SOUTHERN AFRICAN POWER POOL

OPERATING GUIDELINES

REVISION 1.0

MAY 2012

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HISTORY OF REVISION

Revision	***Status***	***Date***	***By***	***Remarks***
Version 1.0	Draft	31 May 2012	SAPP Operating Guidelines Revision Task Team	Major changes and complete revision
Original Version	Final	14 August 1996	SAPP	Adopted from North American Electric Reliability Council (NERC), Operating Guidelines of 27 February 1991.

PREAMBLE

The objective of this document is to ensure that all the Operating Members of the Southern African Power Pool (SAPP) operate the interconnected Southern African electric power network safely, efficiently, effectively and in an environmentally sustainable manner and that all Members participate equitably in the obligations and in the benefits resulting from the Pool. These guidelines will be amended by the Operating Sub-Committee, as need arises.

All interconnected utilities in SAPP must comply with the requirements of this document. It can also be used as a basis to prepare more detailed documents governing the operation of each individual network. It will enable all the Operating Members to monitor the operations of the Southern African Grid and to compare them against a benchmark.

This document supersedes the previous version dated 14 August 1996.

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ACKNOWLEDGEMENTS

The original version of the SAPP Operating Guidelines was based on the North American Electric Reliability Council (NERC), Operating Guidelines (27 February 1991).

The revised version (Version 1.0) also adopted some clauses from NERC Guidelines and Standards.

These guidelines and standards from the North American Electric Reliability Corporation's website are available at http://www.nerc.com/page.php?cid=2|20. This content may not be reproduced in whole or any part without the prior express written permission of the North American Electric Reliability Corporation.

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INTRODUCTION

The English language, both written and spoken, will be the medium of official communication between the Operating Members of the SAPP.

The Operating Guidelines are designed to ensure coordinated operation between interconnected systems and to achieve high levels of system reliability and control at the Points of Interconnection. The Guidelines specify how the basic operating policy of the SAPP shall be implemented and are based on established technical and operating experience accumulated over years. Input of System Controllers is vital to the establishment and maintenance of good operating policy.

In practice, certain Clauses are more important than others. Therefore, the Clauses are classified either as Operating Requirements or as Operating Recommendations.

An Operating Requirement is a statement that describes the obligations of a Control Area Operator or a System Operator or Electricity Supply Enterprise functioning as part of a Control Area. The Operating Requirement may also specify whether compliance to Guidelines must be monitored or not.

An Operating Recommendation is a statement describing good operating practice that should be followed by a Control Area Operator or by a System Operator or Electricity Supply Enterprise belonging to a Control Area. The degree of enforcement of an Operating Recommendation may vary from Control Area to Control Area and should take into account system conditions and characteristics.

Non-compliance to requirements is monitored in various ways and classified in various levels for applicable guidelines. Sanctions and penalties associated with various levels of non-compliance are stated in ***Appendix 1***.

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TERMS USED IN THE GUIDELINES

Adjacent System or Adjacent Control Area:

Any System or Control Area directly Interconnected with (so as to be significantly affected by the existence of) another System or Control Area.

Area Control Error (ACE):

The instantaneous difference between net actual and scheduled interchange, taking into account the effects of Frequency Bias including correction for meter error.

Automatic Generation Control (AGC):

Equipment that automatically adjusts a Control Area's generation from a central location to maintain its interchange schedule plus Frequency Bias.

Cold Reserve:

Cold Reserve is all generating capacity available for operation but not synchronized to the system; it is the Slow Reserve plus Quick Reserve.

Control Area:

Control Area shall mean 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 in the Control Area and the scheduled interchanges with other Control Areas.

Control Area Operator:

An Electricity Supply Enterprise or power utility which operates a Control Area.

Control performance:

The degree to which a Control Area succeeds in matching its generation to its demand plus scheduled power interchanges taking into account the effects of frequency bias, during normal system conditions and also during recovery from a system disturbance.

Credible Contingency:

Any likely contingency based on known equipment in service.

Deadband:

The allowable change in a parameter before a controller responds.

Demand:

The rate at which energy is being used by the customer, expressed in watts.

Disturbance:

Any perturbation to the electric system.

Dynamic Schedule:

A schedule that is continuously adjusted in real time to match an actual interchange. Commonly used for "scheduling" generation from another Control Area.

Electricity Supply Enterprise:

An entity which (i) operates a control centre around the clock; (ii) owns or controls through other means, the operation of several generating units and regularly operates such units to meet a portion or all of its load obligations; or (iii) owns a transmission system already interconnected internationally with neighbouring Electricity Supply Enterprise(s) or may be so interconnected some time in the future. An Electricity Supply Enterprise is either a Power Utility, Independent Power Producer, Independent Transmission Company and or a Service Provider.

Emergency Energy:

Emergency Energy shall mean energy supplied from other Operating Members to an Operating Member who experiences a loss of generating or transmission facilities as the result of an unscheduled outage (or outages) or any cause not reasonably foreseeable.

Emergency Situation:

An Emergency Situation shall mean a situation where a Member is faced with an unplanned loss of generation or transmission facilities or another situation beyond its control, which impairs or jeopardizes its ability to supply its System Demand, adjusted for imports and exports of Firm Power.

Force Majeure:

Force Majeure shall have the same meaning as in Clause 2.18 and Article 14 of the SAPP Agreement Between Operating Members.

Frequency Bias Setting:

A value, in MW/0.1 Hz, set into a Control Area's AGC Equipment to represent a Control Area's response to deviation from scheduled frequency.

Frequency Response or Frequency Response Characteristic (FRC):

The change in frequency that occurs for a change in load-resource balance in an Interconnection.

Governor:

A device in an electric power-generating unit that controls the active power output.

Hourly Value:

Data measured on a clock-hour basis. When related to energy or similar data, it is the integrated accumulation value during the sixty (60) minute interval ending at the hour which is specified.

Inadvertent Energy Flow:

Inadvertent Energy Flow shall mean the difference between the net scheduled energy delivered and the actual net energy delivered in any specific hour under normal conditions

Instantaneous Reserve:

Instantaneous Reserve is defined as generation capacity or contractual interruptible load that is available to respond fully within 10 seconds due to a sudden deviation in frequency outside the allowed deadband. This response must be sustained for at least 10 minutes.

Interconnection:

When starting with a capital letter, it shall mean high voltage transmission lines and substations making up the international backbone of the Southern Africa Grid. When not starting with a capital letter, it shall mean the facilities that connect two adjacent Systems or Control Areas.

Interruptible or Curtailable Load:

Interruptible or Curtailable Load shall mean a consumer load or a combination of consumer loads which can be contractually interrupted or reduced by remote control or on instruction from the utility when such contracts are in place and such instructions have been given from the Member's Control Centre.

Leap-Second:

A second of time added occasionally by the Bureau of Standards to correct for the offset between the clock-hour day and the solar day.

Load:

The amount of electric power delivered or required at any specified point on a system.

Metered Value:

A measured quantity that may be collected by telemetering, SCADA, or other means.

Mothballing:

Keeping a plant stored for longer than one (1) year; the plant is dry stored and may be partially dismantled and specifically protected.

Non-Spinning Reserve:

Shall have the same meaning as Cold Reserve.

Operating Reserve:

The un-used capacity above System Demand which is required to cater for regulation, short-term load forecasting errors, and unplanned outages. It consists of Spinning and Quick Reserve.

Planned Outage:

shall mean outage agreed and confirmed in writing between all relevant Control Centres with at least two weeks notice.

Point of interconnection:

The Point of interconnection between Operating Members shall be a location where their respective transmission facilities are physically connected.

Quick Reserve:

Quick Reserve is capacity readily available from non-spinning reserve which can be started and loaded within ten (10) minutes or load that can be interrupted within ten (10) minutes.

Reserve Storage:

Reserve Storage is plant that is stored for more than three (3) months in a wet or dry stored condition. Some auxiliary plant may be run periodically.

Regulating Margin:

The on-line capacity that can be increased or decreased to allow the system to respond to all reasonable demand changes.

SAPP :

Southern African Power Pool.

Service Schedules:

Service Schedules shall mean schedules governing various types of transactions that may be entered between Operating Members to reduce costs or improve reliability of supply.

Slow Reserve:

Slow Reserve is capacity available from Cold Reserve and considered to be ready for synchronization to the system within twenty-four (24) hours.

Special Protection System (SPS):

Shall mean a protection scheme designed to perform functions other than the isolation of electrical faults; it is also called “remedial action scheme”.

Spinning Reserve:

Spinning Reserve shall mean the unused capacity which is synchronized to the System and is readily available to assume load without manual intervention.

Station Service:

Shall mean electric supply to ancillary equipment used to operate a generating station or substation.

Station Service Generator:

Shall mean a generator used to supply electrical energy to station service equipment.

Supervisory Control and Data Acquisition (SCADA):

Shall mean a system of remote control and telemetry used to monitor and control the transmission system.

System:

A combination of generation, transmission, and other components making up the network of an electric utility, or group of utilities.

System Controller:

An authorized person employed by a System Operator and on duty to monitor and control its System.

System Operator:

An Electricity Supply Enterprise or power utility which has its electric power facilities connected to the SAPP interconnected system.

Time Error Monitor (Monitor):
An electricity supply enterprise or SAPP Coordination Centre designated by SAPP to monitor time error and coordinate time error correction.
Unplanned Outage:
This shall mean outages which are not scheduled with the advance notice of two weeks.
Wheeling:
Wheeling shall mean transmitting an amount of power through the System of an Operating Member who is neither the Seller nor the Buyer of this power.

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GUIDELINE 1 : SYSTEM CONTROL

1.A. GENERATION CONTROL

Background:

Accurate and adequate generator control helps reduce time error, frequency deviations, and Inadvertent Energy interchanges.

Each Control Area should respond to frequency deviations in accordance with the response characteristics of its own System. Most of this response will be reflected in the Control Area's net interchanges. By monitoring the interchange deviations from schedule, the frequency deviation from schedule, and by using the Control Area's frequency response characteristic, it is possible to determine through the AGCs, whether the imbalance between load and generation is internal or external to the Control Area. The AGC will adjust the generation to correct the imbalance. If external, no AGC action should occur. However, the frequency response to the interchange deviations through the governors should be allowed to continue until the external system with the generation surplus or deficiency corrects its imbalance and returns the frequency to schedule.

Until system response can be continuously measured, it must be estimated. This estimate is the tie-line frequency bias setting. The closer the tie-line frequency bias matches the actual system frequency response, the better AGC will be able to distinguish between internal and external imbalances and reduce the number of unnecessary control actions. Therefore, the basic requirement of tie-line frequency bias is that it matches the actual system response as closely as practicable.

Criteria:

Each Control Area Operator shall operate sufficient generating capacity under Automatic Generation Control (AGC):

(1) to continuously balance its generation and interchange schedules to its load,
(2) to provide its contribution to interconnection frequency regulation, as specified hereafter.

Requirements:

1. To determine the Control Area's Area Control Error (ACE) and respond by returning the ACE within specified limits prescribed by the relevant control performance standards, the Automatic Generation Control (AGC) shall continuously compare:

(i) total net actual interchange adjusted for actual frequency and;

(ii) total net scheduled interchange adjusted for scheduled frequency;

ACE shall be defined mathematically as:

$ACE= (NI_A-NI_S)-10\beta(F_A-F_S)-I_{ME}$

Where:

NI_A is the Actual Net interchange. It is the algebraic sum of tie line flows between the Control Area and the Interconnection.

NI_S is the Scheduled Net interchange. It is the net of all scheduled transactions with other Control Areas.

β is the Control Area Frequency Bias

F_A is the Actual Frequency

F_S is the Scheduled Frequency

I_{ME} is Interchange (tie line) Metering Error

The general convention is where the flow into a Control Area is negative and flow out of a Control Area is positive. The combination NI_A - NI_S represents the ACE associated with meeting schedules and is referred to as "flat tie line" control. The mathematical term $10\beta(F_A-F_S)$ is the Control Area's obligation to support frequency. ß is the Control Area's frequency Bias stated in MW/0.1Hz. If the $10\beta(F_A-F_S)$ is used by itself for control, it is called "flat frequency" control.

2. Each Control Area shall provide an amount of Spinning Reserve responsive to AGC to ensure adequate system regulation and satisfy Control Performance Standards.

3. AGC shall be in service all the time and when not possible, arrangements must be made to include the System in an established Control Area or to switch over to temporary manual control.

4. Each Control Area Operator shall operate its AGC on tie-line bias mode, unless such operation is adverse to System or Interconnection reliability in which case the AGC mode can be changed. Events for changing mode of operation shall be recorded and reported to all Control Area Operators and the Coordination Centre as soon as possible. The requirements for tie-line bias control are as follows:

4.1 The Control Area Operator shall set its frequency bias (expressed in MW/0.1 Hz) as close as practical to the Control Area's frequency response characteristic. Frequency bias may be calculated in different ways:

4.1.1 A fixed frequency bias value may be used which is based on a fixed, straight-line function of tie-line deviation versus frequency deviation. The fixed value shall be determined by recording and averaging the frequency response characteristic after several disturbances during peak hours during a rolling twelve (12) month period.

4.1.2 A variable (linear or non-linear) frequency bias value may be used which is based on a variable function of tie-line deviation versus frequency deviation. The variable frequency bias value shall be determined by analyzing frequency response during a rolling twelve (12) month period as it varies with parameters such as load, generation, governor characteristics and frequency.

4.2 The Operating Sub-Committee shall approve the methodology of calculating the frequency bias.

4.2.1 At any given time only one methodology of calculating frequency bias shall be applicable to all Control Areas.

4.3 Each Control Area Operator shall recalculate its frequency bias to reflect any change in response characteristics and report to the Coordination Centre by 1 December of each year and as when significant system configuration changes take place. The Coordination Centre shall coordinate implementation of the new settings by 1 January of each year.

4.3.1 The bias setting or the method used to determine the setting may be changed whenever any of the parameters listed in Clause 3.1.2 above changes.

4.4 Each Control Area Operator must be able to prove to the Operating Sub-Committee that its frequency bias settings closely match its frequency response characteristic. The Coordination Centre shall make random survey using the standard frequency response characteristic survey form (FRC1) to confirm the bias settings. Refer to ***Appendix 1.A*** for the form.

5. Generating units with nameplate ratings of 5 MVA or greater should be equipped with governors operational with a droop between 2% and 10% with an initial setting of 4% for Frequency Response to ensure that the Control Area continuously adjusts its generation to its load plus its net scheduled interchange unless restricted by regulatory mandates. Any change from the initial 4% setting shall be approved by the Operating Sub-Committee.

6. The maximum ACE dead band setting in the AGC shall be a MW value equivalent to frequency deviation of ±0.05Hz considering the frequency bias i.e. ±0.05Hz multiplied

by 10β.

7. Frequency deadband for the governors on generators shall be set to less than ±0.15 Hz.

8. Control Area Operators with a high voltage direct current (HVDC) link to another Control Area connected asynchronously to their Interconnection shall have special protection scheme in service to ensure that any fault on the link does not negatively impact the interconnection, in which case interchange schedule on that link may not be disclosed to other members.

Recommendations:

1. Turbine governors and other control systems, including AGC and HVDC control systems, should be tested periodically to verify their correct operation.

2. Turbine governors, where applicable, should respond to system frequency deviation, unless there is a temporary operating problem.

3. Each Member should establish normal and emergency ramp rates for each generator and each HVDC terminal.

4. Load –limiting devices should be applied only when the rate of load change has an adverse effect on the generators or when it can jeopardize transmission security.

5. The regulating margin should be distributed among sufficient generating units to meet the required control performance standards.

6. Each Control Area Operator should schedule its generation so as to comply with the Control Performance Criteria for any expected change in load characteristics and daily load patterns.

7. All turbine governors should, as a minimum, be fully responsive to frequency deviations exceeding ± 0.15 Hz.

8. Control Area Operators with a high voltage direct current (HVDC) link to another Control Area connected asynchronously to their Interconnection shall have a special protection scheme in service to ensure that any fault on the link does not negatively impact the interconnection, in which case interchange schedule on that link need not be disclosed to other members or interchange schedule related to the HVDC link can be omitted from the ACE equation if it is modeled as internal generation or load.

Compliance:

1. Compliance monitoring process:

Percentages of the time in which the AGC is in service shall be calculated.

2. Levels of Non-Compliance:

2.1. Level 1: There shall be a Level 1 non-compliance if any of the following conditions exist:

2.1.1. AGC is in service less than 98% but at least 96% or more of all hours during which the synchronous generating unit is on line for each calendar quarter, or

2.1.2. AGC is out of service more than 7 calendar days but not more than 14 calendar days due to maintenance or testing, or

2.1.3. AGC is out of service for more than 60 calendar days but not more than 90 calendar days due to failed component, or

2.1.4. Following the granting of an extension for repairs, the AGC was returned to service greater than zero days but less than or equal to 30 days beyond the specified extension repair completion date.

2.2. Level 2: There shall be a Level 2 non-compliance if any of the following conditions exist:

2.2.1. AGC is in service less than 96% but at least 94% or more of all hours during which the synchronous generating unit is on line for each calendar quarter, or

2.2.2. AGC is out of service for more than 90 calendar days but not more than 120 calendar days due to failed component, or

2.2.3. Following the granting of an extension for repairs, the AGC or PSS was returned to service greater than 30 days but less than or equal to 60 days beyond the specified extension repair completion date.

2.3. Level 3: There shall be a Level 3 non-compliance if any of the following conditions exist:

2.3.1. AGC is in service less than 94% but at least 92% or more of all hours during which the synchronous generating unit is on line for each calendar quarter, or

2.3.2. AGC is out of service for more than 120 calendar days but not more than 150 calendar days due to failed component.

2.3.3. Following the granting of an extension for repairs, the AGC was returned to service greater than 60 days but less than or equal to 90 days beyond the specified extension repair completion date.

2.4. Level 4: There shall be a Level 4 non-compliance if any of the following conditions exist:

2.4.1. AGC is in service less than 92% f all hours during which the synchronous generating unit is on line for each calendar quarter, or

2.4.2. AGC is out of service more than 14 calendar days due to maintenance or testing, or

2.4.3. AGC is out of service for more than 150 calendar days due to failed component, or

2.4.4. Following the granting of an extension for repairs the AGC was not returned to service or was returned to service greater than 90 days beyond the specified extension repair completion date, or

2.4.5. Following the granting of an extension for replacement of the excitation system, the AGC is not in service after the specified extension replacement completion date.

3. Sanctions or Penalties:

Refer to ***Appendix 1*** for the table of sanctions or penalties.

1.B. VOLTAGE CONTROL

Background:

Each System Operator shall be operated with adequate capacitive and inductive reactive resources so as to maintain within specified limits, the voltage levels inside the Systems and at the Points of interconnection.

Criteria:

Each System Operator shall maintain system and Interconnection voltages within agreed upon upper and lower limits by operating suitable capacitive and reactive resources. Reactive generation scheduling, transmission equipment switching and load shedding if necessary, shall be implemented to maintain voltage levels under credible contingency conditions.

Requirements:

1. Devices used to regulate transmission system voltages and reactive flows should be under the control of a Control Centre.

2. Control Centres shall monitor transmission system voltages to immediately identify any deviation from prearranged voltage levels and take corrective action. (Refer to ***Appendix 1.B*** "Transfer Capability").

2.1 Pre-arranged voltage levels, reactive control equipment settings and changes in transmission configuration shall be co-ordinated with adjacent Systems.

2.2 Transfer limits shall take into account voltage or reactive power restrictions. These restrictions should be clearly displayed in each Control Centre.

2.3 Control Centres shall monitor and keep reactive power flows within agreed upon limits on the interconnectors between Adjacent Systems.

3. Each System Operator shall keep power system stabilizers in service and tuned to adequately contribute to system stability. Every generator of power rating of 10MW and above shall be equipped with power system stabilizers. In the event of change of status of the power system stabilizers, the System operator shall inform all System Operators.

Recommendations:

1. Important transmission lines should remain in service during light-load periods whenever possible. They should be removed from service for voltage control only after all reactive power sources have been utilised and only if studies indicate that system reliability will not be degraded below acceptable levels. Whenever possible, switching lines out for voltage control, shall be restricted to lines other than the interconnections between adjacent systems.

2. Automatic voltage regulators on generators, synchronous condensers and Static Var Compensators (SVC's) shall be kept in service whenever possible. The status of these should be communicated to adjacent Control Centres whenever any change occurs.

3. Devices used to regulate transmission system voltage and reactive power flows maybe switchable without having to de-energise other equipment facilities.

4. When a generator's automatic voltage regulator is out of service, field excitation shall be maintained at a level adequate for stable operation.

5. Systems with HVDC transmission facilities shall utilize the power resources associated with the DC converters.

Compliance:

1. Compliance monitoring process:

Duration of time when voltages are outside agreed limits at Interconnector bus bars shall be calculated and expressed in percentages per month for each interconnector.

2. Levels of Non-Compliance:

2.1. Level 1: Ten percent of the total monthly time duration outside the limits.

2.2. Level 2: More than ten percent and up to fifteen percent of the total monthly time duration outside the limits.

2.3. Level 3: More than fifteen percent and up to twenty percent of the total monthly time duration outside the limits.

2.4. Level 4: More than twenty percent of the total monthly time duration outside the limits.

3. Sanctions or Penalties:

Refer to ***Appendix 1*** for the table of sanctions or penalties.

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1.C. TIME AND FREQUENCY CONTROL

Background:

The difference between load and generation results in frequency deviations from 50 Hz, and the integrated deviation appears as a departure from standard time.

The satisfactory operation of the Interconnected systems is dependent, in part, upon accurate frequency transducers and recorders and time error devices associated with AGC equipment.

Criteria:

Interconnection frequency shall be scheduled at 50.00 Hz and controlled to that value except for those periods in which frequency deviations are scheduled to correct time error. Operating limits for frequency deviation and time error shall be established with Interconnection reliability as first priority. Each Control Area shall participate in all time error corrections. Time error shall be monitored and corrected.

Requirements:

1. The frequency of the Interconnection shall be maintained between 49.85Hz and 50.15Hz for at least ninety-five percent (95%) of the time.

2. All Control Area Operators shall keep system time error within ±30 seconds under normal conditions.

3. One System Operator or the Coordination Centre shall be selected every year to monitor time error of the Interconnection.

4. One Control Area Operator shall be nominated as a Time Error Coordinator to issue time error correction orders; and time synchronization orders after Systems split.

5. Time error corrections shall start and end on the hour, a notice shall be given at least thirty (30) minutes before the time error correction is to start or stop.

6. Each order of time error correction or time synchronization shall be identified by a number.

7. The time error correction offset shall be implemented as follows:

7.1 The frequency schedule may be offset by 0.02 Hz, leaving the frequency bias unchanged , or

7.2 If the normal frequency (50 Hz) cannot be offset, then the net interchange schedule (MW) may be offset by an amount corresponding to a 0.02 Hz frequency deviation (i.e 20 % of the frequency bias setting).

7.3 Inadvertent interchange accumulations may be paid back unilaterally by offsetting a tie-line schedule when such action will contribute to the correction of a time error.

7.3.1 If time is slow and there is a negative accumulation (under-generation), the AGC may be offset to over-generate and pay –back inadvertent interchange accumulation and at the same time reduce time error.

7.3.2 If time is fast and there is a positive accumulation (over-generation), the AGC may be offset to under-generate and pay-back inadvertent interchange accumulation and reduce time error.

7.3.3 AGC offset may be made by either offsetting the frequency schedule up to 0.02 Hz, leaving the bias setting normal or offsetting the net tie-line schedule by up to 20 % of the Control Area's bias or 5 MW, whichever is greater.

7.3.4 Inadvertent pay-back shall end when either the time error is zero or has changed signs, the accumulation of inadvertent interchanges has been corrected to zero, or a scheduled time error correction begins, which takes precedence over offsetting frequency schedule to pay-back inadvertent.

8. Time error correction or time synchronization notifications will be broadcast by the Time Error Coordinator to the Operating Members.

9. The Monitor shall periodically issue a notification of time error, accurate to within 0.1 second, to Members to ensure uniform calibration of time standards.

10. Each System Operator shall, at least annually, check and calibrate its time error and frequency devices against a common reference approved by the Operating Sub-Committee. Such activity shall be reported to the Co-ordination Centre for information.

11. When one or more systems have been separated from the interconnection, upon reconnection, they shall adjust their time error devices to coincide with the Interconnection by one of the following methods:

11.1 Before connection, the operator of the separated system may institute a time error correction procedure to correct accumulated time error to coincide with the time error notified by the Monitor, or

11.2 After interconnection, the time error devices of the previously separated area may be corrected to coincide with the time error notified by the Monitor. A notification of adjustment time error shall be passed through the Monitor as soon as possible after interconnection.

12. The Control Area Operators shall implement automatic time error control as part of their AGC scheme if agreed by the Operating Sub-Committee.

12.1 If automatic time error correction is used, all Control Area Operators shall participate.

12.2 Automatic time error control in progress shall be suspended whenever an announced time correction is to start.

13. For a credible single contingency, such as a trip of a largest generating unit, or instant loss of load equal to the largest generating unit on the interconnected system, the system frequency shall not deviate to outside 49.50Hz and 50.50Hz.

14. For credible multiple contingencies, such as multiple trips of generating units, or instant loss of load equal to the contingencies on the interconnected system, the system frequency shall not deviate to outside 49.00Hz and 51.00Hz.

15. Control Area Operator(s), System Operator(s) shall start mandatory first level of automatic underfrequency load-shedding no lower than 48.75Hz.

16. On monthly basis the Monitor shall issue reports to the Co-ordination Centre on time error correction and synchronization events.
(Refer to ***Appendix 1.C*** "Time error correction procedures".

Recommendations:

1. Systems using time error devices that are not capable of automatically adjusting for leap-seconds should arrange to receive advance notice of the leap-second and make the necessary manual adjustment in a manner that will not introduce a disturbance into their control system.

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1.D. INTERCHANGE SCHEDULING BETWEEN CONTROL AREAS

Background:

Scheduled interchanges must be coordinated between Control Areas to prevent frequency deviations, accumulation of inadvertent interchanges and violations of mutually agreed transfer limits.

Criteria:

Power transfers between Control Areas shall be scheduled through transmission paths either belonging to those Control Areas or pre-arranged via wheeling contract(s) when other Control Areas are involved.

The net amount of interchange scheduled between Control Areas shall not exceed established transfer limits of the common interconnections and alternate paths which have been arranged for between the parties.

Schedule changes shall be made at a time and rate agreeable to both the supplier and receiver and within the capacity of each Party to control the change.

Requirements:

1. Interchanges shall be scheduled only between Control Area Operators directly interconnected unless there is a wheeling contract or mutual agreement with another Control Area Operator(s) to provide wheeling services.

2. Interchange schedules or schedule changes shall not violate established reliability criteria in another system.

2.1 When Control Areas are interconnected in such a way that parallel flows present reliability problems, the affected Control Area Operators shall develop multi-Control Area interchange monitoring techniques and pre-determined corrective actions to mitigate or alleviate potential or actual transmission system overloads.

2.2 Transfer limits shall be re-evaluated and interchange schedules adjusted as soon as practicable if transmission facilities become overloaded or are taken out of service, or when changes are made to the bulk system which can affect transfer limits. These should be determined both in terms of transient stability and thermal rating and should be provided to the Control Centres on an on-going basis.

3.The maximum net scheduled interchange between two Control Areas shall not exceed the lesser of the following two values:

3.1 The total capacity of the transmission facilities in service between the two Control Areas owned by them or available to them under wheeling arrangements, contracts, or mutual agreements, or

3.2 The SAPP established transfer capacity between two Control Areas considering other transmission facilities available to them under wheeling arrangements. (Transfer Capacity is defined in ***Appendix I.B*** “Transfer Capacity”).

4.The sending, wheeling and receiving Control Area Operators that are parties to an interchange transaction shall agree on schedule’s magnitude, starting and ending times.

5. A change of schedule must be effected five (5) minutes before the hour and must reach the full magnitude five (5) minutes after the hour.

6. The scheduled generation in one Control Area that is to be delivered to another Control Area must also be scheduled with all wheeling Control Area Operators unless there is a contract or mutual agreement among the sending, wheeling and receiving Control Area Operators to do otherwise.

7. Upon purchasing energy or agreeing on energy interchange, it is the obligation of the purchaser to also secure and arrange the wheeling path with affected Control Area Operator(s), System Operator(s), or Electricity Supply Enterprise(s).

8. When there is an event on the Interconnected system that necessitates any change of agreed interchange schedules (e.g. loss of generation or loss of transmission), it is the obligation of the affected System Operator(s) or Electricity Supply Enterprise(s) to notify all affected Control Area Operator(s) or System Operator(s) or Electricity Supply Enterprise(s) promptly so that they can make necessary decisions about the affected interchange transactions e.g. load shedding or purchasing energy from other suppliers.

9. Where there is limited transmission capacity, transactions shall be prioritized according to criteria stated in ***Appendix 1.D.***
10. Schedules shall not be adjusted after-the-fact due to commercial considerations or adjustments during the billing procedure, unless one Control Area Operator used an incorrect schedule.

Recommendations:

1. Stipulations on reservation or allocation of capacities in the bilateral contract(s)

between/amongst developers of transmission paths in question shall take precedence to the priorities recommended here-in.

Compliance:

1. Compliance monitoring process:

Interchange scheduling shall be monitored by the SAPP Coordination Centre monthly.

2. Levels of Non-Compliance:

2.1. Level 1: One instance of violating the requirements of interchange scheduling.

2.2. Level 2: Two instances of violating the requirements of interchange scheduling.

2.3. Level 3: Three instances of violating the requirements of interchange scheduling.

2.4. Level 4: Four or more instances of violating the requirements of interchange scheduling.

3. Sanctions or Penalties:

Refer to ***Appendix 1*** for the table of sanctions or penalties.

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1.E. CONTROL PERFORMANCE STANDARD

Background:

Control performance is the degree to which a Control Area Operator succeeds in matching its generation to its demand plus scheduled power interchanges taking into account the effects of frequency bias. The Control Performance Standard (CPS) and Disturbance Control Standard (DCS) establish minimum standards for control performance and provide a means for measuring the relative control performance of each Control Area. While these standards define the minimum acceptable performance, each Control Area Operator shall meet and strive to exceed these standards.

Criteria:

The Control Performance Standard (CPS) and Disturbance Control Standard (DCS) define a standard of minimum control performance. Each Control Area Operator is to have the best operation above this minimum that can be achieved within the bounds of reasonable economic and physical limitations.

Requirements:

1. **Continuous Monitoring.** Each Control Area Operator shall monitor its control performance on a continuous basis against two Standards: CPS1 and CPS2.

   1.1 **Control Performance Standard (CPS1)**. Over a year, the average of the clock-minute averages of a control area's ACE divided by -10β (β is control area frequency bias) times the corresponding clock-minute averages of Interconnection's frequency error shall be less than a specific limit. This limit, ϵ, is a constant derived from a targeted frequency bound reviewed and set as necessary by the SAPP Operating Subcommittee.

   1.2 **Control Performance Standard (CPS2).** The average ACE for each of the six ten-minute periods during the hour (i.e., for the ten-minute periods ending at 10, 20, 30, 40, 50, and 60 minutes past the hour) must be within specific limits, referred to as L_{10}. See the "Performance Standard Training Document," ***Appendix 1.E.*** Section B.1.1.2 for the methods for calculating L_{10}
2. **Disturbances**

   2.1 **Disturbance conditions:** In addition to CPS1 and CPS2, the Disturbance Control Standard shall be used by each control area to monitor control performance during recovery from disturbance conditions (see the "Performance Standard Training Document," ***Appendix 1.E.*** Section B.2).

   2.2 **Disturbance Control Standard (DCS).** The ACE must return either to zero or to its pre-disturbance level within fifteen (15) minutes following the start of the disturbance.

3. **ACE values:** The ACE used to determine compliance to the Control Performance Standards shall reflect its actual value, and exclude short excursions due to transient telemetering problems or other influences such as control algorithm action.

4. **Performance Standard (CPS) Compliance.** Each CONTROL AREA shall achieve CPS1 compliance of 100% and achieve CPS2 compliance of 90% (see the "Performance Standard Training Document," ***Appendix 1.E.*** Section C).

5. **Disturbance Control Standard (DCS) Compliance.** Each CONTROL AREA shall meet the Disturbance Control Standard (DCS) 100% of the time for reportable disturbances (see the "Performance Standard Training Document," ***Appendix 1.E.*** Section C).

6. Failure to adhere to the control performance standards and disturbance control standard shall attract penalties.

7. System Controllers should monitor and control CPS1, CPS2 and DCS in real time.

Recommendations:

Compliance:

1. Compliance monitoring process:

1.1. Monthly compliance monitoring process shall be the responsibility of SAPP Coordination Centre.

2. Levels of Non-Compliance - CPS1:

2.1. Level 1: The Control Area's value of CPS1 is less than 100% but greater than or equal to 95%.

2.2. Level 2: The Control Area's value of CPS1 is less than 95% but greater than or equal to 90%.

2.3. Level 3: The Control Area's value of CPS1 is less than 90% but greater than or equal to 85%.

2.4. Level 4: The Control Area's value of CPS1 is less than 85%.

3. Levels of Non-Compliance – CPS2

3.1. Level 1: The Control Area's value of CPS2 is less than 90% but greater than or equal to 85%.

3.2. Level 2: The Control Area's value of CPS2 is less than 85% but greater than or equal to 80%.

3.3. Level 3: The Control Area's value of CPS2 is less than 80% but greater than or equal to 75%.

3.4. Level 4: The Control Area's value of CPS2 is less than 75%.

4. Levels of Non-Compliance – DCS

4.1. Level 1: Value of the average percent recovery for the quarter is less than 100% but greater than or equal to 95%.

4.2. Level 2: Value of the average percent recovery for the quarter is less than 95% but greater than or equal to 90%.

4.3. Level 3: Value of average percent recovery for the quarter is less than 90% but greater than or equal to 85%.

4.4. Level 4: Value of average percent recovery for the quarter is less than 85%.

5. Sanctions or Penalties:

Refer to ***Appendix 1*** for the table of sanctions or penalties.

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1.F. INADVERTENT ENERGY MANAGEMENT

Background:

Under normal operating conditions there will be unintentional flow of energy between Control Areas due to instrument and control errors, improper control settings, poor generator response time, fluctuations in demand, etc. The Inadvertent Energy needs to be monitored and managed properly.

Criteria:

Each Control Area Operator shall, through daily schedule verification and the use of reliable metering equipment, accurately account for Inadvertent Energy interchanges. Recognising generation and load patterns, each Control Area Operator shall do its best to minimise inadvertent interchange accumulation. Each Control Area Operator shall reduce accumulated Inadvertent Energy.

An energy meter, with readings provided hourly to the relevant Control Centres shall measure the power transfers at each Point of Interconnection between two Control Areas.

Accumulation of Inadvertent Energy:

Inadvertent Energy is defined to be the difference between the net scheduled energy on the tie-lines in a Control Area and net actual energy delivered on the tie-lines in that Control Area, i.e.:

$IE = NI_A - NI_S$

Where

IE is the Inadvertent Energy in MWh
NI_A is the Actual Net Interchange in MWh
NI_S is the Scheduled Net Interchange in MWh

Requirements:

1. Inadvertent Energy interchange shall be calculated and recorded hourly and may be accumulated as a credit or debit to a Control Area Operator (see ***Appendix 1F***).

2. Inadvertent energy arising from all interchanges between Control Areas shall be

included in the Inadvertent Energy interchange account.

3. Inadvertent Energy accumulations shall be paid back by any one or both of the following methods:

3.1 Method 1- Inadvertent Energy accumulations may be paid back by scheduling interchange with another Control Area.

3.2 Method 2- Inadvertent Energy interchange accumulation may be paid back unilaterally by offsetting tie-line schedules when such action will contribute to the correction of the existing time error according to the following procedure:

3.2.1 If time is slow and there is a negative accumulation (under generation), the AGC may be offset to over-generate and pay-back inadvertent interchange accumulation and reduce time error.

3.2.2 If time is fast and there is a positive accumulation (over-generation), the AGC may be offset to under-generate and pay-back inadvertent interchange accumulation and reduce time error.

3.2.3 AGC offset may be made either offsetting the frequency schedule by up to 0,02 Hz, leaving the bias setting normal or offsetting the net tie-line schedule by up to 20% of the Control Area's bias or 5 MW, whichever is greater.

3.2.4 Inadvertent pay-back shall end when the time error becomes zero or has changed signs, the accumulation of inadvertent interchange has been corrected to zero, or a scheduled time error correction begins, because this action takes precedence over offsetting frequency schedule to pay-back inadvertent.

3.2.5 Control Areas using automatic time error control techniques shall not use Method 2 to reduce their accumulations of inadvertent. Method 1 is the only acceptable way for these Control Areas to reduce their accumulations of inadvertent.

4. Inadvertent Energy interchange accumulated shall be paid back during the same time-of-use and same season-of-use in which it was accrued, e.g. peak, standard and/or off-peak; unless otherwise agreed by the affected Control Areas.

5. Each Control Area Operator shall submit a monthly summary of inadvertent Energy interchange as detailed in ***Appendix I.F*** "Inadvertent Interchange Energy Accounting Practices".

5.1 Inadvertent Energy summaries shall include at least the previous accumulation, net accumulation for the month, and final net accumulation, for all time-of-use periods.

5.2 Each Control Area Operator shall submit its monthly report to the Co-ordination Centre.

5.3 The Coordination Centre shall distribute a monthly report to all Control Area Operators and Operating Sub-Committee.

Recommendations:

Inadvertent Energy may be paid back financially when agreed by affected Control Area Operators.

Compliance:

1. Compliance monitoring process:

1.1 Each Control Area shall submit a monthly summary of Inadvertent Interchange. These summaries shall not include any after-the-fact changes that were not agreed to by the affected Control Areas and the SAPP Coordination Centre.

1.2. Inadvertent Interchange summaries shall include at least the previous accumulation, net accumulation for the month, and final net accumulation, for each time-of-use classification periods.

1.3. Each Control Area shall submit its monthly summary report to the SAPP Coordination centre by the 5th calendar day of the following month.

1.4. Each Control Area shall perform an Area Interchange Error (AIE) Survey as requested by the Operating Sub-Committee to determine the Control Area's Interchange error(s) due to equipment failures or improper scheduling operations, or improper AGC performance.

1.5. The SAPP Coordination Centre shall prepare a monthly Inadvertent Interchange summary to monitor the Control Areas' monthly Inadvertent Interchange and all-time accumulated Inadvertent Interchange.

2. Levels of Non-Compliance:

A Control Area that neither submits monthly summaries and a report to the SAPP Coordination Centre, nor supplies a reason for not submitting the required data, by the 20th calendar day of the following month shall be considered non-compliant.

Level 1: Not submitting the required data, by the 5th calendar day of the following month shall be considered non-compliant.

Level 2: Accumulation of more than 1000MWh of inadvertent energy in a month.

Level 3: Accumulation of more than 2000MWh of inadvertent energy in a month.

Level 4: Not paying back inadvertent energy as agreed by affected parties.

3. Sanctions or Penalties:

Refer to ***Appendix 1*** for the table of sanctions or penalties.

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1.G. CONTROL SURVEYS

Background:

The Co-ordination Centre shall conduct control performance surveys bi-annually or whenever required. The surveys need to be carried out in order to monitor and correct control performance deficiencies in the Control Areas.

Criteria:

The surveys shall serve the purpose of identifying control equipment malfunctions, telemetering errors, improper frequency bias settings, scheduling errors, insufficient generation under automatic generation control, general control performance deficiencies, or other factors contributing to control performance deficiencies.

Requirements:

1. The following surveys, as described in the Control Performance Criteria Training Document, shall be conducted by Control Areas when called for by the Co-ordination Centre:

1.1 An Area Control Error survey to determine the Control Areas' interchange error(s) due to equipment failures, improper scheduling operations, or improper AGC performance.

1.2 An Area Frequency Response Characteristics survey to determine the Control Areas' response to changes in system frequency.

1.3 A Control Performance survey to monitor the Control Area's control performance during normal conditions and during disturbances.

2. The check-list stated in Appendix 1.G shall be used for the surveys.

3. Failure to comply with requirements shall attract penalties in accordance with ***Appendix 1*** and the applicable levels of non-compliance.

Recommendations:

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1.H. CONTROL EQUIPMENT REQUIREMENTS

Background:

All Control Area interconnections shall be equipped to telemeter MW power flows at the Points of Interconnection to both area Control Centres simultaneously. The telemetering shall be from agreed-upon terminals ultilising common metering equipment.

Criteria:

The control equipment of each Control Area shall be designed and operated to enable the Control Area Operator to continuously meet its System and Interconnection control obligations and measure its performance. The control equipment shall be designed and operated in accordance with accepted industry norms.

The Control Centre displays and consoles shall present a clear and understandable picture of Control Area parameters. This shall include the necessary information from the Control Area itself as well as all the necessary information from other Control Areas.

Requirements:

1. Each Control Area Operator shall perform control error checks at the end of every hour using tie-line MWh meters to determine the accuracy of its control equipment.

2. The Control Centre shall adjust control settings to compensate for equipment error until repairs can be made.

3. All tie-line flows between Control Areas shall be included in each Control Area's ACE calculation.

4. Control Centres shall be provided with a recording of those variables necessary to monitor control performance, generation response, and after-the-fact analysis of area performance. As a minimum, Area Control Error (ACE), system frequency, and net actual tie-line interchanges shall be continuously recorded.

5. Adequate and reliable back-up power supplies shall be provided and periodically tested at the Control Centres and other critical locations to ensure continuous operation

of AGC and vital data recording equipment during the loss of normal power supply.

6. All tie-line MW and MWh/hr measurements shall be telemetered to both Control Centres and shall originate from a common, agreed upon terminal using common primary metering equipment.

Recommendations:

1. Any change of status of the Control Equipment should be communicated to all System Operators.
2. Refer to ***Appendix 1.G*** for a check-list for survey of status of control equipment.

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1.I. CONTROL AREA ESTABLISHMENT

Background:

For a System Operator or Electricity Supply Enterprise to be a Control Area Operator, it shall have borders defined by points of Interconnection, equipped with metering and telemetry facilities. It shall have control facilities capable of maintaining continuous balance between the generation under its control and the consumption of electricity in its control and the scheduled interchanges with other Control Areas. It shall contribute to frequency regulation of the entire interconnection. It shall also be capable of meeting the minimum Control Area Performance Standards.

Criteria:

Any Operating Member in the SAPP is eligible to establish a Control Area provided it meets the requirements stipulated in this guideline.

Requirements:

The following are the requirements for a member to establish itself as a Control Area:

1. It shall have a Control Centre operated twenty-four hours a day, complete with data and voice recording facilities, power system parameter monitoring facilities.

2. It shall run own Automatic Generation Control (AGC), determine its own frequency bias, have adequate generation capacity under AGC, monitor and control its Area Control Error continuously, and meet minimum Control Area performance standards stipulated in these Guidelines (quote).

3. It shall have reliable telemetering facilities to measure and receive power and energy signals from all points of interconnection.

4. It shall have reliable and secure telecommunications facilities for intra- and inter-Control Area communications, dedicated voice and data telecommunication channels to adjacent Control Areas, and twenty-four hour daily service for telecommunications and Control equipment.

5. It shall have back-up Control Centre facility running in parallel at a separate geographic location.

Procedure: The following procedure shall apply to members intending to establish a Control Area.

1. The Member shall give a notice to its host Control Area Operator (where applicable), the Co-ordination Centre and the Operating Sub-Committee about the intention to establish a Control Area.

2. The Member shall apply to the SAPP Executive Committee through the Co-ordination Centre and Management Committee.

3. The Executive Committee shall request the Management Committee to carry out a readiness assessment of the applicant prior to approval.

4. Where an application is declined, the reason for such a decision must be recorded. The SAPP Coordination Centre shall communicate to the applicant the outcome of the decisions including any conditions and reasons. Such outcomes must be communicated within a period of twenty-one working days following a meeting of the SAPP Executive Committee.

Recommendations:

1. There shall be no direct appeal to SAPP but applicants would be allowed to resubmit their applications.

2. Applicants should use the standard application form. Refer to ***Appendix 1.I*** for the form.

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1.J. POWER WHEELING

Background:

In an interconnected system a scheduled amount of power is often transmitted over specified time periods through the system of an Operating Member who is not the owner, Seller or Buyer of the power. Such transmission of power is known as wheeling.

Criteria:

Wheeling shall be carried out in such a way that the safety, security and reliability of power supply in the interconnected system are not compromised. Further, the Operating Member whose transmission assets are used for wheeling shall be compensated adequately not only for use of the assets but also for transmission losses caused by the wheeling transactions.

Requirements:

1. Each Operating Member of the Pool undertakes to allow the wheeling of capacity or energy through its system where this is technically and economically feasible, subject to the conditions specified in Schedule I in the Agreement Between Operating Members.

2. Service conditions, identification of assets involved, and cost compensation for wheeling shall be handled as stipulated in the Agreement Between Operating Members Schedule I.

3. An Operating Member shall determine the capacity of wheeling through its assets based on technical and economic considerations of its system. The methods used in this exercise and results there-of shall be disclosed to the Operating Sub-committee whenever needed.

3. If any event occurs or situation arises in the wheeler's system necessitating change in agreed wheeling transactions, it is the duty of the wheeler to inform all affected parties about the event/situation immediately.

4. Wheeling charges shall be calculated and paid for based on transaction schedules.

5. It is the obligation of the Operating Member who receives power to secure a wheeling path.

Recommendations:

1. Wheeling transactions should be communicated to the SAPP Coordination Centre for their energy market administration.

Compliance:

1. Compliance monitoring process:
Power wheeling shall be monitored by the SAPP Coordination Centre.
2. Levels of Non-Compliance:
2.1. Level 1: One instance of violating the requirements of power wheeling.
2.2. Level 2: Two instances of violating the requirements of power wheeling.
2.3. Level 3: Three instances of violating the requirements of power wheeling.
2.4. Level 4: Four or more instances of violating the requirements of power wheeling.
3. Sanctions or Penalties:
Refer to ***Appendix 1*** for the table of sanctions or penalties.

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GUIDELINE 2 : SYSTEM SECURITY

2.A. REAL POWER (MW) SUPPLY

Background:

Each Control Area Operator shall operate its active power resources so as to ensure a level of operating reserve sufficient to account for such considerations as errors in forecasting, generation or transmission equipment unavailability, loss of generating units, forced outage rates, maintenance schedules, regulating requirements and load diversity between Control Areas.

Criteria:

Following the loss of load or of active power resources, the Control Area Operator shall take appropriate steps to reduce its Area Control Error to zero within ten (10) minutes and to protect itself against the next contingency.

The Operating Sub-Committee shall specify the operating reserve policy in terms of:

(i) the permissible ratio between Spinning and Quick Reserve,
(ii) the procedure for applying Operating Reserve policy in practice, and
(iii) the limitations, if any, upon the amount of interruptible load which may be considered as Quick Reserve.

Requirements:

1. Requirements:

1.1 The System Controller shall be kept informed of all generation and transmission resources available for use.

1.2 The System Controller shall have all the necessary information, including weather forecasts and past load patterns, to predict the system's near-term load pattern.

1.3 Each Operating Member shall provide, as a minimum, Operating Reserve as follows:

1.3.1 An amount of Spinning Reserve responsive to Automatic Generation Control

(AGC), which is sufficient to provide normal regulating margin, plus

1.3.2 An additional amount of Operating Reserve sufficient to reduce the Area Control Error to zero within ten (10) minutes following the loss of generating capacity which would result from the most severe single contingency. Interruptible load may be included in Quick Reserve provided that it can be interrupted in less than ten, (10) minutes and remain disconnected until replacement generation can be brought to service.

1.3.3 Additional resources shall be made available as soon as practicable to restore the necessary Operating Reserve after the initial reserve has been used as the result of an incident.

1.4 In order to ensure compliance with Clause 1.3 above, the Operating Reserve shall be sufficiently dispersed throughout the system, shall take into account the effective contribution of unused generating capacity in an emergency, the time required for these contributions to be effective, the transmission limitations at the time and all the local requirements that may exist.

1.5 All Operating Members shall from time to time, review the adequacy of their Operating Reserve policy by evaluating the impact of all relevant contingencies.

2. Operating Reserve Obligation:

Every Operating Member in SAPP shall be obliged to maintain their calculated portion of Operating Reserve sufficient to cover 150% of the loss of the sent out capacity of the largest generating unit in service in the Interconnection at that time. Furthermore, this operating reserve shall be sufficient to reduce the Area Control Error (ACE) to zero within ten (10) minutes after a loss of generation.

The Operating Reserve shall be made up of Spinning Reserve and Quick Reserve. At least 50% of the Operating Reserve shall be Spinning Reserve which will automatically respond to frequency deviations. Interruptible load may be included in the Quick Reserve provided that it can be interrupted remotely in less than ten (10) minutes from the Control Centre.

The above shall establish the minimum amount of Operating Reserve that each Operating Member will be obliged to carry and indicates the level below which a Member is at fault.

Each Member shall declare its annual peak demand and its largest unit that is in service, everytime these values change.

The following formula shall be used to calculate the minimum System Operating Reserve Requirements (SORR) of an Operating Member;

$$SORR = PORR \times \frac{(2Ds/Dt + Us/Ut)}{3}$$

where:

SORR = Minimum System Operating Reserve Requirement
PORR = Total Pool Operating Reserve Requirement
Ds = Individual System's Annual Peak Demand
Dt = Total Sum of Individual System's Annual Peak Demand
Us = Individual System's Largest Unit (sum of Us)

An example where the sharing of Spinning Reserve between Operating Members has been calculated can be found on the following ***Appendix 2.A.***

Recommendations:

1. The effect of station service generators on area security should be considered before their shut down for economic reasons.
2. Categorisation of reserves may be changed by the Operating Sub-Committee to suit prevailing conditions.

Compliance:

1. Compliance monitoring process:

Operating reserves maintained by Operating members shall be monitored in each hour.

2. Levels of Non-Compliance:

2.1. Level 1: If there is one hour during a calendar month in which the Operating Member's Reserve is less than 100% but greater than or equal to 90% of the required Reserve.

2.2. Level 2: If there is one hour during a calendar month in which the Operating Member's Reserve is less than 90% but greater than or equal to 80% of the required Reserve.

2.3. Level 3: If there is one hour during a calendar month in which the Operating Member's Reserve is less than 80% but greater than or equal to 70% of the required Reserve.

2.4. Level 4: If there is one hour during a calendar month in which the Operating Member's Reserve is less than 70% of the required Reserve.

3. Sanctions or Penalties:

Refer to ***Appendix 1*** for the table of sanctions or penalties.

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2.B. REACTIVE POWER (MVAR) SUPPLY

Background:

Each System Operator or Electricity Supply Enterprise shall supply its own reactive power requirements and shall keep appropriate reserves to maintain voltage levels during a contingency. This includes the System Operator's share of the reactive power required by the interconnections between Members' Systems. The reserves shall be located electrically where they can be applied effectively and timeously when a contingency occurs.

Criteria:

System Operators or Electricity Supply Enterprise shall co-ordinate the use of voltage control equipment to maintain transmission voltages and reactive power flows at levels consistent with the Interconnection security.

Where a System Operator or Electricity Supply Enterprise is not able to supply the necessary reactive requirements to maintain voltage levels, the affected Control Area Operator shall source the reactive power from another Control Area Operator that has excess reactive power through bilateral arrangements.

Requirements:

1. The System Controller shall receive all the necessary information on available generation and flows of reactive power.

2. Reactive sources shall be operated so that scheduled voltages can be maintained under all normal and first contingency conditions.

3. Reactive energy sources shall be dispersed and located in such a way that they can be applied effectively and quickly when contingencies occur.

4. Prompt action shall be taken to restore reactive energy resources if these drop below acceptable levels.

5. The System Controller or Electricity Supply Enterprise shall take all necessary actions, including load reductions, to prevent voltage collapse when reactive energy sources are insufficient.

Recommendations:

1. Surveys to determine compliance with voltage limits and reactive power requirements on tie lines should be conducted by the Coordination Centre on a regular basis and at least once a year.

2. Reactive power reserves should be automatically applied in the event of an emergency.

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2.C. TRANSMISSION OPERATION

Background:

Transmission equipment is to be operated within established transfer limits but not above nameplate rating.

Criteria:

When equipment loading or voltage levels deviate from the ratings following a contingency, with the result that the reliability of the Interconnection is at risk, Control Areas experiencing or causing the condition shall take immediate steps to remedy the situation. These steps include informing other System Operators or Electricity Supply Enterprises, adjusting generation, changing schedules between Control Areas, initiating load relief measures and taking every action that may be required.

Transmission system operation shall be co-ordinated between System Operators or Electricity Supply Enterprise. This includes the monitoring of MW and MVar flows and the co-ordination of equipment outages, voltage levels and switching operations that affect two or more Systems.

Requirements:

1. System Controllers shall monitor all critical transmission system loadings and shall check that voltage limits and emergency ratings are not exceeded.

2. Transmission Planned Outages shall be co-ordinated with other Systems that are likely to be affected.

3. Transmission Forced outages shall be communicated to any System that may be affected.

4. Forced Outages of key transmission facilities shall be communicated to all adjacent Systems as quickly as possible.

5. Each Control Area Operator or Electricity Supply Enterprise shall use appropriate, up-to-date studies as reference for establishing transmission operation procedures.

6. Each System Operator or Electricity Supply Enterprise shall keep Power Oscillation Dampers (POD’s) in service on Static Var Compensators (SVC's) and shall report when the POD’s are out of service.

Recommendations:

Important transmission lines should be kept in service during light-load periods whenever possible. They should be removed from service for voltage control only after all other reactive control measures have been implemented in full and provided that studies can show that system reliability is not degraded below acceptable levels.

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2.D. RELAY CO-ORDINATION

Background:

Protection greatly influences the operation of interconnected Systems, especially under abnormal conditions. Protection schemes used on the interconnection for generator tripping and other remedial measures are of primary concern to the respective Members. However, the protection for internal use in a System often directly, or indirectly, affects adjacent Systems.

Special Protection Systems also known as Remedial Action Schemes, are relay configurations designed to perform functions other than isolation of electrical faults. These schemes are usually installed to maximize transfer capability. However, they may be used to maintain system or generator stability or to control active and reactive power flows on critical components immediately following a disturbance, or to split a system or open an interconnection at preplanned locations to prevent cascading. The general design objective for any SPS shall be to perform its intended function(s) in a dependable manner while refraining from unnecessary operation. An SPS can expose a System to a greater reliability risk. The integrity of a whole System may depend on its correct operation.

Criteria:

System Operators or Electricity Supply Enterprises shall co-ordinate the application, and maintenance of protective relays. They shall develop and implement criteria which will enhance system reliability with minimum adverse effects on the Interconnection.

System Controllers shall be familiar with the intended operation of protective relays and shall have access to the information relating to the operation of these relays.

Requirements:

1. Appropriate technical information concerning protective relays shall be available in each Control Centre.

2. System Controllers shall be familiar with the purpose, operation and limitations of protection schemes.

3. If equipment or protection relay fails and reduces system reliability, the appropriate personnel shall be notified and corrective action shall be carried out as soon as possible.

4. All new protective schemes and all modifications to existing protective schemes shall be co-ordinated between neighbouring Systems if these neighbouring Systems are affected by the change.

5. Protection on major transmission lines and interconnections shall be co-ordinated with other interconnected Systems.

6. Neighbouring Systems shall be notified in advance of changes in generating sources, transmission, load or operating conditions which could require changes in their protection schemes.

7. The Control Centres shall monitor the status of every Special Protection System (SPS) and notify all affected Systems of each status change.

Recommendations:

1. Protection design and operation should consider the following:

1.1 Protection schemes should be of minimum complexity consistent with achieving their purpose.

1.2 Back-up protection schemes should be in service to enable Members to carry out normal maintenance and calibration on the main protective scheme without having any impact on protection availability.

1.3 Protection schemes should not normally operate for brief overloads, transient surges or power swings.

1.4 High speed relays, high speed circuit breakers and automatic reclosing should be used where studies indicate their application will enhance stability margins. Single pole tripping and reclosing may be appropriate on some lines.

1.5 Automatic reclosing under out-of-step conditions should be prevented by blocking relays.

1.6 Under-frequency load shedding relays should be co-ordinated so as to ensure system stability and integrity.

1.7 Protection applications, setting and co-ordination should be reviewed periodically and whenever major changes in generation, transmission, load or operating conditions are anticipated.

1.8 The adequacy of the communication channels used for line and other protections, should be assessed periodically. Automated channel monitoring and failure alarms should be provided for protection communication channels if such failure can cause loss of generation, loss of load or cascading outages.

2. Each Member shall implement protection philosophy and preventive maintenance procedures which will improve their system reliability with the least adverse effects on the Interconnection. These procedures shall be provided to all relevant staff and should specify when instruction and training are necessary. Each Member should co-ordinate these procedures with any other Members that could be affected. These procedures should include:

2.1 Planning and application of protection schemes.
2.2 Review of protection schemes and settings.
2.3 Intended operation of protection schemes under normal, abnormal and emergency conditions.

2.4 Testing and preventive maintenance of relays shall be scheduled at regular intervals, as well as other key protection equipment and associated components.

2.4.1 Testing operation of the complete protection scheme should be tested under conditions as close as possible to actual conditions, including actual circuit breaker operation where feasible.
2.4.2 The testing of communication channels between protection relays belonging to different Systems, should be carried out and the test results recorded.

2.5 Analysis of actual protection operation.

3. A prompt investigation should be made to determine the cause of abnormal protection performance and correct any deficiencies in the protection scheme.

4. Special Protection Systems (SPS):

4.1 The Control Centres shall monitor the status of each Special Protection System (SPS) and notify all affected Members of any change in status.

4.2 SPS should be designed for periodic testing without affecting the integrity of the protected System. They should normally achieve at least the same level of reliability as that provided by other protection schemes.

4.3 SPS should be designed with inherent security to minimize the probability of mal-operation, even with the failure of a primary component.

4.4 Each SPS should be reviewed periodically to determine if it is still required and if it will still perform the intended functions. Seasonal changes in the SPS or its relay settings and the concerned Member shall then inform the other Members about the new settings.

4.5 Every time an SPS operates, the incident should be reviewed and analysed for correctness.

5. Prompt action shall be taken to correct the causes of mal-operation.

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2.E. MONITORING SYSTEM PARAMETERS

Background:

The System Controllers must have information available to them at all times so that they can accurately assess the status of the system under normal operating conditions, make the correct decisions following the occurrence of a contingency and rapidly restore system integrity after a disturbance.

Criteria:

Each System Operator shall continuously monitor those parameters (such as MW, Flow, MVAr flow, frequency, voltage, phase angle, etc.), internal and external to its System or Control Area, that indicate the condition of the Interconnection.

The Control Centres shall be provided with adequate equipment to accomplish this objective. Measuring instruments of suitable range and reliability for both normal and emergency conditions shall be installed and maintained at strategic points.

Requirements:

1. Monitoring equipment shall be used to bring to the System Controller's attention, any deviation from normal operating condition and to indicate, if appropriate, the need for corrective action.

2. Each Control Area Operator shall use sufficient instruments of suitable range, accuracy and sampling rate to ensure accurate and timely monitoring of the Interconnection under normal and emergency situations.

3. Control Centres shall monitor transmission line status, MW and MVAr flows, voltages, Load Transfer Capability (LTC), settings and status of rotating and static reactive resources.

4. Control Centres shall monitor system frequency and time error.

5. Reliable instrumentation, including voltage and frequency meters with sufficient range to cover probable contingencies, shall be available in the Control Room of every power station.

6. Automatic oscillographs and other recording devices shall be installed at key locations and set to standard time to assist post- disturbance analysis.

7. Because of possible system separation, frequency information from several locations shall be monitored at the Control Centres.

8. Monitoring shall be sufficient, so that in the event of system separation, both the existence of the separation and the boundaries of the separated areas can be determined.

9. Transmission line monitoring shall be capable of evaluating the impact of losing any significant transmission or generation facility on the Interconnection both inside and outside the Control Area.

10. Critical unmanned facilities shall be monitored for physical security.

11. Planned Outages of generation or transmission facilities shall be taken into account in the monitoring scheme.

12. Voltage schedules shall be co-ordinated from a central location within each Control Area and co-ordinated with adjacent Control Areas.

13. The Coordination Centre shall have a real time monitoring tool. The following information shall be available from Control Centres: ACE, tie line power flows, tie line schedules, frequency, time error, frequency bias, system demand, AGC regulation, status and mode of AGC.

Recommendations:

Compliance:

1. Compliance monitoring process:

Monitoring shall be the responsibility of SAPP Coordination Centre. Non-adherence to transfer limits on tie lines may be caused by scheduling by owners of the system or by third parties. Penalties shall be imposed on the culprit based on hourly average figures.

2. Levels of Non-Compliance:

2.1. Level 1: Not applicable.

2.2. Level 2: Not applicable.

2.3. Level 3: Not adhering to established transfer limits by 5% per day.

2.4. Level 4: Not adhering to established transfer limits by 10% per day.

3. Sanctions or Penalties:

Refer to ***Appendix 1*** for the table of sanctions or penalties.

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2.F. INFORMATION EXCHANGE- NORMAL SYSTEM CONDITIONS

Background:

For reliable operation of the interconnected system there is need to share information.

Criteria:

Information concerning system conditions shall be transmitted to all Control Centres as needed without undue delay.

Requirements:

1. Each Control Area Operator shall disseminate information on actual and scheduled interchanges, voltages and Planned Outages which may have adverse effect on other Control Areas.

2. Control Centers shall notify other Systems of current or foreseen operating conditions which may affect the Interconnection reliability. Examples of operating conditions that may affect reliability are: critically loaded facilities, Planned and Forced Outages, the commissioning of new facilities, abnormal voltage conditions, new or degraded protective systems, Force Majeure and new or degraded communication channels.

3. All Operating Members shall submit daily system reports, including information on system peak demand (actual and forecast), system outages (planned and forced) and any other relevant system operations issues to the Co-ordination Centre by 10:00Hrs. The Co-ordination Centre shall consolidate the information and circulate the daily SAPP outlook report to all System Controllers by electronic mail by 15:00Hrs. Refer to ***Appendix 2.F*** for a template of the daily SAPP system outlook report.

Recommendations:

To ensure that communication networks are functioning properly and timely exchange of information takes place, specific monitoring and testing procedures of communication facilities, should be developed, documented and implemented in every System.

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2.G. INFORMATION EXCHANGE – DISTURBANCE REPORTING

Background:

Affected System Operators or Electricity Supply Enterprises must be kept informed of potential or actual operating problems. Disturbances which result in substantial customer interruptions attract news media. The event and its causes will also be of considerable interest to the Operating Members, and should be viewed by the Control Centres as a learning experience.

Criteria:

Disturbance reporting – Disturbances or unusual occurrences which may jeopardize the operation of the Interconnection, that will result, in equipment damage or customer supply interruptions, shall be studied pro-actively and in sufficient depth by System Operators or Electricity Supply Enterprises to enable the Operating Members to take the appropriate measure to prevent such incidents. The facts surrounding a disturbance shall be made available to all Control Centres and to the Co-ordination Centre.

Requirements:

1. Major operating problems that could affect other Systems shall be reported as soon as possible to neighbouring Systems. These could include loss of generation, of load or of facilities

2. Large disturbances affecting two or more Systems shall be promptly analysed by the affected Members.

3. Based on the magnitude and duration of the disturbance or abnormal occurrence, those System Operators or Control Area Operators or Electricity Supply Enterprises responsible for investigating the incident shall provide oral and/or written reports.

4. The Control Centre(s) experiencing a disturbance, should provide a written preliminary report(s) as per ***Appendix 2G*** to the Coordination Centre within forty-eight (48) hours, followed by detailed written report(s) after further analysis of the disturbance within thirty (30) days of the occurrence.

5. The Coordination Centre shall issue a consolidated preliminary report within seventy-two (72) hours of occurrence and shall issue a consolidated report complete with

conclusions and recommendations fourteen (14) days after receiving the detailed system disturbance report(s). Refer to ***Appendix 2.G*** for the “SAPP Preliminary System Disturbance Report.”

Recommendations:

1. If an operating problem cannot be resolved quickly, the probable duration and possible effects should be reported to the other Control Centres.

2. When there has been a disturbance affecting the Interconnection, Member’s delegates to the Operating Sub-Committee, should make themselves available to the System Operators or Electricity Supply Enterprises immediately affected, in order to assist in the investigation.

Compliance:

1. Compliance monitoring process:
Information exchange shall be monitored by the SAPP Coordination Centre.
2. Levels of Non-Compliance:
2.1. Level 1: One occurrence of non-adherence to requirements of information exchange.
2.2. Level 2: Two occurrences of non-adherence to requirements of information exchange.
2.3. Level 3: Three occurrences of non-adherence to requirements of information exchange or not reporting to neighbouring systems about system disturbances in real time.
2.4. Level 4: Four or more occurrences of non-adherence to requirements of information exchange.
3. Sanctions or Penalties:
Refer to ***Appendix 1*** for the table of sanctions or penalties.

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2.H. MAINTENANCE CO-ORDINATION

Background:

Maintenance shall be co-ordinated amongst System Operators or Electricity Supply Enterprises to ensure the safety of personnel, plant and equipment, system security and reliability of supply.

Criteria:

Each System Operator or Electricity Supply Enterprise shall establish schedules for inspection and preventive maintenance of its generation, transmission and protection facilities: as well as of its control, communication and other auxiliary systems. These maintenance and inspection schedules shall be co-ordinated with other Control Centres and Control Area Operators to ensure that the outage pattern does not violate agreed upon safety and reliability criteria.

Requirements:

1. Planned generator and transmission Outages that may affect the reliability of Interconnected operations, shall be planned and co-ordinated (notification of cancellation at least twenty-four (24) hours in advance) between the affected System Operators and Control Area Operators. Special attention shall be given to the results of pertinent studies. A Planned Outage shall be advised at least two (2) weeks in advance and confirmed in writing. Each Control Area Operator must be advised of any return of equipment to service.

2. If mutually agreed between Members an unplanned outage may be converted to a planned outage, provided that the requesting member submits a documented case specifying the reason for the extended unplanned outage and the time period before the equipment is returned to service.

3. Scheduled generator and transmission outages that may affect the reliability of interconnected operations shall be planned and co-ordinated among affected Members and control areas. Special attention shall be given to results of pertinent studies.

4. Scheduled outages of system voltage regulating equipment, such as automatic voltage regulators on generators, supplementary excitation control, synchronous condensers, shunt and series capacitors, reactors, etc., shall be co-ordinated as required.

5. Scheduled outages of telemetering and control equipment and associated

communication channels shall be co-ordinated between the affected System Operators and Control Area Operators or Electricity Supply Enterprises.

6. Co-ordinated and agreed maintenance schedules shall be submitted by all Control Area Operators and System Operators or Electricity Supply Enterprise to the Co-ordination Centre by 30 November of the year before the start of the new year. The Co-ordination Centre shall publish the schedules to all Operating Members using available information transfer facilities such as electronic mail or the official SAPP website.

7. Common certificates shall be used for live line work, isolating, earthing, releasing for work and handing back tie line equipment. Refer to ***Appendix 2.H (i)*** for the "Circuit Isolation Certificate" and ***Appendix 2.H (ii)*** for the "Live Line Work Certificate".

Recommendations:

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2.I. CONTROL AREA SERVICES

Background:

Control Area Operators are required to offer services for the secure control and operation of the interconnected system. A System Operator or Electricity Supply Enterprise that does not meet the criteria for a Control Area Operator must be hosted by a Control Area.

Criteria:

Control Area services are critical in ensuring that the interconnected system is operated in a safe, secure and reliable manner. Electricity Supply Enterprises within a Control Area need to identify all applicable Control Area services. System Operators or Electricity Supply Enterprise shall adequately compensate Control Area Operators for the services offered.

Requirements:

1. Electricity Supply Enterprises within a Control Area shall contract with the Control Area Operator for all applicable Control Area services.

2.The following shall be part of Control Area services:

2.1.System control
- tie line control
- frequency control

2.2. Transaction scheduling
2.3 Inadvertent energy management
2.4. Transaction accounting
2.5 Telemetry and telecommunications systems

3. Control Area service charges as determined in Appendix 2.I shall be applicable, unless otherwise agreed bilaterally.

4. At least once a year Control Areas shall demonstrate to the Operating Sub-Committee, through Control Performance Survey and system disturbance analysis, their capability to provide the necessary Control Area services to System Operators in their area.

5. Failure to provide contracted Control Area services shall attract penalties in accordance with Appendix 9.

Recommendations:
1. A Control Area can provide Control Area services to another Control Area.

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2.J. CONNECTION AND OPERATION OF INDEPENDENT POWER PRODUCERS

Background:

The deregulation of the Electricity Supply Industry (ESI) and the opening up of SAPP membership to players who are not national power utilities has enabled a few Independent Power Producers (IPPs) to connect their power facilities to the SAPP. Some IPPs connect to the transmission network while others connect to the distribution network. The trend shows that the number of IPPs connecting to the SAPP is growing rapidly. With a few IPPs having large-capacity generation facilities using liquid fuel, gas fuel, or coal fuel, most IPPs have small-capacity generation facilities using renewable energy such as solar, wind or hydro.

Criteria:

To realize maximum benefits from IPPs such as mitigation of power shortages, optimization of energy resources in the region, promotion of sustainable environmentally-friendly energy sources, it is imperative that every IPP plays its part in making the SAPP interconnected system reliable, stable, secure and safe and also plays a part in minimizing energy losses. In doing this, the IPP shall conform to SAPP technical requirements for connection and coordinate its operations with the System Operator to which it is connected. Further, the IPP shall be required to meet the utmost performance in availability of its power facilities.

Requirements:

1. Prior to commissioning, an IPP shall provide all necessary information to its System Operator to enable the System Operator carry out system studies using appropriate software to determine the IPP's impact on the following:
a) System conditions (voltage levels, power flow etc.) before and after selected contingencies.
b) System fault levels.
c) System steady state, transient and dynamic stability.
d) Any other condition required by the System Operator.

2. The System Operator shall carry out necessary system studies to determine reliable, stable and safe condition(s) for connection and operation of the IPP. The System Operator shall then give the IPP an official approval for connection and operation of the IPP.

3. Prior to commissioning, the IPP and the applicable System Operator shall engage in a Connection Agreement. The Connection Agreement shall specify detailed technical and commercial terms and conditions for connection and operation of the IPP power facilities.

4. The IPP's generating unit with nameplate rating of 5 MVA or greater shall be equipped with operational governors with droop settings for frequency response stated in the Connection Agreement.

5. The IPP's generating unit with nameplate rating of 5 MVA or greater shall be equipped with operational automatic voltage regulators.

6. The IPP facility at the Point of Connection shall be equipped with a device capable of isolating the IPP's electrical system from that of the System Operator in the event of a fault on either side. The controlling circuit breaker shall be capable of interrupting the maximum short circuit current. There shall be provision for disconnection of the IPP by sending a trip signal from remote to the controlling circuit breaker. In addition, isolators shall be provided to adequately isolate the controlling circuit breaker at the Point of Connection for maintenance purposes.

7. The IPP facility at the Point of Connection shall be equipped with adequate automatic protection relays as stated in the Connection Agreement. Settings of the protection system shall be agreed upon between the IPP and the System Operator.

8. The connecting transformer between the IPP and the System Operator shall be of agreed upon winding connections and type of grounding (earthing) and shall be sized to deliver rated real and reactive power at an agreed upon range of power factor.

9. The IPP shall have adequate facilities for starting, synchronizing and despatch of its generators. Procedures for starting (whether black start or otherwise), synchronizing (whether manual or automatic) and despatch (whether independent or central) of the IPP generators to the interconnected system, shall be agreed upon between the IPP and the System Operator and shall not adversely affect the quality of power supply.

10. The IPP shall make the following signals available at an appropriate terminal unit at its site for a telecommunication gateway to the Control Centre of the System Operator:
a) Megawatt sent-out (MW) at the Point of Connection.
b) Forecast Active Power Estimate (MW) at the Point of Connection.
c) Reactive Power Import/Export (+/-Mvar) at the Point of Connection.
d) On/Off status indications for all Reactive Power devices exceeding 5 Mvar.
e) Circuit-breaker positions indication. These shall include indications from circuit-

breakers on individual generating units.
f) Status of power system stabilizer.
g) Any other signals requested by the System Operator and agreed by both parties.

11. The IPP shall have a communication gateway facility that can communicate with the Control Centre of the System Operator. The necessary telecommunications links, telecommunications protocol and the requirement on analogue or digital signals shall be specified by the System Operator as appropriate in the Connection Agreement.

12. The IPP shall provide to the System Operator accurate real power and reactive power forecasts. These forecasts shall be provided at 09:00 a.m. on a daily basis for day-ahead for each one (1) hour time-period, by means of an electronic interface in accordance with the reasonable requirements of System Operator’s data system.

13. The IPP shall submit real power and reactive power availability declarations whenever changes in availability occur or are predicted to occur. These declarations shall be submitted by means of an electronic interface in accordance with the requirements of System Operator’s data system.

14. The IPP's control system shall be able to receive an active-power control set-point signal from the Control Centre of the System Operator. This set point shall define the maximum Active Power output permitted from the IPP. The IPP shall be capable of receiving this signal and acting accordingly to achieve the desired change in Active Power output. The IPP shall make it possible for the System Operator to remotely enable/disable the Active-Power control function in the IPP control system. When this remote control is disabled, the IPP shall be capable of operating at agreed reduced levels if required to do so by the System Operator for system security or other reasons.

15. The IPP generators shall supply its registered capacity of real and reactive power and remain synchronised to the interconnected system within the bands of system frequency variation, voltage level variation, voltage un-balance variation, and power factor variation stated in the Connection Agreement. In so doing, the IPP shall participate in system frequency control, system voltage control and power factor control both during normal and abnormal system conditions as stipulated in the Connection Agreement.

16. Any tripping of individual generation units due to frequency excursions shall be staggered and the power-frequency response curve and philosophy for tripping shall be agreed between the IPP and the System Operator.

17. The IPP shall comply with all SAPP rules on equipment maintenance and system disturbance reporting.

18. The IPP shall comply with all SAPP rules on interchange energy scheduling, energy delivery, metering standards, handling of inadvertent energy, and handling of energy losses; provided that where a special agreement exists between the IPP and the System Operator, the System Operator shall carry out all interchange energy scheduling, energy accounting and handling of energy losses with other SAPP Operating Members on behalf of the IPP.

19. Voltage quality distortion levels caused by the IPP at the Point of Connection shall not exceed the apportioned levels as stated in the Connection Agreement. The calculation of these distortion levels shall be based on the SAPP Quality of Supply Standard or approved international standards.

Recommendations:

1. The IPP should provide operational diagrams showing the electrical circuitry of the existing main features, bus bar arrangements, phasing arrangements, earthing arrangements, switching facilities and operating voltages to the applicable System Operator.

2. The IPP should provide its safety rules and a list of authorized system operations personnel to the OSC representative of the applicable System Operator.

3. Operations personnel of the IPP should be authorized and certified based on national or international accepted criteria.

4. Where there have been major replacement or changes in the system design and configuration of the facilities of the IPP, new system studies should be carried out between the IPP and the System Operator and conditions of connection and operation should be revised accordingly.

5. The System Operator through its OSC representative shall share reports of system studies and commissioning of the IPP and any relevant technical data about the IPP with the SAPP Coordination Centre.

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GUIDELINE 3 : EMERGENCY OPERATIONS

3.A. INSUFFICIENT GENERATING CAPACITY

Background:

System Operators should aim to maintain a balance between generation and load at all times in order to ensure system security. When a System Operator loses generation it shall take prompt action to restore frequency and ACE to normal.

Criteria:

A Control Area Operator anticipating a shortage of generation, shall bring to service all available generation, postpone equipment maintenance where possible, schedule energy purchases and prepare itself to reduce load.

A Control Area which experiences a shortage of generation, shall promptly balance its generation and interchange schedules to its load without regard to cost , to avoid excessive use of the assistance provided by interconnection frequency bias. The reserve inherent to frequency deviation is intended to be used only as a temporary source of emergency energy and is to be promptly restored to enable the interconnected Systems to withstand the next contingency. A Control Area Operator unable to balance its generation and interchange schedules to its load shall shed sufficient load to ensure that its Area Control Error (ACE) is corrected.

Requirements:

1. Agreements between neighbouring System Operators or Electricity Supply Enterprises within the SAPP, shall contain provisions for compulsory emergency assistance to Operating Members for periods not exceeding six (6) hours.

2. When a shortage of generation occurs, generation and transmission facilities shall be used to the fullest extent practicable to promptly restore normal system frequency and voltage, and return ACE to the performance criteria specified in Guideline I.E

2.1 If Automatic Generation Control (AGC) has become in-operative, manual control shall be used to balance generation and scheduled interchanges to load.

2.2 The deficient System Operator or Electricity Supply Enterprise shall schedule all available assistance that is required with as much advance notice as possible.

2.3 The deficient System Operator or Electricity Supply Enterprise shall use the assistance provided by the frequency bias only for the time needed to accomplish the following:

2.3.1 Load its operating reserve as fast as possible.
2.3.2 Analyse its ability to recover using only its own resources.
2.3.3 If necessary, determine the availability of assistance from other Members and schedule that assistance.

3. If all other steps prove inadequate to remedy the situation, the deficient System Operator or Electricity Supply Enterprise shall take immediate action which includes, but is not limited, to the following:
3.1 Schedule all available emergency assistance from other Systems.
3.2 Implement manual load shedding.

4. Unilateral adjustment of generation to return frequency to the scheduled value by other Control Centres, beyond that supplied through frequency bias and new interchange schedules, shall not be attempted. Such adjustment may result in the transfer limits of the transmission facilities being exceeded. A Control Area Operator which loses generation is responsible for taking action within thirty (30) minutes to restore frequency to normal by changing generation or interchange schedules through its AGC or manually.

Recommendations:

1. Generators and their auxiliaries should be able to operate reliably at abnormal voltages and frequencies.
2. Plant operators should be supplied with instructions specifying the frequency and voltage below which it is undesirable to continue to operate generators connected to the system.
2.1 Protection systems should be installed to automatically trip the generators at pre-determined high and low frequencies.
2.2 If feasible, generators should be separated with some local, isolated load still connected. Otherwise, generators should be separated carrying their own auxiliary load.
2.3 Identify and address the problems that could delay the restoration of the System.
3. Emergency sources of power should be available to facilitate safe shutdown, enable turning gear operation, minimize the likelihood of damage to either generation units or their auxiliaries, maintain communication channels and facilitate re-start.

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3.B. SUDDEN INCREASE IN SYSTEM LOAD

Background:

System Operators or Electricity Supply Enterprise should aim to maintain a balance between generation and load at all times in order to ensure system security. When a System Operator experiences sudden increase in load it shall take prompt action to restore frequency and ACE to normal.

Criteria:

A Control Area Operator experiencing a sudden increase in load, shall bring to service all available generation, postpone equipment maintenance where possible, schedule energy purchases and prepare itself to reduce load.

A Control Area Operator which experiences a sudden increase in load, shall promptly balanceits generation and interchange schedules to its load without regard to cost , to avoid excessive use of the assistance provided by interconnection frequency bias and ensure that its Area Control Error (ACE) is corrected.

Requirements:

1. Agreements between neighbouring System Operators or within the SAPP, shall contain provisions for compulsory emergency assistance to Operating Members for periods not exceeding six (6) hours.

2. When a sudden increase in load occurs, generation and transmission facilities shall be used to the fullest extent practicable to promptly restore normal system frequency and voltage, and return ACE to the performance criteria specified in Guideline I.E

2.1 If Automatic Generation Control (AGC) has become in-operative, manual control shall be used to balance generation and scheduled interchanges to load.

2.3 The deficient System shall use the assistance provided by the frequency bias only for the time needed to accomplish the following:

2.3.1 Load its operating reserve as fast as possible.
2.3.2 Analyse its ability to recover using only its own resources.
2.3.3 If necessary, determine the availability of assistance from other Members and schedule that assistance.

3. If all other steps prove inadequate to remedy the situation, the deficient system

Operator shall take immediate action which includes, but is not limited, to the following:

3.1 Schedule all available emergency assistance from other System Operators.

3.2 Implement manual load shedding.

4. A Control Area Operator which experiences sudden increase in load is responsible for taking action within thirty (30) minutes to restore frequency to normal by changing generation or interchange schedules through its AGC or manually.

Recommendations:

1. Plant operators should be supplied with instructions specifying the frequency and voltage below which and the loading above which it is undesirable to continue to operate equipment connected to the system.
2. Protection systems should be installed to automatically trip power system equipment at pre-determined high capacity loading and/or low pre-determined low frequencies and voltage levels.
3. Emergency sources of power should be available to cater for sudden increase of system loads.

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3.C. TRANSMISSION - OVERLOAD, VOLTAGE CONTROL

Background:

If a transmission facility becomes overloaded and/or is subjected to abnormal voltage conditions, appropriate relief measures must be taken to restore the system to normal.

Criteria:

If a transmission facility becomes overloaded or if voltage / reactive power levels are outside established limits and the condition cannot be relieved by normal means such as adjusting generation or service schedules, and if a credible contingency under these conditions would adversely impact the Interconnection, appropriate relief measures, including load shedding, shall be implemented promptly to return the transmission facility to within established limits. This action shall be taken by the System Operator or Control Area Operator or Electricity Supply Enterprise experiencing the problem if that System Operator or Control Area Operator or Electricity Supply Enterprise can be identified, or by other System Operators or Control Area Operators or Electricity Supply Enterprise, as appropriate, if that identification cannot readily be made.

Requirements:

1. If an overload on a transmission facility or an abnormal voltage/reactive power condition persists and is caused by another System, the affected System Operator or Electricity Supply Enterprise shall notify the neighbouring or remote System Operator or Electricity Supply Enterprise of the severity of the overload or abnormal voltage/reactive conditions and request appropriate remedy.

2. If an overload on a transmission facility or abnormal voltage/reactive condition persists and equipment is endangered, the affected System Operator or Electricity Supply Enterprise may disconnect the facility at risk. Neighbouring Systems impacted by the disconnection shall be notified prior to switching, if practicable, otherwise, promptly thereafter.

3. Action to correct a transmission overload shall not impose unacceptable stress on internal generation or transmission equipment, reduce system reliability beyond acceptable limits, or unduly impose voltage or reactive burdens on neighbouring Systems. If all other means fail, corrective action may require load shedding.

4. System Operators or Electricity Supply Enterprises shall take all appropriate action up to and including shedding of firm loads in order to keep the transmission facilities within acceptable operating limits.

Recommendations:

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3.D. LOADSHEDDING

Background:

A System Operator or Electricity Supply Enterprise shall carry out load shedding when it is experiencing insufficient generation capacity and/or equipment over load and there is no available support from the interconnected system, to avoid further compromise of system security.

Criteria:

After taking all other remedial steps, a System Operator or Control Area Operator or Electricity Supply Enterprise whose integrity is In jeopardy due to insufficient generation or transmission capacity shall shed customers rather than risk an uncontrolled failure of components making up the Interconnection.

Requirements:

1. When a severe under-frequency occurs, automatic load shedding shall be co-ordinated throughout the Interconnection together with other operations, such as generator tripping or isolation, shunt capacitor tripping, and other automatic actions which occur during abnomal frequency or voltage conditions.
2. Automatic load shedding shall be in steps and initiated by one or more of the following parameters: frequency, rate of frequency decay, voltage level, rate of voltage decay or power flow. See table in ***Appendix 3.D*** “Automatic Under frequency Load Shedding in the SAPP”.
3. If a System or Control Area is separated from the Interconnection and there is insufficient generating capacity to restore system frequency following automatic under-frequency load shedding, additional load shall be shed manually before re-synchronising.

Recommendations:

1. Voltage reduction for load relief should be restored to in the distribution networks. Voltage reductions on the sub-transmission or transmission system may be effective in reducing load; however, voltage reductions should not be restored to on the high voltage transmission system unless the system has been isolated from the Interconnection.
2. In those situations where it will be beneficial, manual load shedding should be implemented to prevent voltage collapse or imminent separation from the Interconnection due to transmission overload.

Compliance:

1. Compliance monitoring process:

Operation of automatic load shedding shall be monitored by the SAPP Coordination Centre.

2. Levels of Non-Compliance:

2.1. Level 1: Shedding only up to 50%of the required amount of load.

2.2. Level 2: Shedding only up to 20%of the required amount of load.

2.3. Level 3: Automatic under-frequency load-shedding not operating in the mandatory category.

2.4. Level 4: Not having an automatic under-frequency load-shedding scheme.

3. Sanctions or Penalties:

Refer to ***Appendix 1*** for the table of sanctions or penalties.

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3.E. SYSTEM RESTORATION

Background:

After a system collapse, restoration shall begin as soon as possible, provided it can proceed in an orderly and secure manner. System Operators or Electricity Supply Enterprise shall co-ordinate their restoration actions.

Criteria:

During system restoration, priority shall be given to the auxiliary supply of power stations and of transmission sub-stations. Even though the restoration is to be expeditious, Control Centres shall avoid premature action to prevent another collapse of the System.

Customer load shall be restored as generation and transmission equipment becomes available, recognizing that load and generation must remain in balance at normal frequency during this process.

Requirements:

1. Each System Operator or Electricity Supply Enterprise shall have a restoration plan:

1.1 Operating personnel shall be trained in the implementation of the plan. Such training should include simulation exercises, if practicable.

1.2 The restoration plan shall be updated, as necessary, to reflect changes in the power network and correct deficiencies found from experience and during the restoration exercises.

1.3 Each Control Area Operator shall identify interconnections with adjacent Control Areas Operator that may be used to restore power and obtain agreement for their use.

1.4 Telecommunication facilities needed to implement the plan shall be periodically tested.

2. Following a disturbance in which one or more areas are isolated, steps shall immediately be taken to return the system to normal:

2.1 The Control Centre shall determine the extent and condition of the isolated area(s).

2.2 The System Controller shall then take the necessary action to restore system frequency to normal, including adjusting generation, placing additional generators on line, or shedding load.

2.3 When voltage, frequency and phase angle permit, the Control Centre may re-synchronise the isolated area(s) with the surrounding area(s), properly notifying adjacent Systems of the size of the area being reconnected and the capacity of transmission lines effecting the reconnection.

Recommendations:

Each System Operator or Electricity Supply Enterprise shall have a restoration procedure.

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3.F. EMERGENCY INFORMATION EXCHANGE

Background:

A System Operator or Electricity Supply Enterprise experiencing an emergency shall immediately communicate its status to all affected System Operators or Electricity Supply Enterprises so that appropriate action is taken by all affected parties.

Criteria:

A System Operator or Control Area Operator or Electricity Supply Enterprise which is experiencing or anticipating an emergency shall communicate its current and future status to neighbouring System Operators and Control Area Operators or Electricity Supply Enterprise within the SAPP. System Operators or Electricity Supply Enterprises able to provide emergency assistance shall make known their capabilities.

Requirements:

1. A System Operator or Electricity Supply Enterprise shall inform neighbouring System Operators and Control Area Operators or Electricity Supply Enterprise within the SAPP, through pre-determined communication channels, whenever the following situations are anticipated or arise:

1.1. The System's condition is burdening other Systems or reducing the reliability of the Interconnection.
1.2. The System Operator is unable to purchase capacity to meet its load and reserve requirements on a day-ahead basis or at the start of an hour.
1.3. The System's line loadings and voltage/reactive power levels are such that a single contingency could threaten the reliability of the Interconnection.
1.4. The System anticipates 8% or greater voltage reduction or appeals to the public for load reduction because of an inability to purchase emergency capacity.
1.5. The System has instituted 8% or greater voltage reduction or appeals to the public to reduce load or load shedding for system wide problems.

Recommendations:

A System Operator or Electricity Supply Enterprise should inform the SAPP Co-ordination Centre about any anticipated and/or experienced system emergency.

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3.G. SPECIAL SYSTEM OPERATION ACTION

Background:

Facilities of each System are vital to the secure operation of the interconnected system, as such System Operators or Electricity Supply Enterprise shall make every effort to secure the Interconnection.

Criteria:

When a System Operator or Electricity Supply Enterprise establishes that its system is endangered by remaining interconnected, it may take such action as it deems necessary to protect its network.

If the Interconnection is split, abnormal frequency and voltage deviations may occur. To permit re-synchronising, relief measures shall be applied by the System Operator(s) or Electricity Supply Enterprise causing the frequency and voltage deviations.

Requirements:

1. When an emergency occurs, a prime consideration shall be to safeguard the Interconnection. This will permit maximum assistance to the System(s) in trouble.

2. If an area is separated during a disturbance, interchange schedules between Control Areas or fragments of Control Areas within the separated area shall be immediately reviewed and appropriate adjustments made in order to facilitate restoration. Attempts shall be made to maintain the adjusted schedules whether generation control is manual or automatic.

Recommendations:

1. If abnormal levels of frequency or voltage resulting from a disturbance make it unsafe to operate the generators or their support equipment connected to the System, their separation or shutdown should be accomplished in a manner which minimizes the time required to re-synchronise and restore the System.

2. AGC should remain operative whenever possible.

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3.H. CONTROL CENTRE BACK-UP

Background:

System Operators or Electricity Supply Enterprise should be in a position to continue their operations in the event that the main Control Centre becomes inoperable.

Criteria:

When an Operating Member develops a plan to ensure continued operations in the situation where a Control Centre becomes in-operable, Guideline I should be taken into account to ensure that the Control Area does not become a burden to the other Systems.

Requirements:

1. Each System Operator shall have a back-up mechanism for its Control Centre.

2. Each Control Area Operator shall have a back-up Control Centre.

Recommendations:

1.1 The back-up control facility should be remote from the site of the main Control Centre.

1.2 Each System Operator should have communication equipment installed at its back-up control facility, capable of communicating with the key points of its own system and with the other System Operators.

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GUIDELINE 4: OPERATING PERSONNEL

4.A. RESPONSIBILITY AND AUTHORITY

Background:

System Controllers need to be assigned sufficient authority and responsibility to ensure the system is operated in a safe and reliable manner.

Criteria:

Each System Controller shall be delegated sufficient status and authority to take any action necessary to ensure that the System or Control Area for which he/she is responsible, is operated in a stable and reliable manner.

Requirements:

1. Each Control Area Operator and Control Centre shall provide its System Controllers with a clear definition of their authority and responsibilities.

2. Each Control Area Operator and Control Centre shall advise the other Control Centres of the authority and responsibilities of its own System Controllers.

3. System Controllers shall be empowered to conduct real time energy trading.

Recommendations:

System Controllers should be capable of offering necessary assistance to other operating personnel on the interconnected system for reliable and safe operation of the interconnected system.

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4.B. SELECTION

Background:

Skilled system controllers should be selected to run the interconnected system to ensure safe and reliable operations.

Criteria:

Each Control Centre Area shall select its System Controllers using criteria likely to promote reliable and safe operation.

Requirements:

1. Personnel selected as System Controllers shall be capable of directing other operating personnel in their own System, and, at the same time, working efficiently with their counterparts in other Control Centres.

2. A System Controller shall have:

• a high level of intellectual ability and above-average reasoning capability especially when under stress:

• reasonable mechanical, electrical and mathematical aptitudes, communication, supervision and decision-making skills.

3. System Controllers shall also be proficient in lower-level assignments necessary for smooth management of the Control Centre.

Recommendations:

1. To maintain an adequate level of capability and expertise in system operations, each System should have and implement screening techniques and selection procedures for its System Controllers. These should include:

1.1 Evaluation of the candidates against a fairly detailed job description.

1.2 Analysis of the candidate's past records and experience.

1.3 In-depth interview with each candidate.

1.4 Evaluation of intelligence, logical frame of mind, technical aptitudes, mathematical and communications skills together with psychological fitness.

1.5 Educational and academic background.

1.6 Physical examination.

2. Establish a Grading Committee in each Control Area to evaluate/interview candidates and assess them against a detailed job description.

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4.C. TRAINING

Background:

The increasing sophistication of Control Centres which covers control equipment, instrumentation and data presentation techniques, plus the interconnection of adjacent Systems, requires careful selection and training of Control Centre personnel. Proper and quick action during an emergency, as well as minute-to-minute operation of a complex system, depends upon human performance. Each System Controller should be well qualified, adequately educated, mentally suited, and thoroughly conversant with the principles and procedures of interconnected system operations.

To operate a power system effectively, a System Controller must have a thorough understanding of the basic principles of electricity and since a power system consists of a variety of components, equipment and apparatus, through understanding of their characteristics and how these devices integrate to form a system, is absolutely essential. The System Controllers should also be capable of supervising others, of good communication and of proper decision-making.

In anticipation of abnormal situations on the Interconnection, System Controllers should receive special training to increase their awareness and make them capable of quickly conveying key information to other Control Centres.

Criteria:

Each System Operator or Control Area Operator or Electricity Supply Enterprise shall provide its personnel with training that is designed to promote reliable and safe operation.

Requirements:

1. Each Control Area Operator shall provide its System Controllers with guidelines to resolve those problems that can be caused by realistic contingencies and known restrictions on equipment.

2. Each System Controller shall be thoroughly educated and trained in the Control Area operating policies and in the basic principles of interconnected system operation as outlined in these Operating Guidelines.

3. The Coordination Centre shall organize a SAPP accredited System Controller training at least once every three years or as and when required.

Recommendations:

1. Each System should implement a training program for its Control Centre personnel.

1.1 Training should include both classroom and on-the-job training.

1.2 Each System should periodically simulate emergency situations in order to maintain a high level of readiness among Control Centre personnel.

1.3 Inter-Utility exchanges of System Controllers should be encouraged.

2. Each System should consider training on power system simulator.

3. Each System should consider the list of items in ***Appendix 4.C***. A for inclusion in their training program.

4. Each System should consider the simulation of unusual occurrences as part of their training program.

5. SAPP System Controllers should be certified according to certification procedures set by the Operating Sub-Committee.

6. Each Control Centre should have at least one certified System Controller on duty at any time.

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4.D. RESPONSIBILITY TO OTHER OPERATING GROUPS

Background:

A key element of good system operation is the efficient transfer of information to other operating personnel in the SAPP during normal and emergency conditions.

Criteria:

The operating personnel of each System Operator and Control Area Operator or Electricity Supply Enterprise shall be responsive to requests for information emanating from other System Operators or Control Area Operators or Electricity Supply Enterprise and from the Co-ordination Centre or the Operating Sub-Committee.

Requirements:

The operating personnel of Systems and Control Areas shall be aware of the operating information required by other Systems or Control Areas and by the Operating Sub-Committee or Co-ordination Centre.

Recommendations:

The operating personnel of each System and Control Area should be designated sufficient authority to respond to the needs of other operating personnel in the SAPP.

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GUIDELINE 5: OPERATIONS PLANNING

5.A. NORMAL OPERATIONS

Background:

System Operators or Electricity Supply Enterprise shall plan their operations in order to ensure safety and reliability on the system.

Criteria:

Each Control Area Operator shall plan its future operations in-co-ordination with other affected Control Areas to ensure that normal operation on the Interconnection proceeds in an orderly and efficient manner.

Requirements:

1. Each Control Area Operator shall schedule its plant and interchanges so as to meet the daily load pattern and the changes in load characteristics.

2. The results of studies dealing with the operation of the System shall be available to System Controllers.

Recommendations:

1. Periodic reviews should be conducted with planning engineers to ensure that the long- term plans comply with the SAPP Operating Guidelines.

2. A Control Centre should participate in the studies conducted by other Control Centres when:

2.1 The facilities in a System may affect the operation of the Interconnection.

2.2 The operating conditions impose restrictions on generating facilities.

2.3 It is necessary to know the operating limitations on the system when all transmission facilities are in service.

2.4 It is necessary to know the operating limitations on the system when transmission facilities are scheduled or forced out of service.

2.5 Voltage and reactive power schedules are likely to be restricted.

3. Studies should be made at least annually (or at such times as system changes warrant) to determine the transfer capacity between Control Areas.

4. The determination of generating capability should take into account, among other variables, weather, ambient air and water conditions, and fuel quality and quantity.

5. Each Control Area Operator should determine the power transfer capabilities of its transmission system and identify potential problems by conducting simulation studies.

5.1 Thermal and stability limits, previous short-and long term loading, voltage limits and seasonal (temperature) characteristics should be considered when determining the capability of transmission facilities.

5.2 Transfer capability studies should consider voltage, reactive, thermal, and stability limits of internal and external system equipment. Generating unit and transmission facility outage patterns should be considered. Studies should determine the additional reactive power that is required under reasonable generating and transmission contingencies.

6. Computer models and data utilized for analysis and planning system operations should be updated and replaced as necessary to ensure that they can accurately and adequately represent the System. The same software and computer platforms should be used throughout the SAPP. (It is recommended to move away from main frame computers to personal computers).

7. Neighbouring systems should use uniform line identifiers and ratings when referring to transmission facilities which are part of points of interconnection.

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5.B. PLANNING FOR SHORT-TERM EMERGENCY CONDITIONS

Background:

To cope with short term emergency conditions, System Operators shall put contingency plans in place to minimize effects of the emergency.

Criteria:

A set of contingency plans consistent with SAPP Operation Guidelines (particularly Guideline III) shall be developed, maintained and implemented to enable the System Operators and Control Area Operators or Electricity Supply Enterprise to cope with operating emergencies. These plans shall be co-ordinated with other System Operators and Control Area Operators or Electricity Supply Enterprise as appropriate.

Requirements:

Plans developed and maintained to cope with operating emergencies shall include procedures that can be executed by System Controllers.

Recommendations:

Appropriate government agencies should be informed about these emergency plans.

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5.C. PLANNING FOR LONG-TERM EMERGENCY CONDITIONS

Background:

To cope with long term emergency conditions, System Operators or Electricity Supply Enterprise shall put contingency plans in place to minimize effects of the emergency.

Criteria:

Each System Operator and Control Area Operator or Electricity Supply Enterprise shall maintain comprehensive and co-ordinated procedures to deal with long-term capacity or energy deficiencies.

Requirements:

1. The SAPP should develop capacity and energy emergency plans that will enable it to reduce to the fullest extent possible, the impact of a capacity of energy shortage on its customers.

Recommendations:

1. Appropriate governmental agencies should be appraised of the capacity and energy emergency plans.

2. If existing interchange agreements cannot be implemented, new agreements providing for emergency capacity or energy transfers, should be prepared.

3. The energy emergency plan should include or consider the following items:

3.1 Co-ordination with neighbouring Systems.

3.2 An adequate plan of fuel inventory which recognizes reasonable delays or problems in the delivery or production of fuel.

3.3 Fuel switch-over and removal of environmental constraints for generating units and other facilities.

3.4 The reduction of the System's own energy use to a minimum.

3.5 Appeals to the public through the media for voluntary load reductions and energy conservation including educational messages on how to accomplish such load reduction and conservation.

3.6 Load management and voltage reductions.

3.7 The operation of all generating sources so as to save the fuel which is in short supply.

3.8 Appeals to large industrial and commercial customers to reduce non- essential energy use and maximize the use of customer-owned generation that relies on fuels other than the one in short supply.

3.9 Use of interruptible and curtailable loads to conserve the fuel in short supply.

3.10 Request appropriate Government Agencies to direct programs which will save energy.

3.11 A mandatory load curtailment plan will be used as a last resort. This plan should preserve the loads essential to the health, safety, and welfare of the community.

3.12 Notify appropriate Government Agencies as the various steps of the emergency plan are implemented.

3.13 Notify co-generators and independent power producers to maximize availability and output.

4. The capacity emergency plan should address the following items:

4.1 Co-ordination with neighbouring Systems.

4.2 Plans to seek removal of environmental constraints which reduce the capacity of generating units.

4.3 The reduction of the System's own energy consumption to a minimum.

4.4 Implementation of load management as appropriate.

4.5 The operation of all generating sources to maximize output and availability.

4.6 Appeals to large industry and commercial customers to reduce no essential energy use during peak and standard hours and maximize any customer owned generation.

4.7 Use interruptible load and curtailable customer loads to reduce capacity requirements.

4.8 Request appropriate Government Agencies to direct programs which will reduce capacity requirements.

4.9 A mandatory load curtailment plan will be used as a last resort. This plan should preserve the loads essential to the health, safety, and welfare of the community.

4.10 Notify appropriate Government Agencies as the various steps of the emergency plan are implemented.

4.11 Notify co-generators and independent power producers to maximize availability and output.

5. Every System Operator and Control Area Operator or Electricity Supply Enterprise should participate in the co-ordination of capacity and energy emergency plans and offer all possible assistance during such emergencies. The following steps should be taken:

5.1 Establish and maintain reliable communications between Systems.

5.2 If a capacity or energy emergency is foreseen, contact neighbouring Systems as far in advance as possible to assess regional conditions and arrange for all the relief that is available or necessary.

5.3 Co-ordinate transmission and generation maintenance schedules to maximize capacity available or to conserve the fuel in short supply; this includes cooling water for hydro stations.

5.4 Arrange deliveries of electrical energy from remote Systems through normal channels.

5.5 Continue to assess the level of generating capacity available and of energy supply and forecast future needs.

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5.D. LOAD SHEDDING

Background:

Each System Operator and Control Area Operator or Electricity Supply Enterprise shall establish a program of manual and automatic load shedding.

Criteria:

Each System Operator and Control Area Operator or Electricity Supply Enterprise shall establish a program of manual and automatic load shedding which is designed to arrest frequency or voltage decays, or extreme power flows that could result in an uncontrolled failure of components of the Interconnection. The program shall be co-ordinated throughout the Interconnection to prevent excessive transmission loadings and voltage deviations.

Requirements:

1. Each System shall establish plans for automatic load shedding and System Controllers shall have authority to implement manual load shedding when necessary.

1.1 Load shedding plans shall be co-ordinated with those of other Members.

1.2 Automatic load shedding shall be initiated as soon as system frequency voltage has declined to a level agreed upon beforehand.

1.2.1 Automatic load shedding shall be carried out in steps and in function of one or more of the following parameters: frequency, rate of frequency decay, voltage level, rate of voltage decay or power flow levels.

1.2.2 The amount of load shed in each step shall be calculated to minimize the risk of uncontrolled separation, loss of generation, or system shutdown.

1.3 Automatic load shedding shall be co-ordinated throughout the SAPP with under-frequency isolation of generating units, tripping of shunt capacitors or any other automatic action which will occur under abnormal frequency, voltage, or power flow conditions.

Recommendations:

1. Automatic load shedding plans should be based on system dynamic performance

where the greatest probable imbalance between load and generation is simulated.

1.1 Plans to shed load automatically should be analysed to ensure that no unacceptable over-frequency, over- voltage or transmission overload will occur.

1.1.1 If over-frequency is likely, the amount of load shed should be reduced or automatic over-frequency load restoration should be provided.

1.1.2 If over-voltages are likely, the load shedding program should be modified to minimize that probability.

2. When scheduling an automatic load shedding operation, the System Controllers should consider the needs of their own Control Area or Utility as well as the capabilities of the interconnectors.

3. A generation-deficient Control Area Operator may establish an automatic isolation plan in lieu of automatic load shedding, if by doing so it removes the burden it has imposed on the Interconnection. This isolation plan may be implemented only with the consent of neighbouring Systems and if it leaves the Interconnection intact.

4. Each System Operator and Control Area Operator or Electricity Supply Enterprise should consider isolating its generators to protect them from extended abnormal voltage and frequency conditions. If feasible, generators should be separated carrying their own auxiliary load.

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5.E. SYSTEM RESTORATION

Background:

Each System Operator and Control Area Operator or Electricity Supply Enterprise shall develop and periodically update a plan to restore its electric network in a stable and orderly manner in the event of a partial or total shutdown. This plan shall be co-ordinated with other Control Area Operators to ensure a consistent restoration of the Interconnection.

Criteria:

A reliable and adequate source of black start power shall be provided. Where these sources are remote from the generating units, instructions shall be issued to expedite availability. Steps to restore generation, shall be verified by real life testing whenever possible.

Requirements:

1. Each System Operator and Control Area Operator or Electricity Supply Enterprise shall establish a restoration plan with adequate operating instructions and procedures to cover emergency conditions, including the loss of vital telecommunication channels.

1.1 Restoration plans must be developed with the intent of restoring the integrity of the Interconnection.

1.2 Restoration plans shall be co-ordinated with neighbouring Systems.

2. System restoration procedures shall be verified by real life testing and simulation.

Recommendations:

1. Where an outside source of power is necessary for starting up generating units, switching procedures should be pre-arranged and periodically reviewed with System Controllers and other operating personnel.

2. Periodic tests should, where possible, be carried out to verify black-start capability.

3. In order to systematically restore loads without overloading the rest of the system, opening circuit breakers should be considered to isolate loads in blacked-out areas i.e. sectionalise the “dead” system.

4. Load shed during a disturbance should be restored only when doing so will have an adverse effect on the System or the Interconnection.

4.1 Load may be restored manually or by supervisory control only by direct action or by an order issued by the Control Centre as generating and transmission capacity become available.

4.2 Automatic load restoration may be used to reduce restoration time.

4.2.1 Automatic restoration should be co-ordinated with neighbouring System Operators and Control Area Operators or Electricity Supply Enterprise.

4.2.2 Automatic restoration should not aggravate frequency excursions, overloading tie-lines, or burden any portion of the Interconnection.

5. All synchronoscopes should be calibrated in degrees. Voltage angle differences at the points of re-synchronisation should be communicated in degrees.

6. Re-energising oil-filled pipe-type cables should be given special consideration, especially if loss of oil pumps could cause gas pockets to form in pipes or potheads.

7. The following should be considered when trying to maintain normal transmission voltage during restoration:

7.1 Remove shunt capacitors, switch-in shunt reactors or add small blocks of load to prevent excessive Ferranti effect when energizing long transmission lines or high-voltage cables at the end of a long, lightly-loaded system.

7.2 The capability of the generators to provide or absorb reactive power.

8. The Control Centres should know the re-synchronising points and procedures. Procedures should provide for alternative courses of action when there is a lack of information or loss of communication that would affect re-synchronising.

9. Each power station should have written procedures for orderly start-up and shutdown of the generating units.

9.1 These procedures should be updated when required.

9.2 Exercises should be held periodically to ensure that plant operators are familiar with the procedures.

10. Each power station should have a source of emergency power to reduce the time required for restarting. Hydro-electric power stations should have built-in restarting facilities.

11. Back-up voice telecommunication facilities, including emergency power supplies and alternative telecommunications channels should be provided to ensure co-ordinated control of operations during the restoration process.

12. Control Centres using SCADA systems should consider providing master trip reset points to each sub-station and power station high voltage yard to expedite the restoration process.

13. Protection schemes should be in working order during the restoration. Relay polarization sources should be maintained during the process.

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GUIDELINE 6: TELECOMMUNICATIONS

6.A. FACILITIES

Background:

In addition to internal System and Control Area telecommunication channels, telecommunication channels shall be installed on every interconnection linking the Member's Systems. These channels should provide adequate telecommunication capabilities during emergency situations, or when adverse operating conditions are imminent.

Criteria:

Each System Operator and Control Area Operator or Electricity Supply Enterprise shall be equipped with adequate and reliable telecommunication facilities internally and with other System Operators and Control Area Operators or Electricity Supply Enterprise to ensure the exchange of information necessary to maintain the reliability of the Interconnection. When possible, redundant facilities using alternative routes and medium, shall be provided.

Requirements:

1. Reliable and secure telecommunication networks shall be provided within and between System Operators and Control Area Operators or Electricity Supply Enterprise.

2. Dedicated telecommunication channels shall be provided between a Control Centre and the Control Centre of each adjacent System.

3. All dedicated telecommunication channels should not require intermediate switching to establish communication.

4. Alternate and physically independent telecommunication channels should be provided for emergency use to back up the circuits used for critical data and voice communications.

5. Restoration services on critical telecommunications channels should be available twenty-four (24) hours per day, every day of the year.

6. Each Control Centre should be able to take control of any telecommunication channel for System Controller use when necessary.

Recommendations:

Each System Operator and Control Area Operator or Electricity Supply Enterprise should inform other System Operators and Control Area Operators or Electricity Supply Enterprise and the Coordination Centre any change of status of availability of the telecommunication facilities.

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6.B. SYSTEM OPERATION TELECOMMUNICATION PROCEDURES

Background:

System Operators shall have appropriate telecommunication procedures to facilitate effective system operations.

Criteria:

Procedures for Control Centre to Control Centre communications, shall be established by System Operators and Control Area Operators or Electricity Supply Enterprise to ensure that data and voice communication between operating personnel are consistent, efficient, and effective during normal and emergency conditions.

Requirements:

Each Control Area Operator shall provide the means to co-ordinate telecommunications between the System Operators or Electricity Supply Enterprise in the Control Area. This shall include the ability to investigate and recommend solutions to telecommunication problems within the Control Area and to other Control Areas.

Recommendations:

Telecommunication procedures to facilitate effective system operations should be shared with the Coordination Centre and other System Operators or Control Area Operators or Electricity Supply Enterprise.

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6.C. LOSS OF TELECOMMUNICATION

Background:

System Operators or Electricity Supply Enterprise shall have alternative telecommunication facilities to ensure continuity of system operations following loss of normal facilities.

Criteria:

Operating instructions and procedures shall be established by each Control Area Operator to enable operations to continue during the loss of telecommunication facilities.

Requirements:

Each Control Area Operator shall have operating instructions and procedures to enable continued operations during the loss of telecommunication facilities.

Recommendations:

Any loss of telecommunication should be reported to the Coordination Centre and affected parties.

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7. PROCEDURE FOR REVISING THESE OPERATING GUIDELINES

INTRODUCTION

These Operating Guidelines shall be based on good logic, scientific reasoning and operating experience. The Guidelines shall be correct, practical and highly considered by all System Controllers. System Controllers shall contribute to the updates and development of the Guidelines to ensure a practical operator's perspective.

The operating policies embodied in the Guidelines shall leave an adequate margin for contingencies. The Directives of the Operating Sub-Committee shall be focused towards interconnected system operations and shall set the pattern for future SAPP and system policies.

The Operating Sub-Committee will continue to investigate the technical background supporting these Guidelines with the assistance of individual Members and through its own efforts. Any Member utility can recommend revisions to the Guidelines through its representation at the Operating Sub-Committee.

REVISION PROCEDURE

1. Any SAPP Member can recommend revisions to the Guidelines through its representative at the Operating Sub-Committee.

1.1 A revision may cover a portion of, or the whole of the Guidelines.

1.2 The proposal for revision must be in writing, and must consider the content of the other Guidelines to ensure compatibility and consistency.

1.3 The proposed revision must indicate whether it is a Requirement, a Recommendation, a Background item, or an Appendix, why it is needed, and how it improves the operating policies.

1.4 The language of the revision shall agree with the purpose. That is, Criteria and Requirements are obligations, while Recommendations and Background statements simply describe good operating practices.

1.5 The person(s) preparing a revision is consistent with the language and format of the Guidelines.

2. The proposed revision shall be presented by a Member representative of the Operating Sub-Committee.

3. The Sub-Committee may vote on the revision directly, or refer it to one or more Work Groups for review or improvement. The proposing member must be represented in the Work Group.

4. If the revision is referred to a Work Group and the Work Group believes a new or revised Guideline is needed, it will prepare a draft for the Operating Sub-Committee's consideration.

5. If the Work Group rejects the proposed revision, the Member can appeal directly to the Operating Sub- Committee through its representative.

6. After a revision is presented to the Operating Sub-Committee and is accepted for further processing:

6.1 The revision shall be distributed to the Operating Members for comments.

6.2 The comments are forwarded to the appropriate Work Group.

6.3 The Work Group produce a revised draft, and if necessary, after considering all the comments, and submit to the Operating Sub-Committee.

7. The amended or new operating guideline requires adoption by the Operating Sub-Committee according to the decision procedures in the Inter-Utility Memorandum of Understanding (IUMOU). However, some amended guidelines may be put on trial period prior to adoption.

8. An amended or new guideline does not need to be re-submitted for approval by the Management Committee. The Management Committee must be informed in writing.

9. Where all the Operating Guidelines have been revised, they shall be submitted to Management Committee for approval.
10. All approved revisions shall be numbered in sequence and history of revision shall be recorded.

11. The Operating Sub-Committee shall evaluate the operating guidelines at least once in ten (10) years.

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8. SIGNATORIES

IN WITNESS whereof the said Operating Members have here to set their hands:

SIGNED ON BEHALF OF: Botswana Power Corporation (BPC)

AT____________________ON THIS__________DAY OF_________________2011

SIGNED: _______________________ WITNESS:_______________________

NAME:_________________________ NAME: __________________________

TITLE: _________________________ TITLE: ___________________________

SIGNED ON BEHALF OF: Copperbelt Energy Corporation (CEC of Zambia)

AT____________________ON THIS__________DAY OF_________________2011

SIGNED: _______________________ WITNESS:_______________________

NAME:_________________________ NAME: __________________________

TITLE: _________________________ TITLE: ___________________________

SIGNED ON BEHALF OF: Electricidade de Moçambique (EDM)

AT____________________ON THIS__________DAY OF_________________2011

SIGNED: _______________________ WITNESS:_______________________

NAME:_________________________ NAME: __________________________

TITLE: _________________________ TITLE: ___________________________

SIGNED ON BEHALF OF: Electricity Supply Corporation of Malawi (ESCOM) Limited

AT____________________ON THIS__________DAY OF_________________2011

SIGNED: _______________________ WITNESS:_______________________

NAME:____________________________	NAME: _____________________________
TITLE: ____________________________	TITLE: ______________________________

SIGNED ON BEHALF OF: Eskom Holdings (of South Africa)

AT______________________ON THIS___________DAY OF___________________2011

SIGNED: __________________________	WITNESS:__________________________
NAME:____________________________	NAME: _____________________________
TITLE: ____________________________	TITLE: ______________________________

SIGNED ON BEHALF OF: Empresa Nacional de Electricidade (of Angola)

AT______________________ON THIS___________DAY OF___________________2011

SIGNED: __________________________	WITNESS:__________________________
NAME:____________________________	NAME: _____________________________
TITLE: ____________________________	TITLE: ______________________________

SIGNED ON BEHALF OF: Lesotho Electricity Company (LEC)

AT______________________ON THIS___________DAY OF___________________2011

SIGNED: __________________________	WITNESS:__________________________
NAME:____________________________	NAME: _____________________________
TITLE: ____________________________	TITLE: ______________________________

SIGNED ON BEHALF OF: Swaziland Electricity Company (SEC)

AT______________________ON THIS___________DAY OF___________________2011

SIGNED: __________________________	WITNESS:__________________________
NAME:____________________________	NAME: _____________________________
TITLE: ____________________________	TITLE: ______________________________

SIGNED ON BEHALF OF: Societe Nationale d'Electricite (of DR Congo)

AT____________________ON THIS__________DAY OF_________________2011

SIGNED: _______________________ WITNESS:_______________________

NAME:_________________________ NAME: __________________________

TITLE: _________________________ TITLE: ___________________________

SIGNED ON BEHALF OF: Tanzania Electricity Supply Company (TANESCO) Limited

AT____________________ON THIS__________DAY OF_________________2011

SIGNED: _______________________ WITNESS:_______________________

NAME:_________________________ NAME: __________________________

TITLE: _________________________ TITLE: ___________________________

SIGNED ON BEHALF OF: ZESA Holdings (of Zimbabwe)

AT____________________ON THIS__________DAY OF_________________2011

SIGNED: _______________________ WITNESS:_______________________

NAME:_________________________ NAME: __________________________

TITLE: _________________________ TITLE: ___________________________

SIGNED ON BEHALF OF: Botswana Power Corporation (BPC)

AT____________________ON THIS__________DAY OF_________________2011

SIGNED: _______________________ WITNESS:_______________________

NAME:_________________________ NAME: __________________________

TITLE: _________________________ TITLE: ___________________________

SIGNED ON BEHALF OF: ZESCO Limited (of Zambia)

AT____________________ON THIS__________DAY OF_________________2011

SIGNED: _______________________ WITNESS:_______________________

NAME:______________________________	NAME: ______________________________
TITLE: ______________________________	TITLE: ______________________________

9. APPENDICES

APPENDIX 1

SANCTIONS OR PENALTIES FOR NON-COMPLIANCE TO THE REQUIREMENTS IN THE GUIDELINES

Non-compliance to requirements of applicable guidelines is monitored in various ways and classified in various levels. Sanctions or penalties associated with various levels of non-compliance are stated in the table below.

Table for Sanctions or Penalties for Non-Compliance to the Requirements in the Guidelines				
Level of Non-Compliance	**Sanctions or Penalties Associated with Non-Compliance**			
	First Offence	Second Offence	Third Offence	Fourth Offence
Level 1	Letter (A)	Letter (A)	Letter (B) and US$1,000.00 or US$1.00 per MW of system peak demand (whichever is lesser)	Letter (B) and US$2,000.00 or US$2.00 per MW of system peak demand (whichever is lesser)
Level 2	Letter (A)	Letter (B) and US$1,000.00 or US$1.00 per MW of system peak demand (whichever is lesser)	Letter (B) and US$2,000.00 or US$2.00 per MW of system peak demand (whichever is lesser)	Letter (B) and US$4,000.00 or US$4.00 per MW of system peak demand (whichever is lesser)
Level 3	Letter (B) and US$1,000.00 or US$1.00 per MW of system peak demand (whichever is lesser)	Letter (B) and US$2,000.00 or US$2.00 per MW of system peak demand (whichever is lesser)	Letter (B) and US$4,000.00 or US$4.00 per MW of system peak demand (whichever is lesser)	Letter (B) and US$6,000.00 or US$6.00 per MW of system peak demand (whichever is lesser)
Level 4	Letter (B) and US$2,000.00 or US$2.00 per MW of system peak demand (whichever is lesser)	Letter (B) and US$4,000.00 or US$4.00 per MW of system peak demand (whichever is lesser)	Letter (B) and US$6,000.00 or US$6.00 per MW of system peak demand (whichever is lesser)	Letter (B) and US$10,000.00 or US$10.00 per MW of system peak demand (whichever is lesser)

APPENDIX 1.A

Frequency Response Characteristic Survey Form (FRC1)

SOUTHERN AFRICAN POWER POOL Frequency Response Characteristic Survey Form FRC 1				
1. Date		Hr. Ending		Control Area:
				Region:
AREA FREQUENCY RESPONSE CALCULATION				
2: Actual Net Interchange Immediately Before Disturbance (Point A)*				MW
3: Actual Net Interchange Immediately After Disturbance (Point B)*				MW
4: Change in Net Interchange				MW Line 3 – Line 2
5: Load (+) or Generation (□) Lost Causing the Disturbance				MW
6. Control Area Response				MW Line 4 – Line 5
7. Change in Interconnection Frequency from Point A to Point B				Hz (–) for frequency decrease; (+) for frequency increase
8. Frequency Response Characteristic				MW/0.1 Hz Line 6 /(Line 7 x 10.0)
OTHER INFORMATION				
9. Frequency Bias Setting				MW/0.1 Hz
10. Net System Demand Immediately Before Disturbance (Point A)				MW
11. Synchronized Capacity Immediately Before Disturbance (Point A)				MW
12.		Frequency at Point A		Hz
13.		Frequency at Point B		Hz
14.	From your charts	Frequency at Point C		Hz

Notes:

Net power delivered *out* of a Control Area (over-generation) is positive (+).Net power received *into* a Control Area (under-generation) is negative (–).

*Control Areas that have a Net Tie Deviation From Schedule Recorder should obtain these values from that device.

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APPENDIX 1.B
TRANSFER CAPABILITY

TRANSFER LIMIT CRITERIA

1. STUDY METHOD

The transfer limits must be determined for normal operation and emergency condition using steady state, stability and voltage collapse models. This must be done using, as far as possible, the N-1 criteria. These limits must be identified and the limit which has the most severe consequences if exceeded, should be recommended as the transfer limit to the appropriate Control Centres. If an operating condition in a system creates a problem, it shall be reflected in the calculation of the transfer limit of the tie-line.

2. CONTINGENCIES

The following single contingencies are recommended:

1.1 Steady State:
• Loss of any transmission line having an impact on the loading of the tie-lines
• Loss of the largest reactive power source
• Evaluation of the danger of voltage collapse

2.2. Transient Condition:
□ System intact:
• Critical transformer in the Interconnected system.
• Loss of one or several generators due to a common cause
• Tripping of one large generator in the system of any SAPP Operating Member.
• Loss of any transmission line or tie-line that could have an impact on the interconnected system

□ Evaluation of the ARC (auto-reclose) policy on tie-lines or any transmission line that will have an impact on the Interconnection.

3. RESULTS ANALYSIS

The studies must ensure that the following criteria are met:

3.1 Steady State:
• No transmission line or transformer should be loaded more than 100% of its nameplate rating.
• The busbar voltages should remain within the following bands

Normal operation:

VOLTAGE	MIN kV (pu)	MAX kV (pu)
765 kV	727 (0.95)	803 (1.045)
533kV	506 (0.95)	559.65 (1.05)
500kV	475 (0.95)	525 (1.05)
400 kV	380 (0.95)	420 (1.05)
350 kV	332.5 (0.95)	367.5 (1.05)
330 kV	313.5 (0.95)	345,5 (1.05)
275 kV	261 (0.95)	289 (1.05)
220 kV	209 (0.95)	231 (1.05)
132 kV	125 (0.95)	138 (1.05)
110 kV	104.5 (0.95)	115.5 (1.05)

The voltage at the following power stations must remain within the following bands:

Kariba South:	Hwange;
324 kV (0.98 pu)	338 kV (1.024 pu)
335 kV (1.015 pu)	345 kV (1.045 pu)

For a N-1 criteria the voltage at Kariba South must remain within the following band:
322 kV (0,9 75 pu)
340 kV (1,03 pu)
Contingency conditions: 10% (consider also insulation limits)

VOLTAGE	MIN kV (pu)	MAX kV (pu)
765 kV	727 (0.95)	803 (1.045)
533kV	506 (0.95)	559.65 (1.05)
500kV	475 (0.95)	525 (1.05)
400 kV	380 (0.95)	420 (1.05)

350 kV	332.5 (0.95)	367.5 (1.05)
330 kV	313.5 (0.95)	345,5 (1.05)
275 kV	261 (0.95)	289 (1.05)
220 kV	209 (0.95)	231 (1.05)
132 kV	125 (0.95)	138 (1.05)
110 kV	104.5 (0.95)	115.5 (1.05)

3.1 Transient Condition:

• The interconnected systems must remain in synchronism following the disturbances mentioned in 2.2 above.

• Following the first swing, the busbar voltages on the Interconnection should not be lower than the values specified in the table below for more than 100 msec:

VOLTAGE	**VOLTAGE DIP**
765 kV	-10%
533 kV	-10%
500 kV	-10%
400 kV	-10%
350 kV	-10%
330 kV	-10%
275 kV	-10%
220 kV	-10%
132 kV	-10%
110 kV	-10%

3. GENERAL

• The system to be studied should be clearly defined as well as the year to study;
• The transfer limits should be studied for peak and minimum load conditions;
• The output of each station should be clearly specified;

During emergencies, the Control Centres can operate the lines at a higher loading than the transfer limits. During such conditions, the Control Centres must realize that they

could experience severe voltage dips, should a fault occur. These risks must be accepted if transfer limits are exceeded. A report has to be issued by the study group and evaluated by the Operating Sub-Committee. The transfer limits shall be updated once the Operating Sub-Committee accepts new results and recommendations.

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APPENDIX 1.C
TIME ERROR CORRECTION PROCEDURES

1. A time correction may be terminated after five (5) hours or after any hour in which a time correction of 0.5 seconds has NOT been achieved. A time correction may be extended beyond five (5) hours if the average correction has exceeded 0.5 seconds per hour.

2. After the termination of a time correction because of the "5-hour rule" above, or failure to make a correction of 0.5 seconds per hour, slow time correction may be reinstated after the frequency has returned to 50 Hz or above for a period of sixty (60) minutes. At least one (1) hour should elapse between the termination and re-initiation notices.

3. The Monitor may postpone or cancel a time correction if requested to do so by any Member, or if warranted by the overall capacity situation.

4. The time reference for the Southern African Power Pool is UTC (Universal Time Co-ordinated) plus two (2) hours.

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APPENDIX 1.D

TRANSMISSION CAPACITY PRIORITY FOR SAPP USE

Note: *The tables are applicable to transmission capacity available to SAPP wheeling after taking into account asset owners' dedicated use.*

(a) TRANSMISSION CAPACITY PRIORITY FOR DAY AHEAD SCHEDULING

PRIORITY FOR DAY AHEAD SCHEDULING	**TRANSACTION**	
	TYPE	**REMARKS**
First (1)	Firm Power Bilateral Transaction as confirmed day ahead.	When competing, the oldest firm transaction takes priority.
Second (2)	Non-Firm Power Bilateral Transaction(s) (including energy un-banking) as confirmed day ahead.	When competing, the oldest non-firm transaction takes priority.
Third (3)	DAM transactions (DAM is run over and above bilateral transactions)	After DAM is closed, DAM transactions shall be firm and shall take priority over non-firm transaction(s).
Fourth (4)	Pay-back of inadvertent energy in kind.	Spare capacity after bilateral and DAM transactions may be utilised in paying back inadvertent energy to reduce accumulation.

(b) TRANSMISSION CAPACITY PRIORITY ON THE DAY OF DELIVERY

PRIORITY ON THE DAY OF DELIVERY	**TRANSACTION**	
	TYPE	**REMARKS**

First (1)	Firm Power Bilateral Transaction as confirmed day ahead.	When competing, the oldest firm transaction takes priority.
Second (2)	Emergency Energy support.	Including any energy sourced for alleviating an emergency situation in the asset owner's system.
Third (3)	Non-Firm Power Bilateral Transaction as confirmed day ahead.	When competing, the oldest non-firm transaction takes priority.
Fourth (4)	DAM transactions (DAM is run over and above bilateral transactions)	After DAM is closed, DAM transactions shall take priority over non-firm transactions except those of asset owners.
Fifth (5)	Pay-back of inadvertent energy in kind.	Spare capacity after bilateral and DAM transactions may be utilised in paying back inadvertent energy to reduce accumulation.

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APPENDIX 1.E
CONTROL PERFORMANCE CRITERIA TRAINING DOCUMENT

[This appendix is at the end of this document after Appendix 4.C.]

APPENDIX 1.F

INADVERTENT INTERCHANGE ENERGYACCOUNTING PRACTICES

INADVERTENT INTERCHANGE ENERGYACCOUNTING PRACTICES

A. INTRODUCTION

Uniform accounting practices will help to identify and eliminate errors. They will also highlight poor control performances that contribute to the accumulation of inadvertent interchanges.

These practices outline the methods and procedures required to reconcile energy accounting and inadvertent interchange balances.

The Control Areas must adhere to the Operating Guidelines to properly monitor and account for inadvertent interchanges.

B. SCHEDULES

All hourly schedules and schedule changes shall be agreed to between the relevant Control Areas prior to implementation. The Agreement shall cover magnitude, rate of change and common starting time.

Dynamic schedule integrated on an hourly basis shall be agreed to between the relevant Control Areas after the end of the hour, but in such a manner as not to impact on inadvertent account.

C. ACCOUNTING PROCEDURES

1. Daily accounting- Each Control Area shall agree with adjacent Control Areas upon the following quantities for each hour and on a daily basis for operational purposes:

1.1 Scheduled interchanges (MWh).
1.2 Actual interchanges (MWh) as derived from the SCADA system or energy meters at the point(s) of interconnection.
1.3 Total amounts during each day for all time-of-use periods i.e. peak, standard, or off-peak.

2. Monthly accounting- After having agreed on scheduled and actual interchanges during the all times-of use of each day, adjacent Control Areas shall verify that the accumulated values for the month end balance.

3. The time of use hours are defined as follows:

TIME OF USE CLASSIFICATION			
Hour Ending	**Weekday**	**Saturday**	**Sunday**
1	Off-Peak	Off-Peak	Off-Peak
2	Off-Peak	Off-Peak	Off-Peak

3	Off-Peak	Off-Peak	Off-Peak
4	Off-Peak	Off-Peak	Off-Peak
5	Off-Peak	Off-Peak	Off-Peak
6	Off-Peak	Off-Peak	Off-Peak
7	Standard	Off-Peak	Off-Peak
8	Peak	Standard	Off-Peak
9	Peak	Standard	Off-Peak
10	Peak	Standard	Off-Peak
11	Standard	Standard	Off-Peak
12	Standard	Standard	Off-Peak
13	Standard	Off-Peak	Off-Peak
14	Standard	Off-Peak	Off-Peak
15	Standard	Off-Peak	Off-Peak
16	Standard	Off-Peak	Off-Peak
17	Standard	Off-Peak	Off-Peak
18	Standard	Off-Peak	Off-Peak
19	Peak	Standard	Off-Peak
20	Peak	Standard	Off-Peak
21	Standard	Off-Peak	Off-Peak
22	Standard	Off-Peak	Off-Peak
23	Off-Peak	Off-Peak	Off-Peak
24	Off-Peak	Off-Peak	Off-Peak

4. A SAPP Public Holiday shall have the same time-of-use classification as a Sunday. The Co-ordination Centre shall publish SAPP Public Holidays every year before the beginning of the year in which they will apply.

C. ADJUSTMENT FOR ERRORS

1. Periodic adjustments shall be made to correct for differences between hourly telemetered MWh totals and the totals derived from the tariff meters on the tie-lines.

2. Adjacent Control Areas shall agree upon the differences described above and shall assign the relevant corrections to the hours.

1. Any adjustment necessary due to known metering errors, transmission losses or other circumstances shall be handled similarly.

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APPENDIX 1.G
CONTROL SURVEY CHECK-LIST AND EVALUATION FORM

UTILITY________________ DATE___________________

KEY RESULT AREA	KEY PERFORMANCE INDICATOR	RESPONSE	COMMENT / REMARKS	EVALUATION	
				NOTES	SCORE (1-10)
Design of Control Equipment	Is Control Equipment in accordance with accepted industry norms?				
	Does the Control Equipment generally display and present clear and understandable picture of Control Area parameters?				
	Is all necessary information from own Control Area displayed and recorded even during major system disturbances?				
	Is all necessary information from other Control Areas displayed and recorded even during major system disturbances?				
	Is Control Equipment able to telemeter MW and MWh power flow at all points of interconnection? (List all points that are and are not telemetered.)				
	Does the Control Area have agreed-upon terminals utilizing common metering equipment with neighbouring systems? (If yes, list number and location of the terminals.)				
	Are back-up power supplies provided for continuous operation of AGC and vital data recording equipment during loss of normal power? (If yes, mention at what locations.)				
	Does the Control Equipment generally enable the Control Area to continuously meet its system and interconnection control obligation as stipulated in the SAPP governing documents?				
Operation of Control Equipment	Are all variables necessary for monitoring control performance of the Control Area provided and recorded?				
	Are all variables necessary for monitoring generation response in the Control Area provided and recorded?				

	Is net actual tie-line interchange of the Control Area continuously recorded?				
	Has the Control Equipment ever broken down? (If yes, mention the date and whether it was repaired or not.)				
	Does the Control Area continuously monitor and record system frequency? (If yes, from which location(s) of the system.				
	Are all tie-line flows included in Area Control Error (ACE) calculation of the Control Area? (List the tie-lines.)				
	At the end of every hour, does the Control Area perform control error checks using tie-line MWh meters to determine the accuracy of Control Equipment? (Note: the Survey Team will select typical hours at random and perform these error checks.)				
	Have control settings of Control Equipment ever been adjusted to compensate for equipment error(s)? (If yes, mention date and location.)				
	Is Area Control Error (ACE) continuously monitored and recorded by the Control Area? (If yes, provide the ACE chart or data derived from digital processing of the ACE signal for a twenty-four (24) hour duration randomly selected by the Survey Team. Also provide the greatest hourly change (either increasing or decreasing) in the Control Area's Net Energy sent out that occurred on the day of the Control Areas peak demand. The Survey Team will use these in the formula for calculating control performance.)				
	Does the Control Area continuously monitor and measure its Control Area performance? (If yes, how often does the Control Area perform after-the-fact analysis of Control Area performance? Provide the results obtained.)				
Automatic Generation Control (AGC)	What is the predominant AGC mode of operation of the Control Area?				
	Have other AGC modes of operation been temporarily implemented by the Control Area? (If yes, say when and why.)				
	Has AGC ever been switched off to manual control? (If yes, say when and why.)				

	List units and capacity of generation under AGC in the Control Area.				
	List units and capacity of generation not under AGC in the Control Area and reason(s) why.				
	Have turbine governors and other control systems, including AGC and HVDC control systems ever been tested to verify their correct operation? (If yes, when and what were the findings?)				
	What are the Control Area's frequency dead band and the ACE dead band settings in Hz for AGC?				
	Has the automatic time error control been implemented in the Control Area's AGC scheme? (If yes, from when?)				
	Has the Control Area ever participated in the correction of time error? (If yes, say how many times and when?)				
	What is the Control Area's frequency bias setting and how was it determined and when was the last time it was reviewed?				
	Is data for calculating system frequency response characteristic available for incidents of frequency excursions that occurred in the last twelve months? (If yes, provide the data. The Survey Team will use this data to cross-check frequency bias.))				
OPERATING PROCEDURES	Does the Control Area have procedures for frequency control? (If yes, highlight them.)				
	Does the Control Area have procedures for voltage control? (If yes, highlight the procedures.)				
	Does the Control Area experience voltage excursions? (If yes, highlight them and course(s) of action taken. Also list available reactive power resources.)				
	Does the Control Area have procedures for time error correction? (If yes, highlight them.)				
	Does the Control Area have automatic under-frequency load shedding scheme. (If yes, highlight the scheme, including amount of load and any grading.)				
	Does the Control Area have operating reserve policy? (If yes, highlight the policy, including				

	amount of spinning and quick reserve.)				
	What is the Control Area's annual peak demand and largest generation unit in service?				
	Does the Control Area have documentation procedures for key control and operations information? (If yes, highlight them.)				
	Does the Control Area have procedures for system disturbance reporting and investigation? (If yes, highlight them.)				
	Does the Control Area have procedures for emergency preparedness? (If yes, highlight them including black-start capabilities.)				
	Does the Control Area have procedures for equipment maintenance? (If yes, highlight them.)				
	Does the Control Area have procedures for system controller communications? (If yes, highlight them.)				
	Does the Control Area have procedures for operation planning? (If yes, highlight them including up-to-date studies being carried out as reference for establishing system operation.)				
	Does the Control Area have a philosophy for protection relay design, coordination and maintenance? (If yes, highlight the philosophy.)				
	Is appropriate technical information concerning protective relays in the Control Area available to system controllers? (If yes, when was it last updated?)				
ENERGY INTERCHANGE	Does the Control Area have energy interchange contracts presently? (If yes, list name, age, and magnitude of both firm and non-firm energy interchange contracts).				
	Does the Control Area manage and account for inadvertent energy on a day-to-day basis? (If yes, highlight methods used.)				
	Does the Control Area pay back inadvertent energy? (If yes, highlight methods used.)				
EQUIPMENT MAINTENANCE	Was last year's maintenance plan fully executed? (If no, say why?)				
	Is the current year's equipment maintenance schedule available? (If yes, say whether it has				

	been coordinated with other systems and communicated to all stakeholders?)				
TELECOM MUNICATION FACILITIES	Are telecommunications facilities readily available for intra- and inter control area communications? (If yes, list them and indicate any dedicated channels to adjacent systems.)				
	Are there any telecommunications facilities that are out of service? (If yes, from when and why?)				
CONTROL ORGANISATION	Does the Control Area have an organisational structure for power system control, operational planning, and energy trading functions? (If yes, provide the chart complete with titles, incumbents, qualifications, experience, level of authority, any vacancies.)				
	Does the Control Area have training programmes for system control, operations and energy trading personnel? (If yes, highlight the programme including the latest beneficiaries with dates)				
CONTROL SECURITY	Does the Control Area have back-up facilities for vital system and operations data? (If yes, highlight them.)				
	Does the Control Area have a plan of action to restore system in an orderly manner in the event of partial or total shutdown? (If yes, when was it last updated and has the operating personnel been drilled in the implementation of the plan?)				
	Does the Control Area have survival plans to continue operation of the system in the event of control centre becoming inoperable? (If yes, have control personnel been drilled on the plans?)				

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APPENDIX 1.I
CONTROL AREA ESTABLISHMENT APPLICATION FORM

SAPP

SOUTHERN AFRICAN POWER POOL

CONTROL AREA ESTABLISHMENT APPLICATION FORM

Please note: *All Applicants are required to provide detailed information to the SAPP Coordination Centre in support of their application for membership. Where applicable, application fees paid are non-refundable.*

1. Applicant Name (Full Corporate Name)

A. Applicant is *(please tick appropriate category):*

☐ A corporation created under the laws of

____

☐ A limited liability company created under the laws of

____

☐ A state owned enterprise created under the laws of

____

☐ A partnership

☐ Other. Please describe.

____

B. Date of incorporation/formation/organization:

____

C. Description of Applicant’s business operations:

____

____

2. **Web Page Address: ____**

3. **Activities that Applicant is currently conducting**

☐ Broker (arranges power transactions without taking title)

☐ Co generator

☐ Cooperative

☐ Municipality or other governmental agency which does not meet the definition of a sate owned enterprise.

☐ Independent Power Producer

☐ Load Aggregator (purchases at wholesale to sell at retail)

☐ Publicly Owned Entity

☐ Power Marketer (purchases and sells at wholesale): *Please provide the certified copies showing approval and or licensing by a regulator or duly appointed to engaging in power marketing activities and the exact name of the entity for which such activities were approved.*

____

☐ Qualifying Facility

☐ Transmission and/or Distribution Company

☐ Vertically Integrated Utility

☐ Other (please describe)

____

4. **Generation**

A. **Applicant's Generation**

☐ No Generation.

☐ (i) Owns, or (ii) leases with rights equivalent to ownership, facilities for the generation of electric energy that are located in the …………………………Control Area.

Please indicate on a separate sheet of paper attached to this Questionnaire the following information for each such facility listed:

i. Total Generation (Name-Plate Capacity);
ii. Net Generation; and
iii. Ancillary services to be provided.

B. Affiliate's Generation

☐ No Generation.

☐ Affiliate(s) (i) Own, or (ii) lease with rights equivalent to ownership, facilities for the generation of electric energy that are located in the SAPP area. Please indicate on a separate sheet of paper attached to this Questionnaire a list of Generation assets in the region, or owned by your Affiliates listed in Section VI

5. Category of SAPP membership:

Please indicate your category of SAPP membership *(select only one)*:

- ☐ **Operating Member** - Must also apply to sign the Agreement between Operating Members (ABOM) and comply with its provisions including but not limited to the Operating Guidelines. Please indicate the aggregate (in megawatts) for your generation facilities in the each country in the region.

- ☐ **Non-Operating Members** - No further application necessary.

- ☐ **Independent Power Producer.** Please indicate the aggregate (in megawatts) for your generation facilities in the each country in the region.

- ☐ **Independent Transmission Company**

- ☐ **Service Providers**

6. Documentation and information required.

Applicants must submit the certified copies of the following documents with this application.

1. Description of corporate structure using a flow chart to include all parent and subsidiary relationships
2. Applicant's ultimate corporate parent including address.
3. A list of all corporate Affiliates / subsidiaries of the applicant, including Affiliates /subsidiaries of your Affiliates/subsidiaries
4. A list of any Affiliates / subsidiaries named above who are members of SAPP.
5. Certified copy of licence(s) or authorisation to engage in cross-border electricity trade issued by a regulator or competent authority /body.
6. Maps showing current and planned interconnection to the SAPP Grid.
7. For applicants from non-SADC member states, certified copy of signed accession to the SADC treaty and proof that any specified terms and conditions have been met.

7. Applicant Contact Information

For further information regarding this application: **Contact(s) and Titles(s):** Primary: Alternate:		
Address – Street	**City, State**	**Region or Country**
Phone(s):	**Fax #:**	**E-mail address:**

Chief Executive Officer: **Contact(s) and Titles(s):** Primary:		
Address – Street	**City, State**	**Region or Country**
Phone(s):	**Fax #:**	**E-mail address (s):**

Evidence of Due Authorization: Applicants are required to provide one of the following: a certified copy of a vote of the applicant's board of directors, or such other body or bodies as may be appropriate, duly authorizing the submission of this application.

SAPP may choose to inspect facilities and hold discussion with the applicant. In the event that inspection is required, the cost thereof shall be borne by the applicant following consultations with the applicant.

Membership Application Fee: The SAPP shall set application fees annually and announce them before 30 April of each year.

Additional Questions: If you have any questions pertaining to the SAPP membership, to avoid any confusion or misinformation that could result from differing interpretations of questions and/or answers, please contact:

SAPP Coordination Centre Manager, Coordination Centre

17th Floor, Intermarket Life Tower, 77 Jason Moyo Avenue

Corner Jason Moyo Ave & Sam Nujoma Street, PO Box GT897, Harare, Zimbabwe
Tel: (263-4) 250560/2/4/9

Fax: (263-4) 250565/6

AFFIDAVIT

I, ________________________, being duly sworn, depose and say that:

2. I am ___________________________ [insert OFFICER (or equivalent) TITLE] of __________________________________[insert APPLICANT NAME], and as a duly authorized representative of ___________________________[insert APPLICANT NAME] with the power and authority to execute contracts on behalf of _________________________________[insert APPLICANT NAME]; I am making this affidavit on behalf of [insert APPLICANT NAME].

3. I have reviewed the Revised Inter Utility Memorandum of Understanding dated as of ______________________________2006, as amended, (the "Agreement") and its financial and other obligations, including the billing policy and financial assurance policies, and I fully understand and acknowledge ___________________________ [insert APPLICANT NAME]'s financial obligations that could arise.

I declare under the pains and penalties of perjury that I have reviewed this affidavit and the statements I have made in it and declare that they are true.

Name: ____

Title: ____

Company: ____

Address:____

Subscribed to and sworn before me on this _____ day of _______________, 200___.

Notary Public: ____

Signature of Applicant: ____

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APPENDIX 2.A
Sharing of Spinning Reserve Between Operating Members

SAPP OPERATING RESERVES FOR 2011					
Sharing of Spinning Reserve Between Operating Members					
Utility Name	Largest Generator [MW]	Maximum Demand [MW]	Spinning Reserve [MW] e	Quick Reserve [MW] f	Operating Reserve [MW] g = e + f
ESKOM	900	35850	517.8	517.8	1035.6
ZESA	220	1714	50.7	50.7	101.5
ZESCO	180	1483	42.4	42.4	84.7
BPC	33	553	10.8	10.8	21.6
EdM	24	435	8.2	8.2	16.4
NAMPOWER	80	451	16.6	16.6	33.2
SNEL	62	1028	20.2	20.2	40.3
LEC	24	108	4.7	4.7	9.4
SEC	10	204	3.7	3.7	7.3
TOTAL	1533	41826	675	675	1350

APPENDIX 2.F

DAILY SAPP SYSTEM STATUS OUTLOOK REPORT FORM

SAPP

SOUTHERN AFRICAN POWER POOL – SYSTEM STATUS OUTLOOK REPORT

1. PEAK LOAD AND LOAD REDUCTION

DATE		BPC	HCB	Eskom	CEC	LEC	NamPower	SEC	SNEL	ZESA	ZESCO
PEAK LOAD (MW)											
TIME OF PEAK LOAD											
LOAD-REDUCTION (MW)											
NOTE(S)											

2. SYSTEM DISTURBANCE(S)

SYSTEM	DATE-TIME	DESCRIPTION

3. PLANT OUTAGE(S)

SYSTEM	START DATE-TIME	END DATE-TIME	DESCRIPTION

4. ABOUT TIE-LINES

TIE-LINE	DATE-TIME	DESCRIPTION

5. PEAK LOAD FORECAST

DATE	TUE 02NOV10	BPC	HCB	Eskom	CEC	LEC	NamPower	SEC	SNEL	ZESA	ZESCO
PEAK LOAD FORECAST (MW)											
LOAD FORECAST TIME											

6. PREVIOUS WEEK OUTLOOK

SYSTEM	DATE-TIME	DESCRIPTION

7. WEEK AHEAD OUTLOOK

SYSTEM	DATE-TIME	DESCRIPTION

8. OTHER

SYSTEM	DATE-TIME	DESCRIPTION

APPENDIX 2.G

PRELIMINARY SYSTEM DISTURBANCE REPORT FORM

S A P P

SOUTHERN AFRICAN POWER POOL – PRELIMINARY DISTURBANCE REPORT

1. UTILITY NAME					
2.1 REPORT BY (NAME)		2.2 PHONE		2.3 E-MAIL	
3.1 DATE AND TIME OF THE DISTURBANCE					
3.2 BRIEF DESCRIPTION OF THE DISTURBANCE					
4. SYSTEM LOAD PRIOR TO THE DISTURBANCE (GENERATION + IMPORTS - EXPORTS) (MW)					

5. FREQUENCY RESPONSE (Hz):	5.1 PRIOR TO DISTURBANCE		5.2 AT WORST POINT		5.3 RESTORED TO	

6. CHRONOLOGICAL ORDER OF EQUIPMENT TRIPS (e.g. GENERATOR, TRANSFORMER, LINE)

NO	TIME	EQUIPMENT	PROTECTION RELAY FLAG / ALARM
1			
2			

7. GENERATION STATUS (OF REPORTING SYSTEM)

7.1 JUST BEFORE THE DISTURBANCE			7.2 JUST AFTER THE DISTURBANCE		
STATION	NO. OF UNITS	TOTAL MW	STATION	NO. OF UNITS	TOTAL MW
TOTAL	0	0.00	TOTAL	0	0.00

8. INTERCHANGE STATUS (OF THE REPORTING SYSTEM) *Note: Import = Negative(-); Export = Positive(+)*

8.1 JUST BEFORE THE DISTURBANCE				8.2 JUST AFTER THE DISTURBANCE			
	TIE LINE	MW	Mvar		TIE LINE	MW	Mvar
1				1			
2				2			

9. IMPORT/EXPORT STATUS IN THE HOUR OF DISTURBANCE *Note: Import = Negative(-); Export = Positive(+)*

	CONTRACT	SCHEDULE(MW)	ACTUAL(MW)		CONTRACT	SCHEDULE(MW)	ACTUAL(MW)
1				3			
2				4			

10. CAUSE OF DISTURBANCE

11. CONCLUSION / RECOMMENDATION / REMARKS

APPENDIX 2.H.(i)
CIRCUIT ISOLATION AND EARTHING CERTIFICATE

<u>Circuit Isolation and Earthing Certificate</u>

Certificate No.:------------------------ Date------------

Circuit:---

<u>Section 1: Isolation Declaration</u>

I hereby declare that in joint operation between ----------- and ---------National Control Centres, the above-mentioned circuit is Isolated from all sources of supply and is now ready to be "Earthed".

Signed on behalf of---------------- Name --------- Time---------

Signed on behalf of---------------- Name --------- Time---------

<u>Section 2: Earthing Declaration</u>

*I hereby declare that the above-mentioned circuit is now "**Isolated and Earthed"**. Safety devices and controlled earths will not be removed untill all Permit-to-work cards have been cancelled by all utilities*

Signed on behalf of---------------- Name --------- Time---------

Signed on behalf of---------------- Name --------- Time---------

<u>Section 3: Circuit Hand-Back</u>

I hereby declare that all Permit-to-work cards on the above-mentioned circuit have been cancelled and that all the working Earths have been removed. Workers and equipment are withdrawn and controlled Earths are still applied.

Signed on behalf of---------------- Name --------- Time---------

Signed on behalf of---------------- Name --------- Time---------

<u>Section 4: Earthing Removal Declaration</u>

I hereby declare that all Earths have been removed from the above-mentioned circuit and it is safe to return to service.

Signed on behalf of---------------- Name --------- Time---------

Signed on behalf of---------------- Name --------- Time---------

Signed on behalf of---------------- Name --------- Time---------

APPENDIX 2.H.(ii)
LIVE LINE WORK CERTIFICATE

<u>Live Line Work Certificate</u>

(This certificate permits the issue of live-line permits-to-work only)

Certificate No.:------------------------ Date------------

Circuit:--

<u>Section 1: Issuing</u>

I hereby declare that in joint operation between ----------- and ---------National Control Centres, the above-mentioned circuit is off "ARC" and "Live-line work in progress" labels have been posted and will remain on the panels, until all the Permit-to-work cards have been cancelled by all parties concerned and also mutually agreed upon by all relevant Control Centres involved.

Signed on behalf of (utility) ----------------- Name --------- Time---------

Signed on behalf of (utility) ----------------- Name --------- Time---------

<u>Section 2: Cancellation</u>

Certificate No.:------------------------ Date------------

I hereby declare that in joint operation between ----------- and ---------National Control Centres, all the Live-line Permit-to-work cards on the abovementioned circuits have been cancelled and that the Live-line Work certificate is now cancelled by all parties concerned.

Signed on behalf of (utility) ----------------- Name --------- Time---------

Signed on behalf of (utility) ----------------- Name --------- Time---------

APPENDIX 2.I

EXAMPLE TABLE FOR CONTROL AREA SERVICES CHARGES

<u>Example:</u> Calculation of Control Area (CA) Service Charges for a TSO (hosted utility)				
<u>Standing Costs</u>			**<u>Formula used</u>**	**<u>Remarks</u>**
WACC (Weighted Average Capital Cost)	8.00%		Input - 8% SAPP value	
Control Area Peak Demand	1000	MW	Input - CA data	Includes peak demand of hosted TSOs
Control Area Installed Generation Capacity	1200	MW	Input - CA data	Includes installed generation of hosted TSOs
TSO Peak Demand	600	MW	Input - TSO data	TSO is the system being hosted by a Control Area
TSO Peak Installed Generation Capacity	600	MW	Input - TSO data	"
TSO portion of the capital costs	0.50		=MAX(B7,B8)/MAX(B5,B6)	"
Capital cost of control system	$10,000,000.00		Input - Actual cost or depreciated cost	Control system is the AGC facility residing at National Control Centre (excluding the control gear at power stations)
Life of control system	15	Yrs		"
Control system capital costs per annum	$1,168,295.45	pa	=-PMT(B4,B11,B10)	"
Capital cost of telecommunications	$1,000,000.00		Input - Actual cost or depreciated cost	Telecommunications system is the facility used to exchange Interconnection and operating information both internally and externally necessary for reliable hosting of a TSO.
Life of telecommunication system	25	Yrs		"
Telecommunication capital costs per annum	$93,678.78	pa	=-PMT(B4,B14,B13)	"
Capital cost of telemetering	$1,000,000.00		Input - Actual cost or depreciated cost	Telemetering system is the facility used to acquire Interconnection and operating system analogue data (power flows, system frequency, system voltages) or status of switches in real time necessary for reliable hosting of a TSO.

Life of telemetering system	20	Yrs		"
Telemetering capital costs per annum	$101,852.21	pa	=-PMT(B4,B17,B16)	"
Total CAS capital costs per annum	$1,363,826.44		=B18+B15+B12	
TSO CAS standing costs	**$681,913.22**	**pa**	=B20*B9	
Holding Costs				
O & M costs	$1,000,000.00	pa	Input - O & M costs	Operation and maintenance of the telecommunications system, telemetering system and energy scheduling system.
Total number of staff per shift	5		Input	Total number of system control staff involved in all activities including those of of hosting a TSO
Number of staff for AGC per shift	1		Input	Equivalent number of system control staff who would be 100% involved in activities of hosting a TSO
AGC cost ratio	0.2		=B29/B28	AGC facility residing at National Control Centre (excluding the control gear at power stations)
AGC O & M costs	$200,000.00	pa	=B30*B27	"
AGC Training costs	$20,000.00	pa	Input from training costs	Training of maintenance and operations staff for the Control system.
Total number of staff involved in interchange energy scheduling	6		Input	Total number of system control staff involved in all activities including those of of hosting a TSO
Number of staff for TSO interchange energy scheduling per shift	1		Input	Equivalent number of system control staff who would be 100% involved in activities of hosting a TSO
Interchange energy scheduling cost ratio	0.166666667		=B35/B34	AGC facility residing at National Control Centre (excluding the control gear at power stations)
Interchange energy scheduling O & M costs	$166,666.67	pa	=B36*B27	"
Interchange energy scheduling Training costs	$10,000.00	pa	Input from training costs	Training of maintenance and operations staff for the Control system.
Holding ACS costs per annum	**$396,666.67**	**pa**	=B31+B32+B37+B38	

TSO CAS holding costs	**$198,333.33**	**pa**	=B34*B9	
Usage Costs				
None identified	$0.00	pa		
TSO CAS usage costs	**$0.00**	**pa**	=B40*B9	

APPENDIX 3.D

UNDER-FREQUENCY LOAD SHEDDING SETTING OF ALL UTILITIES

AUTOMATIC UNDER-FREQUENCY LOAD SHEDDING IN THE SAPP

UTILITY	UNDER-FREQUENCY	% LOAD OF MAX DEMAND TO BE SHED	TIME DELAY
ESKOM	Voluntary 1. 49.2 Hz 2. 49.1 Hz 3. 49.0 Hz Mandatory 1. 48.8 Hz 2. 48.5 Hz 3. 48.2 Hz 4. 47.9 Hz	10% 10% 10% 10% 10%	0,3 seconds 0,3 seconds 0,3 seconds 2 seconds 2 seconds 2 seconds 1 seconds
ZESA	Mandatory 1. 48.8 Hz 2. 48.5 Hz 3. 48.2 Hz 4. 47.5 Hz 5. Rate 0.8Hz/secs	-10% -10% -10% -10% -15%	No time delay No time delay No time delay No time delay No time delay

ZESCO	Mandatory 1. 48.75 Hz 2. 48.5 Hz 3. 48.0 Hz 4. 47.75 Hz 6. Rate 0.8Hz/secs	-8% -8% -5% -8% -15%	700ms 700ms 700ms 700ms No time delay
EDM	Mandatory 1. 49.0 – 48.7 Hz 2. 47.7 – 49.0 Hz	-10% -5%	No time delay No time delay
NamPower	Under review		
BPC	Mandatory 1. 49.0Hz 2. 48.7Hz 3. 48.3Hz 4. 48.1Hz	4.7% 5.2% 9.4% 24.1%	2 seconds 2 seconds 2 seconds 2 seconds
SEC	No scheme		
LEC	No scheme		
SNEL	No scheme		

APPENDIX 4.C

SUGGESTED ITEMS FOR INCLUSION IN THE TRAINING COURSE OF SYSTEM CONTROLLERS

This Appendix lists the items that should be included in a training course for System Controllers.

NORMAL OPERATIONS

1. Basics of Power Flows:

1.1 Alternating Current (AC):

1.1.1 Generation
1.1.2 Transmission
1.1.3 Transformation
1.1.4 Loads and effect on system
1.1.5 Phase angle
1.1.6 Phase shifting transformers
1.1.7 Reactors
1.1.8 Capacitors
1.1.9 Parallel flows

1.2 Direct Current (DC):

1.2.1 Transmission
1.2.2 Interconnections

2. Voltage Control:

2.1 Load characteristics
2.2 Standards
2.3 Schedules
2.4 Cause for voltage deviations
2.5 Generation excitation
2.6 Transformer taps
2.7 Reactive sources e.g

2.7.1 Generators
2.7.2 Synchronous condensers
2.7.3 Capacitors
2.7.4 Reactors
2.7.5 Static VAr compensators

2.8 Line and cable switching

1. ***Concepts of Active Power Control***:

1.1 Operating Reserve
1.2 Dispatching techniques
1.3 Generators AGC's and Governors
1.4 Area Control Error (ACE)
1.5 Interchange control
1.6 Inadvertent interchange
1.7 Special operating programme(s)

2. Economic Operation:

2.1 Dispatching techniques
2.2 Heat rates
2.3 Fuel costs
2.4 Start-up and shutdown costs
2.5 Pumped storage costs
2.6 Unit commitment
2.7 Economic loading
2.8 Effects of Transmission losses
2.9 Reactive flows
2.10 Utilisation of limited

	energy capacity 2.11 Pumped storage capacity 2.12 Incremental and decremental costs 2.13 Accounting procedures
3. Operating Guidelines and Constraints: 3.1 Operating Manual 3.2 Operating Guidelines 3.3 Control Performance Criteria 3.4 Reliability Criteria for Interconnected Systems Operation 3.5 Contingency assessment. 3.5.1 Generator outages 3.5.2 Transmission lines outages 3.5.3 Transformer outages 3.5.4 Busbar Outages 3.5.5 Combination of above 3.5.6 Outages of reactive energy sources 3.6 Equipment capabilities and limits: 1.6.1. Thermal 1.6.2. Voltage / Reactive 1.6.3. Relay 1.6.4. Stability 3.7 Reserve requirements (special) 3.8 Time error and frequency 3.9 Voltage 3.10 Switching-voltage and redistribution of power flows 1.1	***6 Operating considerations:*** 1.1 Safety of personnel and equipment 1.2 Synchronising 1.3 Line switching and clearance 1.4 Ferro resonance 1.5 Metering failures 1.6 Maintenance scheduling criteria: 1.6.1 Generation 1.6.2 Transmission 1.6.3 Substation 1.6.4 Protection ***2. Dynamic Performance of System:*** 2.1 Transient stability 2.2 Oscillations 2.3 Relay action 2.4 Control-initiated swings 2.5 Causes of disturbances 2.6 Special Protection System (SPS)

ABNORMAL OPERATIONS	
3. Dynamic Performance of Equipment: 3.1 Governor response 3.2 Exciter response 3.3 Relays and breakers 3.4 Under-frequency relays: 3.5 Metering 3.6 Automatic controls: 3.6.1 Plant 3.6.2 AGC 3.6.3 Voltage 3.6.4 Generator and load tripping 3.6.5 System separation 3.7 Special Protection System (SPS)	***4. Recognition of Abnormal Conditions:*** 4.1 Loss of load 4.2 Breaker operation 4.3 Line fault 4.4 Generator trip 4.5 Frequency deviation 4.6 Interchange deviation 4.7 Voltage level 4.8 System separation 4.9 Communication with power stations, substations and other utilities 4.10 Parallel flows
5. Remedial Action: 5.1 Islanding 5.2 Load shedding 5.3 Generator dropping / trips 5.4 Shifting generation 5.5 Switching generation 5.6 Isolated system operation 5.7 High-and-low –frequency operation 5.8 High-and-low-voltage operation	***6. Recovery:*** 6.1 Generation start-up capabilities and pick-up rates 6.2 Sectionalising 6.3 Load pickup priorities and problems 6.4 Synchronising within a System and at the Points of Interconnection
COMMUNICATIONS	
1. Facilities Available:	***2. Information Exchange:***

1.1 Common power line carrier schemes 1.2 Private microwave systems 1.3 Radio 1.4 Emergency power supplies 1.5 Satellite communication systems	2.1 Standard terminology 2.2 Neighbouring Systems 2.3 Power Plants 2.4 Substations 2.5 Management 2.6 News Media 2.7 Governmental agencies
INTERCONNECTED SYSTEM OPERATION	
1. SAPP Operating Criteria and Guidelines: 2. ***Philosophy of Operation***: 2.1 Benefits 2.2 Obligations 2.3 Responsibilities 2.4 Authority	3. ***Effects on System Performance***: 3.1 Frequency 3.2 Interchanges 3.3 Reserves 3.4 Mutual assistance 3.5 Pooling arrangements 3.6 Communications ***4. Abnormal Operations:*** 4.1 Responsibilities 4.2 Actions required
MODERN POWER SYSTEM CONTROL AIDS	
1. Equipment: 1.1 Man-machine interface 1.2 Supervisory control 1.3 Data acquisition 1.4 Fail over and restart ***2. Theory and use of Software Applications for Normal and Emergency Conditions:*** 2.1 Interaction of software results on Systems and other programs 2.2 Effects	***3. Alternative Control Methods during Equipment and Software Unavailability:*** ***4. Typical Software Applications:*** 4.1 Economic dispatch 4.2 AGC 4.3 Unit commitment 4.4 Operator load flow 4.5 Contingency analysis 4.6 Corrective strategies 4.7 State estimation

	4.8 Interchange accounting 4.9 Transmission evaluation 4.10 Automated billing
SUPERVISORY SKILLS	SAPP POWER NETWORK
1. Personnel supervision 2. On-the-job training, preparation of 3. Verbal communication 4. Decision - making 5. Influence of stress	1. Overview of the SAPP 2. The SAPP transmission network 3. System operations terminology and equipment ratings 4. System disturbances

APPENDIX 1.E

CONTROL PERFORMANCE CRITERIA TRAINING DOCUMENT

Training Document Subsections

This document provides the NERC Control Performance Compliance Survey coordinator with specific instructions on calculating the control performance of the control area and instructions to complete the survey forms contained in the document as CPS Form 1 and 2 and Form DCS.

The control area is required to continuously monitor its control performance and report its compliance results at the end of each month. This training document provides an explanation of the reporting requirements for the NERC Control Performance Standard.

A. Area Control Error

[Appendix 1A — The Area Control Error Equation]

The control area's Area Control Error (ACE) is the basis for the calculation of control parameters used to evaluate control performance. One part of the NERC Control Performance Standard (CPS) is defined by the control parameter:

$$\left[\left(\frac{ACE_i}{-10B_i}\right)_1 * \Delta F_1\right]$$

wherein the subscript 1 indicates one-minute clock averages. This parameter is used to determine a control area's control performance with respect to the control area's impact on system frequency. The values of ACE to be used throughout the calculation of the control parameter shall reflect its actual value and exclude short excursions due to transient telemetering problems or other influences such as control algorithm actions. Erroneous readings such as “spikes” due to telemetering error or other false influences should be excluded from the calculations. However, the computations should include ALL of the non-erroneous intervals (i.e., do not exclude intervals that contains disturbance conditions). This ACE is defined as net actual interchange less net scheduled interchange less frequency bias contribution and meter error. It does not include offsets (e.g., unilateral inadvertent payback, WSCC’s automatic time error correction, etc.)

B. Performance Standard

[Appendix IA — The Area Control Error Equation]

The CPS is composed of two measures. One measure is a statistical measure of ACE variability and its relationship to frequency error. The second measure is a statistical measure designed to limit unacceptably large net unscheduled power flows. These two measures define the NERC Control Performance Standard. ***The NERC Control Performance Standard is the measure against which all control areas will be evaluated***.

The first measure of the CPS survey provides a measure of the control area’s performance. This control performance measure is defined in Section B.1.1.1. The measure is intended to provide the control area with a frequency-sensitive evaluation of how well the respective area met its demand requirements. The measure is not designed to be a visual indicator that an operator would use to control system generation. Nor is this measure designed to address the issue of unscheduled power flows, or minimization of inadvertent interchange.

The second measure of the CPS survey is designed to bound ACE ten-minute averages and provides an oversight function to limit excessive unscheduled power flows that could result from large ACEs. The measure to limit the magnitude of ACE is described in Section B.1.1.2.

These measurements of control performance apply to all conditions (i.e., both normal and disturbance conditions). The CPS is supplemented by a Disturbance Control Standard that establishes bounds for system recovery. The following discussion expands the definitions of the criteria found in Operating **Policy I.E. — Control Performance** and defines the respective measurements and associated criteria.

Continuous Monitoring Requirements. The NERC Control Performance Standard defines a minimum acceptable control performance that a control area is expected to maintain over all operating conditions.

Parameters. The Control Performance Standard imposes two requirements.

CPS1. Over a given period, the average of the clock-minute averages of a control area's [ACE divided by ten times its bias] times the corresponding clock-minute averages of the Interconnection's frequency error shall be less than the constant on the right-hand side of the following inequality:

$$AVG_{Period}\left[\left(\frac{ACE_i}{-10B_i}\right)_1 * \Delta F_1\right] \leq \in_1^2 \; or \; \frac{AVG_{Period}\left[\left(\frac{ACE_i}{-10B_i}\right)_1 * \Delta F_1\right]}{\in_1^2} \leq 1$$

where: ACE_i is the clock-minute average of ACE (as ACE is defined in Section A),

B_i is the frequency bias of the control area. For those areas with variable bias, an area should accumulate ACE/(–10B) through the AGC cycles of a minute, and save the averaged value at the end of the minute as the clock-minute value of $ACE_i/(-10B_i)$,

ϵ_1 is a constant derived from the targeted frequency bound. It is the targeted RMS of one-minute average frequency error from a schedule based on frequency performance over a given year. The bound is the same for every control area within an Interconnection,

ΔF is the clock-minute average of frequency error from schedule, $\Delta F = F_a - F_s$, where F_a is the actual (measured) frequency and F_s is scheduled frequency for the Interconnection,

I is representative of the control area,

Period is defined as:

a) one year for control area evaluation
b) one month for Performance Subcommittee review

CPS2. Over a clock ten-minute period, the ten-minute averages of a control area's ACE shall be less than the constant on the right-hand side of the following inequality:

$$AVG_{10\text{–minute}}(ACE_i) \leq L_{10}$$

where: $$L_{10} = 1.65 \in_{10} \sqrt{(-10B_i)(-10B_s)}$$

□□□ is a constant derived from the targeted frequency bound. It is the targeted RMS of ten-minute average frequency error from schedule based on frequency performance over a given year. The bound, □□□, is the same for every control area within an Interconnection,

1.65 is a constant used to convert the frequency target to 90% probability. It is the number of standard deviations from the mean of a statistical normal distribution (Gausian distribution) that will result in a probability of noncompliance of 10% (i.e., compliance of 90%),

B_i is the frequency bias of the control area, and

B_s is the sum of the frequency bias settings of the control areas in the respective Interconnection; for systems with variable bias, this is equal to the sum of the minimum frequency bias settings.

For those systems with variable bias, CPS2 becomes:

$$AVG_{10-\text{minute}}(ACE) \leq L_{10}$$

where:

$$L_{10} = 1.65 \in_{10} [-10 AVG_{10-\text{minute}}(B_i)] \sqrt{\frac{B_s}{B_{\text{minimum}}}}$$

$B_{minimum}$ is the area's minimum allowed bias.

Targeted Frequency Bounds. The Targeted Frequency Bounds, □□and □□□, are based on historic measured frequency error. These bounds embody the targeted frequency characteristics used for developing the Control Performance Standard. Each Interconnection will be assigned its own frequency bounds.

The Targeted Frequency Bound for an Interconnection is computed as follows:

NERC Performance Subcommittee (PS) defines a desired frequency profile. This profile will be derived from the frequency experienced over a PS-selected one-year period.

NERC PS collects the frequency data from designated providers within each Interconnection. The frequency bounds are the RMS of the one-and ten-clock-minute averages of the frequency error from schedule. These values are derived from data samples over a given year. NERC PS calculates the targeted frequency bounds, $_1$ and L_{10}, to recognize the desired performance of frequency for each Interconnection.

Compliance for Control Areas. A control area that does not comply with CPS is not providing its required regulation service.

If a control area does not comply with the CPS, the control area is not permitted to provide regulation or other services related to control performance for any other control area(s) or other entities. Those services shall be determined by the NERC PS.

A control area failing to comply shall take immediate corrective action and achieve compliance within three months. If necessary, a control area shall buy sufficient supplemental regulation to achieve compliance.

Compliance for Control Areas Providing Regulation. A control area is not permitted to provide regulation or other services related to control performance (as determined by the NERC Performance Subcommittee) for (an)other control area(s) or other entities external to that control area, if the former control area does not comply with the CPS.

Compliance for Control Areas Participating in Supplemental Regulation. A control area providing or receiving supplemental regulation, either through dynamic schedules or pseudo-ties, will continue to be evaluated on the characteristics of its own area control error with the supplemental regulation service included. The for each of the affected control areas will not change.

$$\left[\left(\frac{ACE_i}{-10B_i}\right)_1 * \Delta F_1\right]$$

Compliance for Control Areas Participating in Overlap Regulation.

Control Areas Providing Overlap Regulation. A control area *providing* overlap regulation shall continue to be evaluated on the characteristics of the combined areas' ACE. The provider control area must calculate and use the combined limit using the sum of its own frequency bias setting, B_i, and the frequency bias setting, B_j, of the control area for which it is providing the overlap regulation.

Control Areas Receiving Overlap Regulation. A control area *receiving* overlap regulation service shall not have its control performance evaluated.

Disturbance Conditions. During a disturbance, controls cannot usually maintain ACE within the criteria for normal load variation. However, an area is expected to activate operating reserve to recover ACE within ten minutes. This requires that a disturbance condition be defined. For purposes of disturbance control compliance, a reportable disturbance is defined as an event whose magnitude is less than or equal to the magnitude of an affected control area's most severe contingency, or is greater than or equal to 80% of the magnitude of the control area's most severe single contingency loss. Regional Reliability Councils may, at their discretion, require a lower reporting threshold.

Normal load and generation excursions (e.g., pumped storage hydro, arc furnace, rolling steel mill, etc.) that influence ACE are not reportable disturbance conditions.

Control Area. A CONTROL AREA shall return its ACE either to zero or to its pre-disturbance ACE level within ten minutes following a disturbance. A control area may, at its discretion, measure its compliance based on the ACE measured ten minutes after the disturbance, or based on the maximum ACE recovery measured within the ten minutes following the disturbance.

Reserve Sharing Group. The disturbance control compliance for a control area within a Reserve Sharing Group is based on the compliance of the Reserve Sharing Group (according to the compliance method chosen in section 3.2.2. of Policy 1A). A reserve sharing group area may, at its discretion, measure this recovery based on the combined ACE measured ten minutes after the disturbance, or on the maximum combined ACE recovery measured within the ten minutes following the disturbance.

C. Calculation of Compliance

Control Compliance Rating. Control area compliance will be determined by examining both CPS parameters. One parameter (CPS1) measures control impact on frequency. This parameter is calculated from a MW-Hz error value computed over a sliding 12-month period. The second parameter (CPS2) is a function of the ten-minute ACE magnitudes over a one-month period. Compliance to the two measures is outlined below:

Control Compliance Rating = Pass if CPS1 $\geq$ 100% *and* CPS2 $\geq$ 90%

Control Compliance Rating = Fail if CPS1 < 100% *or* CPS2 < 90%

Control Performance Standard 1 (CPS1). The frequency-related parameter, CPS1, converts a compliance ratio to a compliance percentage as follows:

$CPS1 = (2 - CF) * 100\%$

The frequency-related Compliance Factor, CF, is a ratio of all one-minute compliance parameters accumulated over 12 months divided by the Target Frequency Bound:

$$CF = \frac{CF_{12-\text{month}}}{(\in_1)^2}$$

where: $CF_{12\text{-month}}$ is defined in Section C.1.1.1,

$\in_1$ is defined in Section B.1.1.1.

Note that compliance percentages can be calculated for other bases (month, day, shift hours, etc.) by simply replacing $CF_{12\text{-month}}$ in the above formula with the appropriate CF value.

$CF_{12\text{-month}}$ Calculation. The rating index is derived from 12 months of data. The basic unit of data comes from one-minute averages of ACE, frequency error and frequency bias settings.

Clock-minute average. A clock-minute average is the average of the reporting control area's valid measured variable (i.e., for ACE and for frequency error, as well as for the control area's frequency bias, as defined in section B.1.1.1.) for each sampling cycle during a given clock-minute.

$$\left(\frac{ACE}{-10B}\right)_{\text{clock-minute}} = \frac{\left(\dfrac{\sum ACE_{\text{sampling cycles in clock-minute}}}{n_{\text{sampling cycles in clock-minute}}}\right)}{-10\text{B}}$$

$$\Delta F_{\text{clock-minute}} = \frac{\sum \Delta F_{\text{sampling cycles in clock-minute}}}{n_{\text{sampling cycles in clock-minute}}}$$

The control area's clock-minute Compliance Factor (CF) becomes:

$$CF_{\text{clock-minute}} = \left[\left(\frac{ACE}{-10B}\right)_{\text{clock-minute}} * \Delta F_{\text{clock-minute}}\right]$$

Hourly Average. Normally, sixty (60) clock-minute averages of the reporting area's ACE and of the respective Interconnection's frequency error will be used to compute the respective Hourly Average Compliance parameter.

$$CF_{\text{clock-hour}} = \frac{\sum CF_{\text{clock-minute}}}{n_{\text{clock-minute samples in hour}}}$$

Accumulated Averages. The reporting entity can recalculate and store each of the respective clock-hour averages ($CF_{\text{clock-hour average-month}}$) as well as the respective number of samples for each of the twenty-four (24) hours (one for each clock-hour, i.e., HE 0100, HE 0200, ..., HE 2400).

$$\text{CF}_{\text{clock-hour average-month}} = \frac{\sum_{\text{days-in-month}} [(\text{CF}_{\text{clock-hour}})(n_{\text{one-minute samples in clock-hour}})]}{\sum_{\text{days-in month}} [n_{\text{one-minute samples in clock-hour}}]}$$

$$\mathrm{CF_{month}} = \frac{\sum\limits_{\text{hours-in-day}} [(\mathrm{CF_{clock\text{-}hour\,average\text{-}month}})(n_{\text{one-minute samples in clock-hour averages}})]}{\sum\limits_{\text{hours-in day}} [n_{\text{one-minute samples in clock-hour averages}}]}$$

The 12-month Compliance Factor becomes:

$$\mathrm{CF_{12\text{-}month}} = \frac{\sum\limits_{i=1}^{12} (CF_{\text{month-i}})(n_{(\text{one-minute samples in month})\text{–i}})]}{\sum\limits_{i=1}^{12} [n_{(\text{one-minute samples in month})\text{-i}}]}$$

Note that if data was not collected for all days of the month (or hours in day, or minutes in hour, etc.), then the summations in the above formulas should be for "sample" days (or hours, minutes, etc.).

At the end of the month, each of the respective hourly averages are used to calculate that month's Compliance Factor as follows:

Control Performance Standard 2 (CPS2). The second parameter in the Control Performance Rating relates to a bound on the ten-minute average of ACE. A compliance percentage is calculated as follows:

$$CPS2 = \left[1 - \frac{\text{Violations}_{\text{month}}}{\left(\text{Total Periods}_{\text{month}} - \text{Unavailable Periods}_{\text{month}}\right)}\right] * 100$$

The $\text{Violations}_{\text{month}}$ are a count of the number of periods that $\text{ACE}_{\text{clock-ten-minutes}}$ exceeded L_{10}. $\text{ACE}_{\text{clock-ten-minutes}}$ is the sum of valid ACE samples within a clock-ten-minute period divided by the number of valid samples.

$\text{Violation}_{\text{clock-ten-minutes}}$ = 0 if $\left|\dfrac{\sum ACE}{n_{\text{samples in 10-minutes}}}\right| \le L_{10}$

= 1 if $\left|\dfrac{\sum ACE}{n_{\text{samples in 10-minutes}}}\right| > L_{10}$

C. Calculation of Compliance

Each area shall report the total number of Violations and Unavailable Periods for the month. L_{10} is defined in Section B.1.1.2.

Determination of Total Periods$_{month}$ and Violations$_{month}$. Since the CPS2 Criterion requires that ACE be averaged over a discrete time period, the same factors that limit Total Periods$_{month}$ will limit Violations$_{month}$. The calculation of Total Periods$_{month}$ and Violations$_{month}$, therefore, must be discussed jointly.

Each 24-hour period beginning at 0000 and ending at 2400 contains 144 discrete ten-minute periods (one more or less due to Daylight Saving Time). Each hour (HH) contains six discrete ten-minute periods, where period 1 spans HH:00$^+$ – HH:10, period 2 spans HH:10$^+$ – HH:20, period 3 spans HH:20$^+$ – HH:30, period 4 spans HH:30$^+$ – HH:40, period 5 spans HH:40$^+$ – HH:50, and period 6 spans HH:50$^+$ – (HH+1):00. For a system that samples ACE every four seconds, for example, the average ACE over a ten-minute period would be defined by the algebraic sum of 150 ACE samples (starting at HH:00:04 and ending at HH:10:00) divided by 150.

An incident of non-compliance is recorded for any ten-minute period where the absolute value of average ACE is greater than L_{10}.

Condition that Impacts the Calculation of Total Periods$_{month}$ and Violations$_{month}$.

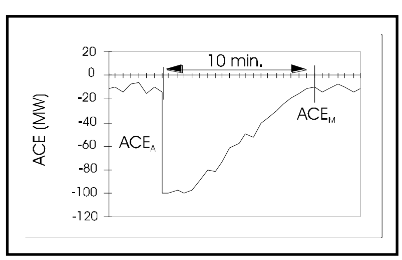
A condition may arise which may impact the normal calculation of Total Periods$_{month}$ and Violations$_{month}$. This condition is a sustained interruption in the recording of ACE.

Sustained Interruption in the Recording of ACE. In order to ensure that the average ACE calculated for any ten-minute interval is representative of that ten-minute interval, it is necessary that ACE remain uninterrupted for a period equal to or greater than five minutes during that ten-minute interval. Should a sustained interruption in the recording of ACE due to loss of telemetering or computer unavailability result in a ten-minute interval not containing a consecutive five-minute sampling of ACE, that ten-minute interval is omitted from the calculation of CPS2.

Data Reporting. The control area is responsible for submitting the Control Performance Standard survey each month. In addition (for post-reporting analysis by the Regional Performance Subcommittee representative), the control area is responsible for retaining sufficient CF and other pertinent data (see Appendix 1H).

Disturbance Control Standard. A control area or reserve sharing group must calculate and report compliance with the Disturbance Control Standard for all disturbances greater than or equal to 80% of the magnitude of the control area's or of the reserve sharing group's most severe single contingency loss. Regional Reliability Councils may, at their discretion, require a lower reporting threshold. Disturbance Control Standard is measured as the percentage recovery, R_i

For loss of generation:

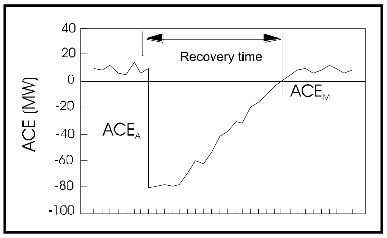


C. Calculation of Compliance

if $ACE_A < 0$

then

$$R_i = \frac{MW_{Loss} - \max(0, ACE_A - ACE_M)}{MW_{Loss}} * 100\%$$



if $ACE_A >= 0$

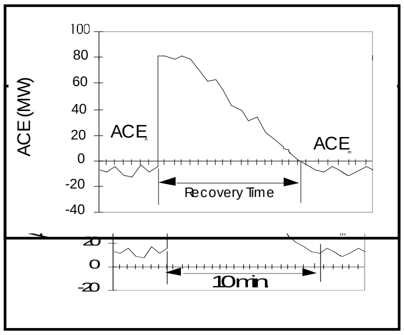
then $$R_i = \frac{MW_{Loss} - \max(0, -ACE_M)}{MW_{Loss}} * 100\%$$

For loss of load:

if $ACE_A > 0$

then

$$R_i = \frac{MW_{Loss} - \max(0, ACE_m - ACE_A)}{MW_{Loss}} * 100\%$$



if $ACE_A <= 0$

then $$R_i = \frac{MW_{Loss} - \max(0, -ACE_m)}{MW_{Loss}} * 100\%$$

where: MW_{LOSS} is the MW size of the disturbance as measured at the beginning of the loss,

ACE_A is the pre-disturbance ACE,

ACE_M is the maximum algebraic value of ACE measured within the ten minutes following the disturbance event. A control area or reserve sharing group may, at their discretion, set $ACE_M = ACE_{10\ min}$, and

ACE_m is the minimum algebraic value of ACE measured within the ten minutes following the disturbance event. A control area or reserve sharing group may, at their discretion, set $ACE_m = ACE_{10\ min}$.

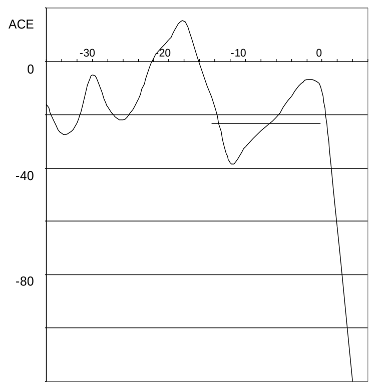
C. Calculation of Compliance

Determination of MW_{LOSS}.

Record the MW_{LOSS} value as measured at the site of the loss to the extent possible. The value should not be measured as a change in ACE since governor response and AGC response may introduce error.

Determination of ACE_A.

Base the value for ACE_A on the average ACE over the period just prior to the start of the disturbance. Average over a period between 10 and 60 seconds prior and include at least 4 scans of ACE. In the illustration to the right, the horizontal line represents an averaging of ACE for 15 seconds prior to the start of the disturbance with a result of ACE_A= - 25 MW.



Determination of ACE_M or ACE_m.

ACE_M is the maximum value of ACE measured within ten minutes following a given disturbance. At the discretion of the control area or of the Reserve Sharing Group, compliance may be based on the ACE measured ten minutes following the disturbance, i.e., $ACE_M = ACE_{10\ min}$.

ACE_m is the minimum value of ACE measured within ten minutes following a given disturbance. At the discretion of the control area or of the Reserve Sharing Group, compliance may be based on the ACE measured ten minutes following the disturbance, i.e., $ACE_m = ACE_{10\ min}$

Examples.

Below is an example of the calculations required for CPS1 monitoring and compliance. The example starts with the first hour of the first day of a month through to the end of the month. Let's assume this area has a bias, B = –60MW/0.1 Hz.

On Day 1, at the beginning of HE 0100, the area must calculate $CF_{clock\text{-}minute}$ by multiplying the clock-minute average ACE (divided by ten times the area's bias) by the clock-minute average frequency error from schedule. Subsequent products are calculated for the remaining clock-minutes of the hour.

HE 0100:		Minute 1	Minute 2	...	Minute 60		
ACE/-10B	(Hz)	-20/-10(-60)	10/-10(-60)	...	40/-10(-60)		
□F	(Hz)	0.005	-0.005	...	0.005	Sum	$CF_{clock\text{-}hour}$ □□□□CF)/n

C. Calculation of Compliance

$CF_{clock\text{-}minute}$ = (Hz^2)	-0.000167	-0.000083	...	-0.000333	0.00525	0.000088
(ACE/-10B) x ΔF (mHz^2)	-166.667	-83.333		333.333	5250.0	87.5000
n (# of samples)	1	1		1	60	

Note that n (# of samples) is based on the number of samples over the hour. Since CPS1 requires minute averages of ACE and frequency error (and there were no data anomalies in this hour), n = 60. The procedure shown above is repeated for each of the 24 hour-periods of the day. As the days of the month continue, the 24 hour-period CF $_{clock\text{-}hour\ average\text{-}month}$ values are averaged as shown below: At the end of the month, a CF_{month} can be calculated.

Hour		Day 1	Day 2	...	Day 31	Sum	CF $_{clock\text{-}hour\ average\text{-}month}$ = [$\Sigma\Sigma$CF x n)]/Σ(n)
HE 0100	$CF_{clock\text{-}hour}$	87.5	93.5	...	92.0		90.5
	n (# of samples)	60	59		57	1842	
	$CF_{clock\text{-}hour}$ x n	5250	5516.5		5244	166,742	
HE 0200	$CF_{clock\text{-}hour}$	90.0	85.0	...	89.5		87.5
	n	58	60		60	1830	
	$CF_{clock\text{-}hour}$ x n	5220	5100		5370	160,170	
...	...	...	...	...	...		...
HE 2400	$CF_{clock\text{-}hour}$	89.0	92.0	...	89.0		89.5
	n	60	59		59	1830	
	$CF_{clock\text{-}hour}$ x n	5340	5428		5251	163,787	

Total n	44,208
Total CF $_{clock\text{-}hour\ average\text{-}month}$ x n	3,930,888
CF_{month} = Σ(CF $_{clock\text{-}hour\ average\text{-}month}$ x n)/ Σ(n)	88.9

A rolling $CF_{12\text{-}month}$ can be calculated using the CF_{month} values.

	Month					
	1	2	...	12	Sum	$CF_{12\text{-month}}$ = [□(CF_{month} X n)/□(n)]
CF_{month}	88.9	93.3	...	91.7		91.3
n	44,208	42,072		42,875	515,030	
CF_{month} X n	3,930,888	3,925,345		3,931,655	47,022,239	

Assuming this area has an $□_1$ of 10 MHz, then its CPS1 compliance percentage would be calculated as follows (as described in section C.1.1):

$$CF = CF_{12\text{-month}} / (□_1)^2$$

$$= 91.3 / (10)^2$$

$$= 91.3 / 100$$

$$= .913$$

$$CPS1 = (2 – CF) \times 100$$

$$= (2 - .913) \times 100$$

$$= (1.087) \times 100$$

= 108.7% which is a “passing” grade (CPS1 must be greater than or equal to 100)

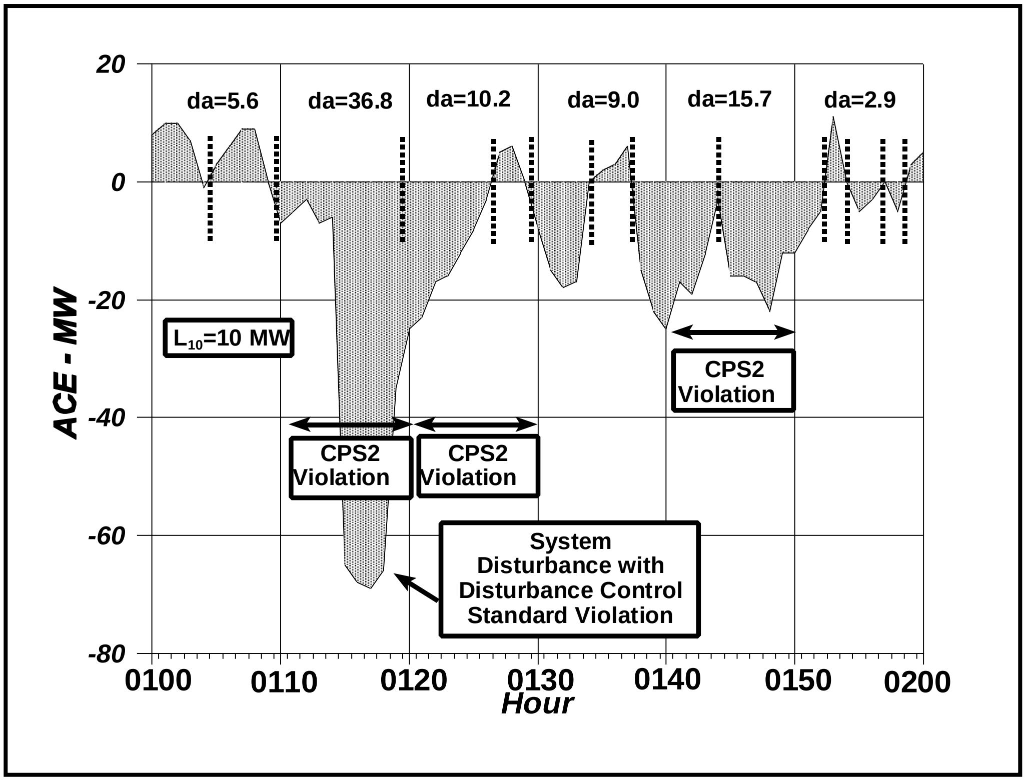


Figure I –- CPS2-L_{10} Compliance & Disturbance Control Standard, 2 Disturbance Examples

Figure I demonstrates various examples of L_{10} compliance (CPS2 Standard) and a disturbance condition (Disturbance Control Standard). Note that Figure I is separated into six distinct, cyclic ten-minute periods. The absolute value of the algebraic mean of the ACE during each period, referred to as d_a, is compared to L_{10} (10 MW for this system) to determine a violation. Note that the fifth interval (0140 – 0150) has recorded a violation because the absolute value of the algebraic mean of 15.7 MW exceeds the L_{10} of 10 MW. Since disturbance conditions are included in the CPS2 calculation, violations are also recorded for the second and third intervals (0110–0120 & 0120–0130).

Note the pattern of the disturbance condition, which began at 0115. During this disturbance, the Disturbance Control Standard was violated. ACE was not restored to its pre-contingency level until 0127 (a 12-minute interval which violates the Disturbance Control Standard).

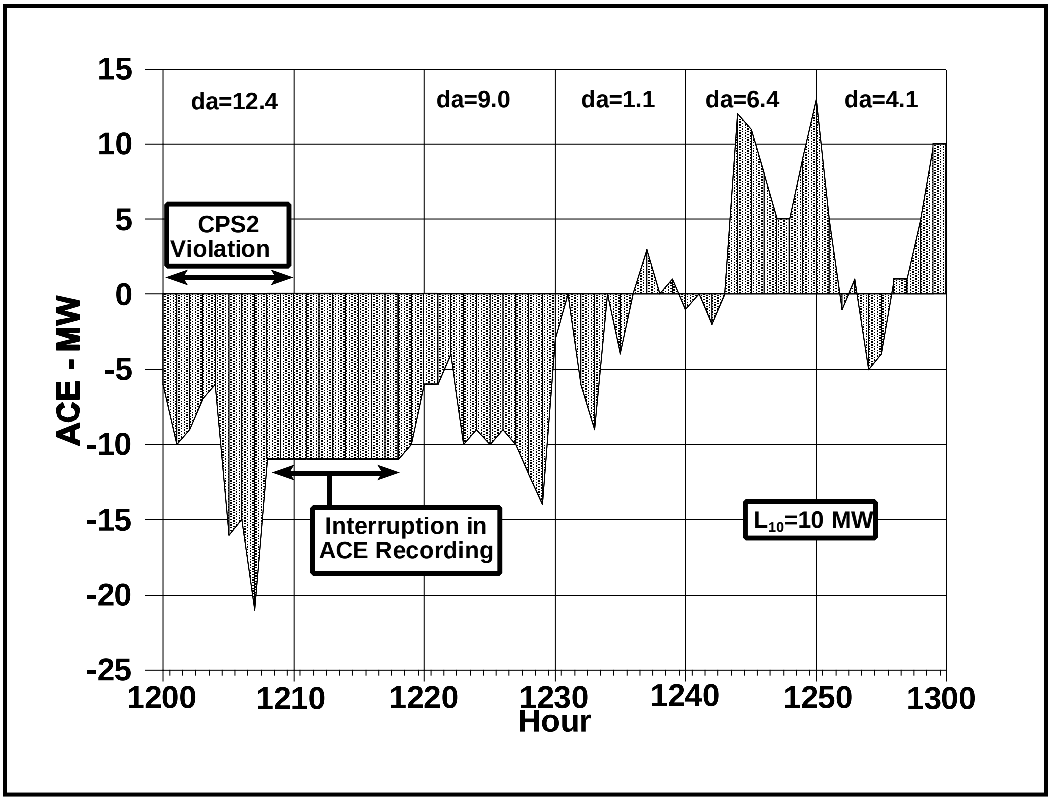


Figure II – L_{10} Compliance Examples

Figure II demonstrates various examples of L_{10} compliance coupled with an interruption in the recording of ACE. At 1209, ACE recording was interrupted and not returned until 1218. Since the ACE recording for the interval 1210 – 1220 did not span a consecutive, uninterrupted period longer than five minutes, this period is eliminated from further CPS Standard analysis. In contrast, the first ten-minute interval of 1200 – 1210 is included in the analysis because ACE recording was interrupted only for the last minute of the interval. In fact, the first interval is in violation because the absolute algebraic mean of 12.4 MW exceeds the L_{10} of 10.0 MW. This algebraic mean of 12.4 MW was calculated for the nine minutes during which ACE was not interrupted. Thus, for this hour, there was one violation out of five intervals.

D. Survey Procedures

Performance Standard surveys will be conducted monthly to analyze each control area's level of compliance with the CPS1 and CPS2 Control Performance Standards. The surveys provide a relative measure of each control area's performance.

Issuance of Survey. Monthly averages are to be completed after the end of each month.

Each control area shall return one completed copy of CPS Form 1, "NERC Control Performance Standard Survey — All Interconnections" to the Performance Subcommittee member representing the Region by the tenth working day of the month following the month reported.

Instructions for Control Area Survey. Using data derived from digital processing of the ACE signal, a representative from each control area will complete CPS Form 1, "NERC Control Performance Standard Survey — All Interconnections."

Hourly Table.

CPS1 Report the clock-hour average compliance factor (CF) for each of the 24-hour periods and the total number of samples in each hourly average (as described in section C.1.1.1.3).

CPS2 For each of the 24 hourly periods of a day, report the monthly total number of CPS2 violations and the number of unavailable ten-minute periods. For example, if there was one violation for hour ending 0100 every day of a 31-day month, a 31 would be entered for the 0100 hourly period.

CPS1, CPS2 Standard Summary.

CPS1 CF_{month} Report the monthly compliance factor and enter in thiscell using the formulas and procedures described in Sections C.1.1.1.3.

	$CF_{12\text{-month}}$	Report the rolling 12-month compliance factor and enter in this cell using the formulas and procedures described in Sections C.1.1.1.
	CPS1 (%)	Calculate the CPS1 percentage compliance and enter in this cell using the formulas and procedures described in Sections C.1.1.
CPS2	TOTAL	Sum the clock-hour average compliance factors, the number of samples, the number of violations, and unavailable ten-minute intervals recorded on the hourly tables and enter the sums on this row for each column.
	CPS2 (%)	Calculate the CPS2 percentage compliance and enter in this row using the formulas and procedures described in Sections C.1.2.

Instructions for Regional and NERC Surveys. From a review of the control areas' surveys, each Regional Survey Coordinator or PS member will complete CPS Form 2, "NERC Control Performance Standard — Regional Summary."

Review CPS Form 1 data received from each control area in the Region for uniformity, completeness, and compliance to the instructions. Iterate with control area survey coordinators where necessary.

Transfer the data from each Form to the appropriate columns on CPS Form 2. Review the comments submitted and, if significant, identify them with the appropriate control areas.

Forward a copy of the completed CPS Form 1 and 2 to the NERC staff.

The NERC staff will combine the Regional reports into a single summary report and send one copy to each PS member.

Each PS member is responsible for sending the summary report to the utilities in the Region.

Disturbance Control Standard.

Each Control Area or Reserve Sharing Group shall report its Disturbance Control Standard compliance quarterly. The completed Disturbance Control Standard survey shall be supplied to NERC by the 20th day following the end of the respective quarter. Where reserve sharing groups exist, the Regional Reliability Council shall decide either to report these on a control area basis or on a reserve sharing group basis. If a reserve sharing group has dynamic membership, then it will be required for the Region to convert the disturbance reporting for the group to a control area basis before reporting to

NERC. If a control area basis is selected, each control area reports the reserve sharing group's performance only for disturbances occurring in their area.

Reportable Disturbance. The definition of a reportable disturbance shall be provided by the respective Regional Reliability Councils. The definition shall include events that cause an ACE change greater than or equal to 80% of a control area's or reserve sharing group's most severe contingency. The definition of a reportable disturbance must be specified in the operating Policy adopted by each Regional Reliability Council. This definition may not be retroactively adjusted in response to observed performance.

Most Severe Single Contingency. A control area's most severe single contingency is defined as the magnitude of the single most credible event that would cause the greatest change in the control area's ACE or as defined by the respective Regional Council.

Excludable Disturbances and Average Percent Recovery. The control areas or reserve sharing group shall report both the number of reportable disturbances that occur in the given quarter, and the average percent recovery for that quarter. The control area must also report the excludable disturbances that occurred in the quarter and the average percent recovery for those excluded events.

Excludable Disturbance. An excludable disturbance is a disturbance whose magnitude was greater than the magnitude of the control area's most severe single contingency.

Average Percent Recovery. The average percent recovery is the arithmetic average of all the calculated R_i's from reportable disturbances during the given quarter. Average percent recovery is similarly calculated for excludable disturbances. (See Section C.2 for calculation of R_i.

Contingency Reserve Adjustment Factor. The quarterly Contingency Reserve Adjustment factor shall include only those reportable disturbances with magnitudes less than or equal to the magnitude of the respective control area's most severe contingency.

Contingency Reserve Adjustment factor. The factor is defined as follows:

when $n_{Quarter} \geq 0$, then

$$CRA_{Quarter} = 200 - \left[\frac{\sum R_i}{n_{Quarter}} \right]$$

when $n_{Quarter} = 0$, then $CRA_{Quarter} = 100$

where $n_{Quarter}$ is the number of reportable disturbances experienced during the

reporting quarter.

i = reportable disturbances.

R_i is defined in section C.2.

Calculation Precision. The Adjustment Factor shall be rounded off to two decimal places.

Exemptions. Exemptions shall be granted in consideration of single events that cause multiple reportable disturbances (e.g., hurricanes, earthquakes, islanding, etc.). A control area or reserve sharing group shall request such exemptions through its Performance Subcommittee representative. The chair of the Performance Subcommittee will rule on the request. Until the ruling is received, the control area or reserve sharing group will consider the request denied. If the request is from the chair's Region then a vice chair will issue the ruling.

Contingency Reserve Adjustment Period. Control areas shall revise their respective Contingency Reserve Requirement by their computed Contingency Reserve Adjustment factor. The adjustments will be effective starting one month following the end of the reported quarter and remains in effect for three months.

Instructions for Disturbance Control Standard Survey. Each control area or Reserve Sharing Group shall report its Disturbance Control Standard compliance quarterly on Form DCS "NERC Disturbance Control Standard Survey."

Mail a copy of the completed Form DCS to the NERC staff.

The NERC staff will combine the Regional reports into a single summary report and send one copy to each Subcommittee member.

Each Subcommittee member is responsible for sending the summary report to the utilities in the Region.

NERC Control Performance Standard Survey

All Interconnections

CPS
Form 1

Region			**Control Area**		
L_{10} -			**Month -**	**Year -**	**ε –**
	CPS1			**CPS2**	
H.E. Central Time	CF	%	Number of Samples	Violations	Unavailable Periods
0100					
0200					
0300					
0400					
0500					
0600					
0700					
0800					
0900					
1000					
1100					
1200					
1300					
1400					

D. Survey Procedures

1500								
1600								
1700								
1800								
1900								
2000								
2100								
2200								
2300								
2400								
CPS1 Month -			0	CPS2 Month -	0		0	

Notes:

NERC Control Performance Standard Survey Σ Regional Summary

CPS
Form 2

Region:	Month:	Year:	Date:

Control Area:		Control Performance Compliance	
ID #	Name	CPS1 Monthly Compliance %	CPS2 Monthly Compliance %

D. Survey Procedures

NERC Disturbance Control Standard Report

Year	Quarter	Disturbances Not Greater than the Most Severe Single Contingency Loss		Disturbances Greater than the Most Severe Single Contingency Loss[3]		This Quarter's CRAF[4]	Previous Quarter's CRAF	Compounded CRAF
Region	Control Area/RSG[1]:	Number	APR[2] (a)	Number	APR			

[1] When reporting as a Reserve Sharing Group (RSG), submit data for the entire group only and list the Control Areas comprising the RSG.
[2] APR indicates the Average Percent Recovery.
[3] Not a performance measure. For informational purposes only.
[4] [200-(a)], please round to the nearest whole percentage.

NOTES/COMMENTS:

A Control Area or Reserve Sharing Group must increase their Contingency Reserve Requirement by the Compounded CRAF. CRAF changes are implemented one month after the end of a reporting quarter and remain in effect for three months.

APPENDIX 2

NERC MINIMUM DATA COLLECTION REQUIREMENTS

Minimum Data Collection Requirements for Use in Monitoring NERC Performance Standards

Appendix Subsections

I. Data Retention

The minimum requirements for control center records (either chart recorders or digital data) used for monitoring NERC Control Performance Criteria are provided here as a guide for control areas to establish uniform data recording and monitoring throughout each Interconnection.

A. Required Data Records

The following data must be digitally recorded for NERC Performance Standard assessment. The use of a visible chart recorder or other device is optional.

Area Control Error (ACE)

System frequency

Net tie deviation from schedule

Net interchange

Frequency bias (for those systems with variable bias)

B. Recording Chart Speed and Width

In order to provide usable data for performance monitoring, the following chart width and speed is recommended:

Chart width: nominal 10" full-scale

Chart speed: 3" per hour

C. Digital Collection

As a general rule, digital data should be sampled at least at the same periodicity with which ACE is calculated. Missing or bad data should be flagged. Collected data should be co-incident; i.e., ACE, system frequency, net interchange, and other data should all be saved at the same time. The format for digital storage should be a standard such as ASCII or EBCDIC for compatibility and portability to other entities.

D. Range for ACE Chart Recorder

The range for the ACE recorder should provide the best resolution for normal operating conditions. Typically, the recorder should use between 1/3 and 2/3 of the chart width during normal operation.

E. Range for Frequency Chart Recorder

The following ranges shall cover full scale on the recorder:

Interconnection	Band	Range
Eastern	Narrow	60 □ 0.25 Hz
	Wide	60 □ 3.00 Hz
Western	Narrow	60 □ 0.30 Hz
	Wide	60 □ 5.00 Hz
ERCOT	Narrow	60 □ 0.50 Hz
	Wide	60 □ 5.00 Hz

Frequency input to the chart recorder shall be an analog signal obtained from a source independent from the control system computer.

F. Range for Net Tie Deviation from Schedule Recorder

Net tie deviation from schedule is the actual net interchange minus scheduled net interchange. The purpose of monitoring net tie deviation from schedule is to provide a measurable interchange response in MW for frequency excursions. This will enable the control areas to more accurately calculate the frequency bias values and comply with NERC frequency response surveys.

The recommended range for this data quantity is □2 times the control area frequency bias. Even extreme frequency excursions are less than □0.1 Hz, therefore, □2 times the control area frequency bias should provide sufficient range and good resolution for external disturbances.

G. Range for Net Interchange Recorder

The range for the net interchange recorder should provide the best resolution for all operating conditions. Some of the possible net interchange conditions which can occur are:

- Operation at the maximum import/export limit.
- Import due to loss of the largest generating unit.
- Normal import/export net interchange.

In order to get the best resolution for the various interchange conditions, the recorder range should be variable. For example, if normal import/export is □100 MW and maximum import/export is □500 MW, then a recorder range that is variable in □100 MW increments is recommended.

H. Measure Accuracy

Control performance and reliable operation is affected by the accuracy of the measuring devices. The recommended minimum values are listed below:

Device	Accuracy	Units
Digital frequency transducer	±0.001	Hz
MW, MVAR, and voltage transducer	±0.25	% of full scale
Remote terminal unit	±0.25	
Potential transformer	±0.30	
Current transformer	±0.50	

I. Data Retention

1. **Performance Standard Data.** Each control area shall retain its ACE, frequency, net tie deviation, and net interchange data for at least one year.

    1.1 Digital information should be kept for at least one year based on the same scan rate at which data is collected. The control area should have the equivalent digital data that would be necessary to create its analog chart.

2. **Disturbance Control Performance Data.** Each control area or Reserve Sharing Group shall retain documentation of the magnitude of each reportable disturbance

as well as the ACE charts and/or samples used to calculate the control area□s or Reserve Sharing group□s disturbance Recovery values (R_i□s). The data shall be retained for one year following the reporting quarter the data was used for.

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