recommend to NERSA the adoption of such Modification Proposals as it concludes will better facilitate achievement of the Market Code Objectives.

(3) The Final Modification Recommendation of the MCAC shall be part of the Modification Recommendation Report which shall include:

(a) the determination of the MCAC on whether or not the Modification Proposal should be adopted;

(b) the reasons for such determination;

(c) where the MCAC is in favour of the proposal, a draft of the text of the proposed Modification;

(d) the original draft of the Modification Proposal;

(e) any dissenting opinions of members of the MCAC;

(f) a copy the Market Operator's opinion and System Operator's opinion on the Modification;

(g) the views of any respondents submitted during the consultation process (including any views of persons invited to give opinions or consultants, experts or advisors contracted to provide advice);

(h) an assessment of the impact of the Modification Proposal including in relation to the Market Code, any Legal Requirements, any other codes relating to the operation of the Market (including the Grid Codes and the Metering Codes) or any other relevant matter;

(i) an assessment, where the MCAC deems appropriate, of any alternative Modification Proposal proposed by any person;

(j) a draft of the specific changes that it is proposed would be necessary to make to the Market Code if the Modification Proposal would be accepted;

(k) proposed timescales for implementation; and

(l) a cost/resource requirements assessment.

4.1.7 No recommendation or decision by MCAC

(1) In the event that the MCAC is unable to make a determination in respect of a Modification Proposal within the timeframes, the matter shall be referred to NERSA. This referral shall detail the proposal and the information. In such event, NERSA shall either make a binding decision, or shall extend the applicable time-limit for the MCAC.

(2) In the event that the MCAC does not issue a determination in respect of a Modification Proposal within the timeframes and does not refer the matter to NERSA, NERSA shall either make a binding decision, or shall extend the applicable time-limit for the MCAC.

4.1.8 Decision of NERSA

(1) Following receipt of a Modification Recommendation Report created by the MCAC, NERSA Authorities shall decide whether to:

(a) direct a Modification in accordance or otherwise with the Final Modification Recommendation of the MCAC;

(b) reject the Final Modification Recommendation of the MCAC; or

(c) direct the MCAC that further work is required in respect of the Modification Proposal concerned in the Final Modification Recommendation, extending the eight-month timeline if necessary.

(2) NERSA shall make their decision in relation to a Modification Proposal as soon as reasonably practicable following receipt of the Final Modification Recommendation.

(3) If approved by NERSA, the Modification shall become effective two business days after the date of the decision of NERSA or such other date as may be specified by NERSA in its decision.

(4) Once any Modification has been made, the MO will be required to implement the change, including making the necessary changes to systems and processes with effect from the date provided. The MO shall publish the decision of the NERSA promptly on its receipt.

4.1.9 Information about the Modifications Process

(1) The MO shall publish information relating to the Modifications Process and the status of each Modification Proposal subject to the confidentiality provisions.

(2) The MO shall provide for a website location or other similar means of publication to be available to the Market Code Secretariat and the MCAC for the Modifications Process.

(3) The MO shall publish notices submitted to it by the MCAC as soon as practicable after receipt of such notices and in any event within two business days after receipt of such notices.

(4) The MCAC shall submit a quarterly report to NERSA including the progress and status of Modification Proposals. These reports shall be published by the MO as soon as reasonably practicable after receipt.

(5) The MO shall publish the determination of NERSA in relation to a Modification Proposal within two business days after such decision has been made and submitted to the MO and, where a Modification Proposal has been accepted, such publication shall include the text of the Modification.

4.1.10 Intellectual Property Issues Associated With Modification Proposals

(1) Each Party submitting a Modification Proposal shall be deemed to have irrevocably licensed any Intellectual Property Rights or other rights to, and to have waived any moral rights in, the content, form or other aspect of the Modification Proposal and such licence and waiver shall be a precondition to the valid submission of a Modification Proposal.

(2) Each person who is not a Party and submits a Modification Proposal shall be required to irrevocably licence any Intellectual Property Rights or other rights to and waive any moral rights in the content, form or other aspect of the Modification Proposal and such licence and waiver shall be a precondition to the acceptance of a Modification Proposal.

(3) A form for Modification Proposals shall be made available on the website provided for the MCAC and such form shall include a licence of Intellectual

Property Rights, and waiver of moral rights in respect of the content, format or other aspects of the proposal.

4.1.11 No Retrospective Effect

(1) For the avoidance of doubt, a Modification shall have effect as and from the date specified by NERSA or, where applicable, the MCAC and in no event shall that date be earlier than the date on which the Modification is approved by NERSA, or, where applicable, the MCAC.

(2) A Modification approved as “urgent” could have retrospective effect if approved by NERSA.

4.1.12 Market Code Secretariat

(1) The Market Code Secretariat will be an integrated part of the Market Operator and formally owned by the Market Operator Manager.

(2) All changes to the Market Code shall be put forward to the Market Code Advisory Committee.

4.2 Market Surveillance Panel

(1) The MSP shall be responsible for monitoring and enforcement of:

(a) the application of the Market Code by the MO and SO;

(b) compliance of Parties to the Market Code (via their licences);

(c) Issue sanctions of category 2 and higher; and

(d) Handling of disputes between Parties.

(2) The MSP shall be comprised of a chairperson and not less than three, but not more than eight, other persons appointed by NERSA, on a part-time basis. The members of the MSP must:

(a) be a citizen of South Africa, who is ordinarily resident in South Africa;

(b) have suitable qualifications and experience in economics, law, engineering, industry or public affairs;

(c) not be an office-bearer of any party, movement, organisation or body of a partisan political nature;

(d) not be an unrehabilitated insolvent;

(e) not be subject to an order of a competent court holding the person to be mentally unfit or disordered; and

(f) not have been convicted of an offence committed after the Constitution of the Republic of South Africa, 1993 (Act No. 200 of 1993), took effect, and sentenced to imprisonment without the option of a fine.

(3) All members of the MSP serve for a term of five years. NERSA may re-appoint a member at the expiry of their term.

(4) NERSA may only remove a member of the MSP if that person becomes subject to any of the disqualifications under 4.2. (2), or for serious misconduct, permanent incapacity or engaging in any activity that may undermine the integrity of the MSP.

(5) Any member may leave the MSP voluntarily at any time. In this case, NERSA shall appoint a new member.

(6) Remuneration of the members of the MSP shall be determined by NERSA and paid by NERSA.

4.3 Market Surveillance Unit

(1) A Markets Surveillance Unit (MSU) shall be established under the MO. This unit shall monitor and survey the markets governed by this Market Code with the main purpose of detecting incorrect behaviour of market participants leading to market abuse. The MSU shall also monitor that the MO is complying with the Market Code and the Market Conduct Rules and its timelines.

(2) The detailed Market Conduct Rules are defined in Annexure 1 to this Market Code.

(3) It is the responsibility of each Market Participant to ensure compliance with the Market Conduct Rules by all relevant parts of its organisation. Each Market Participant shall ensure that any person involved in Trading and/or Clearing on its behalf, including members of management and other persons who makes decisions in relation to Products through the exercise of their employment, profession or other duties towards the Market Participant, are subject to restrictions and obligations that enables the Market Participant to fully and efficiently comply with these Market Conduct Rules.

(4) The MSU shall have the authority to represent and act on behalf of MO in all matters regulated by the Market Conduct Rules and references to MO herein shall be construed accordingly. This authority of MSU includes authority to make requests for information and to issue sanctions according to the same chapter.

(5) Market Participants are obliged to provide all such information as MSU considers relevant either in the context of the performance of its monitoring role or in the context of any investigation of any suspected breach of the Market Conduct Rules as soon as possible following a written request from MSU. Market Participants must make all necessary arrangements with third parties in order to ensure that they are able to comply with their obligations under this section.

(6) Information received must only be used for the purpose of surveillance of the Market Conduct Rules, including the investigation of suspected breaches.

(7) All MSU employees shall include confidentiality clauses in their employment contract to ensure that this information is not unduly shared.

5 DISPUTE MANAGEMENT

(1) A “Dispute” means any claim, dispute or difference of whatever nature between any of the Parties howsoever arising under, out of or in relation to the Market Code in respect of which (i) one Party has served a Notice of Dispute, or (ii) a Notice of Dispute is deemed to have been served. A Dispute includes any Settlement Dispute.

(2) A Notice of Dispute may be served on any number of Parties. Where the MSU reasonably determines that the resolution of a Disputed Event will impact a third Party who has not been served a Notice of Dispute, the MSU will inform that third Party of the existence, nature and progress of the Dispute, while maintaining the confidentiality of the Disputing Parties.

(3) Subject to the rules concerning the commencement of certain Settlement Disputes, a Dispute is deemed to exist when one Party notifies another Party or Parties in writing of the Dispute by way of a Notice of Dispute within ten business days of that Party having become aware of the Disputed Event.

(4) The Notice of Dispute shall briefly set out the nature of the Dispute (including the Disputed Event(s)) and the issues involved. A copy of the Notice of Dispute shall be sent to the Market Operator and, where the Market Operator is a party to the Dispute, to NERSA.

(5) The provisions set out in this Dispute Resolution Process shall not prejudice or restrict any Party’s entitlement to seek interim or interlocutory relief directly from the appropriate Court or Courts with jurisdiction.

(6) The obligations of the Parties under the Market Code (including payment of any invoice amounts by the Invoice Due Date) shall not be affected by reason of the existence of a Dispute, save as provided for in any determination of the Dispute Resolution Board or a Court.

5.1.1 Settlement Disputes

(1) In the event that the MO does not resolve a Settlement Query within the timeframes, or does not resolve a Data Query within the timeframes, the Settlement Query or Data Query, as appropriate, shall automatically become a Settlement Dispute and the Notice of Dispute shall be deemed to have been issued on the date on which the MO was required to issue its determination in respect of the Settlement Query or Data Query.

(2) Without prejudice to the jurisdiction of a Court to award costs pursuant to its jurisdiction in that regard where applicable, the MO shall be liable for all costs in connection with a Settlement Dispute.

(3) In the event that a Party is dissatisfied with the MO’s determination in respect of a Settlement Query or Data Query, the Party that raised the Settlement Query or Data Query may raise a Dispute by issuing a Notice of Dispute to the MO within ten business days of receipt of the MO’s determination.

(4) A matter which is described as a Settlement Query or Data Query shall not be raised as a Dispute.

5.1.2 Objectives of the Dispute Resolution Process

(1) It is intended that the Dispute Resolution Process set out in or implemented in compliance with the Market Code and described in detail in the following paragraphs should to the extent possible:

(a) be simple, quick and inexpensive;

(b) preserve or enhance the relationship between the Disputing Parties;

(c) resolve and allow for the continuing and proper operation of the Market Code and the Market having regard to the Market Code Objectives;

(d) resolve Disputes on an equitable basis in accordance with the provisions of the Market Code having regard to the Market Code Objectives;

(e) take account of the skills and knowledge that are required for the relevant procedure; and

(f) encourage resolution of Disputes without formal legal representation or reliance on legal procedures.

5.1.3 Dispute Resolution Board

(1) Where a Notice of Dispute has been served, a representative of each of the Disputing Parties, each with authority to resolve the Dispute, must meet within ten business days of the date of the Notice of Dispute to seek in good faith to resolve the Dispute. The Disputing Parties shall negotiate in good faith and attempt to agree a resolution.

(2) If the Disputing Parties are unable to reach agreement within a further period of ten business days of meeting, the Dispute may within a further period of three business days be referred by any Disputing Party to a Dispute Resolution Board ("DRB") by way of notice in writing to the other Disputing Party or Parties ("Referral Notice") unless expressly provided otherwise in the Market Code. The Disputing Party shall immediately send a copy of the Referral Notice to the Market Operator (or to NERSA where the Market Operator is a Disputing Party), and the Market Operator shall forward the Referral Notice to the chairperson of the DRB. The Referral Notice shall state that it is given under this paragraph affected, the vice-chairperson of the Panel shall appoint a replacement within five business days of notification of the relevant event. Such appointment shall be final and binding.

(3) The appointment of any member of the DRB may be terminated by unanimous agreement of the Disputing Parties.

(4) Disputing Parties shall continue to perform all of their obligations and functions as required by the Market Code including, for the avoidance of doubt, fulfilling any payment obligations as payment falls due.

5.1.4 Obtaining the DRB's Decision

(1) A Dispute is deemed to be referred to the DRB as of the date of the receipt of the Referral Notice by the MO.

(2) Disputing Parties shall promptly make available to the DRB all such additional information as they consider appropriate or as the DRB may require for the purposes of making a decision on a Dispute. The DRB may request any information it considers relevant.

(3) The DRB shall be entitled to determine the applicable procedure including the manner and the timing of any written submissions and any oral hearings. In determining the applicable procedure, the DRB shall have regard to the considerations above as well as the number of Disputing Parties.

(4) The DRB shall give its decision within (i) thirty business days after the appointment of the DRB where there are no more than two Disputing Parties; (ii) forty business days after the appointment of the DRB where there are more than two Disputing Parties; or (iii) such other period as may be proposed by the DRB and approved by the Disputing Parties. Its decision shall be in writing providing reasons and state that it is given. The decision shall be binding on all Disputing Parties, who shall promptly give effect to it unless or until it shall be revised in an amicable settlement. The Parties shall continue to comply with the Market Code in all respects.

(5) If any Disputing Party is dissatisfied with the DRB's decision, then that Party may, within ten business days after receiving the decision, give notice to the other Disputing Party or Parties and the DRB in writing of its dissatisfaction. If the DRB fails to give its decision within the relevant period, then any Disputing Party may, within ten business days after such period has expired, give notice to the other Disputing Party or Parties and the DRB in writing of its dissatisfaction.

(6) A notice of dissatisfaction shall set out the Dispute and the reason(s) for dissatisfaction. No Disputing Party shall be entitled to commence any Court proceedings of whatever nature in relation to or in connection with a Dispute unless a notice of dissatisfaction has been made.

(7) If the DRB has given its decision on a Dispute to the Disputing Parties and no notice of dissatisfaction has been given by any Disputing Party within ten business days after the date of the DRB's decision, then the decision shall be final and binding upon all Disputing Parties.

5.1.5 Amicable Dispute settlement

(1) Where notice of dissatisfaction has been given, the Disputing Parties shall attempt to settle the dispute amicably before the commencement of any court proceedings may take place. However, unless both Parties agree otherwise, Court proceedings may be commenced on or after the twenty first Working Day after the day on which notice of dissatisfaction was given, even if no attempt at amicable settlement has been made.

5.1.6 Court Proceedings

(1) Unless settled amicably, any Dispute in respect of which a Notice of Dissatisfaction has been issued may only be finally settled by Court proceedings.

(2) A Disputing Party may, in the proceedings before any Court having jurisdiction, adduce evidence or raise arguments not previously put before the DRB in the course of its consideration of the Dispute or included in the notice of dissatisfaction given by that Party. Any decision of the DRB shall be admissible

as evidence in any Court proceedings.

5.1.7 Failure to Comply with DRB's Decision

(1) In the event that:

(a) no Disputing Party has given notice of dissatisfaction within the period; and

(b) the DRB's related decision (if any) has become final and binding; and

(c) a Disputing Party fails to comply with this decision,

(d) then any other Disputing Party may take such action as it deems necessary, including the commencement of court proceedings, to enforce the relevant DRB decision. There shall be no mandatory reference to the DRB or requirement to refer the matter to amicable settlement in respect of such a reference.

6 MARKET PARTICIPATION AND BALANCE RESPONSIBLE PARTIES

6.1 Market Participants and Balance Responsible parties

(1) Market Participants and Balance Responsible Parties are defined in chapter 3.4 above.

(2) Both will be treated as a Party to the Market Code and the same rules apply for admitting them.

6.2 Admitting Parties

(1) A person may only become a Party to the Market Code in accordance with the terms of the Market Code.

(2) In order to become a Party, a person (the "Applicant") must complete and sign an application form which shall be in the form provided by the MO and subsequently send to the MO. The application form specifies all conditions which the Applicant must meet to become a Party**.**

(3) The MO may charge a non-discriminatory Accession Fee to all Applicants which shall be non-refundable.

(4) Where the MO receives an application from an Applicant, it must within ten business days of receiving the application, send a notice to the Applicant informing the Applicant of any further information or clarification which is required in relation to the application or where the application is incomplete. The MO shall provide details of what clarification is required or where the application is incomplete.

(5) If the MO does not receive the clarification or the additional information required within twenty business days of the Applicant having been informed by the MO of the need for such clarification, the Applicant shall be deemed to have withdrawn the application. An Applicant may request additional time to provide any

clarification or additional information and the MO shall not unreasonably withhold consent to any such request.

(6) On receipt of a completed application form and any clarification or additional information requested by the MO and provided that the Applicant fulfils the conditions for accession specified in the application form, the MO shall within ten business days of final receipt of all required information provide the Applicant with a Market Participant Agreement.

(7) The Applicant must submit an executed Market Participant Agreement within ten business days of receipt. An Applicant may request additional time to submit an executed Market Participant Agreement and the MO shall not unreasonably withhold consent to any such request, provided that the date of receipt of the executed Market Participant Agreement shall be earlier than the effective date specified in the Market Participant Agreement.

(8) Following receipt by the MO of an executed Market Participant Agreement, the Applicant shall become a Party on the date specified in the Market Participant Agreement unless the Market Operator and the Applicant agree on a different date separately in writing.

(9) The MO shall publish the fact and date of the accession of each new Party to the Market Code.

(10) An Applicant shall be allowed to participate in the SAWEM during the testing and commissioning period subject to agreement with the MO.

6.3 Defaulting Parties

(1) The following sections on default, suspension and termination shall apply in respect of Default by any Party other than the MO.

(2) A Party shall be in Default where it is in material breach of any provision of the Market Code or any other relevant Code or agreement.

(3) A Party shall notify the MO as soon as reasonably practicable upon becoming aware of any circumstance that will give rise to a Default, and upon the occurrence of a Default.

6.3.1 Default Notice

(1) On becoming aware of a Default in relation to a Party, the MO shall issue to the Defaulting Party a Default Notice specifying the Default.

(2) The MO shall specify in a Default Notice:

A) the nature of the Default;

B) if the Default is capable of remedy, the time from the date of the Default Notice within which the Defaulting Party is required to remedy the Default; and

C) any other action which the MO may reasonably require the Defaulting Party to take in respect of the Default.

(3) The Defaulting Party must comply with the Default Notice.

6.4 Suspending Parties

(1) In the event that:

(A) a Credit Call is made and a Market Participant's Credit Cover Provider fails to meet such demand within the agreed timeframe; or

(B) a Market Participant fails at any time to provide the Required Credit Cover as specified under this Market Code and in accordance with the timeframe as provided;

(2) then, notwithstanding, the MO shall at the same time as or following the issue of the Default Notice to the Defaulting Party in respect of such Default, issue a Suspension Order in respect of all of the relevant Market Participant's Trading Units. A Suspension Order issued shall have immediate effect.

(3) A Suspension Order issued shall be expressed to take effect no earlier than the date of the expiry of the Supplier Suspension Delay Period in respect of any Supplier Unit included in the Suspension Order and no earlier than the expiry of the Generator Suspension Delay Period in respect of any Generator Unit included in the Suspension Order. In respect of each Supplier Unit, the Suspension Order shall not take effect unless NERSA has directed that all demand represented by that Supplier Unit shall be met by a Supplier of Last Resort. During the period before the Suspension Order comes into effect in respect of a particular Trading Unit, NERSA may instruct the MO to issue a notice or notices amending or lifting the Suspension Order in respect of that Trading Unit or any or all of the Trading Units concerned.

(4) A Suspension Order shall not be issued solely by reason of the failure of the Market Participant to have its Credit Cover in place during the two business days permitted for replenishment of Credit Cover or during the ten business days permitted to acquire a new Credit Cover Provider.

(5) The MO may, with the prior written approval of NERSA, issue a Suspension Order in respect of all or any of a Party's Trading Units where:

(A) it becomes unlawful for a Party to comply with any of its obligations under the Market Code;

(B) it becomes unlawful for a Party's Credit Cover Provider to comply with any of its Credit Cover obligations;

(C) a Legal Requirement necessary to enable a Party or its Credit Cover Provider to fulfil its obligations and functions under the Market Code is amended or revoked in whole or in part so as to prevent a Party or its Credit Cover Provider from fulfilling its obligations and functions under the Market Code;

(D) a Party or its Credit Cover Provider suspends or ceases to carry on its business, or any part of its business which is relevant to its activities under the Market Code;

(E) a Party's Credit Cover Provider ceases to be eligible for the purposes of the Market Code to be able to provide the Credit Cover and the Party has not acquired a new Credit Cover Provider within ten business days;

(F) a Party enters into or takes any action to enter into an arrangement or composition with its creditors (except in the case of a solvent and bona fide reconstruction or amalgamation);

(G) a Party's Credit Cover Provider enters into or takes any action to enter into an arrangement or composition with its creditors (except in the case of a solvent and bona fide reconstruction or amalgamation);

(H) a receiver, manager, receiver and manager, administrative receiver, examiner or administrator is appointed in respect of a Party or its Credit Cover Provider or any of their respective assets, or a petition is presented for the appointment of an examiner or administrator, or a petition is presented or an order is made or a resolution is passed for the dissolution of, winding up of or appointment of a liquidator to a Party or its Credit Cover Provider, or a liquidator, trustee in bankruptcy or other similar person is appointed in respect of a Party or its Credit Cover Provider, or any steps are taken to do any of the foregoing or any event analogous to any of the foregoing happens in any jurisdiction;

(I) a Party or its Credit Cover Provider is dissolved or struck off;

(J) a Party or its Credit Cover Provider is unable to pay its debts for the purposes of insolvency per the Insolvency Act 24 of 1936;

(K) a Party which is required to be licensed in respect of any or all of its roles under the Market Code has its Licence revoked in whole or in part or amended, so as to prevent the Party from fulfilling its obligations and functions under the Market Code;

(L) a Party has committed 3 Defaults within a period of twenty business days; or

(M) a Party has committed a Default and has failed for a period of 20 consecutive days, or such longer period as may be set out in the relevant Default Notice, to comply with the terms of such Default Notice.

(6) Where the Market Operator issues a Suspension Order, the Market Operator shall at the same time send a copy of the Suspension Order to NERSA, the System Operators and the relevant Distribution System Operators and publish the Suspension Order.

6.4.1 Effect of Suspension Order

(1) Where the Market Operator issues a Suspension Order, the Suspension Order shall specify the Trading Units to which the Suspension Order shall apply, the date and time from which the suspension will take effect and the terms of the suspension.

(2) The Supplier Suspension Delay Period and the Generator Suspension Delay Period shall be determined from time to time by NERSA and notified to the Market Operator. A determination by NERSA in relation to the duration of the Generator Suspension Delay Period or the Supplier Suspension Delay Period, which amends an existing determination in this regard, shall not have effect until the expiry of a period of ten business days following the amending determination,

or such longer period as may be specified by NERSA, and, in any event, shall not affect any then current Generator Suspension Delay Period or Generator Suspension Delay Period.

(3) On receipt of any determination NERSA, the MO shall publish such determination indicating the date from which it shall take effect.

(4) When a Suspension Order takes effect, the Trading Units to which the Suspension Order applies shall be suspended from participation in the Market until such time as the MO publishes a notice stating that:

(A) the Suspension Order has either been lifted or will be lifted (specifying the date and time); or

(B) the participation of the relevant Party in the Market has been Terminated, or the relevant Trading Units have been Deregistered, in each case in accordance with the Market Code.

(5) The Participation of Suspended Units in the SAWEM may resume but only in accordance with such restrictions as specified in the Suspension Order.

(6) A Suspension Order shall not affect the continuing obligation of any Party whose Trading Units have been suspended to maintain the Required Credit Cover in respect of all of its Trading Units.

(7) A Suspension Order may suspend or restrict any or all of a Party's Trading Units. The Market Operator shall, while a Suspension Order is in place, be entitled to do any act, matter or thing to give effect to the Suspension Order including, without limitation:

(A) rejecting any Offer Data submitted by the relevant Party;

(B) making a Credit Call;

(C) setting-off any amount owed by the relevant Market Participant against the payment of any amounts otherwise due to that Market Participant under the Market Code; or

(D) requesting NERSA and SO or any other Party to take such measures as the MO, acting reasonably, decides are appropriate to give effect to the Suspension Order.

(8) The MO shall remove the Suspension Order if the relevant Party remedies the matter or matters giving rise to the Suspension Order, or the circumstances giving rise to the Suspension Order no longer apply.

(9) Where any Suspension Order is removed by the MO, the MO shall notify this to NERSA, the SO and the relevant Distributors where appropriate and shall publish a notice that the Suspension Order has been lifted.

(10) The Market Participant that has registered the Trading Units to which a Suspension Order applies must comply with the Suspension Order.

(11) This will not take effect if the cause of the Default and Suspension is a Force Majeure Event.

6.5 Terminating and deregistration of Parties

(1) The MO may with the prior written approval of NERSA issue a Termination Order where a Party is in breach of a Suspension Order or has not remedied a Default or taken such action as required by the MO within the timeframe specified in the Suspension Order. A Termination Order may direct the Deregistration of any or all of a Party's Trading Units or the Termination of a Party as a party to the Market Code. Termination of a Party as a party to the Market Code shall have the effect of Deregistration of all of the Party's Trading Units.

(2) The MO shall specify in each Termination Order the Credit Cover which the relevant Party is required, to maintain in respect of any Trading Units being Deregistered pursuant to the Termination Order.

6.5.1 Effect of Termination Order

(1) Where the MO issues a Termination Order, the Termination Order shall specify the time and date from which the Termination or Deregistration will take effect and the terms of the Termination or Deregistration.

(2) Where the MO issues a Termination Order, the MO shall at the same time send a copy of the Termination Order to NERSA, the SO and the relevant Distributors and shall publish the Termination Order.

6.5.2 Voluntary Termination of a Party

(1) A Party may apply at any time to cease to be a Party.

(2) A Party shall give at least ninety business days' notice in writing to the MO (with a copy to the System Operator and NERSA) of its intention to cease being a Party and shall specify the time and date upon which it wishes the Termination to take effect. Voluntary Termination shall have the effect of Deregistration of all of a Party's Trading Units.

(3) Following receipt of a request for Voluntary Termination, the MO shall issue a Voluntary Termination Consent Order if the relevant Party has complied with the following conditions:

(A) all amounts due and payable by the relevant Party pursuant to the Market Code have been paid in full;

(B) any outstanding Default by the relevant Party of the Market Code which is capable of remedy has been remedied;

(C) the written consent of NERSA has been obtained; and

(D) if the Party has registered Supplier Units, the terms of any applicable Metering Code have been complied with in relation to the Deregistration or transfer of those Supplier Units.

(4) The MO shall specify in each Termination Consent Order the Credit Cover which the relevant Party is required, to maintain in respect of any Trading Units being Deregistered pursuant to the Termination Consent Order.

(5) The Voluntary Termination shall take effect at the end of the last Trading Period of the Trading Day specified by the MO in the Voluntary Termination Consent Order so long as, at that time, the relevant Party remains in compliance with the conditions set.

(6) The MO, the SO, the Transmission Asset Owners, the Distributors, the SO and the Meter Data Providers shall not be permitted to terminate they being a party to the Market Code except where so required by NERSA.

6.5.3 Consequences of Termination of a Party

(1) When a Party is Terminated, then:

(A) the MO shall Deregister all of that Party's Trading Units;

(B) the Party must stop all trading in the SAWEM in respect of all of its Trading Units at the time and date specified in the Termination Order or the Termination Consent Order; and

(C) the Party must maintain the Credit Cover for each of its Trading Units in the amounts and for the duration provided as specified in the Termination Order or Termination Consent Order as applicable.

(2) Any Termination of a Party will not affect the accrued rights or obligations of any Party which arose out of, or which relate to any act or omission prior to the date of such Termination and including:

(D) payment of any amount which was or becomes payable under the Market Code in respect of any period before the date of the Termination of the Party (including in relation to any Dispute regarding an event before the Termination of the Party even if the Notice of Dispute is given after the date of Termination of the Party); and

(E) any outstanding breach by it of the Market Code.

(3) A Party shall continue to be liable after its Termination in respect of any obligation under the Market Code for a period of 3 years or any longer period specified under any Applicable Law.

(4) Any provisions of this Market Code which expressly, or by implication are intended to, commence, or continue in effect on or after Termination of a Party shall continue to bind a Terminated Party.

(5) For the avoidance of doubt, a Terminated Party shall continue to be bound by the Dispute Resolution Process in respect of any Disputes arising following its Termination.

6.5.4 Consequences of Deregistration

(1) Where any of a Participant's Trading Units are Deregistered in accordance with the provisions of this Code, whether voluntarily or otherwise:

(A) the Market Participant must stop all trading in the Market in respect of the relevant Units at the time and date specified in the Termination Order or the date specified in the Deregistration Consent Order; and

(B) the Market Participant must maintain the Credit Cover in respect of each of the relevant Trading Units in the amounts and for the duration as specified in the Termination Order or Deregistration Consent Order as applicable.

(2) Where the MO, in the circumstances provided for under the Market Code, accepts a new notice from a Party or Applicant to register a Trading Unit which is at that time registered to another Participant, prior to the Deregistration of that Trading Unit from the existing Participant, then the acceptance of the new Participation Notice shall, unless expressly provided otherwise, be without prejudice to the process for Deregistration of the Trading Unit from the existing Participant in accordance with the timelines set out in the Market Code and the new registration of that Trading Unit shall not take effect until such process has been completed.

6.6 Force Majeure

(1) A Party shall not be liable to any Party for any failure or delay in the performance of any of their respective obligations under this Market Code, other than the obligation to make payments of money, to the extent that such failure or delay is due to a Force Majeure Event, provided that an affected Party shall only be excused from performance pursuant to this section:

a) for so long as the Force Majeure Event continues and for such reasonable period of time thereafter as may be necessary for the affected Party to resume performance of the obligation; and

b) where and to the extent that the failure or delay in performance would not have been experienced but for such Force Majeure Event.

(2) A Party shall not invoke a Force Majeure Event unless it has given notice in accordance with point (3).

(3) Where a Party invokes a Force Majeure Event, it shall give notice to the other relevant Parties as soon as reasonably practicable but in any event within two Business Days of the date on which the affected Party becomes aware of the occurrence of the Force Majeure Event. The notice given under this section shall include particulars of:

a) the nature of the Force Majeure Event;

b) the effect that such Force Majeure Event is having on the affected Party’s performance of its obligations under this Market Code; and

c) the measures that the affected Party is taking, or proposes to take, to alleviate the impact of the Force Majeure Event.

(4) Where a Party invokes a Force Majeure Event, it shall:

a) use all reasonable endeavours to mitigate or alleviate the effects of the Force Majeure Event on the performance of its obligations under this Market Code; and

b) continue to comply with its obligations under this Market Code to the maximum extent practicable.

(5) Where a Party invokes a Force Majeure Event, it shall as soon as practicable notify the other relevant Parties of:

a) any material change in the information contained in the notice referred to in point (3) or in any previous notice given and published pursuant to this point (5); and

b) the cessation of the Force Majeure Event and of cessation of the effects of such Force Majeure Event on the affected Party's performance of its obligations under this Market Code.

7 REGISTRATION OF TRADING RESOURCES AND STANDING DATA

7.1 Market Operator Registry

(6) The data required in sections 7.3 to 7.6 below shall be provided by the Market Participant at registration as part of the Accession process. This data shall be maintained by the MO and changed from time to time at the request of the Market Participant.

(7) The data shall be maintained by the MO in a Registry and shared with the SO.

(8) This Registry shall be available for inspection by NERSA.

(9) Each Market Participant shall be able to review and shall be responsible to update the data held in the Registry relevant to resources operated by the Market Participant and BRPs.

(10) A Market Participant must submit in writing to the MO modifications to the Registry data by 08h00 on the day preceding the date at which the modification becomes effective, unless mutually agreed between the MO and the Market Participant.

7.2 De minimis threshold

(1) The De Minimis Threshold for the purposes of the Market Code and mandatory participation in the Market shall be a Maximum Export Capacity of 1MW.

(2) A Party shall register every Generator which it owns or legally controls, which has Maximum Export Capacity greater than or equal to the De Minimis Threshold and which is covered by a single Connection Agreement and Balancing Agreement, as a Trading Unit under the Market Code.

7.3 Balance Responsible Parties

(1) Specific data relevant to a BRP trading facility shall be submitted by the BRP and maintained by the MO. This data shall include:

(a) Official trading facility name;

(b) Official trading unit names;

(c) Bank account details for the trading facility;

(d) Geographic location of the trading facility;

(e) Network location of the trading facility on the NIPS structure determined by the SO (for network constraint analysis);

(f) Metering arrangement, including the device identification number and access identification for remote interrogation;

(g) If embedded within a network other than the TS, the name of the Distributor responsible for the network;

(h) Identification of the network counter-party for energy flows if different to (g);

(i) The technology type of trading units or facilities (for example, coal-fired thermal, pumped-storage, hydro, wind, solar PV etc.);

(j) The MCR and maximum demand of each trading unit.

7.4 Day-Ahead Market Participant: Common information for trading facilities

(1) At the trading facility level, the following data shall be submitted by the market participant and maintained by the MO:

(a) Official trading facility name

(b) Number of trading units

(c) Bank account details for each trading facility;

(d) Geographic location of the trading facility;

(e) Network location of the trading facility on the NIPS structure determined by the SO (for network constraint analysis);

(f) Metering arrangement, including the device identification number and access identification for remote interrogation;

(g) If embedded within a network other than the TS, the name of the Distributor responsible for the network.

(h) Identification of the network counter-party for energy flows if different to (f);

(2) At the Trading Unit level, the following data shall be submitted by the market participant and maintained by the MO:

(a) The official Trading Unit name;

(b) The unique MO identifier for the Trading Unit, determined by the MO at registration;

(c) Designation as an energy constrained Trading Unit, if applicable;

(d) Designation as a storage Trading Unit, and specifically a pumped-storage trading unit, if applicable;

(e) The maximum sent-out and consumption of the Trading Unit;

(f) The minimum stable generating point (“Mingen”) of the Trading Unit;

(g) The start-up ramp rates and costs of the Trading Unit, expressed as:

(i) The time since operation (in hours) until which the Trading Unit is assumed hot; the associated start-up ramp rate (in MW/hr) from a hot condition; the start-up cost (in R) for starting up from a hot condition; and the associated lead time to synchronisation from a hot condition after an instruction;

(ii) The time since operation (in hours) until which the Trading Unit is assumed warm (assumed as any period in excess of the hot condition); the associated start-up ramp rate (in MW/hr) from a warm condition; the start-up cost (in R) for starting up from a warm condition; and the associated lead time to synchronisation from a warm condition after an instruction;

(iii) The associated start-up ramp rate (in MW/hr) from a cold condition (assumed as any period in excess of the warm condition); the start-up cost (in R) for starting up from a cold condition; and the associated lead time to synchronisation from a cold condition after an instruction.

(h) The minimum run time of the Trading Unit (in hours), being the minimum time that the Unit is prepared to generate or consume. A Trading Unit, if committed by the dispatch algorithm, will be scheduled to generate or consume for a time at least equal to this period under normal circumstances.

(i) The minimum down time of the Trading Unit (in hours), being the minimum time that the Trading Unit is prepared to stay off before being synchronised again. A Trading Unit, if de-committed by the dispatch algorithm, will be scheduled off for a time at least equal to this period under normal circumstances.

(j) Start-up ramp rate, being the rate (in MW/hr) at which the Trading Unit may be loaded between synchronisation and Mingen.

(k) The loading ramp rate, being the rate (in MW/hr) at which the Trading Unit may be loaded between Mingen and MCR;

(l) The de-loading ramp rate, being the rate (in MW/hr) at which the Trading Unit may be de-loaded between MCR and Mingen;

(m) The shut-down ramp rate, being the rate (in MW/hr) at which the Trading Unit may be de-loaded between Mingen and off load;

(n) The certified capacity for Regulating Reserve (in MW) agreed by the SO;

(o) The certified capacity for Instantaneous Reserve (in MW) agreed by the SO;

(p) The certified capacity for 10 Minute Reserve (in MW) agreed by the SO;

(q) The certified capacity for Supplemental Reserve (in MW) agreed by the SO;

(r) The certified capacity for Emergency Reserve (in MW) agreed by the SO

7.5 Day-Ahead Market Participation: Additional data for energy constrained Trading Units

(1) At the Trading Facility level, the following data shall be submitted by the Market Participant and maintained by the MO:

(a) The water resource supplying the Trading Facility, if any, and its capacity;

(b) The names and contact details of any authority responsible for management of the water resource, if any

(2) At the Trading Unit level, the following data shall be submitted by the Market Participant and maintained by the MO:

(a) Cavitation (hydraulic instability) zones,

(b) The maximum energy output or consumption from the Trading Facility per day (in MWh/day);

(c) The maximum energy output or consumption from the Trading Facility per week (in MWh/week);

(d) The minimum energy output or consumption from the Trading Facility per day (in MWh/day);

(e) The minimum energy output or consumption from the water resource per week (in MWh/week);

(f) The certification for Synchronous Condenser Operation (in MVAr) agreed by the SO;

(g) The time taken for mode changes between stand-still, SCO and generating mode in all directions (in minutes).

7.6 Day-Ahead Market Participation: Additional data for storage Trading Units

(1) At the Trading Facility level, the following data shall be submitted by the Market Participant and maintained by the MO:

(a) The water resources connected to the Trading Facility, if any;

(b) The names and contact details of any authority responsible for management of the water resources, if any;

(2) At the Trading Unit level, the following data shall be submitted by the Market Participant and maintained by the MO:

(a) Cavitation (hydraulic instability) zones,

(b) The maximum continuous charging rating (MW) ("MCCR") of each Trading Unit;

(c) The minimum stable charging point (MW) ("mincharge") of each Trading Unit;

(d) For pumped storage facilities;

(i) The (generation energy equivalent) maximum level of the upper reservoir (in MWh);

(ii) The (generation energy equivalent) minimum level of the upper reservoir (in MWh);

(iii) The (generation energy equivalent) maximum level of the lower reservoir (in MWh);

(iv) The (generation energy equivalent) minimum level of the lower reservoir (in MWh);

(v) The (generation energy equivalent) expected inflow into the upper reservoir (in MWh/hr);

(vi) The (generation energy equivalent) expected inflow into the lower reservoir (in MWh/hr);

(vii) The (generation energy equivalent) allowed outflow from the upper reservoir (in MWh/hr);

(viii) The (generation energy equivalent) allowed outflow from the lower reservoir (in MWh/hr);

(ix) The (generation energy equivalent) required outflow from the upper reservoir (in MWh/hr);

(x) The (generation energy equivalent) required outflow from the lower reservoir (in MWh/hr);

(e) For other storage facilities;

(xi) The (generation energy equivalent) maximum level of the storage facility (in MWh);

(xii) The (generation energy equivalent) minimum level of the storage facility (in MWh);

(f) The storage cycle efficiency of the Trading Facility (in percentage);

(g) The certification for Regulating Reserve (in MW) agreed by the SO;

(h) The certification for Instantaneous Reserve (in MW) agreed by the SO;

(i) The certification for 10 Minute Reserve (in MW) agreed by the SO;

(j) The certification for Supplemental Reserve (in MW) agreed by the SO;

(k) The certification for Emergency Reserve (in MW) agreed by the SO;

(l) The certification for SCO (in Mvar) agreed by the SO;

(m) The time taken for mode changes between stand-still, SCO, pumping and generating in all directions (in minutes).

7.7 Interconnections

(1) The international trade shall follow the regulations set out in chapter 8.

(2) The following data shall be submitted by the SO and maintained by the MO for each interconnection with neighbouring countries:

(a) Official interconnection name;

(b) The unique MO or identifier for the interconnection, determined by the MO at registration;

(c) Geographical location of the interconnection;

(d) Network location of the trading facility on the IPS structure determined by the SO (for network constraint analysis);

(e) The names and contact details of the neighbouring network authority and control area authority;

(f) Metering arrangement, including the device identification number and access identification for remote interrogation;

(g) If embedded within a network other than the TS, the name of the Distributor responsible for the network.

(h) Identification of the network counter-party for energy flows if different to (g).

8 INTERNATIONAL TRADE

8.1 Generic provisions

(1) The international trade covers the cross-border bilateral trading with regional counterparts and trade in the organised regional markets governed by Southern African Power Pool (SAPP).

(2) The objectives of these rules are to ensure that the regional trade is performed in such manner that in brings benefit to the South African power sector and ensuring participation based on sound economics.

(3) A generic requirement for all Parties that shall be trading on SAPP is that they hold an Export License in South Africa and that they are a Market Participant in the SAPP markets.

(4) Any Party participating/interacting in the SAPP markets will be under the SAPP governance as well as this Market Code.

(5) The following Parties will be interacting with SAPP markets:

(a) The SO performing the following roles:

(i) Being the provider of the Available Transmission Capacities for all international interconnections from South Africa to the SAPP markets;

(ii) Acting as the TSO under the SAPP regulations;

(iii) Nominate the total scheduled interconnection flows to the MO; and

(iv) Act as the Balance Responsible Party towards SAPP.

(b) The MO performs the following roles:

(i) Act as a representative of the South African Market Participants for those volumes that are traded through the SAWEM;

(ii) For the Day-Ahead Market, create a Net Export Curve representing the aggregated buy and sales offers from the orders in the SAWEM Day-Ahead Market using the order information from the different Market Participants including adjusting for any capacity payments or non-energy based payments;

(iii) For the SAPP intra-day and balancing markets, make available national orders according to the detailed rules set out below;

(iv) Take the scheduled flows from the SAPP markets as a deemed flow in the market clearing in the SAWEM;

(c) The CPA shall manage and maintain the historical regional bilateral contracts and schedule these according to the SAPP Market Book of Rules.

(d) South African Market Participant with a Capacity Payment agreement with the CPA will have the following roles:

(i) A South African Market Participant with a Capacity Payment shall always offer their full capability to the SAWEM;

(ii) It will not be allowed to participate directly in the SAPP regional markets;

(iii) It will indirectly be participating through the MO that will use its orders in the short-term markets (DAM, IDM and BM) and thereby have implicit access to the regional markets;

(iv) It will be a Balance Responsible Party under this Market Code; and

(v) All settlement and financial management will be towards the MO.

(e) South African Market Participant without a Capacity Payment agreement with the CPA will have the following roles:

(i) A South African Market Participant without a Capacity Payment has a choice to whom it will buy or sell its power from;

(ii) It can buy/sell its power through the following channels:

a. A regional bilateral physical contract with an international counterpart. In this event, it will have to secure the transmission capacity through the SO and nominate its planned schedule to the SO to be considered in the management of the transmission capacity towards SAPP. The settlement of this financial bilateral contract will be settled between the parties;

b. A bilateral physical contract with a South African counterpart. In this event, it will have to nominate its planned schedule to the SAWEM to be considered in the SAWEM. The settlement of this financial bilateral contract will be between the parties;

c. A bilateral financial contract with a South African (or regional) counterpart. In this event, it should participate in the SAWEM to be considered in SAWEM to secure a physical position. The settlement of this financial bilateral contract will be between the parties;

d. Subject to being a SAPP Market Participant, participate in the SAPP organised physical markets: FPM (monthly and weekly), DAM, IDM and BM. If successful, nominate its planned schedule to the SO to be considered in the management of the transmission capacity towards SAPP. The settlement of this trade will be between SAPP and the Market Participant;

e. Participate in the SAWEM as a Market Participant under this Market Code; or

f. Any combination of the above.

(iii) It will be a Balance Responsible Party under this Market Code; and

(iv) The settlement and financial management will be against the counterparts in its trades; a potential combination of bilateral contracts counterpart(s), SAPP and MO.

(6) All these different roles will be subject to the rules of this Market Code.

8.2 Regional bilateral contract management

(1) There are two Parties that has the opportunity of trading regional physical bilateral contract: the CPA and a South African Market Participant without a Capacity Payment. In this event, it will have to secure the transmission capacity through the SO and nominate its planned schedule to the SO to be considered in the management of the transmission capacity towards SAPP.

(2) The registration of these bilateral shall be done as per the SAPP rules.

(3) The nominations of the scheduled flows shall be done according to the SAPP rules and timelines.

(4) The total scheduled flows on the interconnections will be reported from SAPP to the SO as per the SAPP timelines and will be forwarded to the MO to be considered in the SAWEM market clearing.

8.3 Trading in the SAPP Forward Physical Markets

(1) In this market, it will only be the South African Market Participant without a Capacity Payment that have the opportunity to participate directly.

(2) It shall enter its order(s) into the SAPP Market as per the SAPP rules and timelines.

(3) A South African Market Participant without a Capacity Payment will be subject to the financial settlement timelines of SAPP if it is successful in buying or selling power in any of these markets.

(4) A South African Market Participant without a Capacity Payment shall nominate its scheduled generation/consumption if it is successful in buying or selling power in any of these SAPP markets.

(5) The flow based on these trades will be sent to the SO as a BRP as per the rules of this Market Code.

8.4 Trading in the SAPP Day-Ahead Market

(1) A South African Market Participant without a Capacity Payment has the opportunity to participate directly in the SAPP DAM.

(2) In addition, the MO will participate on behalf of the SAWEM Market Participants.

(3) This will be done by creating Single hourly orders to SAPP based on a Net Export Curve (NEC) based on the following:

(a) NEC is the difference between local (i.e. per Bidding Zone) aggregated supply and demand curves (in case of perfectly inelastic demand the NEC consists only of supply);

(b) The NEC will represent the sensitivity of the SMP relative to exchange volumes from SAWEM;

(c) Contains minimum amount of required information for bidding into the SAPP DAM as per the SAPP Market Book of Rules;

(d) MO needs to ensure non-violation of internal constraints when constructing the NEC;

(e) The NEC needs to be adjusted based on the applicable capacity payments for any Market Participants to ensure compatibility with the SAPP market; and

(f) NEC construction requires a well-defined & transparent methodology that shall be maintained by the MO and published on their website.

(4) A South African Market Participant without a Capacity Payment will be subject to the financial settlement timelines and rules of SAPP if it is successful in buying or selling power in the SAPP DAM.

(5) A South African Market Participant without a Capacity Payment shall nominate

its scheduled generation/consumption if it is successful in buying or selling power in SAPP DAM.

(6) The MO will use any trading results from SAPP DAM based on its order as a deemed flow in its SAWEM Day-Ahead market clearing.

(7) The flow on the interconnectors based on these trades will be sent to the SO as the South African BRP.

8.5 Trading in the SAPP Intra-Day Market

(1) A South African Market Participant without a Capacity Payment has the opportunity to participate directly in the SAPP IDM.

(2) In addition, the MO will participate on behalf of the SAWEM Market Participants.

(3) This will be done by creating individual hourly orders (to SAPP) based on the following:

(a) The MO will offer unused orders from SAWEM Market Participants that has not been utilised neither as Day-ahead Energy or Day-ahead Reserves, Regulating Reserve (Up), Regulating Reserve (Down), Instantaneous Reserve (Up), 10 Minute Reserve or Supplemental Reserve;

(b) These will be offered to the SAPP IDM as individual orders.

(4) A South African Market Participant without a Capacity Payment will be subject to the financial settlement timelines and rules of SAPP if it is successful in buying or selling power in the SAPP IDM.

(5) A South African Market Participant without a Capacity Payment shall nominate its scheduled generation/consumption if it is successful in buying or selling power in SAPP IDM.

(6) The MO will use any trading results from SAPP IDM based on its order(s) as a deemed flow in the SAWEM market clearing.

(7) The flow on the interconnectors based on these trades will be sent to the SO as the South African BRP.

8.6 Trading in the SAPP Balancing Market

(1) The MO will participate on behalf of the SAWEM Market Participants.

(2) This will be done by creating individual hourly orders (to SAPP) based on the following:

(a) The MO will offer unused orders from SAWEM Market Participants that has not been utilised neither as Day-ahead Energy or Day-ahead Reserves, Regulating Reserve (Up), Regulating Reserve (Down), Instantaneous Reserve (Up), 10 Minute Reserve or Supplemental Reserve or the SAPP IDM;

(b) These will be offered to the SAPP BM as individual orders.

(3) A South African Market Participant without a Capacity Payment will be subject to the financial settlement timelines of SAPP if it is successful in buying or selling power in the SAPP BM.

(4) A South African Market Participant without a Capacity Payment shall nominate its scheduled generation/consumption if it is successful in buying or selling power in SAPP BM.

(5) The MO will use any trading results from SAPP BM based on its order(s) as a deemed flow in its national market clearing.

(6) The same resulting flow in the interconnectors based on these trades will be sent to the SO as the South African BRP.

9 DAY-AHEAD MARKET

9.1 Demand Forecast and Reserve Requirements

(1) The SO shall produce a forecast of system energy demand for each Trading Period of the Dispatch Day (as well as indicative forecasts of system energy demand for each Trading Period for the six days following the dispatch day). This demand shall include network technical losses for each Trading Period of the Dispatch Day (as well as expected exports to, or expected imports from, neighbouring networks), indicating the required total net sent-out from all Generators. The demand forecast shall be produced by 10h00 on the day preceding the Dispatch Day and shall be made available to all Market Participants.

(2) For the avoidance of doubt, this demand forecast is for information only and any Eligible Customer should produce its own forecast as basis for their Bids in the DAM.

(3) The SO shall determine the required reserves for each Trading Period of the Dispatch Day (as well as for each Trading Period of the six days following the Dispatch Day). These requirements shall determine the minimum reserve requirements for each of the following categories:

(a) Regulating Reserve (Up)

(b) Regulating Reserve (Down)

(c) Instantaneous Reserve (Up)

(d) 10 Minute Reserve

(e) Supplemental Reserve

(4) The SO shall establish agreements with generators and demand-side resources for the provision of the required reserves in line with Systems Operations Code.

9.2 BRP Schedules

(1) A BRP shall provide a schedule of the expected sent-out or consumption for each Trading Period of the Dispatch Day (as well as indicative schedules for each Trading Period of the six days following the dispatch day) for any physical trading activity outside the SAWEM. This schedule shall be provided to the MO by 10h00 on the day preceding the Dispatch Day. The information provided shall include:

(a) The Trading Facility name (as in the Registry);

(b) The Trading Period (the Trading Period start time);

(c) The expected sent-out (positive) or consumption (negative) in the Trading Period (in MWh).

9.3 Interconnection Schedules

(1) The SO shall provide a schedule of the expected imports or exports for each Trading Period of the dispatch day (as well as indicative schedules for each Trading Period of the six days following the dispatch day). This schedule shall be provided to the MO by 13h30 on the day preceding the dispatch day.

(2) The SO shall provide an updated intraday schedule of the expected imports or exports for each Trading Period of the dispatch day based on any regional intra-day trading. This schedule shall be provided to the MO at lates 2 hours before the Trading Period starts on the dispatch day. The information provided shall include:

(a) The official interconnection name (as in the Registry);

(b) The Trading Period (the Trading Period start time); and

(c) The expected net import (positive) or export (negative) in the Trading Period (in MWh).

9.4 Day-ahead Market Submissions

(1) Day-ahead Market Participants shall provide a daily submission of the expected availability or maximum consumption of each Trading Unit and the incremental price associated with the dispatch of these Trading Unit(s) for each Trading Period. The schedule should include indicative availability or maximum consumption for each Trading Period of the six days following the dispatch day. This schedule shall be provided by 10h00 on the day preceding the dispatch day. The information provided shall include:

(a) The official Trading Unit name (as in the Registry);

(b) Availability indicators in the form of:

(i) The Trading Period (the Trading Period start time);

(ii) The hourly Declared Available Capacity (in MW), being the maximum sent-out to which the Trading Unit may be scheduled in the for each Trading Period;

(iii) The Declared Maximum Consumption (in MW) for each Trading Period, being the maximum consumption to which the Trading Unit may be scheduled in the Trading Period;

(iv) The Flexible Indicator (either F or I), indicating whether the Trading Unit is flexible (or able to be dispatched) in that Trading Period (F), or inflexible to central dispatch (I);

(v) The Instantaneous Reserve Availability Indicator (either A or U), indicating whether the Trading Unit is available to provide Instantaneous Reserve in the Trading Period (A) or not (U);

(vi) The Regulating Reserve Availability Indicator (either A or U), indicating whether the Trading Unit is available to provide Regulating Reserve in the Trading Period (A) or not (U);

(vii) The 10 Minute Reserve Availability Indicator (either A or U), indicating whether the Trading Unit is available to provide 10 Minute Reserve in the Trading Period (A) or not (U);

(c) The production price, in the form of a piecewise-linear price curve, with parameters set as follows:

(i) The Trading Period (the Trading Period start time) from which the price curve is applicable;

(ii) The Minimum Stable Generation Point of the Trading Unit (MW), which must be the same as the Mingen value for the Trading Unit from the standing data;

(iii) The first elbow point (MW) which must be greater than or equal to the minimum generation point;

(iv) The second elbow point (MW) which must be greater than or equal to the first elbow point;

(v) The third elbow point (MW) which (a) must be equal to the MCR for the Trading Unit from the Registry, and (b) must be greater than or equal to the second elbow point;

(vi) The Emergency Level 1 (EL1) point (MW) which must be greater than or equal to the third elbow point;

(vii) The Cost Increment 0, for the block of capacity between 0MW and the minimum generation point. The Cost Increment 0 must be non-negative;

(viii) The Cost Increment 1, for the block of capacity between the minimum generation point and the first elbow point. The Cost Increment 1 must be non-negative;

(ix) The Cost Increment 2, for the block of capacity between the first elbow point and the second elbow point. The Cost Increment 2 must be greater than or equal to the Cost Increment 1;

(x) The Cost Increment 3, for the block of capacity between the second elbow point and the third elbow point. The Cost Increment 3 must be greater than or equal to the Cost Increment 2;

(xi) The EL1 Cost, for the block of capacity between the third elbow point and the EL1 point. The EL1 Cost must be greater than or equal to the Cost Increment 3.

(d) The consumption price, in the form of a piecewise-linear price curve, with parameters set as follows:

(i) The Trading Period (the Trading Period start time) from which the price curve is applicable;

(ii) The Minimum Consumption Point of the trading unit (MW), which must be the same as the minimum consumption value for the trading unit from the standing data;

(iii) The first elbow point (MW) which must be greater than or equal to the minimum consumption point;

(iv) The second elbow point (MW) which must be greater than or equal to the first elbow point;

(v) The third elbow point (MW) which (a) must be equal to the maximum consumption for the trading unit from the Registry, and (b) must be greater than or equal to the second elbow point;

(vi) The Cost Increment 0, for the block of consumption between 0MW and the minimum consumption point. The Cost Increment 0 must be non-negative;

(vii) The Cost Increment 1, for the block of consumption between the minimum consumption point and the first elbow point. The Cost Increment 1 must be non-negative but less than or equal to Cost Increment 0;

(viii) The Cost Increment 2, for the block of consumption between the first elbow point and the second elbow point. The Cost Increment 2 must be non-negative but less than or equal to the Cost Increment 1;

(ix) The Cost Increment 3, for the block of consumption between the second elbow point and the third elbow point. The Cost Increment 3 must be non-negative but less than or equal to the Cost Increment 2.

9.5 Additional submission from energy-constrained Trading Units

(1) An energy constrained Trading Unit shall also indicate the Energy Limit applicable to the Dispatch Day (in MWh) above which the MO may not schedule additional energy from the Trading Unit, as well as the Energy Limit applicable to each of the six days following the dispatch day. An indication of the total Energy Limit for the full seven days (in MWh) shall also be provided above which the MO may not schedule additional energy from the Trading Unit. In each Trading Period the Trading Unit shall also indicate:

(a) The preferred run flag (either Y or N), indicating whether the Generator prefers to run this Generating Unit in that Trading Period (Y), or not (N). This allows the Generator to set the preferred regime to meet the water commitments imposed by the Water Authorities.

9.6 Dispatch Algorithm

(1) The MO shall determine an Unconstrained Schedule which will determine the optimal dispatch for all Trading Units for each Trading Period of the Dispatch Day, taking into consideration the BRP submissions, reserve requirements, interconnection schedules, and the production and consumption prices and parameters of Market Participants' Trading Units, but without consideration of network constraints.

(2) The dispatch algorithm objective shall be to minimise the total cost of generation required to meet the expected demand (as reflected by the consumption submissions by Market Participants), constrained by the reserve requirements and technical capabilities of Trading Units.

(a) The total cost of generation will include the incremental cost of production for each scheduled Generator, the start-up costs for Generators synchronised during the period and the costs of dispatching Supplier Unit(s).

(b) Regulating, Instantaneous and 10 Minute Reserve will be co-optimized with the energy dispatch schedule, taking into account the individual reserve requirements. Supplemental Reserve will be optimized independently based on availability, certification and supplemental requirements as determined by the SO.

(3) The dispatch algorithm will optimise the storage cycle to minimise the cost of generation over a week, considering storage cycle efficiency and the limits imposed on the storage levels (including targets instituted by the SO for storage levels at specific times).

(4) Once the Unconstrained Schedule is determined, the MO shall determine a Constrained Schedule which incorporates transmission network constraints.

(5) The Constrained Schedule dispatch algorithm objective shall also be to minimise the total cost of generation within the additional security constraints imposed by the SO to cater for transmission network and other constraints required to meet security of supply objectives.

(6) The SO will dispatch the system based on the Constrained Schedules calculated by the MO.

(7) A more detailed description of the dispatch algorithm will be maintained by the MO and published on their website.

9.7 Day-Ahead Trading Unit Prices

(1) The Day-Ahead Trading Unit prices shall be calculated ex ante, shall be prices per Trading Period and shall be calculated for all Trading Period s of the Settlements Periods of the Dispatch Day.

(2) The Trading Unit prices shall be calculated by, at the latest, 14:00 hours of every

day for the following Dispatch Day. The Constrained Schedule shall be used to calculate the cost of lost opportunity as the Trading Unit is compensated elsewhere for differences from Unconstrained to Constrained Schedule.

(3) Unit prices shall be applicable only to the particular Trading Unit for which they are calculated.

9.7.1 Cost of Lost Opportunity for Regulating Up Reserve Capacity (CLO_{RURC})

(1) The price shall be determined for each settlement period of the Dispatch Day and shall be calculated in Rand per MW per Trading Period. The price shall only be determined for individual Trading Units contracted to provide Regulating Up Reserve capacity. This is the price for loss of opportunity in the SAWEM due to the provision of Regulating Up Reserve capacity.

(2) The price shall be equal to the difference of the SMP for the particular settlement period and the energy price of the Trading Unit at the contracted operating point. If the Trading Unit's contracted volume coincides with an elbow point of the price curve the next increment's price shall be used. If the Trading Unit's contracted volume coincides with the MCR point increment price 3 will be used.

(3) The price shall be set equal to zero if the Trading Unit's energy price exceeds the SMP for a particular Settlement Period.

$$CLO_{RURCTuh} = \max(SMP_h - IP_{Tuh},\ 0)$$

where:

CLO_{RURC}	$\Rightarrow$	Cost of Lost Opportunity for Regulating Up Reserve Capacity
SMP	$\Rightarrow$	System Marginal Price
IP	$\Rightarrow$	Incremental Price
Tu	$\Rightarrow$	Specific Trading Unit
h	$\Rightarrow$	Trading Period

9.7.2 Cost above Energy Market for Regulating Down Reserve Capacity (CEM_{RDRC})

(1) The price shall be determined for each Settlement Period of the Dispatch Day and shall be calculated in Rand per MW per Trading Period. The price shall only be determined for individual Trading Units contracted to provide Regulating Down Reserve capacity. This is the cost above the price paid for energy in the market due to the provision of Regulating Down Reserve capacity.

(2) The price shall be equal to the difference of the energy price of the Trading Unit at the contracted volume and the SMP for the particular Settlement Period. If the Trading Unit's contracted volume coincides with an elbow point of the price curve the lower increment's price shall be used. If the Trading Unit's contracted volume coincides with the Minimum Stable Generation point the increment price 1 will be used.

(3) The price shall be set equal to zero if the Trading Unit's energy price exceeds

the SMP for a particular settlement period.

$$CEM_{RDRCTuh} = \max(IP_{Tuh} - SMP_h,\ 0)$$

where:

CEM_{RDRC}	$\Rightarrow$	Cost above Energy Market for Regulating Down Reserve Capacity
SMP	$\Rightarrow$	System Marginal Price
IP	$\Rightarrow$	Incremental Price
Tu	$\Rightarrow$	Specific Trading Unit
h	$\Rightarrow$	Trading Period

9.7.3 Cost of Lost Opportunity for Instantaneous Reserve Capacity (CLO_{IRC})

(1) The price shall be determined for each Settlement Period of the Dispatch Day and shall be calculated in Rand per MW per Trading Period. The price shall only be determined for individual Trading Units contracted to provide Instantaneous Reserve Capacity. This is the price for loss of opportunity in the SAWEM due to the provision of Instantaneous Reserve Capacity.

(2) The price shall be equal to the difference of the SMP for the particular Settlement Period and the energy price of the Trading Unit at the contracted operating point. If the Trading Unit's contracted volume coincides with an elbow point of the price curve the next increment's price shall be used. If the Trading Unit's contracted volume coincides with the MCR point increment price 3 will be used.

(3) The price shall be set equal to zero if the Trading Unit's energy price exceeds the SMP for a particular Settlement Period.

$$CLO_{IRCTuh} = \max(SMP_h - IP_{Tuh},\ 0)$$

where:

CLO_{IRC}	$\Rightarrow$	Cost of Lost Opportunity for Instantaneous Reserve Capacity
SMP	$\Rightarrow$	System Marginal Price
IP	$\Rightarrow$	Incremental Price
Tu	$\Rightarrow$	Specific Trading Unit
h	$\Rightarrow$	Trading Period

9.7.4 Cost of Lost Opportunity for Ten-minute Reserve Capacity (CLO_{HRC})

(1) The price shall be determined for each Settlement Period of the Dispatch Day and shall be calculated in Rand per MW per Trading Period. The price shall only be determined for individual Trading Units contracted to provide Ten-minute Reserve Capacity. This is the price for loss of opportunity in the SAWEM due to the provision of Ten-minute Reserve Capacity.

(2) The price shall be equal to the difference of the SMP for the particular settlement

period and the energy price of the Trading Unit at the contracted operating point. If the Trading Unit's contracted volume coincides with an elbow point of the price curve the next increment's price shall be used. If the Trading Unit's contracted volume coincides with the MCR point increment price 3 will be used.

(3) The price shall be set equal to zero if the Trading Unit's energy price exceeds the SMP for a particular Settlement Period.

$$CLO_{HRCTuh} = \max(SMP_h - IP_{Tuh},\ 0)$$

where:

CLO_{HRC}	⇒	Cost of Lost Opportunity for Ten-minute Reserve Capacity
SMP	⇒	System Marginal Price
IP	⇒	Incremental Price
Tu	⇒	Specific Trading unit
h	⇒	Trading Period

9.8 Day-Ahead System Prices

(1) The day-ahead system prices shall be calculated ex ante, shall be prices per Trading Period and shall be calculated for all Trading Periods of the Settlements Periods of the Settlement Day.

(2) The system prices shall be calculated by, at the latest, 14:00 hours of every day for the following Trading Day based on the Unconstrained Schedule.

9.8.1 Market Price Cap

(1) The Market Price Cap shall be set by the MCAC. The Market Price Cap, set in Rand per MW- Trading Period, shall provide the maximum price level for the System Marginal Price in each Trading Period. The Market Price Cap shall be set as the peak active energy Wholesale Tariff for the year (averaged between the two seasons, weighted by number of months in each season, and inclusive of legacy and subsidy charges where applicable).

9.8.2 System Marginal Price for Energy (SMP)

(1) The SMP shall be determined for each Settlement Period of the Trading Day, and shall be calculated in Rand per MW- Trading Period.

(2) The SMP shall be the incremental price, at the scheduled (unconstrained) volume, of the most expensive flexible Trading Unit scheduled to run in the particular Settlement Period. If the Trading Unit's scheduled volume coincides with an elbow point of the offer curve, including the Maximum Continuous Rating and excluding the Minimum Stable Generation point, the SMP shall be equal to the incremental price just below the particular elbow point.

(3) The SMP shall not exceed the Market Price Cap in any Trading Period, and shall be set at the Market Price Cap if it would otherwise be higher than the Market Price Cap.

(4) An inflexible Trading Unit shall not be able to set the SMP. A Trading Unit shall

be regarded inflexible either by the way it is scheduled to run in a particular Settlement Period or through the availability and operating intent of the Trading Unit, that can restrict the way a Trading Unit may be scheduled, namely:

(i) If a Trading Unit is scheduled to run at or below its Minimum Stable Generation during a Settlement Period; or

(ii) If a Trading Unit is declared inflexible for the Trading Period in the bid offer; or

(iii) If a Trading Unit is constrained by ramping; or

(iv) If a Trading Unit is constrained by Regulation downwards.

(5) For Settlement Periods where all Trading Units are inflexible the SMP shall be set to zero (0).

9.8.3 System Marginal Price for Regulating Up Reserve Capacity (SMP_{RURCh})

(1) The System Marginal Price for Regulating Up Reserve Capacity shall be determined for each Settlement Period of the Dispatch Day, and shall be calculated in Rand per MW.

(2) The System Marginal Price for Up Regulating Reserve Capacity shall be equal to the highest Cost of Lost Opportunity for Regulating Up Reserve Capacity among Trading Units contracted to provide Regulating Up Reserve Capacity in the particular Settlement Period.

$$\boxed{SMP_{RURCh} = \text{highest}\ (CLO_{RURCTuh})}$$

where:

SMP_{RURCh} ⇒ System Marginal Price for Regulating Up Reserve Capacity

$CLO_{RURCTuh}$ ⇒ Cost of Lost Opportunity for Regulating Up Reserve Capacity

(3) For Settlement Periods where all the Trading Units that have been contracted to provide Regulating Up Reserve Capacity have a Cost of Lost Opportunity for Regulating Up Reserve Capacity of zero (0), the System Marginal Price for Regulating Up Reserve Capacity shall be set to zero (0).

9.8.4 System Marginal Price for Regulating Down Reserve Capacity (SMP_{DRRCh})

(1) The System Marginal Price for Regulating Down Reserve Capacity shall be determined for each Settlement Period of the Dispatch Day, and shall be calculated in Rand per MW.

(2) The System Marginal Price for Regulating Down Reserve Capacity shall be equal to the highest Cost above Energy Market for Regulating Down Reserve Capacity among Trading Units contracted to provide Regulating Down Reserve Capacity in the particular Settlement Period.

$$SMP_{RDRCh} = \text{highest}\ (CEM_{RDRCTuh})$$

where:

SMP_{RDRCh}	$\Rightarrow$	System Marginal Price for Regulating Down Reserve Capacity
$CEM_{RDRCTuh}$	$\Rightarrow$	Cost above Energy Market for Regulating Down Reserve Capacity

(3) For Settlement Periods where all the Trading Units that have been contracted to provide Regulating Down Reserve Capacity have a Cost above Energy Market for Regulating Down Reserve Capacity of zero, the System Marginal Price for Regulating Down Reserve Capacity shall be set to zero (0).

9.8.5 System Marginal Price for Instantaneous Reserve Capacity (SMP_{IRCh})

(1) The System Marginal Price for Instantaneous Reserve Capacity shall be determined for each Settlement Period of the Dispatch Day, and shall be calculated in Rand per MW.

(2) The System Marginal Price for Instantaneous Reserve Capacity shall be equal to the highest Cost of Lost Opportunity for Instantaneous Reserve Capacity among Trading Units contracted to provide Instantaneous Reserve Capacity in the particular Settlement Period.

$$SMP_{IRCh} = \max\ (\text{highest}\ (CLO_{IRCTuh}))$$

where:

SMP_{IRCh}	$\Rightarrow$	System Marginal Price for Instantaneous Reserve Capacity
CLO_{IRCTuh}	$\Rightarrow$	Cost of Lost Opportunity for Instantaneous Reserve Capacity

(3) For Settlement Periods where all the Trading Units that have been contracted to provide Instantaneous Reserve Capacity have a Cost of Lost Opportunity for Instantaneous Reserve Capacity of zero, the System Marginal Price for Instantaneous Reserve Capacity shall be set equal to zero.

9.8.6 System Marginal Price for 10-minute Reserve Capacity (SMP_{MRCh})

(1) The System Marginal Price for 10-minute Reserve Capacity shall be determined for each Settlement Period of the Dispatch Day, and shall be calculated in Rand per MW.

(2) The System Marginal Price for Ten-minute Reserve Capacity shall be equal to the highest Cost of Lost Opportunity for Ten-minute Reserve Capacity among Trading Units that have been contracted to provide Ten-minute Reserve Capacity in the particular Settlement Period.

$$SMP_{MRCh} = \max(\text{highest } (CLO_{MRCTuh}))$$

where:

SMP_{MRCh}	⇒	System Marginal Price for Ten-minute Reserve Capacity
CLO_{MRCTuh}	⇒	Trading Unit's Cost of Lost Opportunity for Ten-minute Reserve Capacity

(3) For Settlement Periods where all the Trading Units that have been contracted to provide Ten-minute Reserve Capacity have a Cost of Lost Opportunity for Ten-minute Reserve Capacity of zero, the System Marginal Price for Ten-minute Reserve Capacity shall be set equal to zero.

9.9 Day-Ahead Settlements

9.9.1 Day Ahead Energy Payment for Generation and Consumption (EPM)

(1) The day-ahead energy payment (EPM) shall be paid to all Trading Units for the energy scheduled for both Generation and Consumption in the Unconstrained Schedule at the System Marginal Price.

$$EPM_{ij} = SG_{ij} * SMP_j$$

where:

EPM	⇒	Energy Payment
SG	⇒	Scheduled Energy (positive for energy produced, negative for energy consumed)
SMP	⇒	System Marginal Price
i	⇒	Specific Trading Unit
j	⇒	Settlement Period

9.9.2 Constrained Schedule Adjustments

(1) Where the Trading Unit scheduled energy as contained in the Unconstrained Schedule is adjusted in the Constrained Schedule by the SO to accommodate system conditions, additional payments or charges will be made to compensate the Trading Unit for the change in scheduled energy.

9.9.2.1 Payments for Constrained Purchases

(1) Additional energy arising from the Constrained Schedule will be paid by the MO at the incremental price offered by the Trading Unit in the day-ahead submissions.

$$CPP_{ij} = \qquad \text{where } CG_{ij} > SG_{ij}$$

where:

CPP	⇒	Constrained Purchases Payment
IP	⇒	Incremental Price Curve (stepwise)

i	⇒	Specific Trading Unit
j	⇒	Settlement Period
SG	⇒	Unconstrained Schedule (positive for energy produced, negative for energy consumed)
CG	⇒	Constraint Schedule (positive for energy produced, negative for energy consumed)

9.9.2.2 Charge for Constrained Sales

(1) The MO will charge Trading Units for the reduction in energy schedules arising from the Constrained Schedule at the incremental price offered by the Trading Unit in the day-ahead submissions.

$$CSC_{ij} = \qquad \text{where } SG_{ij} > CG_{ij}$$

where:

CPC	⇒	Constrained Sales Charge
IP	⇒	Incremental Price Curve (stepwise)
i	⇒	Specific Trading Unit
j	⇒	Settlement Period
SG	⇒	Unconstrained Schedule (positive for energy produced, negative for energy consumed)
CG	⇒	Constraint Schedule (positive for energy produced, negative for energy consumed)

9.9.3 Reserve Capacity Payments

(1) Capacity payments may only be made to a Reserve Resource that had contracted reserve capacity. Capacity not contracted for reserves shall not receive any reserve capacity payments.

(2) Capacity contracted for reserve may have been utilised. A Reserve Resource with an acceptable performance by the utilised reserve capacity will receive the capacity payment for the contracted amount of that reserve capacity.

(3) A Reserve Resource with contracted reserve capacity not utilised may have been instructed to deliver an energy amount different to the contracted amount. A Reserve Resource with acceptable performance in the real-time balancing of energy will receive the capacity payment for the contracted amount of the corresponding reserve capacity.

(4) A Reserve Resource with contracted reserve capacity not utilised and not instructed to deliver an energy amount different to the contracted amount or delivering an energy amount different to the contracted amount against instruction, may still receive reserve capacity payments. These payments will depend on the Reserve Resource's actual energy delivery compared to its actual capacity available and also assessing its ability to perform acceptably had the reserve been requested to be utilised.

(5) A Reserve Resource capacity qualifying for payment will be limited by the effective availability of the Trading Unit to provide the reserve.

9.9.4 Payment for Regulating Up Reserve Capacity (PAY_{RURCh})

(1) The payment to a Trading Unit for Regulating Up Reserve Capacity shall be equal to the product of the System Marginal Price for Regulating Up Reserve Capacity and the Trading Unit's Regulating Reserve Up Capacity qualifying for payment in the particular Settlement Period.

$$PAY_{RURCTuh} = SMP_{RURCh} * \text{Capacity Qualifying}_{Tu}$$

where:

$PAY_{RURCTuh}$	$\Rightarrow$	Payment for Up Regulating Reserve Capacity
SMP_{RURCh}	$\Rightarrow$	System Marginal Price for Regulating Up Reserve Capacity

(2) The Capacity Qualifying$_{Tu}$ for a Trading Unit is equal to:

(i) the Capacity Contracted for Regulating Up Reserve for the Trading Unit, if the resource had performed satisfactorily when utilised, or if the resource had performed unsatisfactorily when utilised but had performed on instruction in the real-time balancing of energy;

(ii) Minimum of the Capacity Contracted for Regulating up Reserve for the Trading Unit; and the Effective Available Capacity for the Trading Unit less the official energy Sent-out / Consumption for the Trading Unit (if this difference is positive), if the contracted capacity had not been utilised, or if it had performed unsatisfactorily when utilised, or if the resource performed against instruction in the real-time balancing of energy, or if the resource did not provide balancing services, and

- Official energy Sent-out for the Trading Unit >= Minimum Generation for the Trading Unit, and
- Official energy Sent-out for the unit <= Maximum Continuous Rating for the Trading Unit;

(iii) Nil, for all other conditions.

(3) The Capacity Qualifying$_{Tu}$ for a Trading Unit is equal to:

(i) Minimum of the Capacity Contracted for Regulating Reserve for the Trading Unit, and the Effective Available Capacity for the Trading Unit less the minimum Consumption Point for the Trading Unit (if this difference is positive).

9.9.5 Payment for Regulating Down Reserve Capacity (PAY_{RDRCh})

(1) The payment to a Trading Unit for Regulating Down Reserve Capacity shall be equal to the product of the System Marginal Price for Regulating Down Reserve Capacity and the Trading Unit's Regulating Down Reserve Capacity qualifying for payment in the particular Settlement Period.

$$PAY_{RDRCTuh} = SMP_{RDRCh} * Capacity\ Qualifying_{Tu}$$

where:

$PAY_{RDRCTuh}$	⇒	Payment for Regulating Down Reserve Capacity
SMP_{RDRCh}	⇒	System Marginal Price for Regulating Down Reserve Capacity

(2) The Capacity Qualifying$_{Tu}$ is equal to:

(i) The Capacity Contracted for Down Regulating Reserve for the Trading Unit, if the resource had performed acceptably when utilised; or if the contracted capacity had not been utilised; or if the resource had performed unsatisfactorily when utilised but the resource performed on instruction in the real-time balancing of energy;

(ii) Minimum of the Capacity Contracted for Regulating Down Reserve for the Trading Unit and the official energy Sent-out for the Trading Unit less the Minimum Generation of the Trading Unit (if this difference is positive), and

- Official energy Sent-out for the Trading Unit <= Maximum Continuous Rating for the Trading Unit; and
- Effective Available Capacity for the Trading Unit >= official energy Sent-out for the Trading Unit.

if the contracted capacity had not been utilised, or if it had performed unsatisfactorily when utilised, and if the resource performed against instruction in the real-time balancing of energy, or if the resource did not provide balancing services;

(iii) Nil, for all other conditions.

9.9.6 Payment for Instantaneous Reserve Capacity (PAY_{IRCh})

(1) The payment to a Trading Unit for Instantaneous Reserve Capacity shall be equal to the product of the System Marginal Price for Instantaneous Reserve Capacity and the Trading Unit's Instantaneous Reserve Capacity qualifying for payment in the particular Settlement Period.

$$PAY_{IRCTuh} = SMP_{IRCh} * Capacity\ Qualifying_{Tu}$$

where:

PAY_{IRCTuh}	⇒	Payment for Instantaneous Reserve Capacity
SMP_{IRCh}	⇒	System Marginal Price for Instantaneous Reserve Capacity

(2) The Capacity Qualifying$_{Tu}$ for a Trading Unit is equal to:

(i) the Capacity Contracted for Instantaneous Reserve for Trading Unit Tu, if the resource had performed satisfactorily when utilised, or if the resource had performed unsatisfactorily when utilised but had performed on instruction in the real-time balancing of energy;

(ii) Minimum of the Capacity Contracted for Instantaneous Reserve for the Trading Unit and the difference between the Effective Available Capacity for the Trading Unit and the official energy Sent-out for the Trading Unit (if this difference is positive), if the contracted capacity had not been utilised, or if it had performed unsatisfactorily when utilised, or if the resource performed against instruction in the real-time balancing of energy, or if the resource did not provide balancing services, and

- Official energy Sent-out for the Trading Unit >= Minimum Generation for the Trading Unit, and
- Official energy Sent-out for the Trading Unit <= Maximum Continuous Rating for the Trading Unit;

(iii) Nil, for all other conditions.

(3) The Capacity Qualifying_{Tu} for a Trading Unit is equal to the minimum of the Capacity Contracted for Instantaneous Reserve for the Trading Unit and the difference between the effective availability for the Trading Unitand the Minimum Consumption Point for the Trading Unit (where this difference is positive).

9.9.7 Payment for 10-minute Reserve Capacity (PAY_{MRCh})

(1) The payment to a Trading Unit for Ten-minute Reserve Capacity shall be equal to the product of the System Marginal Price for Ten-minute Reserve Capacity and the Trading Unit's Ten-minute Reserve Capacity qualifying for payment in the particular Settlement Period.

$$\boxed{PAY_{MRCTuh} = SMP_{MRCh} * \text{Capacity Qualifying}_{Sa}}$$

where:

PAY_{MRCTuh} ⇒ Payment to Trading Unit Tu for Ten-minute Reserve Capacity

SMP_{MRCh} ⇒ System Marginal Price for Ten-minute Reserve Capacity

(2) The Capacity QualifyingTu for a Trading Unit is equal to:

(i) the Capacity Contracted for Ten-Minute Reserve for Trading Unit Tu, if the Trading Unit had performed on instruction in the real-time balancing of energy (since the utilisation of Ten-Minute Reserve capacity takes place in the real-time balancing of energy process);

(ii) Minimum of the Capacity Contracted for Ten-minute Reserve for Tu and the difference between the Effective Available Capacity for the Trading Unit t and the official energy Sent-out for the Trading Unit (if this difference is positive) If the resource is a Generating Unit and

- Official energy Sent-out for the Trading Unit > Minimum Generation of the Trading Unit if the Minimum Generation = 0, or

- Official energy Sent-out of the Trading Unit >= Minimum Generation of the Trading Unit if the Minimum Generation > 0 and
  - Official energy Sent-out of the Trading Unit <= MCR of the Trading Unit, and
  - Effective Available Capacity of the Trading Unit >= official energy Sent-out of the Trading Unit;

(iii) Minimum of the Capacity Contracted for Ten-minute Reserve for the Trading Unit and the Cold Reserve Availability of the Trading Unit, if the resource is a Generating Unit and the official energy Sent-out of the Trading Unit = 0;

(iv) Minimum of the Capacity Contracted for Ten-Minute Reserve for the Trading Unit and the difference between the Effective Available Capacity of the Trading Unit and the Minimum Consumption Point for the Trading Unit (where this difference is positive), if the resource is a Supplier Unit and the Effective Available Capacity of the Trading Unit >= Minimum Consumption Point of the Trading Unit.

(v) Nil, for all other conditions.

9.10 Day Ahead Energy Payment Above Price Cap (EPM)

(1) An additional day-ahead energy payment (AEPM) shall be paid to a flexible Trading Unit bidding above the Market Price Cap for the energy scheduled in the Unconstrained Schedule at the difference between the Incremental Price offered by the Trading Unit and the System Marginal Price.

$$\text{AEPM}_{ij} = \int_0^{SE} \max\left(IP_i - SMP_j, 0\right)$$

where:

AEPM	⇒	Additional Day-Ahead Energy Payment
IP	⇒	Incremental Price Curve (stepwise)
SMP	⇒	System Marginal Price
i	⇒	Specific Trading Unit
j	⇒	Settlement Period
SE	⇒	Scheduled Energy in Unconstrained Schedule

9.11 Publishing Schedule Reports

(1) The MO shall provide to the Market Participants daily Unconstrained Schedule and Constrained Schedule reports by 14h00 of the day preceding the Dispatch Day.

(2) Each Market Participant shall be informed of the expected Sent-Out or consumption for each Trading Period of the Dispatch Day as well as capacity

allocated to reserves, the prices applicable in each Trading Period (for each Trading Unit and system prices) and the settlements for each Settlement Period.

(3) The MO shall also provide a daily general adequacy report indicating for each Trading Period of the Trading Day the expected demand, reserve requirements, the capacity available to meet the demand, capacity allocated to reserves, the total expected sent-out and consumption determined by the dispatch algorithm as well as the system prices. This report shall be published by 14h00 on the day preceding the Trading Day.

(4) The SO shall maintain a daily report on the constraints experienced in scheduling and the deviation between the Unconstrained Schedule and the Constrained Schedule. This report shall be produced and submitted to NERSA on request.

10 INTRA-DAY MARKET

(1) An intra-day market auction clearing will take place at regular six-hour intervals (18h00 on the day before the Trading Day, and 0h00, 06h00, 12h00, 18h00 on the Trading Day) to manage re-declarations of Availability from Market Participants. Each intra-day auction will result in revised schedules for Trading Units, with the first iteration on 18h00 on the day before Trading Day, and the fifth iteration on 18h00 on the Trading Day.

(2) The Day-ahead submissions from Market Participants, including price curves, technical parameters and availability, shall be automatically available for the IDM but Market Participants may re-declare Availability for the IDM. A Market Participant may indicate that their day-ahead schedules are not available for re-scheduling in the IDM. A BRP that is not a Market Participant may not adjust their scheduled production or consumption.

(3) The MO shall produce new schedules for the expected production or consumption of Market Participants based on the intra-day auction, such that:

    (1) The intra-day schedule shall reflect the re-declared Availability from Market Participants;

    (2) The intra-day schedule reflects a security constrained schedule without violating network or other system constraints;

    (3) Non-willing Market Participants will not be re-scheduled unless the SO imposes new network or other system constraints;

    (4) Reserves scheduled in the day-ahead schedule shall not be adjusted unless the Trading Unit is no longer available for the reserve, or has reduced availability to offer the reserve. In this instance other resources may be scheduled for the reserve category to restore the System Operator required capacity for that category. Resources thus scheduled shall earn a Top-Up Reserve Payment for the capacity allocated.

(4) The MO shall publish the revised schedule within an hour of the auction clearing.

(5) For the purposes of the IDM a Trading Unit is considered to purchase energy

"against instruction" when the Trading Unit:

(1) Reduces the Declared Available Capacity in an hour leading to a decrease in scheduled energy for that hour or any other hour impacted by technical considerations;

(2) Increases the Declared Maximum Consumption in an hour leading to a decrease in scheduled energy (i.e. an increase in the scheduled consumption) for that hour or any other hour impacted by technical considerations;

(6) For the purposes of the IDM a Trading Unit is considered to purchase energy "on instruction" when the Trading Unit experiences a decrease in scheduled energy (i.e. decreased generation or increased consumption) without changing the Declared Available Capacity or Declared Maximum Consumption (i.e. is scheduled by the Market Operator to respond to the changing circumstances of other Trading Units).

(7) For the purposes of the IDM a Trading Unit is considered to sell energy "against instruction" when the Trading Unit:

(1) Increases the Declared Available Capacity in an hour while declared Inflexible leading to an increase in scheduled energy for that hour or any other hour impacted by technical considerations;

(2) Decreases the Declared Maximum Consumption in an hour leading to an increase in scheduled energy (i.e. an increase in the scheduled consumption) for that hour or any other hour impacted by technical considerations;

(8) For the purposes of the IDM any Trading Unit is considered to sell energy "on instruction" when the Trading Unit experiences an increase in scheduled energy (i.e. increased generation or decreased consumption) without changing the Declared Available Capacity or Declared Maximum Consumption (i.e. is scheduled by the Market Operator to respond to the changing circumstances of other Trading Units).

(9) The MO shall charge Trading Units for the reduction in energy schedules on instruction arising from each IDM iteration at the incremental price offered by the Trading Unit in the day-ahead submissions.

$$IDC_{ijn} = \int_{IDG_{ijn}}^{IDG_{ijn-1}} IP_i \text{ where } IDG_{ijn-1} > IDG_{ijn}$$

where:

IDC	$\Rightarrow$	Intra-Day Charge
IP	$\Rightarrow$	Incremental Price Curve (stepwise)
i	$\Rightarrow$	Specific Trading Unit
j	$\Rightarrow$	Settlement Period
n	$\Rightarrow$	Iteration of Intra-Day Auction, where n=0 for the Constrained Schedule from the Day-Ahead Market
IDG	$\Rightarrow$	Intra-Day Auction Schedule (positive for energy produced, negative for energy consumed)

(10) The MO shall pay Trading Units for the increase in energy schedules (both on

instruction and against instruction) arising from each IDM iteration at the incremental price offered by the Trading Unit in the day-ahead submissions.

$$IDPM_{ijn} = \int_{IDG_{ijn-1}}^{IDG_{ijn}} IP_i \text{ where } IDG_{ijn} > IDG_{ijn-1}$$

where:

IDPM	⇒	Intra-Day Payment
IP	⇒	Incremental Price Curve (stepwise)
i	⇒	Specific Trading Unit
j	⇒	Settlement Period
n	⇒	Iteration of Intra-Day Auction, where n=0 for the Constrained Schedule from the Day-Ahead Market
IDG	⇒	Intra-Day Auction Schedule (positive for energy produced, negative for energy consumed)

(11) An Intra-day Price shall be calculated for each iteration of the Intra-day auction for each hour where the total volume of energy purchased against instruction in the hour is greater than the total volume of energy sold against instruction in the hour. In all other cases the Intra-day Price for the hour is set to the SMP in the hour.

(1) The Intra-Day Selling Stack consists of Trading Units where energy schedules are increased on instruction in the IDM iteration in the hour. The weighted average of the incremental prices in the Intra-Day Selling Stack (calculated as the sum of incremental price * incremental volume, divided by the sum of the incremental volume) is the Intra-day Price for the hour for the IDM iteration. If the Intra-day Price exceeds the SMP by more than 5% of the SMP, then the Intra-day Price is set at the SMP+5%.

(12) The MO shall charge Trading Units for the reduction in energy schedules against instruction arising from each IDM iteration at the Intra-day Price for that IDM iteration for that hour.

$$IDC_{ijn} = \max(IDG_{ijn-1} - IDG_{ijn}, 0) * IDP_{jn}$$

where:

IDC	⇒	Intra-Day Charge
IDP	⇒	Intra-day Price
i	⇒	Specific Trading Unit
j	⇒	Settlement Period
n	⇒	Iteration of Intra-Day Auction, where n=0 for the Constrained Schedule from the Day-Ahead Market
IDG	⇒	Intra-Day Auction Schedule (positive for energy produced, negative for energy consumed)

(13) If a Trading Unit experiences a change in schedule in any iteration of the IDM auction clearing that reverses any change in schedule due to a prior iteration of the IDM auction clearing, or even reserves an adjustment due to the constrained schedule in the day-ahead market, then the payment arising from the prior iteration, or the adjustment due to the constrained schedule, shall be negated for

the portion of the reversal due to the more recent iteration of the IDM auction clearing.

(14) With the exception of (13) above all payments and charges calculated under each iteration of the IDM shall be cumulative.

11 REAL-TIME DISPATCH

11.1 Inputs to the Real-time Dispatch Schedule

(1) The SO shall have the ability to determine a real-time dispatch schedule. This Real-time Dispatch Schedule shall be authorized for use by AGC at the SO's discretion. In addition, the SO may determine a revised Constrained Schedule for each Trading Period of the Dispatch Day based on revised input data during the day.

(2) Revisions to the interconnector schedules may be submitted by the SO based on updated flow report(s) from SAPP acting in its role as the national BRP at any time for the remainder of the Dispatch Day, indicating the revised expected imports or exports.

(3) Revisions to the availability of Trading Units may be made to the SO at any time for the remainder of the Dispatch Day, indicating the revised Trading Period availability for the Trading Units.

(4) When dispatchable Generators become aware that there is a constraint limiting their output they must declare that constraint with the reason and the expected time for the constraint to be lifted.

11.2 Dispatch Algorithm

(1) The real-time dispatch algorithm shall adjust the Day-Ahead Constrained Schedule (or a revised Constrained Schedule determined on the Dispatch Day, following the same methodology as the day-ahead schedule) based on the revised input data and the real-time network model.

(2) This dispatch algorithm shall take into account the transmission and distribution network and generator constraints (including ramping and energy constraints).

11.3 Schedule Reports

(1) Each Trading Unit shall be informed of the expected Sent-Out and capacity allocated to reserves for each Trading Period of the remainder of the Dispatch Day as determined in the revised Constrained Schedule determined on the Dispatch Day.

(2) The SO shall also provide a revised general adequacy report indicating the expected demand, reserve requirements, the capacity available to meet the demand, capacity allocated to reserves and the total expected Sent-out determined by the revised Constrained Schedule.

(3) The SO shall maintain a daily report on the revised Constrained Schedule (where applicable) and the real-time dispatch schedule. This report shall be produced and submitted to NERSA on request.

11.4 Dispatch Instructions

(1) The SO shall maintain an electronic log of system conditions at regular intervals as well as the integrated system information per Trading Period. This log shall include the conditions relating to frequency, generation, interconnector flows, corridor flows and voltages.

(2) These interval data shall be held by the SO for three years at which time the four-second data may be deleted. The integrated data per Trading Period shall be maintained for five calendar years from the day of dispatch.

(3) The system condition log shall be utilised for audit purposes to support the reasons for dispatch instructions.

(4) The SO shall issue dispatch instructions to qualifying Trading Units to indicate the required sent-out or consumption level.

(5) Non-dispatchable Trading Units may be expected to follow specific dispatch instructions in the case of an emergency operating condition in the NIPS or the existence of a need for curtailment. These instructions must be duplicated into a separate electronic log for commercial reconciliation purposes.

(6) Should curtailment be necessary the SO shall, in issuing such instruction, consider the total economic cost.

(7) These dispatch instructions shall be logged by the SO, taking the form of:

(a) The official Trading Unit name (as in the Registry);

(b) The date and time of the dispatch instruction;

(c) The expected Sent-Out or Consumption level

(8) An audit mechanism must be maintained to allow for verification of the logged details.

(9) The day-ahead Constrained Schedule (or revised Constrained Schedule determined on the day, where applicable) shall constitute a dispatch instruction unless replaced by a manual or automatic dispatch instruction from the SO.

(10) The real-time dispatch schedule shall constitute a dispatch instruction (replacing the day-ahead instruction) unless itself replaced by a manual or automatic dispatch instruction from the SO.

(11) If the SO has issued a dispatch instruction to a Trading Unit that replaced the day-ahead schedule, the SO must continue to issue dispatch instructions before the start of each Trading Period (or 5-minute interval) to indicate the level of sent-out or Consumption from the Trading Unit.

(12) The Instructed Energy for each Trading Unit for each Trading Period shall be calculated based on the System Operator dispatch instructions, taking ramping constraints into account. The Instructed Energy shall form the basis for

payments in the Balancing Mechanism.

12 PARTICIPANT METERING AND RECONCILIATION

12.1 Metering installations

(1) Market participants, including BRPs, shall ensure that metering installations conform to the Metering Code;

(2) The metering installations shall be connected at the Point of Delivery as defined in the Balancing Agreement;

12.2 Metering data

(1) The MO's Metering Service Provider shall be able to remotely interrogate all metering installations and verify metering data;

(2) Metering reports associated with the metering installations shall be produced daily with verified metering data finalised within seven days after the Trading Day.

12.3 Reconciliation of data

(1) The MO shall ensure that all metered energy imported or exported at each metering point is allocated such that the energy imported at each metering point to one BRP is equal to the energy exported from another BRP.

(2) The net energy imports to a Trading Unit (as defined by the net imports at each metering point allocated in the Registry) shall constitute the actual energy position of the Trading Unit for the purposes of the Balancing Mechanism.

13 BALANCING MECHANISM

13.1 Balancing Stacks

(1) Within seven days of the end of the Dispatch Day, all dispatch instructions shall be logged and verified, and all metering data for every Trading Unit shall be collated and verified. On the eighth day following the dispatch day, two balancing stacks shall be determined for each hour of the dispatch day, one for Balancing Energy Sold to the SO and another for Balancing Energy Bought from the SO.

(2) The Balancing Energy Sold stack is derived from the price curves of Trading Units. Only Trading Units that are declared available and flexible for the Trading Period are included in the Balancing Energy Sold stack. The capacity available is limited at the minimum point by the sum of the day-ahead scheduled energy and the day-ahead scheduled instantaneous reserve, and on the maximum point by the least of the declared availability and the effective available capacity of the Trading Unit. Energy increments meeting these requirements and constraints are stacked in increasing order of energy cost.

(3) The Balancing Energy Bought stack is derived from the price curves of trading

units. Only Trading Units that are declared available and flexible for the Trading Period are included in the Balancing Energy Bought stack. The capacity available is limited at the maximum point by the day-ahead scheduled energy, and on the minimum point by the minimum stable generation point. Energy increments meeting these requirements and constraints are stacked in decreasing order of energy cost.

13.2 Imbalances

(1) For each Trading Period of the dispatch day the following shall be determined:

(a) The instructed energy output for each Trading Unit for the Trading Period, based on the dispatch instructions given by the SO (adjusted for ramping constraints);

(b) The actual metered energy output or consumption for each Trading Unit.

(2) The total Imbalance Energy Bought for the Trading Period is determined as the sum of all deviations of the actual metered energy from the instructed energy where the instructed energy exceeds the actual energy.

(3) The total Imbalance Energy Sold for the Trading Period is determined as the sum of all deviations of the actual metered energy from the instructed energy where the actual energy exceeds the instructed energy.

13.3 Balancing Payment (On Instruction)

(1) Ex-Post Balancing Settlement calculations shall be performed daily per Settlement Period of the Dispatch Day and shall be paid as Rand per Trading Period (positive for payments from the MO to participants; negative for payments from participants to the MO).

(2) The SO issues dispatch instructions to Trading Units. The MO will pay these Trading Units that respond to the instructions (or receive payment from these resources) based on the day-ahead energy prices submitted by the Trading Unit.

(3) Other deviations (between actual generation or consumption and scheduled generation or consumption) shall pay the MO (or be paid by the MO) based on calculated Balancing Prices for each Settlement Period.

13.3.1 Dispatch Energy

(1) Dispatch Energy (DE) is the energy volume calculated from the SO's Dispatch Instructions (in the form of a tuple (t, v, R), with t being the time (in whole minutes) at which the Trading Unit should be at energy sent-out volume v (in MWh) , and R being the ramping rate applicable to the type of instruction (in MW/min)) in each Settlement Period.

(2) Treating each Settlement Period individually, with a start time S and end time E, and day-ahead schedules applied as an instruction with t = S unless replaced by a new dispatch instruction;

1. In each Settlement Period determine:

a. the last instruction prior to the start of the Trading Period (I_0) as the instruction with max t where t < S
b. the list of instructions effective in the Trading Period ($I_1 \dots In$) with t >= S and t < E.
c. the first instruction after the end of the Trading Period (I_{n+1}) as the instruction with min t where t >= E

2. Looping through all instructions 1..n+1,
   a. Calculate r in each case as the start time of the ramp to reach volume v such that

$$r_i = t_i - \frac{v_i - v_{i-1}}{R}$$

   b. Determine the Dispatch Energy (i.e. instructed volume) as:

$$DE = \frac{1}{M}\sum_{i=1}^{n+1} v_{i-1}(\min(t_i, E) - \max(t_{i-1}, S)) + Ramp(I_i)$$

Where

$$Ramp(I_i) = \begin{cases} \frac{1}{2}(t_i - r_i)(v_i - v_{i-1}) & if\ S \le r_i\ and\ t_i < E \\ \frac{1}{2}(t_i - r_i)(v_i - v_{i-1}) - \frac{1}{2}(S - r_i)^2 R * sgn(v_i - v_{i-1}) & if\ r_i < S\ and\ t_i < E \\ \frac{1}{2}(E - r_i)^2 R * sgn(v_i - v_{i-1}) & if\ S \le r_i < E\ and\ t_i > E \end{cases}$$

M = number of minutes in the settlement period (i.e. 60)

(3) The calculated Dispatch Energy (DE) may be superseded by an agreed or adjudicated Dispatch Energy as an outcome of a dispute regarding the value. The MCAC may adjudicate a value for Dispatch Energy where the dispute is not resolved between the Market Participant and SO.

13.3.2 Additional Sales to the Balancing Mechanism (On Instruction)

(1) Energy supplied to the Balancing Mechanism on instruction from the SO will be paid at the incremental price offered by the Trading Unit in the day-ahead submissions.

$$\text{BPM}_{ij} = \int_{\text{SE}}^{\min(IE,AE)} \max(IP_i, SMP_j)$$

where:

BPM	⇒	Balancing Payment
IP	⇒	Incremental Price Curve (stepwise)
i	⇒	Specific Trading Unit
j	⇒	Settlement Period
SE	⇒	Contracted Energy
AE	⇒	Actual Energy
IE	⇒	Instructed Energy

13.3.3 Additional Purchases from the Balancing Mechanism (On Instruction)

(1) Energy purchased from the Balancing Mechanism on instruction from the SO will be bought at the incremental price offered by the Trading Unit in the day-ahead submissions.

$$BPM_{ij} = -\int_{\min(IE,AE)}^{SE} \min(IP_i, SMP_j)$$

where:

BPM	⇒	Balancing Payment
IP	⇒	Incremental Price Curve (stepwise)
i	⇒	Specific Trading Unit
j	⇒	Settlement Period
SE	⇒	Contracted Energy
AE	⇒	Actual Energy
IE	⇒	Instructed Energy

13.3.4 Additional Purchases from the Balancing Mechanism (On Instruction) above Market Price Cap

(1) Energy purchased from the Balancing Mechanism on instruction from the SO for energy above the Market Price Cap will be bought at the difference between the incremental price offered by the generating unit in the day-ahead submissions and the Market Price Cap.

$$BPM_{ij} = -\int_{\min(IE,AE)}^{SE} \max(IP_i - MPC, 0)$$

where:

BPM	⇒	Balancing Payment
IP	⇒	Incremental Price Curve (stepwise)
MPC	⇒	Market Price Cap
i	⇒	Specific Trading Unit
j	⇒	Settlement Period
SE	⇒	Contracted Energy
AE	⇒	Actual Energy
IE	⇒	Instructed Energy

13.4 Balancing Payment (within MAB)

(1) Ex-Post Balancing Settlement calculations shall be performed daily per Settlement Period of the Dispatch Day and shall be Rand per Trading Period.

(2) For the purposes of Balancing calculations, the MAB for all participants is set to 5%.

(3) Energy purchased from or supplied to the Balancing Mechanism within the MAB shall be deemed to be against instruction for the purposes of calculating the Balancing Prices, but shall not incur penalties inherent in these prices.

13.4.1 Additional Sales to the Balancing Mechanism

(1) Energy supplied to the Balancing Mechanism within the MAB relative to the Actual Energy will be paid at the System Marginal Price set for the Trading Period in the day-ahead market.

$$\text{If } SE_{ij} <= AE_{ij} <= (\max(IE_{ij},SE_{ij}) + (1+MAB)*AE_{ij})$$
$$BPM_{ij} = BPM_{ij} + \max(AE_{ij}-\max(IE_{ij},SE_{ij}),0) * SMP_{j}$$

where:

BPM	⇒	Balancing Payment (this can be cumulative with prior calculations)
i	⇒	Specific Trading Unit
j	⇒	Settlement Period
SE	⇒	Contracted Energy
AE	⇒	Actual Energy
IE	⇒	Instructed Energy

13.4.2 Additional Purchases from the Balancing Mechanism

(1) Energy purchased from the Balancing Mechanism within the MAB relative to Actual Energy will be bought at the System Marginal Price set for the Trading Period in the day-ahead market.

$$\text{If } (\min(IE_{ij},SE_{ij}) - (1-MAB)*AE_{ij}) <= AE_{ij} <= SE_{ij}$$
$$BPM_{ij} = BPM_{ij} - \max(\min(IE_{ij},SE_{ij})-AE_{ij},0) * SMP_{j}$$

where:

BPM	⇒	Balancing Payment (this can be cumulative with prior calculations)
i	⇒	Specific Trading Unit
j	⇒	Settlement Period
SE	⇒	Contracted Energy

AE	⇒	Actual Energy
IE	⇒	Instructed Energy

13.4.3 Additional Sales to the Balancing Mechanism above Market Price Cap (within MAB)

(1) Energy supplied to the Balancing Mechanism above the Market Price Cap within the MAB relative to the Actual Energy will be paid at the difference between the incremental price offered by the Trading Unit in the day-ahead submissions and the System Marginal Price set for the Trading Period in the Day-Ahead Market.

If $SE_{ij} <= AE_{ij} <= (\max(IE_{ij},SE_{ij}) + (1+MAB)*AE_{ij})$

$$BPM_{ij} = BPM_{ij} + \int_{\max(IE,SE)}^{AE} \max(IP_i - SMP_j, 0)$$

where:

BPM	⇒	Balancing Payment (this can be cumulative with prior calculations)
i	⇒	Specific Trading Unit
j	⇒	Settlement Period
IP	⇒	Incremental Price Curve (stepwise)
SMP	⇒	System Marginal Price
SE	⇒	Contracted Energy
AE	⇒	Actual Energy
IE	⇒	Instructed Energy

13.4.4 Additional Purchases from the Balancing Mechanism above Market Price Cap (within MAB)

(1) Energy purchased from the Balancing Mechanism above the Market Price Cap within the MAB relative to Actual Energy will be bought at difference between the incremental price offered by the Trading Unit in the day-ahead submissions and the System Marginal Price set for the Trading Period in the Day-Ahead Market.

If $(\min(IE_{ij},SE_{ij}) - (1-MAB)*AE_{ij}) <= AE_{ij} <= SE_{ij}$

$$BPM_{ij} = BPM_{ij} - \int_{AE}^{\min(IE,SE)} \max(IP_i - SMP_j, 0)$$

where:

BPM	⇒	Balancing Payment (this can be cumulative with prior calculations)
i	⇒	Specific Trading Unit
j	⇒	Settlement Period

IP	⇒	Incremental Price Curve (stepwise)
SMP	⇒	System Marginal Price
SE	⇒	Contracted Energy
AE	⇒	Actual Energy
IE	⇒	Instructed Energy

13.5 Calculation of Balancing Prices

(1) The Balancing Prices shall be calculated ex-post, shall be prices per Trading Period and calculated for all Trading Periods of the availability declaration periods of day 'n'. Preliminary balancing prices shall be calculated on days 'n+1' through 'n+6'. The official prices will be calculated on day 'n+7'.

(2) There shall be two Balancing Prices calculated for each Trading Period of the availability declaration periods of day 'n', one for the Selling of energy to the Balancing Mechanism, the other for the Buying of energy from the Balancing Mechanism.

13.6 Load Forecast Error (LFE)

(1) The SO shall be responsible for providing the Load Forecast to the MO for each Trading Period of the day. This Load Forecast shall be used to determine the scheduling of resources in the day-ahead market, and is expressed in terms of total net Sent-Out by Generators (excluding expected pumping demand for each Trading Period). The actual total Sent-Out by Generator (less pumping demand), referred to as the Net System Demand, shall be determined for each Trading Period of day 'n' ex-post. This Net System Demand shall be compared to the Load Forecast to determine the Load Forecast Error (LFE) for each Trading Period of the day, such that:

$$\boxed{LFE_j = NSD_j - LF_j}$$

where:

LFE	⇒	Load Forecast Error
j	⇒	Settlement Period
LF	⇒	Load Forecast
NSD	⇒	Net System Demand

All instructions relating to demand-side interventions which have an impact on the Net System Demand, including but not limited to interruptible load, load shedding / curtailment, virtual power station and flexible services utilisation, need to be accounted for in the LFE calculation.

13.7 Balancing Price (Buying)

(1) The total volume of imbalance energy bought is the sum of the energy deviations where Trading Units are below contract. If the LFE is positive it is added to this imbalance energy bought to determine the imbalance to be used in calculating the Balancing Price (Buying).

(2) Trading Units included on the Balancing Selling Stack are utilised for the purposes of calculating the Balancing Price (Buying) in order of ascending energy price. The increments offered in the stack are used in the calculation up to the point where the stack is exhausted or the imbalance is satisfied (whichever comes first). The weighted average of these incremental prices (calculated as the sum of incremental price * incremental volume, divided by the sum of the incremental volume) is the indicative Balancing Price (Buying), used to provide an indication of the cost of balancing. If the indicative Balancing Price (Buying) is less than the SMP, the Balancing Price (Buying) is set to the SMP.

(3) The Balancing Price (Buying) shall be set as the SMP + 5% in each Settlement Period.

13.8 Balancing Price (Selling)

(1) The total volume of imbalance energy sold is the sum of the energy deviations against instruction where Trading Units are above contract. If the LFE is negative the absolute value of the LFE is added to this imbalance energy sold to determine the imbalance to be used in calculating the Balancing Price (Selling).

(2) Trading Units included on the Balancing Buying Stack are utilised for the purposes of calculating the Balancing Price (Selling) in order of descending energy price. The increments offered in the stack are used in the calculation up to the point where the stack is exhausted or the imbalance is satisfied (whichever comes first). The weighted average of these incremental prices (calculated as the sum of incremental price * incremental volume, divided by the sum of the incremental volume) is the indicative Balancing Price (Selling), used to provide an indication of the cost of balancing. If the indicative Balancing Price (Selling) is less than the SMP, the Balancing Price (Selling) is set to the SMP.

(3) The Balancing Price (Selling) shall be set as the SMP - 5% in each settlement period.

13.9 Balancing Payment (Against Instruction)

(1) Ex-Post Balancing Settlement calculations shall be performed daily per Settlement Period of the Dispatch Day and shall be Rand per Trading Period (positive for payments from the MO to Market Participants; negative for payments from Market Participants to the MO).

13.9.1 Additional Sales to the Balancing Mechanism (Against Instruction)

(1) Energy supplied to the Balancing Mechanism against instruction from the SO will be paid at the minimum of the Balancing Price (Selling) for the Settlement Period and the System Marginal Price for the Settlement Period.

$$\text{If } AE_{ij} > \max(IE_{ij},SE_{ij})*(1+MAB)$$
$$BPM_{ij} = BPM_{ij} + [(AE_{ij} – \max(IE_{ij}, SE_{ij})) * BPS_{j},]$$

where:

BPM	⇒	Balancing Payment (this can be cumulative with prior calculations)
i	⇒	Specific Trading Unit
j	⇒	Settlement Period
SE	⇒	Contracted Energy
AE	⇒	Actual Energy
IE	⇒	Instructed Energy
BPS	⇒	Balancing Price (Selling)
SMP	⇒	System Marginal Price

13.9.2 Additional Purchases from the Balancing Mechanism (Against Instruction)

(1) Energy purchased from the Balancing Mechanism against instruction from the SO will be bought at the maximum of the Balancing Price (Buying) for the Settlement Period and the System Marginal Price for the Settlement Period.

$$\text{If } AE_{ij} < \min(IE_{ij},SE_{ij})*(1-MAB)$$
$$BPM_{ij} = BPM_{ij} - [(\min(IE_{ij}, SE_{ij})-AE_{ij}) * BPB_{j}]$$

where:

BPM	⇒	Balancing Payment (this can be cumulative with prior calculations)
i	⇒	Specific Trading Unit
j	⇒	Settlement Period
SE	⇒	Contracted Energy
AE	⇒	Actual Energy
IE	⇒	Instructed Energy
BPB	⇒	Balancing Price (Buying)
SMP	⇒	System Marginal Price

13.9.3 Additional Purchases from the Balancing Mechanism above Market Price Cap (Against Instruction)

(1) Energy purchased from the Balancing Mechanism against instruction from the SO above the Market Price Cap will be bought at the difference between the incremental price offered by the Trading Unit in the day-ahead submissions and the Balancing Price (Buying) for the Settlement Period.

$$\text{If } AE_{ij} < \min(IE_{ij},SE_{ij})*(1-MAB)$$
$$BPM_{ij} = BPM_{ij} - \int_{AE}^{\min(IE,SE)} \max(IP_i - BPB_j),0)$$

where:

BPM	⇒	Balancing Payment (this can be cumulative with prior calculations)
i	⇒	Specific Trading Unit
j	⇒	Settlement Period
SE	⇒	Contracted Energy
AE	⇒	Actual Energy
IE	⇒	Instructed Energy
BPB	⇒	Balancing Price (Buying)
IP	⇒	Incremental Price

14 SETTLEMENT REPORTS

14.1 Schedule Reports

(1) The MO shall provide the day-ahead and intra-day scheduling reports to Market Participants as required under Sections 9.11 and 11.3.

(2) These reports shall be kept for a minimum of three full calendar years from the day of operation.

14.2 Dispatch Reports

(1) The SO shall provide a report to NERSA when requested on the dispatch instructions issued to all Trading Units. This report shall cover the day-ahead and revised schedules along with the real-time dispatch schedule and dispatch instructions for each Trading Unit for each Trading Period at five minute intervals including the AGC settings and the tie-line actuals and contracts per Trading Period.

(2) The actual metered energy imports and export from each Trading Unit and for each Trading Period (or 5 min interval where metered) shall also be included in the above report.

14.3 SO Reports to NERSA

(1) The SO shall on a monthly basis provide NERSA with the following system data in a format approved by NERSA on a per Trading Period basis:

(a) The Sent-Out for each Generating Unit for which the SO has Telemetry. For pumped-storage units, pump energy is to be reported separately;

(b) The use (sent-out energy) of emergency generation;

(c) The use of Virtual PS and Interruptible customers;

(d) The tie-line actual and contracted MW;

(e) The system demand ;

(f) The generation load losses;

(g) The load shed;

(h) The imports and exports.

(2) The SO shall on a monthly basis provide NERSA with a curtailment report detailing the curtailment instructions issued to non-dispatchable generation with the reasons and cost.

15 FINANCIAL SETTLEMENT

15.1 Settlement Items

(1) The MO shall carry out or procure settlements in accordance with the Market Code of the following amounts:

(a) Trading Payments due to Market Participants in respect of their registered Trading Units for each Billing Period;

(b) Trading Charges payable by Market Participants in respect of their registered Trading Units for each Billing Period;

(c) Charges to Market Participants in respect of their registered Trading Units for Unsecured Bad Energy Debt;

(d) Charges to Market Participants in respect of their registered Trading Units for Unsecured Bad Capacity Debt;

(e) Fixed Market Operator Charges payable by Market Participants in respect of their registered Trading Units for each year or period to which the Fixed Market Operator Charge relates; and

(f) Variable Market Operator Charges payable by Market Participants in respect of their Trading Units for each Billing Period.

(2) All of the payments and charges set out in the paragraph above shall be calculated in accordance with the Market Code and, except where otherwise stated, shall exclude VAT.

(3) The MO shall, through its contract with the Market Bank, administer the banking services required pursuant to the Market Code for Market Participants. The Market Operator and each Market Participant shall, in each case in relation to those banking arrangements that it requires in order to comply with the Market Code, procure, use, make available and administer such banking arrangements.

(4) The Market Bank shall be a bank which is appointed by the MO according to the rules of this Market Code.

(5) The Market Operator shall establish and operate in accordance with the Market Code a Trading Clearing Account at a branch of the Market Bank to and from which all Trading and Capacity Payments calculated in accordance with the Market Code are to be made.

(6) Each Trading Clearing Account shall be an interest bearing account.

(7) Any Interest received on the Trading Clearing Accounts shall accrue to the Market Participant.

15.2 Provision of Cash Collateral

(1) A Market Participant may at any time provide a cash deposit as part of its Required Credit Cover as permitted. Where a Market Participant decides to provide such a cash deposit, then the Market Participant shall establish and

maintain a Collateral Reserve Account with the Market Bank. Each Collateral Reserve Account shall be an interest bearing account. If a Market Participant chooses to establish a Collateral Reserve Account as part of its Required Credit Cover, then it must provide to the MO such documents and in such form as the MO may require from time to time.

(2) The Collateral Reserve Account in relation to each relevant Market Participant shall contain the cash element of that Market Participant's Posted Credit Cover on the following terms:

(a) the Collateral Reserve Account shall be in the sole name of the MO with the designation "Market Collateral Reserve Account relating to [Insert Market Participant Details]";

(b) the Market Participant and the MO shall have irrevocably instructed the Market Bank to make payment against the sole instruction of the MO in accordance with the Market Code; and

(c) to give effect to the provisions of the Market Code in relation to Collateral Reserve Accounts, with effect from the time of payment into the relevant Collateral Reserve Account, the relevant Market Participant thereby charges all sums paid into and accruing on that account by way of first fixed charge over cash at the Market Bank in favour of the MO as agent and trustee for it and the Market Creditors to secure the relevant Market Participant's payment obligations under the Market Code.

(3) Where, at any time, a Market Participant (or Applicant, as applicable) wishes to establish a Collateral Reserve Account and, where appropriate, the MO shall require the Market Participant (or Applicant, as applicable) to complete and sign the particulars of charge in respect of such Collateral Reserve Account within such timelines as may be specified by the MO, having regard to any applicable time limit for the registration. Without prejudice to the foregoing, the MO shall, unless the relevant Participant undertakes otherwise, register the prescribed particulars with regard to the establishment of each Collateral Reserve Account pursuant to prevailing banking legislation, as appropriate, and/or at such other registry or registries as may be appropriate.

(4) The Trading Clearing Accounts shall be established and maintained in the name of the MO. The cash in and rights relating to each Trading Clearing Accounts, opened and any balance in any of the accounts shall be held on trust by the MO without obligation to invest in accordance with the provisions of this section. The MO shall not commingle any funds standing to the credit of the Trading Clearing Accounts, or any Collateral Reserve Account with its own personal or any other funds.

(5) Notwithstanding the previous paragraph, the MO shall hold the trusts as provided for in this Section subject to its entitlement to make payments into and out of the Trading Clearing Accounts a for the purpose of settling any Costs.

(6) Except as expressly provided for in this Market Code, no Party or Market Participant shall enter into any arrangements which assign or charge or purport to assign or charge any interest any Party or Market Participant may have in any Trading Clearing Account or Collateral Reserve Account.

(7) The MO shall procure that an electronic funds transfer (EFT) facility with the

Market Bank is provided to enable it to make all payments to Market Participants under the Market Code. Payments shall only be made by the MO and Market Participants in the Market through an EFT facility.

(8) The EFT facilities procured by the MO shall be consistent with standard banking practice.

(9) In procuring the establishment of the EFT facility, the MO shall use its reasonable endeavours to ensure that the use of the EFT facility does not impose unreasonable restrictions on the Market Participants' normal banking arrangements.

(10) Each Party (or Applicant, as applicable) shall give to the MO in accordance with the registration requirements, details of the bank account or bank accounts to which the MO is instructed to make payments pursuant to the Market Code to such Party's Market Participant(s), and shall provide to the MO such further information in relation to such bank account or bank accounts as the MO may reasonably request. Each Party shall establish and maintain such a bank account at a bank. Where a Party or Participant changes the bank account or bank accounts to which payments are made pursuant to the Market Code, it shall inform the MO and provide details of the new bank account or bank accounts. The Market Operator shall not be responsible for any loss to any Party or Market Participant where the MO has not been informed by the relevant Party or Market Participant of any change in bank account details.

(11) The MO shall maintain detailed ledger accounts of all funds held in the Trading Clearing Accounts, Collateral Reserve Accounts and all other bank accounts held by it at the Market Bank showing all monies paid in and paid out in respect of each Market Participant and, where requested by a Market Participant or its Party, the MO shall provide full details of all such payments and funds in relation to such Market Participant only and shall keep all information in respect of each Market Participant confidential. Notwithstanding the foregoing, the MO shall be entitled to disclose any information or data in relation to any Trading Clearing Account or Collateral Reserve Account held at the Market Bank to the Market Auditor or relevant Revenue Authority where required or where otherwise required by law.

15.2.1 Establishment of Trusts

(1) The MO shall hold all funds in the Trading Clearing Accounts and such rights (including, without limitation, all rights of action) as shall from time to time be vested in it with regard to payments due and owing by Market Participants or with regard to the provision of Credit Cover by each Participant including:

(a) all monies from time to time standing to the credit of each Trading Clearing Account relating to any Trading Period;

(b) all rights of the MO to call for and enforce payment of amounts owing under the Market Code (including, for the avoidance of doubt, any Shortfall or Unsecured Bad Debt) or to make a Credit Call; and

(c) any interest receivable in respect of any amounts due pursuant to the Market Code relating to any Trading Period,

on trust for Creditors in accordance with their individual respective proportionate entitlements as they arise in accordance with the Market Code (or to the extent that any Credit Cover shall relate to any Variable Market Operator Charge, on trust for the MO in accordance with the Market Code). Upon termination of the said trusts, any residual balance after satisfaction of the entitlement of all Creditors shall be held for all Market Participants in accordance with their individual respective proportionate entitlements as they arise in accordance with the Market Code.

(2) The respective rights of the Creditors to the assets held by the MO on trust in the Trading Clearing Accounts shall be determined in accordance with the Market Code and in accordance with the following principles:

(a) the extent of each Creditor's individual rights shall be deemed to consist of the aggregate of the claims (to the extent not paid or otherwise settled) of such Creditor in respect of each Trading Period; and

(b) the assets referred to above shall be deemed to consist of a series of funds, each fund representing the rights or monies owed, paid, held or otherwise attributable to each Trading Period in relation to Trading Payments and Capacity Payments.

(3) The MO shall not be obliged to segregate moneys into separate funds.

(4) The MO shall hold the Collateral Reserve Assets in respect of each Participant that establishes and maintains an Collateral Reserve Account in accordance with the Market Code on trust as follows:

(c) at any time when no amounts owed by any such Market Participant are overdue, on trust to repay to that Market Participant the monies, together with any interest accrued on such monies, held in the relevant Collateral Reserve Account as part of that Participant's Posted Credit Cover; and

(d) with automatic effect as soon as any amount owed by a Market Participant becomes overdue and becomes a Shortfall (excluding any Market Operator Charge), such amount of the monies deposited in the relevant Collateral Reserve Account by such Participant as is equal to the amount of the Shortfall and any applicable Interest (or Default Interest as applicable) in respect of the relevant Participant on trust for the Creditors and the balance (if any) shall be held on trust in respect of that Participant; and

(e) with automatic effect as soon as any Variable Market Operator Charge owed by a Market Participant becomes overdue and where there is no Shortfall or Unsecured Bad Debt in respect of that Participant at that time or, if there is such Shortfall or Unsecured Bad Debt only after the Collateral Reserve Assets have been applied to meet the Shortfall or Unsecured Bad Debt in full, such amount of the monies then held in the relevant Collateral Reserve Account as is available up to the amount of the Variable Market Operator Charge outstanding and any applicable Interest on trust for the MO in accordance with the Market Code and the balance (if any) shall be held on trust.

(5) Each Market Participant which has funds remitted by it for the credit of a relevant Collateral Reserve Account agrees that none of the remittances shall be repayable (or capable of being repaid) to it or its Party, except where provided otherwise in accordance with the provisions of the Market Code, until

Deregistration of the Market Participant's Trading Unit(s) becomes effective in accordance with the Market Code and, and the Market Participant has paid in full all amounts actually or contingently owed by the relevant Market Participant to any Creditor or the MO pursuant to the Market Code.

(6) Each Participant with a Collateral Reserve Account undertakes not to seek withdrawal of any funds to which it may otherwise be entitled in the relevant Collateral Reserve Account. The MO shall reject any purported notice of withdrawal.

(7) If a Participant is not in default in respect of any amount owed to a Market Creditor, then:

(a) the MO shall transfer quarterly to the relevant Participant the interest credited to the relevant Collateral Reserve Account unless the Market Participant requests otherwise;

(b) the MO shall transfer to such Market Participant within two business days after a written request from such Market Participant (exclusive of the day of request) any amount of the balance which exceeds the amount which such Participant has agreed to maintain in the relevant Collateral Reserve Account from time to time in accordance with this Section and the Market Code, provided that the Market Participant at all times maintains its Required Credit Cover;

(c) the Market Participant shall be entitled to change the composition of its Posted Credit Cover in satisfying the Required Credit Cover provided any reduction in any amount standing to the credit of the relevant Collateral Reserve Account does not result in a breach of the Required Credit Cover.

(8) Except as expressly provided for in the Market Code, each Party and Market Participant waives any right it might otherwise have to set off against any obligation owed to the MO, the Market Bank or any other Party or Market Participant any claims such Party or Market Participant may have to or in respect of any monies standing to the credit of the relevant Trading Clearing Account, or Collateral Reserve Account as applicable.

(9) No Party or Market Participant shall have any claim against the MO for breach of trust or fiduciary duty by the MO under the Market Code except in the case of reckless or wilful misconduct.

15.3 Description of Timelines

15.3.1 Settlement Day

(1) All Settlement of Trading Payments and Trading Charges are based on a Settlement Day.

(2) The terminology "SD+xWD" means during the Working Day which ends x business days after the end of the Settlement Day.

15.3.2 Billing Period

(1) All Trading Payments and Trading Charges shall be aggregated on a Billing Period basis which is defined as one Month commencing at 00:00 on the first day of the month.

(2) The terminology "BP+xWD" means during the Working Day which ends x business days after the end of the Billing Period.

(3) The terminology "BP+xM" means during the last Month which ends x Months after the end of the Billing Period.

15.3.3 Settlement Calendar

(1) The Market Operator shall publish, four months prior to the start of each Year, a Settlement Calendar for all days in the coming Year which shall include the following information:

(a) details of Non-business days;

(b) details of:

i. when Indicative Settlement Statements are due (for each type of Settlement Statement);

ii. when Initial Settlement Statements are due (for each type of Settlement Statement);

iii. each Invoice issue date (for each type of Invoice);

iv. the Invoice due date (for each type of Invoice);

v. the Self Billing Invoice issue date (for each type of Self Billing Invoice);

vi. the Self Billing Invoice due date (for each type of Self Billing Invoice); and

vii. the Timetabled M+1 Settlement Reruns for relevant Settlement Periods.

15.3.4 Invoices, Self-Billing Invoices and Debit Notes

(1) The MO shall produce and issue Invoices and Self Billing Invoices for Trading Payments and Trading Charges in accordance with the following:

(a) Indicative Settlement Statements for Trading Payments and Trading Charges shall, in respect of each Settlement Day in a Billing Period, be produced and issued to all Participants in respect of their Units by 17:00 on Settlement Day + 1WD;

(b) the Data Verification Period for Trading Payments and Trading Charges commences at the time of issue of the Ex-Post Indicative Settlement Statements and ends at 17:00 on Settlement Day + 4WD;

(c) Initial Settlement Statements shall be issued to all Participants in respect of their Units by 12:00 on Settlement Day + 5WD; and

(d) Invoices and Self Billing Invoices for Trading Payments and Charges shall be issued to all Participants in respect of their Units by 12:00 on BP+5 WD.

(2) Payment shall be in accordance with the following:

(a) each Indicative Settlement Statement, Initial Settlement Statement, Invoice and Self Billing Invoice shall be based on the data then available to the Market Operator at the time of its production;

(b) each Invoice and Self Billing Invoice shall include the amount of all applicable charges and payments and shall include any applicable VAT charges;

(c) each Debit Note (where applicable) shall include the amount of the Unsecured Bad Debt as applicable and shall include any applicable VAT charges;

(d) any invoiced Market Participant shall pay each Invoice in full without deduction, set-off or counterclaim (except as otherwise expressly provided for in the Market Code) by paying the amount due into the relevant Trading Clearing Account for full value by the Invoice Due Date; the Invoice Due Date is 12:00, three business days after the date of the Invoice; and

(e) the Market Operator shall, subject to the provisions of the Market Code, pay each Self Billing Invoice less any applicable Debit Note to any Market Participant who is a Creditor by paying the amount due from the Trading Clearing Account to the Market Creditor's designated bank account or bank accounts for full value by the Self Billing Invoice due date. The Self Billing Invoice due date is 17:00, four business days after the date of the Self Billing Invoice.

(3) The MO shall issue Invoices and Self Billing Invoices on the date appearing on the relevant Invoice or Self Billing Invoice as appropriate.

(4) If any Invoiced Market Participant fails to pay an Invoice in full, then the Market Participant has a Shortfall and the MO shall forthwith make a Credit Call on the Market Participant's Posted Credit Cover for payment of the Shortfall. The MO shall identify the Settlement Period to which the Shortfall relates in making any Credit Call. Default Interest shall accrue on any Shortfall and Unsecured Bad Debt in accordance with the Market Code.

(5) If the MO fails to pay pursuant to the Market Code (except as otherwise provided for in the Market Code) the full amount owing pursuant to a Self-Billing Invoice for full value by the Self-Billing Invoice Due Date, then Default Interest shall accrue on the amount outstanding in accordance with the Market Code.

(6) If any Market Participant fails to pay its Variable Market Operator Charge in accordance with the Market Code, the MO shall be entitled to make a Credit Call against the Posted Credit Cover of that Market Participant for payment of the amount of the overdue Variable Market Operator Charge. The MO shall ensure that any amounts recovered relating to the Variable Market Operator Charge and any Interest thereon are not paid into or commingled or combined in any way with the Trading Clearing Accounts and shall deposit the funds recovered as a result of such a Credit Call in the relevant Market Operator Charge Account. Any unpaid Market Operator Charge shall not and shall never be treated as a Shortfall or an Unsecured Bad Debt under the Market Code. The MO shall only be entitled to make a Credit Call in relation to overdue Variable Market Operator Charge

where there is no Shortfall or Unsecured Bad Debt in respect of that Market Participant at that time or, if there is such Shortfall or Unsecured Bad Debt, only after the relevant Participant's Posted Credit Cover has been applied to meet the Shortfall or Unsecured Bad Debt in full.

(7) Despite the making of a Credit Call by the MO, if the Market Participant meets any Shortfall either through its own funds, its Posted Credit Cover, or a combination of the foregoing by 12:00 on the next Working Day after the Invoice Due Date then Settlement shall continue to proceed in accordance with the Market Code.

(8) If the Shortfall is not paid in full by 12:00 on the next Working Day after the Invoice Due Date, then:

(a) the amount of the Shortfall shall become an Unsecured Bad Debt for the purposes of this Market Code;

(b) the MO shall, where practicable, withhold, deduct or set off payment of any amount due pursuant to the Market Code to the Defaulting Participant until the amount of the Unsecured Bad Debt and any applicable Default Interest has been recovered in full.

(9) The Shortfall or the Unsecured Bad Debt as applicable shall be a debt owing by the Defaulting Participant to the MO as trustee and agent for all Participants beneficially interested therein as provided for in the Market Code and affected thereby pro-rated according to their individual respective proportionate entitlements in the Shortfall or the Unsecured Bad Debt concerned.

(10) Where a Market Participant has an Unsecured Bad Debt relating to any Trading Period(s) then, without prejudice to the MO's rights or obligations under the Market Code and notwithstanding any other provisions of the Market Code, the MO shall procure that each Self Billing Invoice relating to the Trading Period(s) affected by such Unsecured Bad Debt shall be subject to the calculation of an adjustment by a reduction in the amount payable to each affected Creditor pro-rated in accordance with the individual respective proportionate entitlement of each such Market Creditor (excepting any Defaulting Participant, which would otherwise be a Creditor until the Unsecured Bad Debt and any applicable Default Interest has been recovered in full and any Self Billing Invoices issued to it whether or not relating to the Trading Periods concerned shall, until such event, be subject to the calculation of an adjustment by such amount or amounts up to the amount of the Unsecured Bad Debt and any applicable Default Interest, and relevant Debit Notes shall be issued to it) for payment of the relevant Unsecured Bad Debt, in accordance with the Market Code. The MO shall issue the appropriate adjustments to the Self Billing Invoices in the form of a Debit Note to each of the applicable Market Creditors ("Reduced Participants") and the Defaulting Participant within the timeframe of making the payment. The MO shall make payments to each Market Participant for the amount of the Self Billing Invoice less the applicable Debit Note.

(11) In the event that, for any Market Participant (an "Excess Participant"), the amount of the Debit Note would exceed the amount of the applicable Self Billing Invoice (a "Debit Note Excess"), the MO will make no payment to the Excess Participant in respect of that Settlement Period. In addition, the Excess Participant shall, within two business days of the receipt of the relevant Debit Note, make a payment to the relevant Trading Clearing Account as applicable for the amount

of the Debit Note Excess. The Market Operator shall calculate further reductions in the payments to each Market Creditor (other than the Excess Participant) by the amount of the Debit Note Excess applied pro-rata to their respective proportionate entitlements. The Market Operator shall issue a Debit Note to each Market Creditor showing the original reduction resulting from the Unsecured Bad Debt and, in respect of each Market Creditor other than the Excess Participant, the relevant proportion of the Debit Note Excess. In the event that upon receipt of an Excess Debit Note, a further Market Participant or Market Participants become Excess Participants, then the Market Operator shall repeat the process of calculation of reduction, and the resultant Debit Notes shall show the resultant reductions for each relevant Market Creditor, until the amount due in respect of each Self Billing Invoice net of a Debit Note or Excess Debit Note is positive or zero. Any Debit Note Excess which remains unpaid after the second Working Day shall be treated as a Shortfall.

(12) All Parties agree that the MO as trustee and agent shall be entitled and irrevocably authorise the MO, to take all necessary action against a Market Participant (or its Party where legally necessary) with an Unsecured Bad Debt to recover any Unsecured Bad Debt on behalf of Market Creditors consequently incurring loss and to deal with any recovered monies in accordance with the Market Code. Any such action of the MO to recover the Unsecured Bad Debt shall not be subject to the Dispute Resolution Process.

(13) The MO shall consult the MCAC in relation to any plans for the pursuit of any Unsecured Bad Debt. The MO shall take into account the views of the MCAC as to the most appropriate action to take against a Party in respect of the Unsecured Bad Debt of any of its Market Participants.

(14) Where the MO partially or fully recovers any Unsecured Bad Debt, the MO shall procure the payment of any such monies into the relevant Trading Clearing Account as applicable. Then the MO shall issue an appropriate Self Billing Invoice to each Reduced Participant for an amount pro-rated to the individual respective proportionate entitlement of each Reduced Participant in the amount of the relevant Unsecured Bad Debt recovered relating to the Trading Periods concerned with the issue of the Self Billing Invoices for the then next immediate Billing Period (excepting, where the Unsecured Bad Debt and any applicable Default Interest has not been fully recovered, the Defaulting Participant, which would otherwise be a Market Creditor, until the Unsecured Bad Debt and any applicable Default Interest has been recovered in full). The MO shall pay each such Self Billing Invoice in accordance with the Market Code.

(15) If any payments made by the MO pursuant to any Self Billing Invoice and any Debit Note or otherwise pursuant to the Market Code to any Market Participant do not correspond exactly with their respective payment entitlements established in accordance with the Market Code, then (and the Parties and Market Participants agree and consent to the actions of the MO as set out as follows):

(a) in the case of overpayment by the MO, the Market Participant receiving any such overpayment shall pay back the difference between the amount of the payment received and the actual amount due to the MO on becoming aware of the overpayment or, in any event, in accordance with the Market Code on the issue of an Invoice by the MO to the Market Participant concerned for the relevant amount. Any Market Participant receiving any overpayment shall be obliged to notify the MO of this on becoming aware of such overpayment detailing, where possible, the amount and date of the overpayment and details of any Self Billing Invoice and any Debit Note pursuant to which it was made. As soon as the MO becomes aware of the overpayment, the MO shall issue an overpayment Invoice for the relevant amount and the Market Participant shall pay the Invoice in accordance with the Market Code;

(b) in the case of underpayment to any Market Participant by the MO not otherwise permitted pursuant to any other provision of the Market Code, the MO shall, in accordance with the Market Code, pay the difference between the amount of the payment received and the actual amount due, with Default Interest on that difference, to the Market Participant concerned on becoming aware of the underpayment or on being notified of the underpayment by the Market Participant concerned. The MO shall also issue an underpayment Self Billing Invoice to the Market Participant concerned for the relevant amount with Default Interest from the date of the underpayment until the date of payment of the relevant Self Billing Invoice. Any Market Participant receiving any underpayment shall notify the MO of this on becoming aware of such detailing, where possible, the amount and date of the underpayment and details of any Self Billing Invoice or Debit Note pursuant to which it was made.

(16) If any payments made by any Market Participant pursuant to any Invoice or otherwise pursuant to the Market Code do not correspond exactly with their respective payment obligations established in accordance with the Market Code, then (and the Parties and Participants agree and consent to the actions of the Market Operator as set out as follows):

(a) in the case of overpayment by the relevant Market Participant, the MO, unless otherwise restricted from doing so pursuant to the Market Code, shall pay back the difference between the amount of the payment remitted and the actual amount due with Interest on that difference to the relevant Market Participant on becoming aware of the overpayment or on being notified of the overpayment by the Market Participant concerned (except where the Market Participant is a Defaulting Participant). The Market Operator shall then issue an overpayment Self Billing Invoice to the Market Participant concerned for the relevant amount with Interest from the date of the overpayment until the date of payment of the relevant Self Billing Invoice and pay it to the Market Participant in accordance with the Market Code. Any Market Participant making any overpayment shall notify the MO of this on becoming aware of such overpayment detailing, where possible, the amount and date of the overpayment and details of any Invoice pursuant to which it was made. The MO shall notify any Market Participant making an overpayment on becoming aware of such detailing, where possible, the amount and date of the overpayment and details of any Invoice pursuant to which it was made and issue an overpayment Self Billing Invoice for the relevant amount with Interest and shall pay the overpayment Self Billing Invoice in accordance with the Market Code.

(17) Any Market Participant making any underpayment or anticipating that it will be making an underpayment in respect of any Invoice shall notify the MO of this on becoming aware that full payment of any Invoice will not be made by the Invoice Due Date detailing, where possible, the amount and date of the underpayment and details of any Invoice to which it relates.

(18) All payments under this Section shall be made on the basis that a Market Participant shall only be entitled to claim reimbursement of an overpayment

made by it pursuant to the Market Code if, and then only to the extent that, the aggregate amounts paid by the Market Participant in respect of the relevant Payment Due Date exceed the total amounts payable by that Market Participant to Creditors in respect of that Payment Due Date together with all amounts (if any) overdue from that Market Participant in respect of Settlement Periods prior to the relevant Payment Due Date.

(19) If:

(a) a payment is received by the MO under a Letter of Credit after a sum has been withdrawn from an Collateral Reserve Account (where applicable) to make good (in whole or in part) a Shortfall or Unsecured Bad Debt (or any overdue Variable Market Operator Charge where applicable); and

(b) the aggregate of the amounts paid out of that Collateral Reserve Account and paid under the Letter of Credit in respect of a relevant Market Participant exceeds the Shortfall or Unsecured Bad Debt (or any overdue Variable Market Operator Charge where applicable),

then any excess paid over the Shortfall or Unsecured Bad Debt (or any overdue Variable Market Operator Charge where applicable) shall be remitted with any applicable Interest by the MO to the relevant Market Participant's bank account or bank accounts.

(20) Where payments in respect of one or more Settlement Period(s) are fully or partially outstanding, any payments made shall be, and shall be deemed to be, settled according to the following priority:

(a) first, in or towards settlement of amounts outstanding under the Market Code in respect of Timetabled Settlement Reruns (with the longest outstanding Settlement Period to which a Timetabled Settlement Rerun relates being settled first); and

(b) secondly, in or towards settlement of amounts outstanding under the Market Code for Settlement with the longest outstanding Settlement being settled first.

15.3.5 Settlement Reruns

(1) The objective of all Settlement Reruns is to adjust the financial positions of Market Participants to reflect any differences between data used for Settlement and any updated data received.

(2) There will be one timetabled Settlement Rerun for each Billing Period. The Timetabled Settlement Rerun shall take place in the first month after the Billing Period (BP+1M). The MO shall publish the precise date of these in advance in the Settlement Calendar.

(3) The MO shall issue Settlement Rerun Statements to Market Participants for each of their registered Units in the event of any Settlement Rerun arising from a Settlement Query, Data Query or Settlement Dispute.

(4) Each Settlement Rerun Statement will be in the same format as the Initial Settlement Statement and must include the data from the previous Settlement Statement relating to the relevant Billing Period and any revised values for all

Trading Periods where these values are different.

(5) The MO shall be entitled to undertake Settlement Reruns as provided for in the Market Code in addition to the timetabled Settlement Reruns.

(6) When a Settlement Rerun results in any change to any amount payable under the Market Code, the MO shall issue adjusted Invoices and Self Billing Invoices and payment shall be made.

15.4 Queries to Settlement Data

15.4.1 Data Verification Period

(1) A Market Participant may raise a Data Query in respect of any Settlement Item or other elements of data which have an impact on the Settlement Items included in the Indicative Settlement Statement by giving notice to the MO during the Data Verification Period and will use reasonable endeavours to raise any such Data Query as early as possible within the Data Verification Period before the production and issue of the Initial Settlement Statement.

15.4.2 Data Queries

(1) The MO shall use reasonable endeavours to resolve all Data Queries within three business days of the issue of the Indicative Settlement Statement.

(2) The MO must resolve a Data Query within ten business days after the Data Query is filed. Where the MO requests any assistance from any Market Participant to resolve a Data Query, that Market Participant shall promptly assist the MO in dealing with the Data Query concerned in order to facilitate the MO in meeting that timetable.

(3) The MO shall procure that (i) prices and market schedules will be recalculated for the relevant Settlement Day(s), and (ii) a Settlement Rerun shall then be undertaken in the event that the MO in resolving a Data Query determines that:

(a) Commercial Offer Data or Technical Offer Data has been applied incorrectly; or

(b) Actual Availability or Dispatch Quantity has been calculated incorrectly.

and that the correct application or calculation of any such amount would require it to change by more than the Settlement Recalculation Threshold.

(4) The Market Operator shall procure that (i) prices and market schedules will be recalculated for the relevant Settlement Day(s), and (ii) a Settlement Rerun shall then be undertaken in the event that the MO in resolving a Data Query determines that:

(a) Metered Energy has been applied incorrectly; or

(b) Market schedules has been calculated incorrectly,

and that the correct application or calculation of any such amount would require it to change by more than the Settlement Recalculation Threshold.

(5) If the MO does not resolve the Data Query within the period set, then it shall be deemed to give rise to a Settlement Dispute unless the Party concerned agrees to give the MO more time, such period not exceeding ten business days, to resolve the Data Query.

(6) Any change to Settlement resulting from the resolution by the MO of a Data Query that was not processed prior to the production of the Initial Settlement Statement for Trading Payments or Trading Charges shall fall into one of the two following categories:

(a) Change to Settlement Items with Low Materiality;

(b) Change to Settlement Items with High Materiality.

(7) The MO shall calculate the materiality of a change to Settlement Items, or other elements of data which have an impact on the Settlement Items, arising from the resolution of a Data Query or a Settlement Query by reference to a single Settlement Statement or Statement of Market Operator Charges as appropriate.

(8) In the event that there is a change to Settlement Items with Low Materiality, the MO shall procure that the revised corrected input data shall be used for the relevant Settlement Period for which Final Settlement has not occurred, and Settlement shall then take place on the next timetabled Settlement Rerun.

(9) In the event that there is a change to Settlement Items with Low Materiality resolved after the final Timetabled Settlement Rerun, the MO shall procure that an additional Settlement Rerun for the relevant Settlement Period shall then be performed.

(10) In the event that there is a change to Settlement Items with High Materiality, the MO shall procure that the revised corrected input data shall be corrected for the relevant Settlement Period and an additional Settlement Rerun for that Settlement Period shall then be performed.

15.4.3 Settlement Queries

(1) Before raising a Settlement Dispute, a Market Participant must raise a Settlement Query in respect of those matters.

(2) A Market Participant may raise a Settlement Query in respect of the application of Metered Generation or the calculation of any of the following amounts:

(a) Metered Energy;

(b) Dispatch Instruction; or

(c) Actual Availability.

(3) Notwithstanding any other provision of the Market Code, a Market Participant may raise a Settlement Query in the event of any difference between a Settlement Item on the Indicative Settlement Statement and the same item on the Initial Settlement Statement, without the Market Participant having filed a Data Query in relation to that Settlement Item.

(4) Any changes to Settlement resulting from a Settlement Query on an Initial

Settlement Statement, on an Invoice or on a Self-Billing Invoice, shall be placed into one of the two following categories:

Change to Settlement Items with Low Materiality;

Change to Settlement Items with High Materiality.

(5) In the event that there is a change to Settlement Items with Low Materiality, the MO shall procure that the revised corrected data will be used for the relevant Settlement Period for which Final Settlement has not occurred, and Settlement shall then take place on the next Timetabled Settlement Rerun.

(6) The MO shall calculate the materiality of a change to Settlement Items arising from the resolution of a Settlement Query by reference to a single Energy Settlement Statement or statement of Market Operator Charges.

(7) In the event that there is a change to Settlement Items with Low Materiality resolved after the final Timetabled Settlement Rerun, the MO shall procure that an additional Settlement Rerun for the relevant Settlement Period shall then be performed.

(8) In the event that there is a change to Settlement Items with High Materiality, the MO shall procure that the revised corrected data shall be used for the relevant Settlement Period and a Settlement Rerun for that Settlement Day shall then be performed.

(9) A Market Participant is entitled to file a Settlement Query at any time before 17:00 on the fifth Working Day after the last Timetabled Settlement Rerun.

(10) The MO must resolve a Settlement Query within one month after the Settlement Query is filed with it. If the MO does not resolve the Settlement Query within that period, then it shall be deemed to give rise to a Settlement Dispute unless the Party concerned agrees to give the MO more time (not exceeding ten business days) to resolve the Settlement Query.

15.4.4 Settlement Disputes

(1) A Market Participant may only raise a Settlement Dispute in respect of an Initial Settlement Statement or an Invoice or a Self-Billing Invoice insofar as it relates to Trading Payments and Trading Charges after the Initial Settlement Statements for Trading Payments and Trading Charges are issued to relevant Market Participants.

(2) A Settlement Dispute shall also arise where the MO has not resolved a Data Query within the period provided for or where the MO has not resolved a Settlement Query within the period provided for.

(3) The MO shall procure that (i) price and market schedules shall be recalculated, and (ii) a Settlement Rerun will then be undertaken in the event that as a result of an Upheld Dispute it is determined that:

(a) Offer Data has been applied incorrectly; or

(b) Dispatch Quantity has been calculated incorrectly.

and that the correct application or calculation of any such amount would require it to change by more than the Settlement Recalculation Threshold.

(4) Upheld Disputes shall be placed into one of two categories:

(a) Upheld Dispute with Low Materiality; or

(b) Upheld Dispute with High Materiality.

(5) The MO shall calculate the materiality of a change to Settlement Items arising from the resolution of a Settlement Dispute by reference to a single Settlement Statement or statement of Market Operator Charges.

(6) In the event of an Upheld Dispute with Low Materiality, the MO shall procure that the revised corrected data shall be used for the relevant Settlement Period for which Final Settlement has not occurred, and Settlement shall then take place on the next Timetabled Settlement Rerun.

(7) In the event of an Upheld Dispute with Low Materiality after the final Timetabled Settlement Rerun, the MO shall procure that an additional Settlement Rerun for the relevant Settlement Period shall then be performed within the timeframe directed by the Dispute Resolution Board as a result of the Dispute Resolution Process.

(8) In the event of an Upheld Dispute with High Materiality, the MO shall procure that the revised corrected data will be used for the relevant Settlement Day and an additional Settlement Rerun for the relevant Settlement Day shall then be performed within the timeframe directed by the Dispute Resolution Board as a result of the Dispute Resolution Process.

15.5 Consequences

(1) Any payment due under the Market Code by any Party or Market Participant shall continue to be due and payable in accordance with its terms (including as to timing) notwithstanding (i) any Data Queries, Settlement Queries or Settlement Disputes in respect of such payments or (ii) any Shortfall, Unsecured Bad Debt, Default, Suspension, Deregistration or Termination arising in relation to any such Party or Market Participant.

(2) Where the resolution of a Data Query, Settlement Query or Settlement Dispute requires a Settlement Rerun, the MO will procure the carrying out of a Settlement Rerun in relation to the Settlement Day(s) that are the subject of the Data Query, Settlement Query or Settlement Dispute.

(3) Where the resolution of a Settlement Query or Settlement Dispute raised by a Market Participant requires a Settlement Rerun, the MO shall apply the result of that Settlement Rerun to all Market Participants.

15.6 Market Operator charge

(1) The MO shall apply charges to a Market Participant or BRP as per the approved tariff structure

15.7 Recovery of unsecured bad debt

(1) The MO shall procure that any amount of Unsecured Bad Energy Debt is charged to all Market Participants (other than that those whose Default has given rise to the relevant Unsecured Bad Debt) in proportion to their total payments in a month.

15.8 Recovery of unpaid Market Operator charge

(1) The MO's claim against any Market Participant relating to any overdue Market Operator Charge shall rank pari passu with the claims of any other Party for any Shortfall or Unsecured Bad Debt.

15.9 Interest payment

(1) Any Party may claim interest, compounded Monthly from the first day following the due date of a Billing Period to date of payment, at a rate per annum equal to the prevailing prime overdraft rate charged by First National Bank of Southern Africa Limited against any Market Participant relating to any overdue payment.

15.10 Credit cover

(1) Each Market Participant shall comply with its obligation to provide the Required Credit Cover calculated in relation to it and notified to it by the MO in accordance with the Market Code.

(2) The Market Operator shall calculate the Required Credit Cover for each Market Participant as provided for in this section.

(3) Each Market Participant must maintain its Credit Cover with a Credit Cover Provider. The acceptable form of Credit Cover which Market Participants can post is a cash held deposit in a Collateral Reserve Account.

(4) A Credit Cover Provider shall be a Bank which must:

(a) hold a South African Banking Licence; or

(b) be an international bank that is authorised or approved by the relevant regulatory authority or is otherwise eligible to provide banking services in South Africa and under this Market Code.

(5) If a Participant's Credit Cover Provider is no longer qualified to issue or hold Credit Cover, the Market Participant shall re-post its Required Credit Cover with a Bank that satisfies the requirements in the previous paragraph within ten business days of the Market Participant's Credit Cover Provider ceasing to be qualified. This period shall not form part of the Settlement Risk Period.

(6) If the Market Operator, following a Credit Call, draws down any amounts from the Market Participant's Posted Credit Cover, such that the Posted Credit Cover no longer meets the Market Participant's notified Required Credit Cover, the Market Participant shall within two business days fully re-establish the Required Credit Cover and shall notify the MO on doing this.

(7) Credit Cover is subject to the following conditions:

(a) a Market Participant's Posted Credit Cover shall be available for draw down by the MO making a Credit Call on a Market Participant's Credit Cover Provider as provided for in the Market Code and shall continue to remain in place until such time as all amounts due in respect of the Market Participant concerned under the Market Code have been paid in full;

(b) the MO, but not any Party or Market Participant, has the right to deduct from or set off against a Market Participant any outstanding claims and liabilities of that Market Participant against any amounts owing pursuant to any Invoice under the Market Code relating to that Market Participant without the prior consent of any such Market Participant concerned;

(c) the Market Participant cannot reduce the amount of the Posted Credit Cover below the Required Credit Cover calculated by the MO and notified to the Market Participant in accordance with the Market Code;

(d) a Market Participant shall notify the MO at least one Working Day in advance of any change to its Posted Credit Cover;

(e) In the event of Termination of a Party or a Market Participant or Suspension or Deregistration of a Market Participant's Units, the Market Participant's then applicable Required Credit Cover shall remain in place in accordance with the Market Code until all amounts due by the Market Participant concerned under the Market Code have been paid in full, and further subject to the Fixed Credit Requirement specified in the relevant Termination Order, Voluntary Termination Consent Order or Deregistration Consent Order as applicable;

(f) in the event of the Deregistration of any of a Party's Units, the relevant Market Participant shall maintain the Fixed Credit Requirement in respect of that Unit until the last Settlement Rerun for the Settlement Day equal to the day of Deregistration of each Unit.

(8) The MO shall calculate the level of Required Credit Cover in accordance with the Market Code to cover a Market Participant's actual and potential payment liabilities in respect of its Units and participation in the Market (including, for the avoidance of doubt, the Variable Market Operator Charge) at any time. A Market Participant's Required Credit Cover shall be calculated to cover:

(a) its Actual Exposure (credit exposure resulting from Invoices that have been issued but not yet paid, and from amounts in Settlement Statements for which no Invoice has been issued); and

(b) its Undefined Potential Exposure (potential exposure resulting from accrued obligations that have not yet been included in any Settlement Statement and future obligations which would be likely to have been accrued before a Participant could be suspended from trading in the Pool for Default).

15.10.1 Parameters for the Determination of Required Credit Cover

(1) The MO shall make a report to NERSA at least 4 months before the start of the year proposing the parameters relating to the calculation of the Required Credit Cover, for application in the following year.

(2) The MO's report must set out any relevant research or analysis carried out by the MO and the justification for the specific values proposed. Such a report may, and shall if so requested by NERSA, include alternative values from those proposed and must set out the arguments for and against such alternatives.

(3) The MO shall publish the approved value(s) for each parameter within five business days of receipt of NERSAs determination or two months before the start of the year to which they shall apply whichever is the later.

15.10.2 Monitoring of Credit Cover

(1) The MO shall recalculate the Required Credit Cover, for each Market Participant every Working Day and shall send to each Market Participant its recalculation of that Market Participant's Required Credit Cover by 17:00 on that Working Day.

(2) Where the daily recalculation of Required Credit Cover determines that additional Credit Cover is necessary, the MO shall issue to the relevant Market Participant by 17:00 on the same Working Day a Credit Cover Increase Notice specifying the amount of additional Credit Cover required to be posted to satisfy its Required Credit Cover. The Market Participant shall post the additional necessary Credit Cover by 17:00 on the second Working Day thereafter.

(3) If a Market Participant has been issued with a Credit Cover Increase Notice in accordance with paragraph above, it may meet the terms of the Credit Cover Increase Notice by taking any combination of the following steps:

(a) taking steps to increase its Posted Credit Cover; or

(b) paying an outstanding Invoice early.

(4) The MO shall provide the Market Participant with a Warning Notice on any Working Day when its Warning Limit is reached. Each Market Participant shall be entitled to specify its own Warning Limit. However, NERSA shall set the maximum value for the Warning Limit in writing in advance of each Year to which it shall apply. This shall operate as the default Warning Limit for all Market Participants. Any Market Participant may require the MO to set a lower Warning Limit for it.

(5) Where a Market Participant reasonably expects that the total metered quantities with respect to its Supplier Units will increase by more than the Credit Cover Adjustment Trigger, then it shall inform the MO as soon as reasonably possible. Such a Market Participant shall be an adjusted Market Participant.

(6) Each adjusted Market Participant shall provide such additional information to the MO to enable the Market Operator to calculate revised values of Required Credit Cover.

15.10.3 Calculations for Required Credit Cover

(1) For the purposes of Credit Cover monitoring and calculations:

(a) a Market Participant is a New Participant from the commencement of their participation; and,

(b) a Market Participant ceases to be a New Participant when the length of time between the commencement of their participation and the last Trading Period covered in the most recent Settlement Statement issued for that Market Participant is greater than the length of time for the last full Billing Period.

(2) A Market Participant is an adjusted Market Participant where the Market Participant notifies the MO of a change in circumstances. A Market Participant ceases to be an Adjusted Participant when the length of time between their notification and the last Trading Period covered in the most recent Settlement Statement issued for that Participant is greater than the length of time covered by the last full Billing Period.

(3) The calculation of the Required Credit Cover shall be based on the historical trading activity of the Market Participant.

(4) The MO shall calculate the Actual Supplier Exposure (ASEpf) for a Market Participant p in respect of its Supplier Units for the Actual Exposure Period f as follows:

$$\boxed{ASE_{pf} = \sum\nolimits_{u\ in\ p}\left(\sum\nolimits_{i\ in\ f} SUM\ SALES\ from\ Inv + Settlement * UEF\right)}$$

where:

ASE	⇒	Actual Supplier Exposure
p	⇒	Market Participant
u	⇒	Specific Trading Unit
i	⇒	Settlement Period
f	⇒	Actual Exposure Period
UEF	⇒	Undefined Exposure Factor

(5) The Required Credit Cover for the Undefined Exposure shall be calculated as:

15.10.4 Calling in Credit Cover

(1) Where the MO exercises its right to make a Credit Call on a Market Participant's Posted Credit Cover in accordance with the Market Code, the MO:

(a) shall be entitled to draw down on the Collateral Reserve Account;

(b) shall, as soon as reasonably practicable and notwithstanding any other provisions of the Market Code relating to Notices, notify the Market Participant in writing, using a rapid means of communication such as email or fax, that it has made the Credit Call on the Market Participant's Credit Cover Provider; and

(c) shall as soon as reasonably practicable after making such a Credit Call and issuing the notice, notify the Market Participant of the amount of Shortfall, the sums called from the Market Participant's Collateral Reserve Account and the Settlement Period(s) concerned.

(2) Where the MO draws down any amounts from the Market Participant's Posted Credit Cover, the Market Participant shall, within two business days, fully re-establish at minimum the Required Credit Cover as calculated and notified to it.

15.11 Implementation of Administered Settlement

15.11.1 General Principles in the Event of Administered Settlement

(1) In implementing Administered Settlement, the MO shall, insofar as reasonably practicable, adopt a balance between the following principles:

(a) make use of all available data, and limit to the maximum extent practicable the use of estimated values;

(b) operate within the Settlement timescales, and be subject to the Settlement Query and Settlement Dispute provisions;

(c) seek results which are as close as possible to those which would have been calculated under the normal Settlement processes;

(d) obtain the prior written approval of NERSA for the detailed calculations and methodology used; and

(e) publish details of the calculations and methodology used as soon as practicable thereafter.

15.11.2 Estimation of Data in the Event of Administered Settlement

(1) To the extent necessary, the MO may estimate any Settlement data in the event of Administered Settlement.

15.11.3 Administered Settlement in the Event of Market Software System Failure

(1) In the event of System Failure for a Trading Day, the MO will calculate an Administered Schedule for all Trading Periods for the Trading Day.

(2) An Administered Schedule comprises Administered Prices for each Trading Period and Administered Quantities for each Generator Unit for each Trading Period.

(3) In creating an Administered Schedule, the objective of the MO shall be to reproduce, to the greatest degree practicable, the results that would have been determined by the System Software.

(4) The price value for each Trading Period in the Trading Day will be set to equal the relevant Administered Price.

(5) The market schedules value for each Generator Unit for each Trading Period for the Trading Day will be set to equal the relevant Administered Quantity value.

(6) All Settlement calculations will be made using these values for Price and Administered Quantities.

(7) In the event of Administered Settlement resulting from System Failure, then once the System Failure is corrected, the MO shall procure that Settlement Reruns shall be undertaken as soon as reasonably possible in respect of the relevant

Trading Periods and that revised Settlement Statements, Invoices and Self Billing Invoices in respect of the relevant Billing Period or Periods shall be issued to Market Participants.

15.11.4 Administered Settlement in the event of Electrical System Collapse

(1) In the event of Electrical System Collapse, Administered Settlement will be implemented using the following rules:

(2) The following variables will be set to the metered quantity for the time of the Electrical System Collapse of any Trading Unit;

a) SG_{ij}

b) Capacity Qualifying_{Tu} for all reserve types;

c) IPi

(3) After this, the SADEW market algorithm shall run based on these data.

15.11.5 Management of Taxes and VAT

(1) The following paragraphs deal with the treatment of VAT for the purposes of the Market Code (if required).

(2) Notwithstanding the terms of the VAT Agreement all Market Participants shall indemnify and keep indemnified the MO, its officers, employees and agents against any liability which the Market Operator may incur as a result of the failure of any Market Participant to pay or account for any VAT due on any Invoice or Self Billing Invoice (or Debit Note where applicable).

(3) If any Market Participant shall fail properly to pay or account for any amount of VAT payable or receivable by it, that Market Participant shall indemnify and keep indemnified each non-defaulting Market Participant (on an after tax basis, but taking account of any tax relief available to the relevant Market Participant, as the case may be) against any liability which such non-defaulting Market Participant or Market Participants shall incur consequently.

16 DATA AND IT MANAGEMENT

(1) The detailed procedures relating to the systems and the communication of data transactions by each Party to the MO and by the MO to one or more Parties and the rules and principles for the publication by the MO of data and information relating to the trading arrangements in the SADEW will be maintained in a separate document published on the MO´s website.

(2) This document shall include inter alia:

a) Data communication channels, including the type(s) of channels, the requirements for both MO and Parties on maintaining these channel(s), the required IT security, support in testing and updating/upgrading these;

b) Data categories;

c) Daily procedures and timing;

d) The MO´s data storing of transactions;

e) Cyber security and data protection;

f) Procedures for managing failures;

g) How rounding is managed in the MO´s system; and

h) A generic provision of the specification of the algorithm.

(3) The MO is responsible for maintaining the required software and hardware up to date and delivering the required service to the Parties as set out in this Market Code.

(4) The IT infrastructure and software shall be subject to a bi-annually audit.

17 TRANSITION ARRANGEMENTS

(1) In the six months prior to the Commencement Date applications for Balance Responsible Parties and Market Participants may be processed by the Market Operator as per this Code with an allowance for the response for such accession applications increased to thirty business days;

(2) In the three months following the Commencement Date applications for Balance Responsible Parties and Market Participants shall be processed by the Market Operator with an allowance for the response for such accession applications increased to twenty business days;

17.1 Vesting Contracts for Eskom generators

(3) All Eskom generators shall conclude a Vesting Contract with the Central Purchasing Agency prior to the Commencement Date. These Vesting Contracts will be valid for the Transition Period. The Vesting Contracts shall be subject to NERSA approval and oversight and shall contain:

a) Availability payments to reflect the power station’s fixed costs, and shall be dependent on the declared and actual availability of the generating units at any time;

b) Energy hedge payments to reflect the power stations’ variable cost of generation and manage the price risk for the power stations during the transition; and

c) Ancillary service payments for additional services provided to the System Operator.

(4) The Eskom generators shall be obliged to be active Market Participants (and Balance Responsible Parties) as required in the Market Code, and subject to the payments associated with day-ahead, intra-day and balancing energy as well as

day-ahead reserves.

(5) The energy hedge payments for the Eskom generators in the Vesting Contracts shall be associated with fixed volumes for each calendar month of the Transition Period, with a difference payment equal to the fixed volume multiplied by the difference between the Vesting Contract energy price and the unweighted average of the day-ahead system marginal price for energy over the month.

$$EHDP_{gm} = EHV_{gm} * (CEP_{gm} – ASMP_{m})$$

where:

EHDP ⇒ Energy Hedge Difference Payment

m ⇒ month

g ⇒ Eskom generator

EHV ⇒ Energy Hedge Volume as per the vesting contract

CEP ⇒ Contract Energy Price as per the vesting contract

ASMP ⇒ Unweighted average of the System Marginal Price for each hour of the month

(6) The energy hedge volumes in the Vesting Contracts for the first year of the Transition Period shall be set equal to the expected energy production at each Eskom power station. The energy hedge volumes shall be reduced in each subsequent year by 20%, subject to NERSA adjustment based on a potential extension of the transition period.

17.2 Vesting Contracts for licensed distributors

(7) Eskom Distribution and any licensed distributor applying for market participation shall conclude a Vesting Contract with the Central Purchasing Agency prior to the Commencement Date. These Vesting Contracts will be valid for the Transition Period. The Vesting Contracts shall be subject to NERSA approval and oversight and shall contain:

a) Energy hedge payments to manage the price risk for the distributor during the transition; and

b) Elements of wholesale pricing as required by NERSA including, but not limited to, generation capacity charges, legacy charges and subsidy charges.

(8) Any licensed distributor that applies for market participation during the Transition Period shall conclude a Vesting Contract with the Central Purchasing Agency prior to market participation. The Vesting Contracts shall be valid for the remainder of the transition, be subject to NERSA approval and oversight, and contain similar elements to existing Vesting Contracts. Expected volumes associated with such a licensed Distributor shall be include in the Vesting Contract and an associated adjustment with the Eskom Distribution Vesting Contract volumes shall be affected.

(9) The energy hedge payments for the distributors in the Vesting Contracts shall be associated with fixed volumes for each time-of-use period in each calendar month of the Transition Period, with a difference payment equal to the fixed

volume multiplied by the difference between the Vesting Contract energy price and the unweighted average of the day-ahead system marginal price for energy over the time-of-use period for the month.

$$EHDP_{dtm} = EHV_{dtm} * (CEP_{tm} - ASMP_{tm})$$

where:

EHDP	$\Rightarrow$	Energy Hedge Difference Payment
m	$\Rightarrow$	month
d	$\Rightarrow$	distributor
t	$\Rightarrow$	time-of-use period (utilising the Eskom Megaflex time-of-use structure to determine the hours associated with each period)
EHV	$\Rightarrow$	Energy Hedge Volume as per the vesting contract
CEP	$\Rightarrow$	Contract Energy Price as per the vesting contract
ASMP	$\Rightarrow$	Unweighted average of the System Marginal Price for each hour of each time-of-use period of the month

(10) The energy hedge volumes in the Vesting Contracts for the first year of the transition period shall be set equal to the expected energy consumption by each distributor. The energy hedge volumes shall be reduced in each subsequent year by 20%, subject to NERSA adjustment based on a potential extension of the Transition Period. Where a distributor becomes a market participant after the Commencement Date the expected energy consumption shall be approved by NERSA and the applicable reduction based on the completed years from Commencement Date applied to determine the energy hedge volumes.

(11) The capacity rate applicable to the availability payment for each Eskom power station will decline in proportion to the reduction in the energy hedge volumes.

ANNEXURE I – MARKET CONDUCT RULES

(1) Market Participants must at all times act in accordance with these Market Conduct Rules when engaged in trading and related activities and shall seek to promote integrity and efficiency in the Market. Market Participants shall take due account to any relevant regulatory or legal obligations, any proper and relevant professional standards of conduct, and the need for the Markets to operate fairly and efficiently for all Market Participants.

(2) Each Market Participant shall ensure that any orders placed by it reflect a real purchase or sales interest, and that all transactions to which it is a party are genuine.

(3) A Market Participant may not in any way improperly influence the price or price structure in the Markets, or otherwise disturb other Market Participants' access to or participation in the market.

(4) Market Participants must not apply unreasonable business methods when carrying out trading and shall always seek to act in accordance with good business practice.

(5) Market manipulation is defined as:

entering into any transaction or issuing any order to trade in electricity market products which:

(A) gives, or is likely to give, false or misleading signals as to the supply of, demand for, or price of the wholesale electricity market products;

(B) secures or attempts to secure, by a person, or persons acting in collaboration, the price of one or several wholesale electricity market products at an artificial level, unless the person who entered into the transaction or issued the order to trade establishes that his reasons for doing so are legitimate and that that transaction or order to trade conforms to accepted market practices on the wholesale electricity market concerned; or

(C) employs or attempts to employ a fictitious rumour or any other form of deception or contrivance which gives, or is likely to give, false or misleading signals regarding the supply of, demand for, or price of wholesale electricity market products;

or

(D) disseminating information through the media, including the internet, or by any other means, which gives, or is likely to give, false or misleading signals as to the supply of, demand for, or price of wholesale electricity market products, including the dissemination of rumours and false or misleading news, where the disseminating person knew, or ought to have known, that the information was false or misleading.

(6) When information is disseminated for the purposes of journalism or artistic expression, such dissemination of information shall be assessed taking into account the rules governing the freedom of the press and freedom of expression in other media, unless:

(A) those persons derive, directly or indirectly, an advantage or profits from the dissemination of the information in question; or

(B) the disclosure or dissemination is made with the intention of misleading the market as to the supply of, demand for, or price of wholesale electricity market products;

(7) Attempt to manipulate the market is also considered an abuse and shall be considered a case for investigation and prosecution according to the sanction rights in section (19) of this article.

(8) Inside information means information of a precise nature which has not been made public, which relates, directly or indirectly, to one or more wholesale electricity products and which, if it were made public, would be likely to significantly affect the prices of those wholesale electricity products.

(9) Whether or not information can be regarded as inside information must be assessed on a case-by-case basis. Determining what is inside information is not straightforward, for instance identical information may or may not constitute inside information depending on the current market situation, because in a strained situation the information may be more likely to affect prices significantly.

(10) As a starting point, if a normal rational trader would assess that it would be possible to profit from trading on the information that is a good indication that the information could be considered as being significant, and therefore may constitute inside information.

(11) Insider information shall be published using the prescribed information service in the SAWEM.

(12) The prohibition of insider trading is set out as:

Persons who possess inside information in relation to a wholesale electricity market product shall be prohibited from:

(A) using that information by acquiring or disposing of, or by trying to acquire or dispose of, for their own account or for the account of a third party, either directly or indirectly, wholesale electricity products to which that information relates;

(B) disclosing that information to any other person unless such disclosure is made in the normal course of the exercise of their employment, profession or duties;

(C) recommending or inducing another person, on the basis of inside information, to acquire or dispose of wholesale electricity market products to which that information relates.

(13) Note: information regarding the market participant's own plans and strategies for trading should not be considered as inside information. Consequently, Market Participants do not have to publish information regarding marginal costs at power plants, water values etc.

(14) Disclosure of transparency information

(A) The information to be publicly disclosed shall be limited to information relevant to facilities for production, consumption or transmission of electricity regarding (a generation unit is defined as one generator and a production unit is defined as a unit holding several generation units):

(B) Any outage, limitation, expansion or dismantling of capacity in the transmission grid affecting cross zonal capacities by 50 MW or more, up to three (3) years forward, including updates of such information;

(C) Any outage, limitation, expansion or dismantling of capacity in the transmission grid affecting power feed-in and/or consumption by 50 MW or more, up to three (3) years forward, including updates of such information;

(D) Any outage, limitation, expansion or dismantling of capacity of 200 MW or more for one Generation Unit, or 20 MW or more for one Production Unit with an installed capacity of 200 MW or more, up to three (3) years forward, including updates of such information;

(E) Any erroneous or missing Orders in the Market of 200 MW or more;

(F) Any Inside Information not covered by sub-paragraph (i) to (iv) above.

(15) Where information is subject to public disclosure pursuant to this section, the public disclosure shall when relevant as a minimum include information on:

(A) The affected geographical area(s);

(B) The affected Trading Unit or Transmission Line;

(C) The time of decision or occurrence of the event;

(D) The installed capacity in MW;

(E) The available capacity to the market in MW during the event;

(F) The estimated start time of the event, and the corresponding stop time;

(G) The cause of the event;

(16) Each Market Participant shall publicly disclose any this information in an effective and timely manner through a publicly available system. These disclosure requirements do not apply to information regarding the Party's own plans and strategies for trading. Effective and timely manner shall be considered as to be within 1 hour unless the Market Participant can provide legitimate justification for the publication delay.

(17) The procedures applicable to the investigation by MSU of possible breaches and disciplinary actions of these Market Conduct Rules shall be as follows:

(A) If MSU suspects a breach of the Market Conduct Rules, it will initiate an investigation. Such investigations may be initiated in the sole discretion of MSU regardless of the knowledge of the Market Participant(s) involved.

(B) If the investigations of MSU support the suspicion of a breach of Applicable Law, MSU may in its sole discretion report to NERSA.

(C) If the investigations of MSU support the suspicion of a breach of these Market Conduct Rules, MSU may in its sole discretion recommend disciplinary actions (sanctions) against the Market Participant(s) involved, as further provided for below.

(D) MSU may issue a sanction based on the sanctions approved by NERSA on a case-by-case basis.

(18) Decision of MSU

(A) The MSU manager will in its full discretion decide if and what disciplinary actions that shall be applied against the Market Participant(s).

(B) The decision by the MSU manager shall be notified in writing to the relevant Market Participant(s). In the event of MSU publishing the decision, the relevant Market Participant(s) shall be notified in due time prior to such publication.

(C) MSU manager should formally report directly to Market Surveillance Panel on investigations and conclusions of an investigation.

(19) MSU may impose sanctions if the Market Participant does not comply with the Market Conduct Rules or other parts of these Market Rules. The MSU are authorized to impose sanctions of category A as listed in table 1. Sanctions of category B must be imposed by MSP.

(20) By signing these Market Rules each Market Participant accept charges imposed under this section as an enforceable basis for execution.

(21) MSP will be the body taking the decision of suspension a member due to misconduct in the SAPP.

(22) Appeal process to sanctions given by MSU:

(A) If the sanctions have been given by the MSU (category A), the affected member may appeal to the MSP.

(B) If the sanctions have been given by the MSP (category B), the affected member may appeal to NERSA.