THE ESWATINI GRID CODE

The Network Code

2 of 8 Code Documents

Version 1.1

January 2023

Enquiries: The secretariat,
ESERA, Eswatini
Telephone: +268 24048425
Email: secreteriat@esera.org.sz

Table of Contents

List of Figures

List of Tables

1 <u>*Introduction*</u>

(1) This code contains the standards used to plan and develop the *Transmission System (TS)*.

2 <u>*Transco technical design requirements*</u>

(1) The purpose of this section is to document the design and other technical standards that the *Transco* shall adhere to.

2.1 Equipment design standards

(1) *Primary Substation Equipment* shall comply with *IEC* specifications. Application shall cater for local conditions, e.g. increased pollution levels and should be determined by or in consultation with the *Customer*.

(2) The *Transco* shall design, install and maintain equipment in accordance with the standards.

(3) *Customers* may require the *Transco* to provide documentary proof that their connection equipment complies with all relevant standards, both by design and by testing.

2.2 Clearances

(1) Clearances shall at least comply with IEC requirements.

2.3 CT and VT ratios and cores

(1) *CT* and *VT* ratios and cores shall be determined by or in consultation with the *Transco*.

2.4 Standard Busbar arrangements and Security criteria

(1) *Substation*s on the *TS* shall be configured according to the principles described in this section.

2.4.1 *Transmission Substation* standard *Busbar* arrangements

(1) The reliability and availability of the *TS* is not dependent only on *TS* lines, transformers, and other primary and secondary plant; the *Busbar* layout also plays a part. It is important that the *Busbar* layout and what it can do for the reliability and availability of the *Customer's* supply be prudently assessed when planning the *TS*.

(2) The standard arrangement shall be based on providing one *Busbar* zone for every main transformer/line normally supplying that *Busbar*. The *Transco* shall however consider local conditions, type of equipment used, type of load supplied and other factors in the assessment of the required *Busbar* redundancy. System reliability criteria as described in the *TS* Planning and Development Section should also be adhered to.

2.4.2 Use of bypasses

(1) Bypasses provide high line availability by allowing circuit breakers to be taken out of service for maintenance and testing without affecting line availability

(2) The bypass with single *Busbar* selection shall be used at 66 kV, 132 kV and 220 *kV* on single line radial feeds to provide continuity of supply when maintaining the line breakers

(3) The bypass with double *Busbar* selection shall be used on new 400 *kV*, 330 *kV* lines and 220 *kV* lines where justified.

2.5 Motorised isolators

(1) The provision of motorised isolators at new *Substations* is to be based on the following:

(2) All 132kV to 400 *kV* isolators shall be motorised at new *Substations*.

(3) Isolators 66 *kV* and below shall be specified on individual merit (importance ranking vs. cost vs. remoteness)

2.6 Earthing isolators

(1) Earthing isolators shall be provided at new *Substations* where the fault level is designed for 20 *kA* and above.

2.7 Busbar Protection CT's

(1) For phase 3 *Busbar Protection* schemes, single sets of *CT's* shall be used on bus couplers and bus section breakers (i.e. 3 *CT's* instead of 6 *CT's*) to reduce the probability of a double bus zone outage for a *CT* fault on a bus coupler or bus section breaker (i.e. non-overlapped zones will apply).

(2) At *Power Station*, overlapped bus zones shall be retained to ensure fastest possible clearance of *Busbar* faults.

2.8 Tele-control

(1) Either *Participant* may be permitted to have tele-control equipment in the *Substations* / yards / buildings of the other *Party*, to perform agreed monitoring and control. Access shall be provided to such equipment.

(2) *Transco* shall have reliable *SCADA* facilities (including telecommunications, computers and *RTUs*) for the all *TS* connected facilities

(3) *Distributors* shall have reliable *SCADA* facilities (including telecommunications, computers and *RTUs*) for the *Distribution System* connected directly to the *TS*, to provide the necessary response where system conditions require.

2.9 Transformer tap change

(1) The *Transco* shall install remote tap changing facilities and automatic tap changing facilities on all new transformers.

(2) Transformers used in the *TS* at 66kV and above are normally not on automatic tap change. Transformers supplying a *Customer* are usually on automatic tap change. Voltage levels, sensitivity and time settings and on/off auto tap changing shall be determined by the *System Operator* in consultation with the *Customer*, and the *Transco*.

2.10 Substation drawings

(1) The following set of drawings shall be made available by the respective asset owners for all *points of supply*, if required by the other *Party* for the purposes of connection:

(2) Station Electric Diagram

(3) Key Plan

(4) Bay Layout Schedules

(5) Foundation, Earthmat and Trench Layout

(6) Steelwork Marking Plan

(7) *Security* Fence Layout

(8) Terrace, Road and Drainage Layout

(9) Transformer Plinth

(10) General Arrangement

(11) Sections

(12) Slack Span Schedule

(13) Barrier Fence Layout

(14) *Security* Lighting

(15) Floodlighting Parameter Sketch

(16) *Protection* details

(17) Contour Plan

3 <u>Protection requirements</u>

(1) This section specifies the minimum *Protection* requirements for *Transco*'s as well as typical settings, to ensure adequate performance of the *TS* as experienced by the *Customers*.

(2) The *Transco* shall at all times install and maintain *Protection* installations that comply with the provisions of this section.

(3) The *Transco* shall conduct periodic testing of equipment and systems to ensure and demonstrate that these are performing to the design specifications. Tests procedures shall be according to the manufacturers' specifications.

(4) The *Transco* shall make available to *Customers* all results of test performed on equipment for reasonable requests.

(5) *Protection* schemes are generally divided into:

(6) equipment *Protection* and

(7) System *Protection*.

3.1 Equipment Protection requirements

3.1.1 Feeder ***Protection***: 220kV and above

3.1.1.1 ***Protection*** Design Standards

(1) New feeders shall be protected by two equivalent *Protection* systems – Main 1 and Main 2.

(2) The Main 1 and Main 2 *Protection* systems shall be fully segregated in secondary circuits.

(3) An additional earth fault function shall be incorporated in the main *Protection* relays or installed separately to alleviate possible deficiencies of distance relays in detection of high resistance faults.

3.1.1.2 ***Protection*** Settings

(1) The *Protection* relays shall provide reliable *Protection* against all possible short circuits, provide remote and/or local back up for not cleared *Busbar* faults and are not set to provide overload tripping.

(2) Where specifically required, the feeder *Protection* may be set, if possible, to provide remote back up for other faults as agreed upon with other *Participants*.

3.1.1.3 Automatic Re-closing

(1) Automatic re-closing (*ARC*) facilities shall be provided on all feeders.

(2) The *System Operator* shall decide on *ARC* selection based on real time system, environmental constraints and consultation with *Customers*, with regard to equipment capabilities and in accordance with the *ARC* philosophy below. All *ARC* settings and methodology shall be implemented by the *Transco* and be made available to *Customers* on request.

3.1.1.4 *ARC* cycles

(1) Either of the following two *ARC* cycles for single phase faults shall be used:

(2) Double attempt *ARC* cycle for persistent fault:1ph fault – 1ph trip – 1ph *ARC* – 3ph trip – 3ph *ARC* – 3ph trip – lockout

(3) Single attempt *ARC* cycle for persistent fault: 1ph fault – 1ph trip – 1ph *ARC* – 3ph trip – lockout

(4) The *ARC* cycle for a multi-phase fault shall be: multi-phase fault – 3ph trip – 3ph *ARC* – 3ph trip – lockout

(5) On some lines the *ARC* is being switched off according to the following operational needs:

(6) Sporadically, when high risk of line fault is recognised, for live line work or to reduce breaker duty cycle where breaker's condition is questionable.

(7) Periodically, during season of high fault *Frequency*,

(8) Permanently, on lines with the highest fault *Frequency* throughout the year or on *Customers*' request.

(9) Whenever an *ARC* could initiate a severe power swing or an Out-Of-Step condition in weakly interconnected systems.

3.1.1.5 Single Phase *ARC*

(1) In most applications the dead time of Single Phase *ARC* is selected to 1 second but may differ for different system requirements. The closing of the breaker is performed without synchronisation as the synchronism is maintained via remaining phases that are closed during the whole incident.

3.1.1.6 Three Phase *ARC*

3.1.1.6.1 Fast *ARC*

(1) Fast *ARC* i.e. fast closing of the breaker without checking synchronism is not used on the *TS* to avoid stress to the rotating machines at the *Power Station*s and at the *Customers*' plant. This option is available on *Protection* panels and can be selected in case of *emergency* i.e. when as a result of outages or disturbance load/generation islands are interconnected via a single line. The operating practice, however, is to use only single phase *ARC* (fast by its nature) in such situations as a compromise between supply reliability and stress to the equipment.

3.1.1.6.2 Slow *ARC*

(1) The Dead Line Charging (*DLC*) end is selected in line with the Table 1 below based on fault level (FL) at the connected *Substations* A and B.

Table 1: Selection of Dead Line charging end of the line.

End A End B	*Substation* FL<10kA	*Substation* FL>10kA	*Power Station*
Substation FL<10kA	*Substation* with higher FL	*Substation* A	*Substation* B
Substation FL>10kA	*Substation* B	*Substation* with lower FL	*Substation* B
Power Station	*Substation* A	*Substation* A	*Power Station* with lower FL

(2) In most applications the dead time of slow *ARC* is selected to 3 seconds at *DLC* end of the line. At the synchronising end of the line the *ARC* dead time is usually selected to 4 seconds. The close command will be issued only after synch-check is completed. This may take up to 2 seconds if synchronising relays are not equipped with direct slip *Frequency* measurement. The breaker may take longer to close if its mechanism is not ready to close after initial operation at the time when the close command is issued.

(3) On the line between two *Power Station*s the dead time at the *DLC* end should be extended to 25 seconds to allow *Generators'* rotors oscillations to stabilise. The dead time on the synchronising end is then extended accordingly to 30 seconds.

(4) The synchronising relays are installed at both ends of the line to enable flexibility in *ARC* cycles and during restoration.

3.1.1.7 Power Swing Blocking

(1) New distance relays on the *TS* shall be equipped with power swing blocking facility. All unwanted operations of distance relays during power swing conditions shall be blocked on the *TS*.

3.1.2 Feeder *Protection*: 132kV and below, at *Transco Substation*s

3.1.2.1 Design Standard

(1) These feeders shall be protected by a single *Protection* system, incorporating either distance or differential *Protection* relays, unless otherwise agreed. Back up shall be provided by definite time and inverse definite minimum time (*IDMT*) over-current and earth fault relays.

(2) The *Protection* shall be equipped with automatic re-closing. Synchronising relays shall be provided on feeders that operate in "ring supplies" and are equipped with line voltage transformers.

3.1.2.2 Protection Settings

(1) *Protection* relays shall provide reliable *Protection* against all possible short circuits, provide remote and/or local back up for *Un*-cleared *Busbar* faults and should not be set to provide overload tripping where measurements and alarms are provided on *SCADA* system. In isolated applications where *SCADA* system is not available, overload tripping will be provided. Where overload conditions are alarmed at *Control Centres*, it is the *Control Centre* responsibility to reduce load to an acceptable level as quickly as possible.

3.1.2.3 Automatic Re-closing

(1) The *Customer* shall determine *ARC* requirements. The *System Operator* may specify additional *ARC* requirements for system *Security* reasons, which could extend beyond the *Transco Substations*.

3.1.3 Tele-*Protection* requirements

(1) New distance *Protection* systems shall be equipped with tele-*Protection* facilities to enhance the *Speed of Operation*.

3.1.4 Transformer and reactor *Protection*

(1) The standard schemes for transformer *Protection* comprise a number of systems, each designed to provide the requisite degree of *Protection* for the following fault conditions:

(2) Faults within the tank

(3) Faults on transformer connections

(4) Overheating

(5) Faults external to the transformer

(6) The *Transco* shall consider the application of the following relays in the design of the *Protection* system:

3.1.4.1 Transformer *IDMT E/F*

(1) The *MV E/F Protection* is to discriminate with the feeder back-up *E/F Protection* for feeder faults

3.1.4.2 Transformer *HV*/*MV IDMT O/C*

(1) The *System Operator* requires that the *IDMT O/C* does not operate for twice transformer full load. Overloading of the transformer is catered for by the winding and oil temperature *Protection*. However, network requirements may be such that the above standard cannot be applied. In this case, a mutually agreed philosophy may be used.

3.1.4.3 Transformer *HV*/*MV* Instantaneous *O/C*

(1) This back-up *Protection* is to cater for flash-overs external to the Transformer (*TRFR)* on the *HV* side or *MV* side and should operate for minimum fault conditions (possibly as well for an *E/F* condition). However, the overriding requirement is not to operate for through faults or for magnetising inrush current.

3.1.4.4 Transformer LV (Tertiary) *IDMT*/Instantaneous *O/C*

(1) This *Protection* is to operate for external faults between the main delta winding of the *TRFR* and the auxiliary *TRFR*, but not for faults on the secondary side of the auxiliary *TRFR*. The auxiliary *TRFR* is protected by Buchholz and temperature *Protection*.

3.1.4.5 Transformer Current Differential *Protection*

(1) This is the main transformer *Protection* for *E/F* and phase to phase faults. Maximum sensitivity is required, while ensuring no incorrect operation for load, for through fault conditions or for magnetising inrush current, with its attendant decaying offset.

3.1.4.6 Transformer High Impedance Restricted *E/F*

(1) This *Protection* is an additional *Protection* for the *TRFR* differential relay to cater for earth faults close to the star point of the *TRFR* winding, where phase to phase faults are most unlikely to occur.

3.1.4.7 Transformer Thermal Overload

(1) Winding temperature and oil temperature relays, supplied by the manufacturer are used to prevent transformer damage or life time reduction due to excessive loading for the ambient temperature or during failure of the cooling system.

3.1.5 *Transmission System Busbar Protection*

(1) *Busbars* shall be protected by current differential *Protection* (bus-zone) set to be as sensitive as possible for the "in-zone faults" and maintain stability for any faults outside the protected zone, even with fully saturated *CT*.

3.1.6 *Transmission System* bus coupler and bus section *Protection*

(1) Bus-coupler and bus-section panels are equipped with *O/C* and *E/F Protection*.

3.1.7 *Transmission System* shunt capacitor *Protection*

(1) All the new high voltage capacitor banks shall be equipped with sequence switching relays to limit inrush current during capacitor bank energisation. Inrush reactors and damping resistors shall also be employed to limit inrush current.

(2) The following *Protection* functions shall be provided for all types of *Protection* schemes:

(3) Unbalanced *Protection* with alarm and trip stages

(4) Over-current *Protection* with instantaneous and definite time elements

(5) Earth fault *Protection* with instantaneous and definite time sensitive function

(6) Overload *Protection* with *IDMT* characteristic

(7) Over-voltage with definite time

(8) Circuit breaker close inhibit for 300 seconds after de-energisation

(9) Ancillary functions as indicated below.

3.1.8 Over-voltage ***Protection***

(1) Primary *Protection* against high transient over-voltages of magnitudes above 140% (e.g. induced by lightning) shall be provided by means of surge arrestors. To curtail dangerous, fast developing over-voltage conditions that may arise as a result of disturbance, additional over-voltage *Protection* shall be installed on shunt capacitors and feeders.

(2) Over-voltage *Protection* on shunt capacitors is set to disconnect capacitor at 110% voltage level with a typical delay of 200 milliseconds to avoid unnecessary operations during switching transients.

(3) Over-voltage *Protection* on the feeders is set to trip the local breaker at voltage level of 120% with a delay of 1 to 2 seconds.

3.1.9 Ancillary ***Protection*** functions

(1) *Protection* systems are equipped with auxiliary functions and relays that enable adequate co-ordination between *Protection* devices and with bay equipment. The *Transco* shall consider the following functions for all new *Protection* system designs:

3.1.9.1 Breaker Fail / Bustrip

(1) Each individual *Protection* scheme is equipped with breaker fail / bustrip function to ensure fast fault clearance in case of circuit breaker failure to interrupt fault current.

3.1.9.2 Breaker Pole Discrepancy

(1) Breaker pole discrepancy *Protection* compares, by means of breaker auxiliary contacts, state (closed or opened) of breaker main contacts on each phase. When breaker on one phase is in a different position than breakers on remaining phases a trip command is issued after time delay.

3.1.9.3 Breaker Anti-pumping

(1) To prevent repetitive closing of the breaker in case of fault in closing circuits the standard *Protection* schemes provide breaker anti pumping timer. Circuit breakers are often equipped with their own anti pumping devices. In such cases anti pumping function is duplicated.

3.1.9.4 Pantograph Isolator Discrepancy

(1) The pantograph isolator discrepancy relay operates in the same manner as breaker pole discrepancy and is used to issue local and remote alarm.

3.1.9.5 Master Relay

(1) Transformer and reactor *Protection* schemes are equipped with latching master relay that require manual reset before the circuit breaker is enabled to close. The master relay is operated by *Unit Protection* that indicates possibility of internal failure.

3.2 System Protection requirements

3.2.1 Under-frequency load shedding

(1) The actions taken on the power system during an under-frequency condition is defined in the System Operation Code.

(2) Under-frequency load shedding relays shall be installed in the *IPS* as determined by the *System Operator* in consultation with *Distributors* and *End-Use Customers*. The respective asset owners shall pay for the installation and maintenance of these relays.

(3) Under-frequency relays shall be tested periodically. *Distributors* and *End-Use Customers* shall submit to the *System Operator* a written report of each such test, within a *Month* of the test being done, in the format specified in the Information Exchange Code. The testing shall be done by isolating all actual tripping circuits, injecting a *Frequency* to simulate a *Frequency* collapse and checking all related functionality.

3.2.2 Out of step tripping

(1) The purpose for the out-of-step tripping *Protection* is to separate power system in a situation where a loss of synchronous operation takes place between a *Unit* or *Units* and the main power system. In such a situation system separation is desirable to remedy the situation. Once the islanded system is stabilised it can be reconnected to the main system.

(2) The *System Operator* shall determine and specify the out-of step tripping (OST) functionality to be installed at selected locations by the *Transco*.

3.2.3 Under-voltage load shedding

(1) Under-voltage load shedding *Protection* schemes are used to prevent loss of steady-state stability under conditions of large local shortages of reactive power (voltage collapse). Automatic load shedding tripping of suitable loads is carried out to arrest the slide.

(2) The *System Operator* shall determine and specify the under-voltage load shedding functionality to be installed at selected locations by the *Transco*.

3.2.4 Sub-synchronous resonance *Protection*

(1) The sub-synchronous resonance (*SSR*) condition may arise on a power system where a *Generator* is connected to the main power system through long series compensated *TS* lines. The potential for unstable interaction is sensitive to system topology and is greater with the higher degree of compensation and larger thermal turbo-*Generators* are employed. The *SSR* condition is addressed either through *Protection* or mitigation. In case of *Protection*, a suitable relay shall be deployed as part of the turbo-*Generator Protection* that will lead to the *Unit* disconnection on detection of the *SSR* condition. The *Protection* does not reduce or eliminate the torsional vibration, but rather detects it and acts to remove the condition leading to the resonance. Mitigation, on the other hand, acts to reduce or eliminate the resonant condition. Mitigation is needed only under conditions when it is desirable or essential to continue operation when the power system is at or near a resonant condition.

(2) New *Generators* shall liaise with the *Transco* regarding *SSR Protection* studies. Least-cost solutions shall be determined by the *Transco* in accordance with the *TS* planning and Development Section, and implemented by the relevant asset owner.

3.2.5 *Protection* Settings impact on Network Stability (Dynamic Stability)

(1) Minimum clearance times for *Protection* in *Distributor* or *End-Use Customer* networks will be determined on a case by case basis in order to ensure Dynamic Stability of the *TS*.

3.3 Protection system performance monitoring

(1) To maintain high level of *Protection* performance and long term sustainability, the *Transco* shall monitor *Protection* performance.

(2) Each *Protection* operation shall be investigated for its correctness based on available *Information*. The *Transco* shall provide a report to *Customers* affected by a *Protection* operation when requested to do so.

4 Nomenclature

(1) All safety terminology shall comply with the *Transco* Operating Regulations for High Voltage Systems (ORHVS).

5 <u>*TS planning and development*</u>

(1) This section specifies the technical, design and economic criteria and procedures to be applied by the *Transco* in the planning and development of the *TS* and to be taken into account by *Customers* in the planning and development of their own systems. It specifies *Information* to be supplied by *Customers* to the *Transco*, and *Information* to be supplied by the *Transco* to *Customers*.

(2) The development of the *TS*, will arise for a number of reasons including, but not limited to:

(3) a development on a *Customer* system already *connected to the TS*;

(4) the introduction of a new *TS Substation* or *Point of Connection* or the modification of an existing connection between a *Customer* and the *TS*;

(5) The cumulative effect of a number of such developments referred to in (a) and (b) by one or more *Customers*.

(6) the need to reconfigure, decommission or optimise parts of the existing network.

(7) Accordingly, the development of the *TS* may involve work:

(8) at a *Substation* where *Customer*'s plant and/or apparatus is *connected to the TS*;

(9) on *TS* lines or other facilities which join that *Substation* to the remainder of the *TS*;

(10) on *TS* lines, *TS Substations* or other facilities at or between points remote from that *Substation*.

(11) The time required for the planning and development of the *TS* 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 in undertaking the new work while maintaining satisfactory *Security* and quality of supply on the existing *TS*.

5.1 Planning process

(1) The *Transco* shall follow a planning process divided into major activities as follows:

(a) Needs identification.

(b) Formulation of alternative options to meet this need.

(c) Studying these options to ensure compliance with agreed technical limits, and justifiable reliability and quality of supply standards.

(d) Costing these options on the basis of present-*day* capital costs and using appropriate net discount rates, establish the net present cost of each option.

(e) Determining the preferred option.

(f) Building a business case for the preferred option using acceptable justification criteria.

(g) Requesting approval of preferred option and initiating execution.

5.2 Identification of the need for TS development

(1) The *Transco* shall source relevant *Data* from relevant national planning studies, specific *Customer Information*, Governmental and *Customer* development plans to establish the needs for network strengthening.

5.3 Forecasting the demand

(1) The *Transco* is responsible for producing the *TS* demand forecast for the next five years and updating it annually and for estimating the load forecast for the next 10 years.

(2) The *TS* demand forecast shall be determined for each *Point of Supply*. Generation and import capacity plans shall be used to obtain the annual generation patterns.

(3) To forecast the maximum demand (*MW*) for each *TS Substation*, the *Transco* shall use *Distributor* and *End-Use Customer* load forecasts. Final loads are reconciled with *Data* from various sources.

(4) The load forecast shall be adjusted at various levels (making use of diversity factors determined from measurements and calculations) to line up with the higher-level *Data*.

(5) All *Distributors* and *End-Use Customers* shall annually, by end October, supply their 5-year ahead load forecast *Data* and an estimate for the 10 years ahead demand as detailed in the Information Exchange Code.

5.4 Technical limits and targets for planning purposes

(1) The limits and targets against which proposed options are checked by the *Transco* shall include technical and statutory limits which must be observed, and other targets, which indicate that the system is reaching a point where problems may occur. If technical or statutory limits are not achieved, alternative options shall be evaluated. If targets are not achieved, some options may be still acceptable as per the investment criteria.

5.4.1 Voltage limits and targets

(1) Technical or statutory limits are stated in

(2) Table 2 and Table 3:

Table 2: Technical and Statutory Voltage Limits

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 lines, capacitors, reactors, etc.: Maximum Fault Level Minimum Fault Level	 0.03 U_N 0.075 U_N
Statutory voltage change on bus supplying *Customer* for any period longer than 10 consecutive minutes (unless otherwise agreed in Supply Agreement)	0.10 U_N U_N + OR - 10%

Table 3: Standard Voltage Levels

U_N (KV)	U_M (KV)	$(U_M-U_N)/U_N$ %
765	800	4,58
400	420	5,00
330	346.5	5,00
275	300	9,09
220	245	11,36
132	145	9,85
88	100	13,63
66	72,5	9,85
44	48	9,09
33	36	9,09
22	24	9,09
11	12	9,09

(3) Target voltages for planning purposes are as in Table 4:

Table 4: Target Voltages for Planning Purposes

Minimum steady state voltage on any bus not supplying a *Customer* With multiple feeder supplies: With single feeder supplies and after contingency for multiple feeder supplies:	 $0.95\ U_N$ $0.90\ U_N$
Maximum harmonic voltage caused by *Customer* at *PCC*:	According to SZNS 028
Maximum negative sequence voltage caused by *Customer* at *PCC*:	According to SZNS 028
Maximum voltage change due to load varying N times per hour:	$(4.5\ \log_{10}N)\%$ of U_N
Maximum voltage decrease for a 5% load increase at receiving end of system (without adjustment):	$0.05\ U_N$

5.4.2 Other targets for planning purposes

5.4.2.1 Transmission System Lines

(1) Thermal ratings of standard *TS* lines shall be determined and updated from time to time. The temperatures used are 90ºC for aluminium conductor steel reinforced lines providing a *Firm Supply* (under single contingencies), and 75ºC for lines of copper or aluminium alloy or aluminium conductor steel reinforced lines not providing a *Firm Supply*. The thermal ratings shall be used as an initial check of line overloading. If the limits are exceeded the situation shall be investigated as it may be possible to defer strengthening depending on the actual line and on local conditions.

5.4.2.2 Transformers

(1) Standard transformer ratings shall be determined and updated from time to time using *IEC* specifications. The permissible overload of a specific transformer depends on load cycle, ambient temperature and other factors. If target loads are exceeded the specific situation shall be assessed as it may be possible to defer adding extra transformers, depending on the actual transformer and on load conditions.

5.4.2.3 Series Capacitors

(1) With the system healthy, the maximum steady state current should not exceed the rated current of the series capacitor.

(2) *IEC* 143 standards call for cyclic overload capabilities as follows:

(3) 8 hours in a 12-hour period: 1.1 times rated current

(4) ½ hour in a 6 hour period: 1.35 times rated current

(5) 10 minutes in a 2 hour period: 1.5 times rated current

(6) In addition, the *Transco* may require an occasional over-current rating of:

(7) 2 hours once per year: 1.3 times rated current

(8) The particular rating to be used must match the duration of the contingency with the required overload capability. Duration of contingency will depend on ability to pick up generation or shed load and the load profile.

(9) Any *Transco* wishing to install a new series capacitor or modify the size of an existing series capacitor, shall at his expense and according to the *Transco's* requirements, arrange for sub synchronous resonance, harmonic and *Protection* coordination studies to be conducted to ensure that sub synchronous resonance will not be excited in any *Generator*.

5.4.2.4 Shunt Reactive Compensation

(1) Shunt capacitors shall be able to operate at 30% above their nominal rated current at *Un* to allow for harmonics and voltages up to *Um*.

(2) Reactive compensation, whether new or modified, may cause harmonic resonance problems. Any *Participant* wishing to install or modify such equipment shall at his expense arrange for harmonic resonance studies to be conducted. If such studies indicate possible harmonic resonance conditions which could impact on the *TS*, such *Party* shall inform the *System Operator* before proceeding with the installation or modification.[1]

5.4.2.5 Circuit Breakers

(1) Normal and fault current ratings for standard switchgear are determined and updated from time to time. These ratings, and the following limits specified for circuit breakers, shall not be exceeded:

(2) Single-phase breaking current: 1.15 times 3 phase fault current

(3) Peak making current: 2.55 times 3 phase rms fault current

5.4.2.6 Secondary *ARC* current during single-phase re-closing

(1) The secondary *ARC* current shall not exceed:

(2) 20 amps rms with recovery voltage of 0.4 pu

(3) 40 amps rms with recovery voltage of 0.25 pu

5.4.3 Reliability criteria for planning purposes

(1) A system cannot be made 100% reliable as planned and *forced outage*s of components will occur, and multiple outages are always possible, despite having a very low probability of occurrence. From an economic point of view optimum reliability is obtained when the cost involved in reducing the load not supplied by one kW is just equal to the value of this unsupplied kW to the economy or to the specific *Customer* involved. The appropriate

degree of reliability depends on the probability of loss of supply and the probable amount of load not supplied when an outage does occur.

(2) The *Transco* shall formulate long-term plans for expanding or strengthening the *TS* on the basis of the justifiable redundancy.

5.4.4 Contingency criteria for planning purposes

(1) A system meeting the n-1 (or n-2) contingency criterion must comply with all relevant limits outlined in 7.4.1 (voltage limits) and the applicable current limits, under all credible system conditions.

(2) For contingencies under various loading conditions it shall be assumed that largest, normally-used, generating plant is in service to meet the load and provide *Spinning Reserve* for the more probable n-1 network contingency the most unfavourable generation pattern within these limitations shall be assumed, while for the less probable n-2 network contingency an average pattern shall be used. More details of load and generation assumptions for load flow studies are given in section 7.4.5.

(3) The generation assumptions for the n-1 and n-2 network contingencies do not affect the final justification to proceed with investments, but merely check that the backbone of the network is still sufficient to meet an n-1 or n-2 contingency.

5.4.5 Integration of *Power Station*s

(1) When planning the integration of *Power Station*s the following criteria shall apply:

5.4.5.1 *Power Stations* of less than 1000 *MW*

(1) With all connecting lines healthy 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, connection shall be done with a minimum of two lines.

(2) Transient stability shall be maintained following a successfully cleared single phase fault where economically justifiable.

(3) If only a single line is used it shall be able to be selected to alternative *Busbars* and be able to go on to bypass at each end of the line

5.4.5.2 *Power Stations* of more than 1000 *MW*

(1) 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

(2) With the two most onerous line outages (n-2) it shall be possible to transmit 83% of the total output of the *Power Station* to the system

5.4.5.3 ***Busbar* arrangements**

(1) *Busbar* layouts shall allow for selection to alternative *Busbars* and the ability to go on to bypass, and not more than 1000 *MW* of generation shall be connected to any bus section, even with one bus section out of service.

5.4.5.4 Information required

(1) To enable the *Transco* to successfully integrate new *Power Stations*, detailed *Information* is required per *Unit* and *Power Station*, as described in the Information Exchange Code.

5.5 Criteria for network investments

(1) The planning limits, targets and criteria form the basis for evaluation of the long-term development of the *TS*.

(2) The *Transco* shall only invest in the *TS* when the required development meets the approved investment criteria specified in this section. The *Transco* shall invest if the development meets the approved criteria, however it may be mutually agreed with affected *Customers* to waiver certain investments.

(3) Any one of the following investment criteria, each applicable under different circumstances, can be applied.

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

(5) The following key economic parameters shall have a *SERA* approved process of being established:

- (a) Discount rate
- (b) Cost of unserved energy

5.5.1 Least economic cost criteria.

(1) When investments are made in terms of improved supply reliability and/or quality, this would be the preferred method to use. This methodology should also be used to determine and/or verify the desired level of network or equipment redundancy. The methodology requires that the cost of poor network services needs to be determined. These include the cost of interruptions, load shedding, network constraints, poor quality of supply (*QOS*), etc. Statistical analysis of network outages is also required.

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

(3) Value of improved *QOS* to *Customers* > Cost to the *Service Provider* to provide improved *QOS*

(4) From the equation above 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).

(5) Equation above can be stated differently as: Annual value (E/kWh) x Reduction in *EENS* to Consumers (kWh) > Annual cost to the *Service Provider* to reduce *EENS* (R)

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

(7) The cost of unserved energy 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 consumers, the availability of *Customer* back-up generation and many other factors.

(8) Figure 4 indicates the concept of a load profile, while figure 5 indicates the energy not served. This is in the event of a load growing to 125 *MVA* whereas the firm transformer rating is 100 *MVA*.

Figure 1: Typical Load Profile

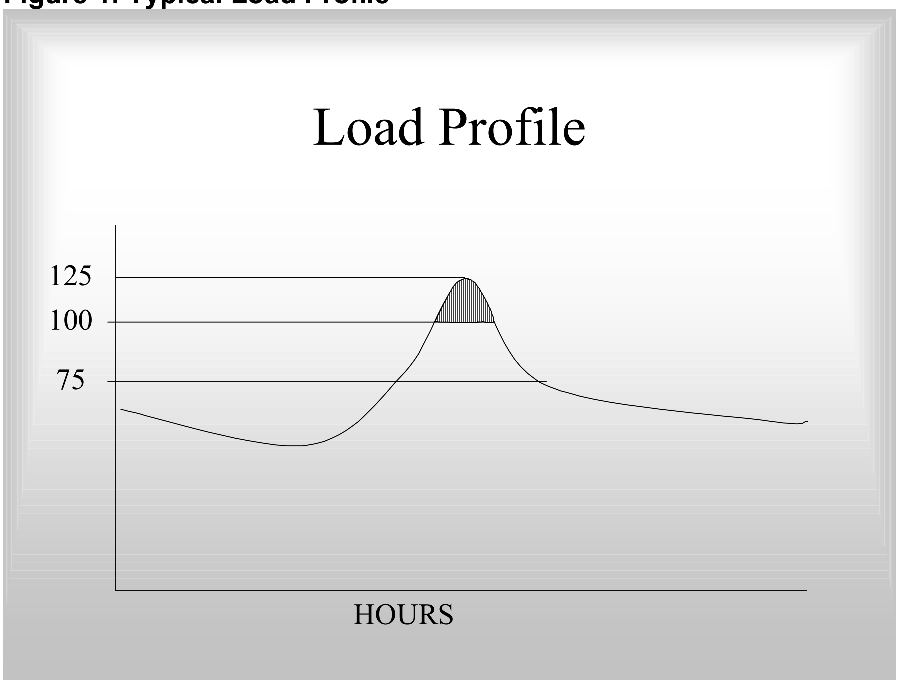
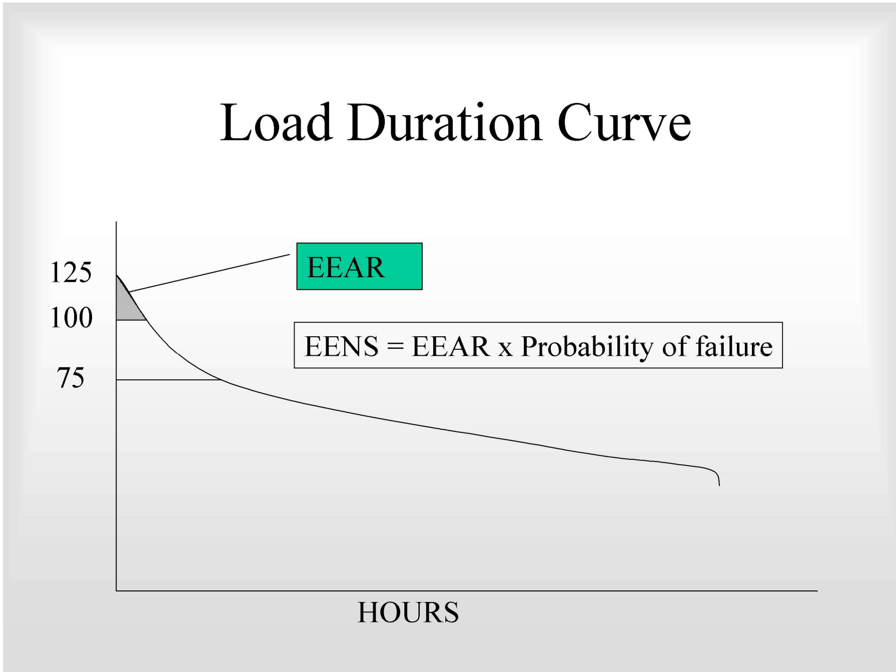


Figure 2: Load Duration Curve



5.5.2 Cost reduction investments

(1) Proposed expenditure which is intended to reduce *Service Providers'* costs (for example, shunt capacitor installations, telecommunication projects and equipment replacement which reduce costs, external telephone service expenses and maintenance costs respectively) or the cost of *Losses,* reductions in curtailed generation, congestion management, or other *Ancillary Services*, should be evaluated in the following manner:

(2) Firstly, it is necessary to calculate the net present value of the proposed investment using the discounted cash flow method. This should be done by considering all cost reductions (e.g. savings in system *Losses*) as positive cash flows, off-setting the required capital expenditure. Once again, *sensitivity analysis* with respect to the amount of capital expenditure (estimated contingency amount), the annual average incremental cost of generation (when appropriate) and, future load growth scenarios is required. As before, a resulting positive net present value indicates that the investment is justified over the expected life of the proposed new asset.

5.5.3 Statutory or strategic investments

(1) It must also be stressed that Eswatini is still a developing country and certain strategic decisions would therefore need to be taken in order to encourage development in the country.

(2) This category of projects include the following:

(3) Investments formally requested by government. This includes investments that will allow Eswatini to become more self-sufficient in electricity supply, integration of renewable energy power plants and issues pertaining to the electrification of Eswatini.

(4) Increased connection with neighbouring countries and *SAPP* requirements to allow the Eswatini Electricity Industry access to other markets.

(5) Projects necessary to meet environmental legislation, for example the construction of oil containment dams.

(6) Expenditure to satisfy the requirements of the Occupational Safety and Health Act of 2001. This classification is intended to ensure the safety of operating and maintenance personnel who are exposed to possible danger when busy with activities related to electricity transmission.

(7) Possible compulsory contractual commitments.

(8) Servitude acquisition

(9) This category shall not be used for justifying projects that are merely not of economic benefit.

5.6 Development investigation reports

(1) The *Transco* shall compile, before any development of the *TS* is approved, a detailed development investigation report. The report shall be used as the basis for making the investment decision and shall as a minimum contain the following elements:

(2) A description of the problem/request

(3) Alternatives considered (including non-transmission or capital) and an evaluation of the long-term costs/benefits of each alternative.

(4) Detailed techno-economic justification of the selected alternative according to the approved investment criteria.

5.7 Transmission System Master Plan

(1) The *Transco* shall annually publish a five year ahead network expansion plan, indicating the major capital investments planned (but not yet necessarily approved).

(2) This plan shall be based on all *Customer* requests received at that time, network load forecasting, as well as *Transco* initiated projects.

5.8 Mitigation of network constraints

(1) The *Transco* has the obligation to resolve network constraints.

(2) Network constraints shall be regularly reviewed by the *Transco*. Economically optimal plans shall be put in place around each constraint, which can involve investment, the purchase of the *constrained generation Ancillary Service* or other solutions.

5.9 Interfacing between Participants

(1) The *Transco* shall ensure regular interfacing with *Customers* regarding network development. One objective shall be to achieve overall optimal plans, ensuring economically efficient investment.

5.10 Special Customer requirements for increased reliability

(1) Should a *Customer* require a more reliable connection than the one provided for by the *Transco*, and the *Customer* is willing to pay the total cost of providing the increased reliability, the *Transco* shall meet the requirements at the lowest overall cost.

(2) Customers paying extra for reliability should be able to recoup some of the expenses from other *Customer*s. Details regarding recovery of direct costs should be included in connection agreement.

6 Network maintenance

(1) *Participants* shall operate and maintain the equipment owned by them. The cost of such operation and maintenance shall be borne by the respective *Participants* unless such equipment is proved to have been damaged by a negligent act or omission of a *Participant* other than the owner, its agents or employees, in which case the responsible *Participant* shall be liable for the costs of repairing such damage.

(2) *Participants* shall monitor the performance of their plant and take appropriate action where deteriorating trends are detected.