SAPP TRANSMISSION PLANNING CRITERIA

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TABLE OF CONTENTS

1. INTRODUCTION

The objective of the system planning criteria is to ensure that the criteria specified are adhered to during the inter-utility planning process. System planning is to ensure the development of a reliable, efficient, and economical system for the transmission of electricity from generators to load centres. The Transmission Planning Criteria set out the standards that are applied in the planning period. The criteria set are the minimum standards set at the SAPP level. Utilities may choose to apply their more stringent criteria.

2. TRANSMISSION SYSTEM PLANNING AND DEVELOPMENT

This report specifies the criteria and procedures to be applied in the planning and development of the transmission system. It furthermore provides for accountability for transmission system planning and development and sets the required standards and targets.

The development of the transmission system may occur for a number of reasons, including but not limited to:

- changes to customer requirements or networks
- the introduction of a new transmission substation or point of connection or the modification of an existing connection between transmission systems
- the cumulative effect of a number of developments as referred to above
- the need to reconfigure, decommission or optimise parts of the existing network.

The time required for the planning and development of the transmission system will depend on the type and extent of the necessary reinforcement and/or extension work, the need or otherwise for statutory planning consent, the associated possibility of the need for public participation and the degree of complexity involved in undertaking the new work while maintaining satisfactory security and quality of supply on the existing transmission system and interconnection.

The transmission system shall be developed in accordance with the countries' regulatory framework as a minimum.

3. THE PLANNING PROCESS

The following planning process shall be followed divided into major activities as follows:

- Identification of the problem
- Formulation of alternative options to meet the need
- Study of these options to ensure compliance with agreed technical limits and justifiable reliability and quality of supply standards
- Costing of these options on the basis of approved procedures
- Determination of the preferred option
- Building of a business case for the preferred option using the agreed justification criteria
- Request for approval of the preferred option and initiation of execution.

4. IDENTIFICATION OF THE NEED FOR TRANSMISSION SYSTEM DEVELOPMENT

The utility /entity shall source relevant data on customer information, system performance statistics, load forecasting data, to establish the need for network strengthening.

The needs shall be determined through the modelling of the transmission system over a twenty to thirty year term, utilising reasonable load and generation forecasts and equipment performance scenarios.

5. TRANSMISSION SYSTEM DEVELOPMENT PLAN

The entity /utility shall annually publish a five-year-ahead transmission system development plan by end December to feed into the overall SAPP transmission system development plan. The plan will indicate the major capital investments planned. The plan shall include at least:

- a list of planned investments including costs
- diagrams displaying the planned changes to the transmission system
- an indication of the impact on customers in terms of service quality and cost

6. TRANSMISSION PLANNING CRITERIA

The Transmission Planning Criteria sets out the standards that are applied in the ~~in the~~ short, medium and long term planning period. The primary aim of transmission planning is to maintain stable operation of the bulk transmission system for most probable system contingencies. The transmission network shall maintain continuity of power supply to customers under any single contingency or N-1 contingency.

6.1 TRANSMISSION PLANNING PRINCIPLES

Transmission planning is to ensure the development of a reliable, efficient, and economical system for the transmission of electricity for the long-term benefit of transmission users and the country. The planning process involves the application of technical reliability criteria, economics, and consideration of transmission operations, maintenance and protection, co-ordination with generation and distribution functions, Information Communication and Technology (ICT), strategic considerations and environmental aspects.

6.2 TRANSMISSION PLANNING CONCEPTS

The interconnected transmission system should be capable of performing reliably under a wide variety of expected system conditions while continuing to operate within equipment and electric system thermal, voltage and stability limits as specified in this criteria. Electric power systems must be planned to withstand contingencies and maintenance outages. Extreme event contingencies which measure the robustness of the electric system should be evaluated for risks and consequences.

6.3 COORDINATED PLANNING

SAPP members operate a highly interconnected system and shall coordinate transmission planning that affects the interconnectors. The planning and development of transmission facilities will be coordinated with neighbouring systems to preserve the reliability benefits of interconnected operations.

6.4 PLANNING CRITERIA

Individual members may develop planning criteria that shall, as a minimum, conform to this Transmission Planning Criteria. Individual member criteria shall consider the following:

a) Overload power above nominal being carried on any single transmission circuit, multi-circuit transmission line, way leave, as well as through any single transmission station shall be avoided.

b) Inter utility power flows shall not result in risk to the electric system under normal and contingency conditions as outline in this criteria.

c) Sufficient reactive capacity shall be planned within the SAPP system at appropriate places to maintain transmission system voltages within voltage limits or as determined by the member under contingency conditions.

6.5 PLANNING ASSESSMENT STUDIES

Individual members shall perform individual transmission planning studies and shall cooperate and participate in SAPP regional studies. These planning studies are for the purpose of identifying any planning criteria violations that may exist and developing plans to mitigate such violations. Members shall contact SAPP whenever new facilities are in the conceptual planning stage so that optimal integration of any new facilities and potentially benefitting parties can be identified. Studies affecting more than one system owner will be conducted jointly. Reliability studies will examine post-contingency steady state conditions as well as stability, overload, cascading and voltage collapse conditions. Updates will be done annually or whenever there is a significant change in the system conditions.

6.6 POWER TRANSFER CAPABILITY

Transfer capability is the measure of the ability of the interconnected systems to reliably move power from one area to another area over all transmission circuits between those areas under specified system conditions. Transfer capability is also directional in nature.

Some major points concerning transfer capability analysis are outlined below:

a) **System Conditions-** Base system conditions are indentified and modeled for the period being analyzed, including projected customer demand generation dispatch, system configuration and scheduled power transfers.

b) **Critical Contingencies-** During transfer capability studies, both generation and transmission system contingencies are evaluated to determine which facility outages are most restrictive to the transfer being analyzed.

c) **System Limits-** The transfer capability of the transmission network can be limited by thermal, voltage, stability or contractual considerations.

7. CONTIGENCY CRITERIA FOR LONG TERM PLANNING PURPOSES

7.1 With one line or transformer or reactive compensation device out of service (N-1), it shall be possible to supply the entire load under all credible system operating conditions.

7.2 A system meeting the N-1 contingency criterion must comply with all relevant voltage limits and the applicable current limits, under all system conditions.

8. INTEGRATION OF POWER STATIONS

Integration of power stations

(1) When the integration of power stations is planned, the following network redundancy criteria shall apply:

Power stations of less than 1 000 MW

- With all connecting lines in service, it shall be possible to transmit the total output of the power station to the system for any system load condition. If the local area depends on the power station for voltage support, the connection shall be made with a minimum of two lines.
- Transient stability shall be maintained following a successfully cleared single-phase fault.
- If only a single line is used, it shall have the capability of being switched to alternative busbars and be able to go onto bypass at each end of the line.

Power stations of more than 1 000 MW

- With one connecting line out of service (N-1), it shall be possible to transmit the total output of the power station to the system for any system load condition.
- With the two most onerous line outages (N-2), it shall be possible to transmit the total output of the power station less its smallest unit to the system.
- Smallest unit installed at the power station shall only include units that are directly connected to the transmission system and are centrally dispatched.

(2) Transient stability shall be retained for the following conditions:

- A three-phase line or busbar fault, cleared in normal protection times, with the system healthy and the most onerous power station loading condition; or
- A single-phase fault cleared in “bus strip” times, with the system healthy and the most onerous power station loading condition; or
- A single-phase fault, cleared in normal protection times, with any one line out of service and the power station loaded to average availability.

(3) The cost of ensuring transient stability shall be carried by the generator if the optimum solution, as determined by the System Operator, results in unit or power station equipment being installed.

(4) Busbar layouts shall allow for selection to alternative busbars. In addition, feeders must have the ability to go onto bypass.

(5) The busbar layout shall ensure that no more than 1 000 MW of generation is lost as a result of a single contingency.

(6) To enable the System Operator to successfully integrate new power stations, detailed information is required per unit and power station.

(7) When the integration of a nuclear facility or off-site power supply to a nuclear facility is planned, the levels of redundancy and/or reliability of the transmission system and off-site power supply requirements specified in its nuclear operating license or by the National Nuclear Regulator within the country shall apply.

9. VOLTAGE LIMITS AND TARGETS

The busbar voltages should remain within the following bands under system healthy conditions:

Network Condition	**Voltage Limit**
system healthy:	0.95 – 1.05 pu
after N-1 contigency before corrective actions:	0.90 – 1.05 pu
after N-1 contigency after corrective actions:	0.95 – 1.05 pu

The minimum voltage limit under different contingency conditions for system planning studies (after N-1 contingency) should be 0.95 pu. unless otherwise specified by the customer.

The technical and statutory limits are shown in the table below:

Table: Voltage limits for planning purposes

Nominal continuous operating voltage on any bus for which equipment is designed	U_N
Maximum continuous voltage on any bus for which equipment is designed Note: To ensure voltages never exceed Um, the highest voltage used at sending end busbars in planning studies should not exceed 0.98 Um	U_M
Minimum voltage on Point of Common Coupling (PCC) during motor starting	0.85 U_N
Maximum voltage change when switching, capacitors, reactors, etc. (system healthy)	0.03 U_N (healthy)
Statutory voltage on bus supplying customer for any period longer than 10 consecutive minutes (unless otherwise agreed in Supply Agreement)	U_N + or -5%

The target voltages for planning purposes are shown in the table below:

Table: Target voltages for planning purposes

Minimum steady state voltage at bus supplying customer load	0.95 U_N
Minimum steady state voltage on any bus not supplying a customer system healthy: after designed contingency:	0.95 U_N 0.90 U_N
Maximum harmonic voltage caused by customer at PCC: Individual harmonic: total (square root of sum of squares):	0.01 U_N 0.03 U_N
Maximum negative sequence voltage caused by *customer* at PCC: Continuous single-phase load connected phase-to-phase: Multiple, continuously varying, single-phase loads:	0.01 U_N 0.015 U_N
Harmonic voltage limits:	**As defined in** IEC 61000
Maximum voltage change owing to load varying N times per hour:	$(4.5 \log_{10} N)\%$ of U_N
Maximum voltage decrease for a 5% (MW) load increase at receiving end of system (without adjustment):	0.05 U_N

10. EQUIPMENT LOADING LIMITS

10.1 TRANSMISSION LINES

Utilities shall determine thermal ratings of standard transmission lines and update these from time to time. The thermal ratings shall be used as an initial check of line overloading.

No transmission line should be loaded more than its nominal thermal limit under normal operating conditions or more than its contingency rating under N-1.

Network Condition	Thermal rating limit
System healthy:	Rate A (Normal Rating)
Under N-1 contingency:	Rate B (Contingency Rating)

10.2 TRANSFORMERS

No transformer should be loaded more than 100% of its normal thermal limit under any operating conditions.

Network Condition	Thermal rating limit
System healthy:	Thermal rating of transformers (i.e. the 100% rating)
Under N-1 contingency:	Thermal rating of transformers (i.e. the 100% rating)

10.3 SERIES CAPACITORS

The maximum steady state current should not exceed the rated current of the series capacitor and under normal conditions. Use the IEC standards (60143) for cyclic overload capability.

10.4 SHUNT REACTIVE COMPENSATION

Shunt capacitors shall be able to operate at 30% above their nominal rated current to allow for harmonics and voltage up to Um.

Reactive compensation, whether new or modified, may cause harmonic resonance problems and harmonic resonance studies must be conducted.

10.5 SHUNT REACTIVE DEVICE SWITCHING

The size of shunt capacitor and reactor banks is limited by the voltage change caused by switching a bank. As a first approximation the per unit voltage change can be determined by dividing the capacitor bank size (MVAr) by the three phase fault level in MVA.

This voltage change when switching shunt devices should not exceed:

- three percent (3%) with the system healthy or
- five percent (5%) under contingency conditions.

Switching studies are required to prove the above conditions.

10.6 CIRCUIT BREAKERS

Rupturing capacity of circuit breakers should meet the maximum system fault levels and other conditions considered for the safe and secure operation of the system.

11. STABILITY CRITERIA

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 %
400 kV	-10 %
330 kV	-10%
275 kV	-10%
220 kV	-10%
132 kV	-10%
110 kV	-10%

12. MAXIMUM POWER TRANSFER CRITERIA

The maximum power transfer across a power corridor is determined when the power transfer exceeds one of the four following conditions:

1. Any busbar voltage drops below 0.95 pu for system healthy conditions, unless agreed between utilities.
2. The power flow on the corridor exceeds 95% of the maximum power transferred at the knee point of the PV curve for that corridor (Pmax)
3. The reactive power exceeds 90% of the locally installed SVCs and/or generator reactive capacity in the affected area, i.e. a minimum 10% reactive reserve per area must be maintained on the SVCs and/or generators.
4. The drop in voltage for a 5% increase in load without transformer tap changer action exceeds 5%.

13. FAULT LEVEL

The expansion of the network will take into account the need to limit fault levels to within the fault current rating of the installed equipment. Fault level calculations will be done for the peak load case for purposes of confirming the adequacy of existing switchgear ratings or specifying the ratings of new switchgear. For fault calculations, the voltages will be set to unity when there is maximum generation in service. Refer to IEC standard 6909 (Voltage factor 1.1)

- Both three phase and single phase fault currents must be determined

- Both three phase and single phase should be within the rapture capacity.

When specifying the ratings of new switchgear and other equipment, consideration should be given to the impact on fault levels of later system developments, e.g. new generation or additional lines or transformers, to ensure as far as practicable that new equipment will be adequately rated for its expected service life.

14. EQUIPMENT STANDARDISATION

Refer to IEC standards or equivalent. Equipment should conform to International Standards.

15. ECONOMIC JUSTIFICATION CRITERIA

When evaluating different options, transmission projects should be selected based on the least life cycle cost option. Detailed techno-economic evaluation should be carried out in accordance with approved investment criteria.

15.1 CRITERIA FOR NETWORK INVESTMENTS

The entity /utility shall invest in the transmission system when the required development meets the technical and investment criteria specified in this section.

The entity /utility shall assess and communicate all impacts timeously such that provision can be made for budgeting and implementation of related changes.

Any one of the investment criteria below, each applicable under different circumstances, can be applied.

Calculations will assume a typical project life expectancy of 25 years, except where otherwise dictated by plant life or project life expectancy.

The following key economic parameters shall be considered:

- Discount rate
- Cost of Unserved Energy
- Other parameters as specified by SAPP

15.2 LEAST ECONOMIC COST CRITERIA

These criteria shall apply under the following circumstances:

- When investments are made in terms of improved supply reliability and/or quality to attain the limits or targets
- To determine and/or verify the desired level of network or equipment redundancy

The methodology requires the cost of poor network services to be determined. These include the cost of:

- interruptions
- load shedding
- network constraints
- poor quality of supply (*QOS*).

The least-cost investment criterion equation to be satisfied can be expressed as follows:

"Value of improved *QOS* to customers > cost to the service provider to provide improved *QOS*"

From this equation it is evident that if the value of the improved QOS to the customer is less than the cost to the service provider, then the service provider should not invest in the proposed project(s). The investment decision shall then be delayed such that optimised economic benefit can be derived.

This implies that for the criteria to be satisfied:

"COUE annual value (US$/kWh) x annual reduction in EENS to consumers (kWh) > annual cost to the service provider to reduce EENS (R)"

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

The cost of unserved energy (COUE) is a function of the type of load, the duration and frequency of the interruptions, the time of the day they occur, whether notice is given of the impending interruption, the indirect damage caused, the start-up costs incurred by the customers, the availability of customer backup generation and many other factors.

16. GLOSSARY

Words and expressions in the Transmission Planning Criteria shall bear the following meanings:

Credible system contingency
The largest credible multiple event of the sudden and unplanned disconnection of a unit from the power system or the largest credible other contingency. The largest credible multiple contingency is the loss of 1 800 MW generation (typically three coal-fired units, either Koeberg units, or the loss of the Cahora Bassa supply).

Cost of unserved energy (COUE)
The value that is placed on a unit of energy not supplied due to an unplanned outage of a short duration.

Forced outage
An outage that is not a planned outage.

IEC – International Electrotechnical Commission

Long term planning period
Planning for a period over five years

Losses
Electrical energy losses associated with generation, transformation or transmission of electricity.

Loss of load probability
A calculated risk of loss of generation capacity or loss of customer load

Medium term planning period:
Planning between three and five years

Power station
One or more units at the same physical location.

Point of common coupling (PCC)
The electrical node, normally a busbar, in a transmission substation where different feeds to customers are connected together for the first time.

Reliability of supply
The ability of the power system to endure a generation or network contingency without interrupting the supply to the customers.

Short term planning period:
Planning between one to three years

System healthy
A system condition where all commissioned plant is operational in the affected area.

System operator
The legal entity licensed to be responsible for short-term reliability of the power system, which is in charge of controlling and operating the transmission system and dispatching generation (or balancing the supply and demand) in real time.

Transmission
The conveyance of electricity through the transmission system.

Transmission equipment
Any cable, overhead line, transformer, switchgear, etc. installed on the transmission system for *transmission* purposes, together with any ancillary equipment necessary for and used in connection with such equipment, including such buildings or any part thereof as may be required to accommodate such equipment or ancillary equipment.