TECHNICAL GUIDELINES FOR
INTERCONNECTION OF ELECTRICAL GRIDS IN AFRICA

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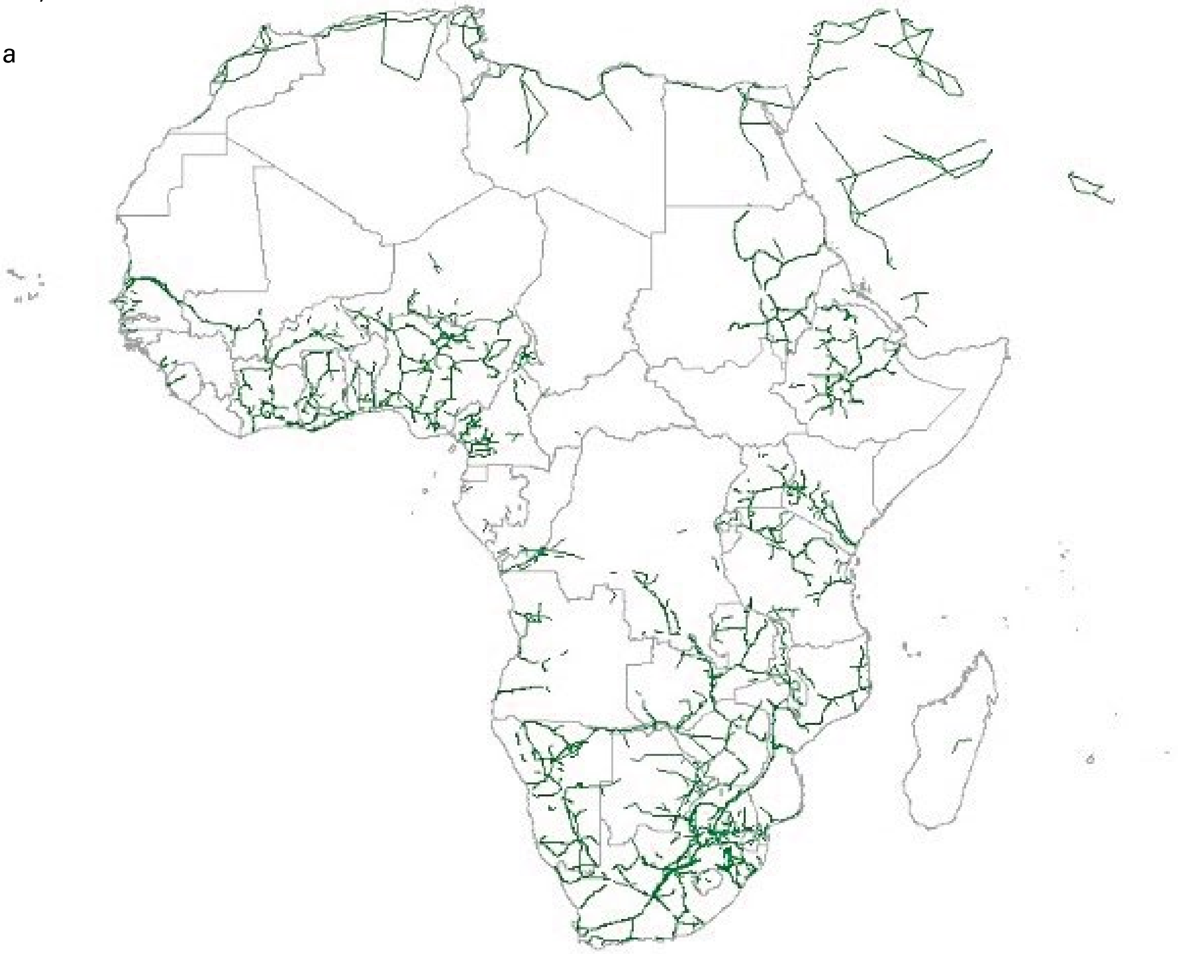

TECHNICAL GUIDELINES FOR **INTERCONNECTION OF ELECTRICAL GRIDS IN AFRICA**

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AFSEC Foreword

The African Electrotechnical Standardization Commission (AFSEC) was established inter alia to improve the wellbeing of the African population, mainly by the promotion, development, and application of harmonized standards on the entire continent in order to improve access to electricity.

To achieve these objectives, AFSEC has the mission to:

- Identify existing electrotechnical standards and prioritize the needs of the African Continent with regard to standardization;
- Harmonize the existing standards, by verification and recommending them to its members for adopting them as AFSEC African Regional Standards;
- Identify standards that need to be customised for African conditions by the adaption of them by a AFSEC Technical Committee or
- In the case of specific needs, a AFSEC Technical Committee with related experts produces standards or technical guides, for consideration by the members of AFSEC for the purpose of identical adoption.
- Produce guides to assist and give technical guidance with standardisation and a QI in the Africa Continent.

Recognizing the need for appropriate guide for Africa, AFSEC TC 8, which is a mirror committee of IEC TC 8, was tasked to develop Technical Guidelines for interconnection of African electrical grids.

The committee decided to reference existing regulations, IEC and AFSEC standards to facilitate the project.

The Guide covers regulatory frameworks, system design principles, component selection, installation practices, testing and commissioning procedures, maintenance guidelines, safety precautions, and documentation requirements.

NOTE: AFSEC collaborates closely with International Electrotechnical Commission (IEC) in accordance with conditions determined by agreement between the two organizations

Introduction

This guideline provides the high-level scope to cater for the design and operational requirements for the IPS. An assumption made is that each African utility will have its own Transmission System Planning Standard and a Generation Adequacy Standard detailing the requirements for ensuring system adequacy. Although planning criteria are traditionally used to determine the best techno-economic decision based on capital expenditure, adequacy requirements may not always be met due to economic constraints, thus the risk of violating the regional grid codes should be assessed, and operational mitigation solutions formulated. This guideline is aimed at ensuring that the interconnections are designed and consistently operated in a manner that secures and improves the reliability of the continent's IPS.

The implementation and compliance monitoring of this technical guideline should be done by regional or continental bodies. The responsibility of the power pools will be to flag where these criteria are violated and use them as input into longer term planning requirements for generation and network adequacy. Power pools are also encouraged to utilise existing committees, project teams, working groups, and other methods to ensure the IPS is constantly updated and maintained, in such a way that it is in line with regional operating guidelines and complies with the grid codes.

The benefits of grid synchronisation of the IPS between power pools are:

- **Enhanced Reliability:** Grid synchronisation allows multiple electrical grids or power systems to work together seamlessly. This redundancy and interconnectivity enhance the overall reliability of the power supply. If one grid experiences a failure or outage, power can be sourced from other synchronised grids, reducing the risk of widespread blackouts.

- **Improved Power Quality:** Synchronised grids can maintain a more stable voltage and frequency, resulting in better power quality. This means fewer voltage sags, surges, and fluctuations, which can be harmful to sensitive equipment and electronics.

- **Optimized Resource Utilization:** Grid synchronisation enables the efficient use of generation resources across a broader geographical area. Power can be generated where it's most cost-effective and transmitted to areas with high demand, reducing the need for redundant and costly local generation.

- **Enhanced Grid Resilience:** Synchronised grids are better equipped to withstand and recover from various system disturbances, severe weather events, equipment failures, or cyberattacks. They can isolate and manage problems more effectively and restore power quickly.

- **Increased Grid Capacity:** By connecting and synchronising multiple grids, the overall capacity of the power system can be increased. This can support economic growth and accommodate the growing demand for electricity.

- **International Power Exchange:** In the case of international grid synchronisation, neighbouring countries can exchange electricity efficiently. This can promote energy security, cooperation, and economic benefits through cross-border power trading. Electricity can be transmitted from areas with surplus power during low-demand hours to regions with higher demand during peak hours, ensuring a stable power supply.

- **Economic Benefits:** Grid synchronisation can lead to cost savings by reducing the need for excess capacity, lowering operational costs, and providing access to cheaper sources of electricity.

- **Energy Market Development:** Synchronised grids often support the development of energy markets, allowing for competitive pricing and efficient allocation of resources.

Important factor required for synchronised interconnected networks:

- **Protection Systems**: Robust protection systems should be in place to isolate any faults or disturbances in one grid from affecting the other grid. This includes the use of relays, circuit breakers, and other protective devices.

- **Control and Communication:** Adequate control and communication systems should be established to monitor grid conditions and control the flow of power between the grids. This may involve Phasor Measurement Units (PMUs), Supervisory Control and Data Acquisition (SCADA) systems, and advanced control algorithms.

- **Compliance with Standards**: Grid synchronisation should adhere to relevant national and international standards, regulations, and grid codes established by regulatory authorities and industry organisations.

- **Steady-State and Transient Stability:** The grids should exhibit both steady-state and transient stability to handle normal operating conditions as well as disturbances or contingencies without cascading failures.

- **Load Sharing and Power Flow Control**: Mechanisms for load sharing and power flow control between the interconnected grids should be in place to distribute power effectively while maintaining stability.

- **Emergency Procedures:** Protocols and procedures for emergency situations, such as grid faults or sudden load changes, should be established to ensure the safety and stability of both grids during unexpected events.

1 SCOPE

This document provides the guidance on technical aspects of planning, design, and operation of an interconnected power system (IPS). An IPS is normally large and complex because it comprises several system operators, spanning a wide geographical area. Grouping these system operators into Control Areas facilitates effective delivery of such obligations as power frequency and tie line control, keeping of reserves, and continuous real time monitoring, necessary for safe, secure, stable, and reliable operations. The document presents processes for Control Area operations, equipment maintenance and outage management. An IPS is often exposed to adverse conditions that may damage equipment and endanger staff and the public. The document gives guidelines on implementation of protection systems necessary for clearing faults and handling of power system emergencies. Measuring power flows and the quality of power supply on interconnectors is essential for both commercial and technical management of power systems. Further, telecommunication is the enabler of many power system operations systems such as SCADA systems. This document, therefore, gives technical guidelines on energy metering, power quality, and telecommunications. The document recognises the importance of grid codes, various power system operations requirements set by such bodies as regional power pools, and international electrotechnical standards. These are referenced in many areas. Application of this document promotes technical compliance and performance monitoring, as required by various authorities in the power supply sector. Lastly, this document focuses on AC power systems and is limited to high level technical guidance.

2 REFERENCES

The following documents contain provisions which, through reference in this text, constitute provisions of this guide. All documents are subject to revision and, since any reference to a document is deemed to be a reference to the latest edition of that document, parties to agreements based on this guide are encouraged to take steps to ensure the use of the most recent editions of the normative documents indicated below. Information on currently valid national and international standards and specifications can be obtained from the appropriate national standards organization.

The following referenced documents are required in the application of this standard. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies:

IEC 61000 series all parts: Electromagnetic compatibility (EMC)

IEC Technical Report 62511: 2014 Guidelines for the design of interconnected power systems

Note: added to AFSEC regional adoption catalogue as **AFSEC 62511:2024**

IEC TS 63217:2021
Utility-interconnected photovoltaic inverters - Test procedure for over voltage ride-through measurements

IEC TS 63102:2021
Grid code compliance assessment methods for grid connection of wind and PV power plants

IEC TS 63060:2019
Electric energy supply networks - General aspects and methods for the maintenance of installations and equipment

IEC TR 60870-1-1:1988
Telecontrol equipment and systems. Part 1: General considerations. Section One: General principles

IEC 62053-11:2003
Electricity metering equipment (a.c.) - Particular requirements Part 11: Electromechanical meters for active energy (classes 0,5 1 and 2)

Note: added to AFSEC regional adoption catalogue as **AFSEC IEC 62053-11:2003**

IEC 62053-22 : 2020 ed2
Electricity metering equipment - Particular requirements - Part 22: Static meters for AC active energy (classes 0,1S, 0,2S and 0,5S)

IEC 62053-23 : 2020 ed2
Electricity metering equipment - Particular requirements - Part 23: Static meters for reactive energy (classes 2 and 3)

IEC 62053-24:2020.
Electricity metering equipment - Particular requirements - Part 24: Static meters for fundamental component reactive energy (classes 0,5S, 1S, 1, 2 and 3)

Note: added to AFSEC regional adoption catalogue as **AFSEC IEC 62053-24:2020**

IEC 62052-11: 2003
Electricity metering equipment (AC) - General requirements tests and test conditions - Part 11: Metering equipment (French and English)

Note: added to AFSEC regional adoption catalogue as **AFSEC IEC 62052-11:2003**

IEC60044-7:1999 ed1.0
Instrument transformers - Part 7: Electronic voltage transformers

IEC60044-8:2002 ed1.0
Instrument transformers - Part 8: Electronic current transformers

3 TERMS AND DEFINITIONS

For the purposes of this document, the following terms and definitions apply.

Adequacy
ability of an electric power system to supply the aggregate electric power and energy required by the customers, under steady-state conditions, with system component ratings not exceeded, bus voltages and system frequency maintained within tolerances, taking into account planned and unplanned system component outages.
[SOURCE: IEC 60050-191:1990, 191-21-01]

Area control error (ACE)
The mismatch between instantaneous demand and supply in a control area. It combines the *frequency* error and the *tie-line error.*

Automatic generation control (AGC)
The automatic centralised closed loop control of units by means of the computerised *EMS* of the *System Operator*. Unit output is controlled by changing the set-point on the governor.

Auxiliary supply
Supply of electricity to auxiliary systems of a *unit* or *substation* equipment.

Busbar
An electrical conduit at a *substation* where lines, transformers and other equipment are connected.

Contingency
event, usually involving the loss of one or more elements, which affects the IPS at least momentarily.

Continuous capacity
rated continuous load-carrying ability, expressed in megawatts (MW) or megavolt-amperes (MVA) of generation, transmission, or other electrical equipment.

Control area
electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its net interchange schedule with other control areas and contributing to frequency regulation of interconnections.

Delayed fault clearance
fault clearing which is consistent with the correct operation of a breaker failure protection group and its associated breakers, or of a backup protection group with an intentional time delay.

Demand
the magnitude of an electricity supply, expressed in kilowatts or kilovoltamperes.
[SOURCE: IEC 60050-691:1973, 691-02-02]

Dependability (protection)
The probability of not failing to operate under given conditions for a given time interval
[IEC 50 – 448]

Droop
The *MW*/Hz characteristic according to which *governing* will take place. This is expressed as the percentage increase in *frequency* that will theoretically cause a *unit* to go from *MCR* to zero.

Element of power system
any electric device with terminals that may be connected to other electric devices.
e.g., generator, transformer, circuit breaker, or bus section

Emergency
A situation where *generators, transmission* or *distribution service providers* have an unplanned loss of facilities, or another situation beyond their control, that impairs or jeopardises their ability to supply their system demand.

Emergency reserves
Reserves that are infrequently used. The *System Operator* can use this capacity not only for reserves but also for emergency operation and voltage control.

Fault
an unplanned occurrence or defect in an item which may result in one or more failures of the item itself or of other associated equipment
[SOURCE: IEC 60050-604:1987, 604-02-01,]

Forced outage
unplanned outage whose onset, automatic or manual, cannot be deferred.
[SOURCE: IEC 60050-191:1990, 191-24-03]

Generation
a process of producing electrical energy from other forms of energy
Note 1 to entry: The amount of electric energy produced, usually expressed in kilowatt-hours (kWh) or megawatt hours (MWh).
[SOURCE: IEC 60050-601:1985, 601-01-06]

Instantaneous reserve
Generation capacity or demand side managed load that is available to respond fully within 10 seconds to a drop in *frequency*. This response must be sustained for at least 10 minutes.

Interconnected power system (IPS)
interconnected electrical power system within a wide area, comprised of system elements assigned to different local areas within the same operating authority or a different operating authority (e.g. ISOs) on which faults or disturbances can have a significant adverse impact outside of the local area

Interconnection
Single or multiple transmission links between transmission systems enabling electric power and energy to be exchanged between these networks by means of electric circuits and/or transformers
[SOURCE: IEC 60050-601:1985, 601-01-11]

Load
device intended to absorb power supplied by another device or an electric power system.
[SOURCE: IEC 6005-151:2001, 151-15-15]

Load shedding
the process of deliberately disconnecting preselected loads from a power system in response to an abnormal condition in order to maintain the integrity of the remainder of the system. [SOURCE: IEC 60050-603:1986, 603-04-32]

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

Maintenance outage
the removal of equipment from service to perform work on specific elements that can be deferred.

Metering installation
An installation that comprises an electronic meter that is remotely interrogated, has an electronic communication link and is connected to the NTC's metering database. The installation includes VT and CT as required.

NERC CPS1, CPS2 and DCS criteria
The *control area* and disturbance performance criteria of the North American Electricity Reliability Council (NERC) that are applicable to control areas in *SAPP*.

Normal fault clearance
fault clearing which is consistent with the correct operation of the protection system and with the correct operation of all circuit breakers or other automatic switching devices intended to operate in conjunction with that protection system.

Operating limit
the maximum value of the most critical system operation parameter(s) which meets: (a) pre-contingency criteria as determined by equipment loading capability and acceptable voltage conditions, (b) stability criteria, and (c) post-contingency loading and voltage criteria.

Planned outage
outage scheduled in advance, for maintenance or other purposes.
[SOURCE: IEC 60050-191:1990, 191-24-01]

Primary frequency control
The automatic adjustment of a *unit* output in response to deviations in the system *frequency*, by means of the local *governor* control system of the turbine. This control is proportional to the system *frequency* deviation.

Protection
provisions for detecting faults or other abnormal conditions in a power system, for enabling fault clearance, for terminating abnormal conditions, and for initiating signals or indications.

Protection relay
measuring relay which, either solely or in combination with other relays, is a constituent of a protection equipment.
[SOURCE: IEC 60050-448:1995, 448-11-02]

Regulating reserves
Generation capacity or demand side managed load available to start responding to AGC instructions within 10 seconds and be fully activated in 10 minutes. This reserve category reserves capacity as part of the regulation ancillary service. The purpose of this is to allow for enough capacity to control the frequency and control area tie-lines power within acceptable limits in real time.

Relay
electrical device designed to produce sudden predetermined changes in one or more electric output circuits, when certain conditions are fulfilled in the electric input circuits controlling the device.
[SOURCE: IEC 60050-151:2001, 151-13-31]

Reliability
the ability of an item to perform a required function under given conditions for a given time interval.
[SOURCE: IEC 60050-191:1990, 191-02-06, modified]

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

Reserved capacity
A negotiated capacity in *MVA* that is allocated by the service provider to the customer at a particular *point of supply*.

Security
ability of an electric power system to operate in such a way that credible events do not give rise to loss of load, stresses of system components beyond their ratings, bus voltages or system frequency outside tolerances, instability, voltage collapse, or cascading.
[SOURCE: IEC 60050-191:1990, 191-21-03]

Short circuit
accidental or intentional conductive path between two or more conductive parts, whether made accidently or intentionally, forcing the electric potential differences between these conductive parts to be equal to or close to zero (relatively low impedance) Note 1 to entry: The term fault or short-circuit fault used in this document refers to a short circuit.

Special protection system (SPS)
protection system designed to detect abnormal system conditions and take corrective action other than the isolation of faulted elements Note 1 to entry: Such action may include changes in load, generation, or system configuration to maintain system stability, acceptable voltages, or power flows. Conventionally switched, locally controlled shunt devices are not SPSs, while Generation Rejection Protection Scheme for system stability is an SPS. As an example, automatic under frequency load shedding to stabilize the system frequency in an area during an event leading to declining frequency is not considered an SPS.

Spinning reserve
generating capacity, kept in reserve to compensate for all possible deviations in the power balance that may occur between normal conditions and those which actually occur, and thus to ensure a reliable and economic electricity supply.

Stability
ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances. Note 1 to entry: Power system stability can be classified as voltage, rotor angle and frequency stability.

Substation (of a power system)
a part of an electrical system, confined to a given area, mainly including ends of transmission or distribution lines, electrical switchgear and control gear, buildings, and transformers.
[SOURCE: IEC 60050-601:1985, 601-03-02]

Tie-line error
The algebraic difference between actual and scheduled power flow on a tie-line interconnecting adjacent *control areas*.

Transfer capability
operating limit relating to the permissible power transfer between specified areas of the transmission system.

Transmission system (TS)
the whole of the means of transmission between two points, comprising the transmission medium, terminal equipment, any necessary intermediate equipment, and any equipment provided for such ancillary purposes as power feeding, supervision and testing.

[SOURCE: IEC 60050-704:1993, 704-04-10, modified – definition 1 removed]

Related IEC reference document:

IEC Technical Report 62511
Guidelines for the design of interconnected power systems
IEC TR 62511:2014(E) provides guidelines in planning and design of the interconnected power system (IPS) and consequently achieve the delivery of reliable supply service. The guidelines for the design of interconnected power systems within this document will enhance system reliability, mitigate many of the adverse impacts associated with the loss of a major portion of the system or unintentional separation of a major portion of the system, and will not be consequential because of normal design contingencies. In the context of this Technical Report, interconnected power system means an entity's (control area or a system operator) high-voltage transmission system that can adversely impact other connected systems due to faults and disturbances within its area. In the case of large areas, the system operator may define a subset of its area to keep the adverse impact contained within a smaller portion of its system. This Technical Report specifies the recommended techniques for securing an IPS to ensure a high level of reliability. Generally, interconnected power systems are synchronously connected or asynchronously connected through DC interconnections. This document aims to ensure that the interconnections are designed and operated consistently on both ends. The recommendations include design and operation requirements to withstand the primary contingencies specified in this document.

4 CONTROL AREA

Interconnected power systems are large and complex in terms of geographical arears and number of equipment to be managed. To facilitate the ease of control and operations management they can be demarcated into control areas.

The regional power pools organisations should define control areas which means “an electrical system with borders defined by points of the 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.”

The criteria for control area operation are that 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. Control Area Operators are required to provide Control Area Services and Regulating Reserves for the secure control and operation of the interconnected system.

The frequency control of the entire IPS is dependent on how well each control area manages its frequency within the acceptable dead band as required by the grid codes and operating guidelines of member utilities. The frequency control is also enabled by the generation and load adequacy as well as the regulating reserves requirements stipulated in regional guidelines to ensure frequency stability during probable contingencies. Control area operators should also manage flows between control areas within hourly contracts to minimize imbalances or unscheduled energy in real time.

The control area arrangement should be setup for the simplification of control operations given the unique configuration of each grid.

5 TRANSFER LIMIT MANAGEMENT

Transfer limits between the utilities shall be clearly defined, including the operational scenarios of applicability.

On an annual basis, studies should be performed to determine transfer limits between interconnecting areas, and this should be used as an input into the scheduling process to determine power flow contracts between interconnecting areas. These contracts should be honoured by all power pool member utilities to ensure efficient frequency control and can be enabled by having a functional automatic generation control (AGC) on all sides of the interconnector.

6 FREQUENCY MANAGEMENT

Power frequency is common across interconnected systems, and any deviation from the frequency scheduled value (50Hz), stipulations in the regional grid codes and guidelines will have a negative impact on the reliability of power supply to all customers and could also lead to the system collapse. The rate of change of frequency (ROCOF) depends on the inertias of rotating generators and loads connected to the network.

Control Area Operators are required to perform frequency management by balancing the available generation to the load and take corrective action when mismatch occurs in real time. They should ensure that there is sufficient amount of reserves in their control areas to cater for disturbances.

In primary frequency control, the generators in their control areas should act directly in response to the actual frequency deviation using the decentralized frequency control approach.

The secondary frequency control should be performed using the centralized frequency control approach where generators and loads change their output on instruction from a central coordinator located at their National Control Centres (NCCs). Secondary frequency control should be performed using Automatic Generating Control (AGC) and/or manual reserve instructions to complement AGC capacity. AGC is a centralized control loop that co-ordinates the generators and its main function is to restore the system frequency to the nominal value or to the agreed dead band.

Control Area Operators are expected to comply with the internationally used frequency Control Performance Standards (CPS) and Disturbance Control Standards (DCS) and these KPI should be monitored by power pools. All Control Areas are required to achieve compliance of at least 100% for CPS1, 90% for CPS2 and 100% for DCS on all reportable disturbances measured over a year:

- CPS1 measures the extent to which the member utility complies with frequency control requirements within a minute on average.

- CPS2 measures the extent to which the member utility complies with frequency control requirements within 10 minutes on average.

- DCS measures extent to which the member utility has recovered Area Control Error (ACE) to pre-disturbance levels within 10 minutes.

The IPS is not designed to handle all possible contingencies and combinations of contingencies that could lead to large frequency deviations, but automatic remedial schemes should be designed to arrest the frequency decline by shedding the predetermined loads. This should be studied and implemented in such a way that enough load is shed in stages to arrest and bring the frequency back into the stipulated dead band. The Under Frequency Load Shedding Scheme (UFLS) scheme is the final barrier against a system blackout when considering a rapid frequency decline.

The control areas of the power pools should ensure the integrity of the scheme through:

- Regular audit of the performance of the scheme.

- Verification of performance of the scheme after an event.

- Ensuring adequate load remains on the scheme, particularly during manual load shedding. It should be ensured that a pre-determined percentage of system load, determined through system studies remains on the scheme during manual load shedding.

- Ensure coordination of settings across interconnected systems

7 SYSTEM VOLTAGE MANAGEMENT

Maintaining healthy voltage is one way of reducing technical losses and ensuring system stability. Power system controllers have a responsibility to maintain voltage levels within specified limits.

7.1 Voltage Stability

Voltage stability is a local phenomenon and is defined as the ability of the system to remain within stipulated levels after a probable contingency. Voltages should be maintained within the following bands under system healthy conditions and during planned outages. After a single contingency, before corrective action is taken, the voltage may reduce between 0.9 – 0.98pu. After corrective action has been taken, the voltage should return to between 0.95pu and 1.05pu. After the contingency the voltage should be restored within 15 min. The applicable power pool technical guidelines or grid code requirements for power factor, voltage ride through and reactive power management should take precedence.

The long term as well as dynamic voltage stability studies to determine the transfer limit should be performed on annual basis. All power pools should ensure that equipment identified by these studies to support voltages at the interconnectors, such as SVCs and shunt reactive compensation devices are installed, in working order and well maintained.

Related refence document:

IEC TS63217:2021 ed1
Utility-interconnected photovoltaic inverters - Test procedure for over voltage ride-through measurements

IEC TS 63217:2021 provides a test procedure for evaluating the performance of Over Voltage Ride-Through (OVRT) functions in inverters used in utility-interconnected photovoltaic (PV) systems.

This document is most applicable to large systems where PV inverters are connected to utility high voltage (HV) distribution systems. However, the applicable procedures may also be used for low voltage (LV) installations in locations where evolving OVRT requirements include such installations, e.g. single-phase or 3-phase systems. This document is for testing of PV inverters, though it contains information that may also be useful for testing of a complete PV power plant consisting of multiple inverters connected at a single point to the utility grid. It further provides a basis for utility-interconnected PV inverters numerical simulation and model validation

7.2 Ferranti Voltage

When energizing long lines, the open end of the line will experience Ferranti voltages. These voltages must remain within the ratings of the equipment, and it should hence not exceed more than 1.1pu on the open end of the line. When calculating the expected Ferranti voltage rise, each case must be investigated on an individual basis considering the realistic voltages, on that part of the network, under which they will operate under light loading conditions. These interconnectors could be long and should have line reactors installed on both ends of the line to deal with Ferranti voltage effect. The reactors should be planned, designed, and sized appropriately for the network.

7.3 Switching Voltage

When switching reactive compensation devices, the voltage should not rise more than 3% under system healthy and not more than 5% under contingency.

7.4 Voltage collapse

The transmission network should be designed and operated in such a way that it is never overcompensated by shunt capacitor banks i.e., for an increase of load at any bus bar, the voltage should decrease. This is equivalent to a negative slope on the power- voltage (P-V) curve for any bus bar. Furthermore, the voltage at maximum power transfer (knee point of the P-V curve) should be lower than nominal voltage.

The following limits can be defined:

- *5% from maximum power transfer limit*. This limit (in MW) is 95% of the maximum power transferred at the knee of a P-V curve. 5% of the load being increased to determine the transfer limit is used as a safety margin to avoid operating the power system too close to the knee of the P-V curve.

- *0.95p.u. voltage limit*. This limit (in MW) is the maximum power transfer at which all bus bar voltages are at or above 0.95p.u.

- *10% reactive power reserve margin limit*. This limit (in MW) is the maximum power transfer at which all generators or Static Var Compensators (SVCs) in the area are at or below 90% of their maximum reactive power output. This limit is commonly used on networks that use SVCs to increase power transfer and experience voltage collapse at relatively high voltage.

The lowest of the above transfer limits under single contingency conditions is the overall limiting factor and is the maximum safe power transfer limit. The power system should be operated in such a way that none of these limits are violated following the next worst contingency.

If the network design is such that it is not possible to operate the interconnector within these margins without load shedding pre-emptively, this should be highlighted, and a remedial action scheme should be implemented. Under system healthy conditions the power system should not be operated beyond the limits above.

7.5 Power quality

It is important that at points of interconnection, power should comply with the grid code requirements or relevant IEC standards.

Power quality measuring instruments should be installed at each end of the interconnection. The power quality meter should be capable of measuring voltage regulations, voltage unbalance, harmonics, voltage dips and interruption events. The instruments should be calibrated and certified by the relevant certification authority. The instruments should be tested, maintained, and re-calibrated as per system operator guidelines.

Power quality violations should be investigated and mitigated by the interfacing system operators.

Related IEC reference standard:

IEC61000 - all parts

8 GRID SYNCHRONISATION AND ITS CONDITIONS

Grid synchronisation is the process of harmonizing various electrical parameters of two or more grids or power systems, including aligning their frequencies, voltage levels, and phase angles, to enable their interconnection and seamless operation. Grid synchronisation ensures that the electrical grids can work together smoothly and safely, avoiding voltage or frequency mismatches that could disrupt the stability and reliability of the interconnected systems.

Conditions for Grid Synchronisation:

- Frequency Matching: The frequencies of the two grids must be very close or ideally identical.
- Voltage Compatibility: The voltage levels of the grids should be matched. If they are not, transformers or other voltage control devices may be necessary to match the voltage levels at the interconnection point.
- Phase Synchronisation: The phase angles of the voltage waveforms and phase sequence in the two grids should be synchronised to ensure that the waveforms are aligned in time. Phase sequence confirmation is required when commissioning new plant or following a major network configuration change.

Synchronising equipment should be installed at both ends of the interconnectors. Acceptable tolerances of above parameters before synchronizing should be as per applicable regional guidelines or agreed between interfacing parties.

Both grids should exhibit stable voltage and frequency characteristics. Sudden voltage or frequency fluctuations can disrupt synchronization. Each grid should be operated within its specified reliability and quality standards. This prevents voltage and current surges when interconnecting the grids.

9 TRANSIENT / ANGULAR STABILITY

Angular stability refers to the ability of the interconnected synchronous machines to remain in synchronism when subjected to a disturbance. The time frame of interest in transient stability studies is usually 3 to 5 seconds following the disturbance. It may extend to 10 to 20 seconds for very large systems with dominant inter-area swings.

The system needs to be transiently stable for worst single contingency under any circumstances. In the case that the system is not transiently stable for a double contingency then at least one of the following operational mitigations should be implemented:

- A remedial action scheme to prevent instability (this being the preferred solution) or.
- A system operational guideline with recommendations on how the network must be operated to cater for the worst possible contingency.

The transient stability for power stations of MW sizes stipulated by related grid codes must be maintained after the following incidents:

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

The control area operators should operate the IPS as far as practically possible to prevent instability, uncontrolled separation, or cascading outages from occurring because of the most severe double contingencies. For this reason, transient stability should also be maintained for a three-phase line fault/busbar fault cleared in normal protection times with any one circuit out of service.

10 SMALL SIGNAL STABILITY

The small signal stability is defined as the "ability of the power system to maintain synchronism when subjected to small disturbances". The small signal instability is usually caused by weak link between generation pools and insufficient synchronising torques and local loads to assist with the damping of system oscillations. Small Signal Stability of the system can be interpreted by means of linear and eigenvalue analysis which helps by identifying poorly damped or unstable modes in power system dynamic models. Power oscillations in the IPS are always present and are triggered by the small changes in both generation and load. These oscillations are mainly due to the energy transfer between the rotating masses of the machines on the power systems interconnected by weak transmission lines. When these oscillations are excited by system disturbances, they grow to amplitudes that can cause undesirable effects on the system and could damage power system plant and equipment.

Interregional joint studies should be performed to assess the frequency modes that exist in the IPS, the level of damping and their point of controllability. The inter-area power oscillations with frequency modes of 0.1 to 0.5 Hz are a characteristic of the relatively weak link between the two systems. Studies done to establish if sufficient damping of power oscillations exist should be used for the correct tuning of Power System Stabilizers (PSS). Active control devices such as Power Oscillation Dampers (POD) and PSS should always be correctly tuned and operational.

Wide Area Measurement Systems (WAMS) using Phasor Measurements Units (PMU) are increasingly used to monitor and improve these oscillations that are observed on the IPS. A phasor based WAMS is a network of fast time synchronized measurements of voltage and current phasors (synchro-phasors) that enables users to monitor the angular stability and dynamics of a power system. Continuous monitoring enables operators to perform corrective actions promptly before an issue escalates and presents a risk to the integrity of the system. In this way, the reliability and stability of the IPS network is improved. It is recommended that such systems be implemented.

Most Control area operators are faced with challenges in operating modern power system networks because of capacity constraints, reserve shortages and increasing of intermittent inverter-based generation. WAMS is thus recommended to assist with the situational awareness of this modern and complicated power system networks.

11 CONTROL AND MONITORING REQUIREMENTS

Each System Operator should have a Supervisory Control and Data Acquisition (SCADA) system for control and monitoring of its network. When connecting two networks, it is important to confirm the System Operator point of control boundaries. Each System Operator will only have rights to control the network on its side of these boundaries, unless otherwise agreed.

In most cases the control areas will need to have visibility beyond the control boundaries, at least up to the first interfacing substations. The parties will need to agree on the extent of visibility required, and this equipment can then be included in the corresponding SCADA systems. The key operational data should be shared between control areas via protocols such as Inter-Control Centre Protocol (ICCP) to facilitate effective coordinated control of the IPS. This may require the existing SCADA to be upgraded in some instances.

12 PROTECTION REQUIREMENTS

The purpose of protection is to clear faults as fast as possible to maintain the stability of the network. The general protection requirements for the interconnected systems should ensure that the IPS has a reliable and adequate protection and control system designs and operations.

Transmission Extra High Voltage (EHV) interconnectors shall be protected by two equivalent protection system (Main 1 and Main 2). These mains must be fully segregated in their secondary circuits. The protection system must include either distance or differential protection relays or both depending on the line length. The protection system must also include backup protection for protection against high resistance single phase to ground.

High Voltage (HV) feeders shall be protected by single or dual main protection system and shall have both backup protection for both single phase and phase to phase faults.

Protection settings must be calculated such that the protection system is sensitive, dependable, secure, and fast for all possible short circuits. To aid with speed of operation, distance protection applications must be equipped with tele-protection facilities. To aid with both speed and security, differential protection applications must be equipped with dedicated fibre tele-protection facilities. This is to ensure correct protection operation that will clear faults in protection time, limit the impact to the faulted area and allow for stable, safe, and secure operation of the IPS. Backup Direct Current (DC) systems with appropriate capacity and standby time is required to sustain the substation plant and equipment.

At the points of connection there shall also be synch check facilities to ensure that voltage and frequency measurements are within acceptable range whenever the systems are being connected.

Incorrect protection operation as a result of incorrect setting or relay maloperation can be the cause or contributing factor to a major network outage incident. Therefore, protection systems should be tested and maintained regularly. Testing of interconnector protection equipment should be coordinated between the two areas. Test reports should be made available to relevant stakeholders.

To improve the protection performance, the KPIs which looks at the security and dependability of the protection schemes should be formulated, monitored, trended, and benchmarked against international practices.

13 METERING

Metering is an important part of the interconnected system as it provides information for billing purposes and power quality measurement.

The metering circuit (Current Transformers, Voltage Transformers etc) should comply to applicable international standards.

Related standards:
IEC 60044-7:1999 (VT's) & **IEC60044-8:2002** (CT's)

Main and backup meters shall be installed at each end of the interconnection. All metering facilities at all interconnection points should have the metering register. The meters should be capable of measuring in all four quadrants, calibrated and certified by the relevant certification authority.

The following metering process should be established:

- the registration of a Connection Point, Metering Point, and relevant Grid Participants;
- verification of compliance with the Grid Code; and
- auditable control of changes to the registered information.

The metering system should be tested, maintained, and re-calibrated as per system operator guidelines and international standards.

Standards that can be referenced :
IEC-62052 part 11:2003 (meters);
IEC- 62053: part11:2003 (active energy meters class), part 22 (active energy meters class S), part 23(reactive energy meters) and part 24:2020 (reactive energy meters class)

Neighbouring system operators should agree on the process for managing metering data. This agreement should cover aspect such as data synchronisation, confidentiality management, remote access, storage, etc.

14 TELECOMMUNICATION

Telecommunication is essential for the safe and reliable operation of the power system. It enables functions such as SCADA, WAMS as well as network protections schemes. It also enables voice communication between control centres. Its performance is key to the security of the power system and thus require stringent specifications and high levels of levels of availability.

The system operators should ensure that adequate connectivity bandwidth is available for the interconnector substation to facilitate data transfers and operations by control area operators. They should also ensure that there is telecommunication network redundancy to reduce the risk of network unavailability. KPI for equipment and network availability should be set, monitored, and trended in line with international best practice.

Related IEC reference standard :
IEC TR 60870-1-1:1988
Telecontrol equipment and systems .
Part 1 – General considerations, sections one:

General Principles - *S*pecifies classes for environmental conditions under which telecontrol equipment has to operate. Gives an overall view of the functional elements contributing to basic structures and to the choice of telecontrol system configurations.

It deals with functions which are typical for any process to be monitored and controlled but emphasizes the specific problems which characterize geographically widespread processes, such as the dominant influence of telecommunications links with restricted bandwidth and often low signal-to-noise ratio. However, this report serves only as an introduction to the detailed standards and recommendations laid down in Parts 2-5 of IEC 60870.

15 OPERATIONAL PROCESSES

The following processes should be in place for safe and reliable operations of the interconnected power system:

15.1 Commissioning and re-commissioning procedures

There should be an agreement between the utilities on commissioning processes. Commissioning of interfacing equipment should be jointly planned by the two system operators. There should be an agreement on the commissioning procedures, and on the communication protocols during commissioning. Commissioning reports should be available to relevant stakeholders before energising.

15.2 Emergency preparedness procedures

Emergency preparedness procedures shall be put in place to ensure speedily recovery in case of contingencies. The interfacing system operators should align on the suitability and applicability of such procedures.

15.3 Outage co-ordination

Neighbouring system operators should agree on the process of scheduling outages, particularly as it relates to the interconnectors. To the extent possible, these outages should be kept to the minimum with both utilities aligning the maintenance plans with these schedules.

System operators should also agree on the outages to be informed about in the neighbouring network.

15.4 Maintenance procedures

Maintenance is crucial for ensuring optimum and reliable operation of interconnectors. Maintenance of interconnectors must be coordinated among all system operator in the interconnection. Maintenance must not be limited to main high voltage equipment, but also include auxiliary systems such as telecommunication, metering, telecontrol, protection, and battery systems at border substations. Maintenance plans must be established and communicated in advance among all stakeholders. Efforts must be taken to safeguard reliability of the power system during maintenance. Safety rules must be followed during maintenance to protect personnel, the general public, and equipment.

All member utilities shall be responsible for ensuring that their equipment is adequately maintained as per the applicable standards, e.g. [IEC 63060]. As far as possible, naming, numbering, and colour-coding of interconnector equipment should be standardised.

Maintenance of interconnector equipment and auxiliary systems must be carried out according to manufacturer's manual and in compliance with national legislation. Outage of interconnector equipment and auxiliary systems for maintenance must be backed by system simulations to inform real time monitoring and control of the power system. All identified contingencies must be mitigated to ensure power system reliability during maintenance. Annual interconnector maintenance plans for a particular year must be established and agreed among affected parties. System Operators should utilise modern software for determining optimum power flow and analysing contingencies during maintenance outages of interconnectors.

Two or more interconnectors should not be released on maintenance at the same time, unless specified measures have been taken to safeguard reliability of the power system.

Upon return to service of the interconnector, all stakeholders, especially market participants, must be informed. Neighbouring system operators of an interconnector must use common certificates for high voltage switching, isolation, earthing and giving permit to work. As far as possible equipment on one end of the interconnector should be maintained at the same time as the other end. Failure to carry out interconnector maintenance and associated reasons must be reported. Breakdown maintenance and forced outages of interconnectors must be investigated and measures implemented to prevent recurrence.

Related IEC references standard

IEC TS 63060:2019.
IEC TS 63060:2019(E) provides guidance to develop maintenance requirements of installations and equipment in electric power networks. It is primarily meant for the operators of electric power networks, particularly those of public power supplies, including High-Voltage DC transmission (HVDC). This scope does not include:

– railway networks,

– installations of end consumer networks,

– installations for electric power generation.

Crises handling, e.g. in emergency situations, is not within the scope of this document

The system operators should ensure that performance measures are defined, monitored, and trended as recommended in this document. When required, corrective action should be taken.

Bibliography

SAPP & WAPP/ECOWAS related guidelines on interconnected grids/networks

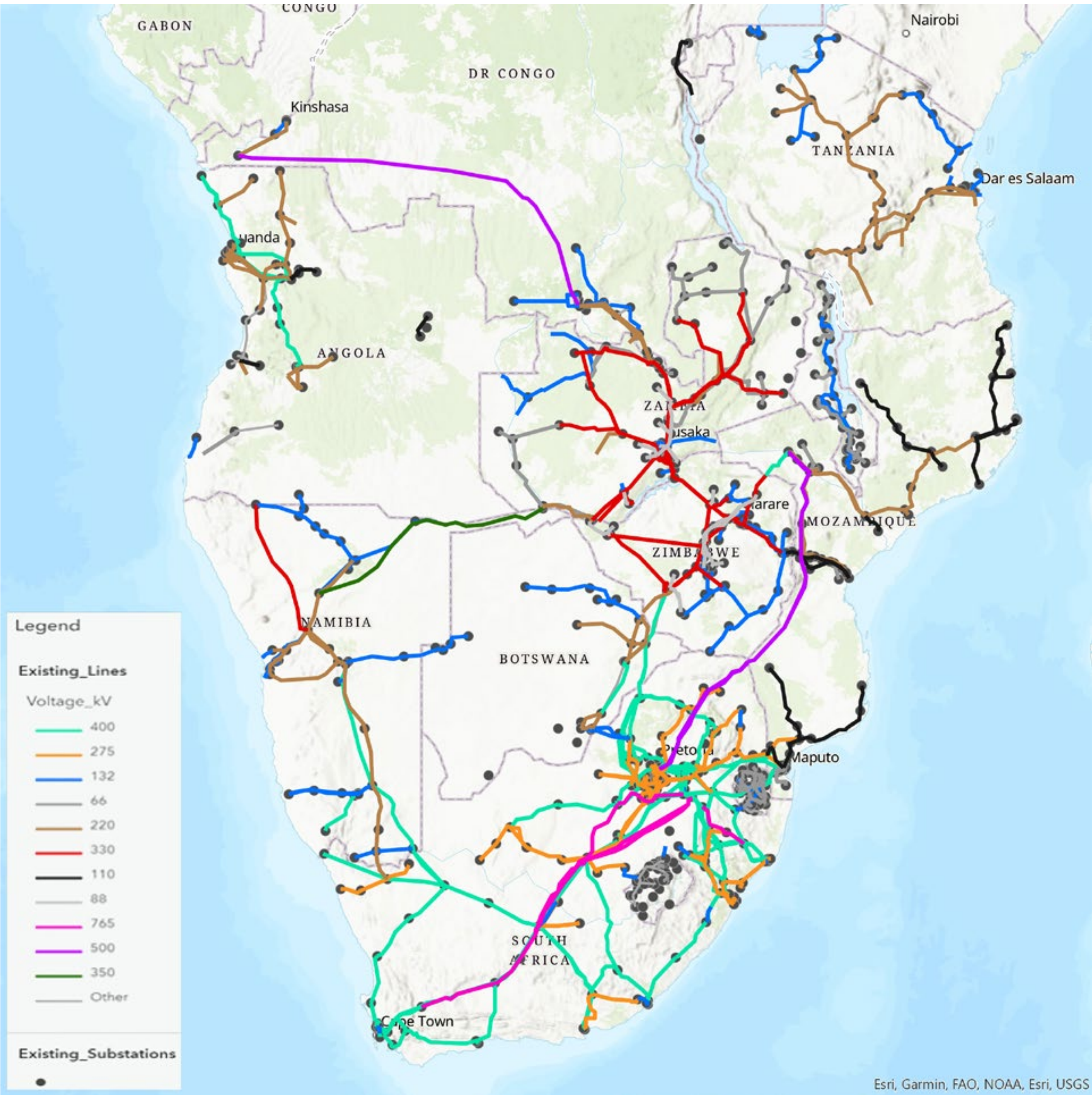


Figure 1: SAPP electrical network

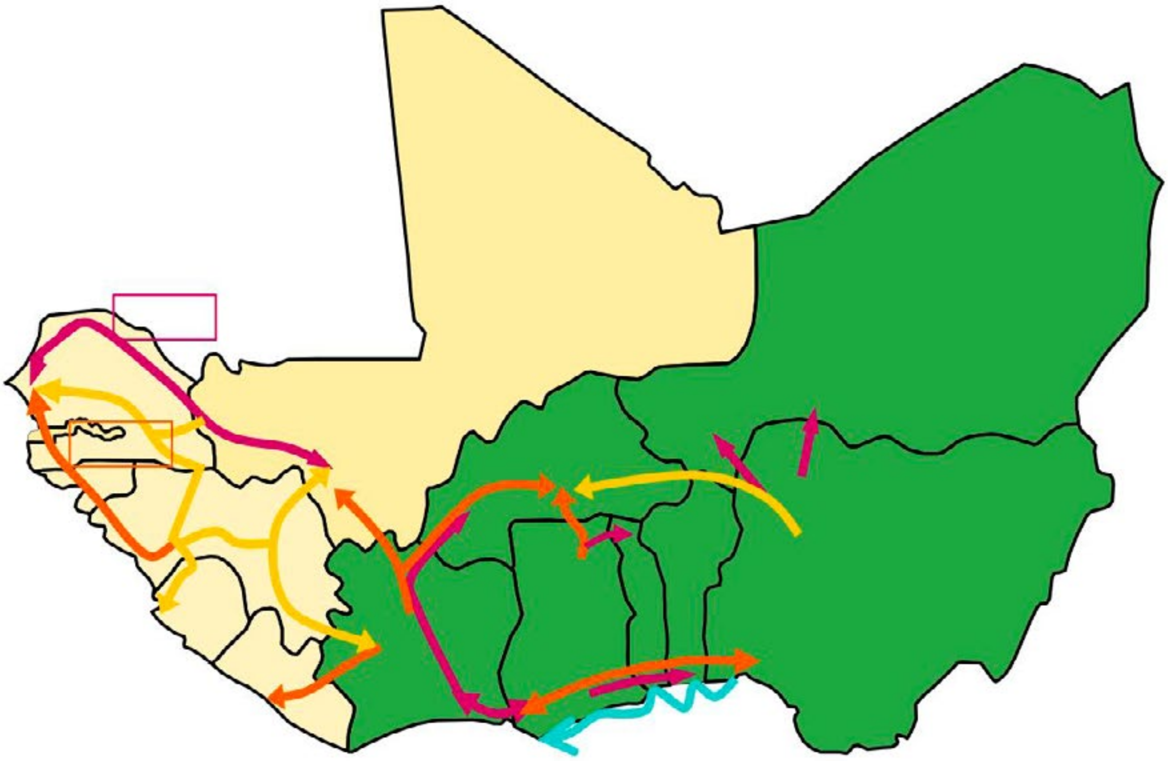
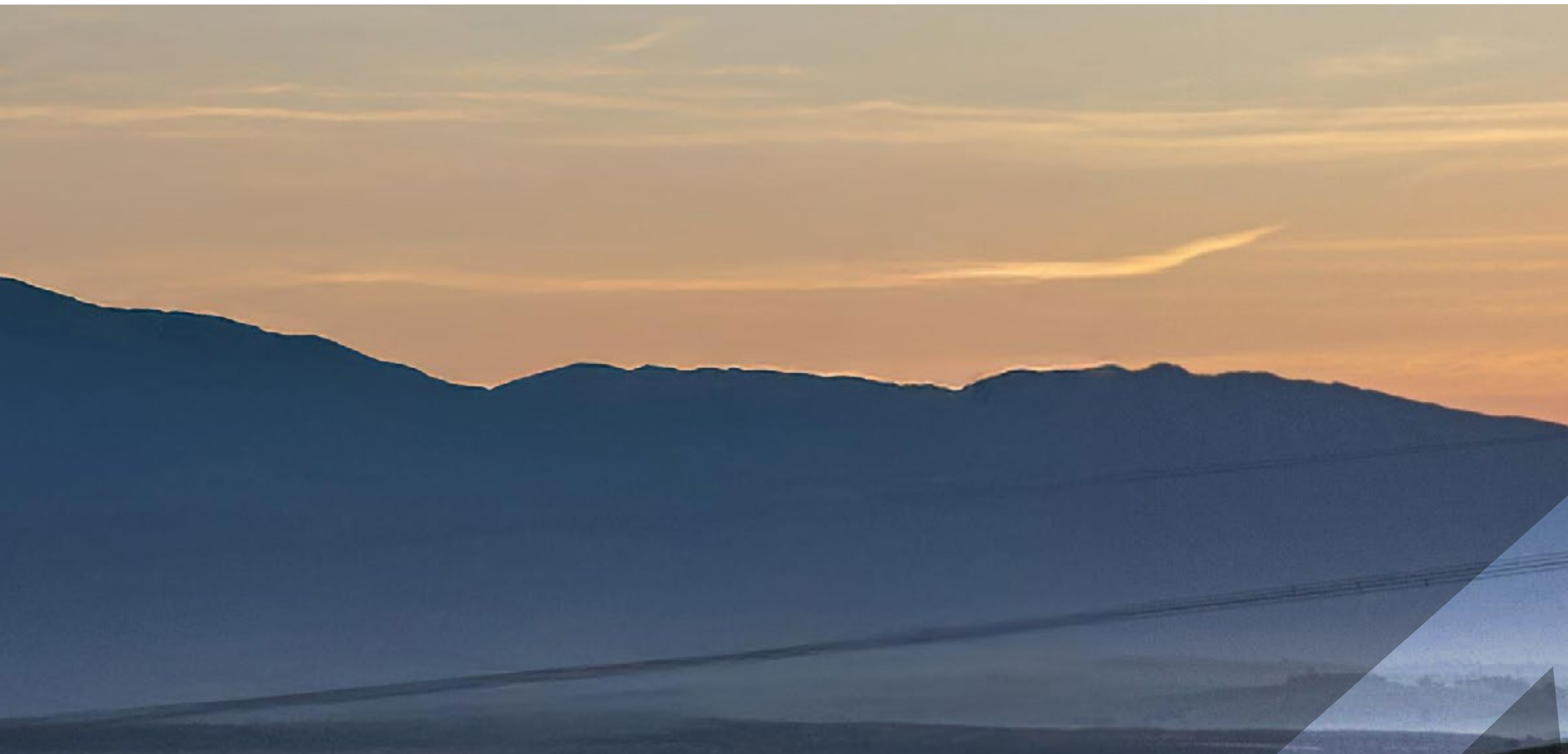


Figure 2: WAPP electrical network



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