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SOUTH ASIA REGIONAL INITIATIVE FOR ENERGY INTEGRATION (SARI/EI)

Harmonisation of Grid Codes, Operating Procedures and Standards to Facilitate/ Promote Cross-Border Electricity Trade in the South Asia Region

(Task Force-2 Report)

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Grid Codes, Operating Procedures, Standards, Electricity Laws, Regulation and Policies (English version only) of South Asian countries as exist in public domain as of July, 2016 and as received by SARI/EI Secretariat from Task Force-2 Members as of April, 2016 has been reviewed and analyzed. Any changes/amendments made in Grid Codes, Operating Procedures, Standards, Electricity Laws, Regulation and Policies of SA countries or any new Grid Codes, Operating Procedures, Standards, New Electricity Laws, Regulation and Policies which has come into force after July, 2016 has not been reviewed and analyzed as a part of this study. This study concluded in the month of September, 2016 after incorporating comments and suggestions of all the stakeholders. The Framework Grid Code Guidelines (FGCG) and recommendations are suggestive in nature and do not necessarily reflect the view of the organizations that task force members represents and Technical Team at SARI/EI Project Secretariat and of the Consultant and the organization each of them represents as no legal vetting of the Framework Grid Code Guidelines has been carried out as part of this study. The Framework Grid Code Guidelines can be considered by each South Asian Country Governments, Regulatory Authorities/Commission as a base document for harmonization of Grid Codes, Operating Procedures, Standards for promoting Cross Border Electricity Trade in the South Asian Region and to stimulate further discussion and analysis in the South Asia Region for harmonization of Grid Codes, Operating Procedures, Standards vis-a-vis creation of a safe, secure, reliable planning, development, operation of an integrated regional power transmission system in South Asia from the perspective of promoting and accelerating Cross Border Electricity Trade in the South Asian Region.

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Harmonisation of Grid Codes, Operating Procedures and Standards to Facilitate/ Promote Cross-Border Electricity Trade in the South Asia Region: **Framework Grid Code Guidelines**

(Task Force-2 Report-Volume-III)

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Contents

Abbreviations

AEDB	Alternative Energy Development Board
AEPC	Alternative Energy Promotion Centre
ANSI	American National Standards Institute
ASAP	As Soon As Possible
ATC	Available Transfer Capability
AVR	Automatic Voltage Regulator
BA	Balancing Authority
BBMB	Bhakra Beas Management Board
BEA	Bhutan Electricity Authority
BERC	Bangladesh Electricity Regulatory Commission
BES	Bulk Electric System
BIMSTEC	Bay of Bengal Initiative for Multi-Sectorial Technical and Economic Cooperation
BIS	Bureau of Indian Standards
BPC	Bhutan Power Corporation Limited
BPDB	Bangladesh Power Development Board
CACM	Capacity Allocation and Congestion Management
CASA	Central Asia-South Asia
CBET	Cross-Border Electricity Trade
CBSOC	Cross-Border System Operator Compensation
CC	Connection Code
CDSO	Closed Distribution System Operator
CEA	Central Electricity Authority
CEB	Ceylon Electricity Board
CERC	Central Electricity Regulatory Commission
CT	Current Transformer
CTU	Central Transmission Utility
DABS	Da Afghanistan Breshna Sherkat
DAS	Data Acquisition System
DC	Direct Current
DCS	Digital (or Distributed) Control System
DDR	Dynamic Disturbance Recording
DESCO	Dhaka Electric Supply Company Ltd.
DFR	Digital (or Disturbance) Fault Recorder
DGPC	Druk Green Power Corporation
DIC	Designated ISTS Customer
DISCOMs	Distribution Companies

DME	Disturbance Monitoring Equipment
DOED	Department of Electricity Development
DPDC	Dhaka Power Distribution Company
DSA	Dynamic Stability Analysis
DSM	Deviation Settlement Mechanism
DSO	Distribution System Operator
DVC	Damodar Valley Corporation
EC	European Commission
EGCB	Electricity Generation Company of Bangladesh
EHV	Extra High Voltage
EMTP	Electro-Magnetic Transients Program
ENTSO-E	European Network of TSOs for Electricity
EUE	Expected Un-Served Energy
FACTS	Flexible AC Transmission System
FCR	Frequency Containment Reserves
FR	Frequency Restoration
FRR	Frequency Restoration Reserves
GCERP	Grid Code Enforcement and Review Panel
GCMC	Grid Code Management Committee
GENCOs	Generation Companies
GSU	Generator Step Up
HV	High Voltage
HVDC	High Voltage Direct Current
ICT	Inter-Connecting Transformer
IEC	International Electro-Technical Commission
IEEE	Institute for Electrical and Electronic Engineers
IEGC	Indian Electricity Grid Code
IPP	Independent Power Producer
IPS/UPS	Integrated Power System/Unified Power System of Russia
IRADe	Integrated Research and Action for Development
IROL	Interconnection Reliability Operating Limits
ISGS	Inter State Generating Station
IST	Indian Standard Time
ISTS	Inter-State Transmission System
LDC	Load Dispatch Center
LECO	Lanka Electricity Company
LFC	Load Frequency Control
LFSM-O	Limited Frequency Sensitive Mode – Over Frequency

LOLP	Loss of Load Probability
LVRT	Low Voltage Ride Through
MCR	Maximum Continuous Rating
MEA	Maldives Energy Authority
MNRE	Ministry of New and Renewable Energy
MOU	Memorandum of Understanding
NC RFG	Network Code-Requirement for Generators
NEA	Nepal Electricity Authority
NEPRA	National Electric Power Regulatory Authority
NERC	North American Electric Reliability Corporation
NESC	National Electrical Safety Code
NGO	Non-Governmental Organisation
NLDC	National Load Dispatch Centre
NTDC	National Transmission and Dispatch Company
O&M	Operation and Maintenance
OC	Operation Code
OLTC	On Load Tap Changer
OSHA	Occupational Safety and Health Administration
P.U	Per Unit
PA	Planning Authorities
PAEC	Pakistan Atomic Energy Commission
PBS	Palli Bidyut Samiti
PC	Planning Code
PCC	Point of Common Coupling/Connection
PEPCO	Pakistan Electric Power Company
PGCB	Power Grid Company of Bangladesh
PJM	Pennsylvania-New Jersey-Maryland
POSOCO	Power System Operation Corporation Limited
PPA	Power Purchase Agreement
PPIB	Private Power and Infrastructure Board
PSS	Power System Stabiliser
PST	Phase Shifting Transformers
PUCSL	Public Utilities Commission of Sri Lanka
RA	Reliability Authorities
REB	Rural Electrification Board
RES	Renewable Energy Sources
RFI	Request For Interchange
RLDC	Regional Load Dispatch Centre

RPC	Regional Power Committee
RR	Replacement Reserves
RTU	Remote Terminal Unit
SA	South Asian
SAARC	South Asian Association for Regional Cooperation
SAFEC-E	SAARC Framework Agreement for Energy Cooperation (Electricity)
SAPP	Southern African Power Pool
SAR	South Asian Region
SARI/EI	South Asia Regional Initiative for Energy Integration
SASEC	South Asia Sub-regional Economic Cooperation
SCADA	Supervisory Control And Data Acquisition
SCR	Short Circuit Ratio
SDC	Scheduling and Dispatch Code
SEB	State Electricity Board
SLDC	State Load Dispatch Centre
SoE	Sequence of Event
SOL	System Operating Limits
SPD	System Planning Department
SPS	System Protection Schemes
STELCO	State Electric Company Limited
STU	State Transmission Utility
ToD	Time of the Day
TP	Transmission Planners
TRM	Transmission Reliability Margin
TSEP	Transmission System Expansion Plan
TSO	Transmission System Operator
TSP	Transmission Service Provider
TTC	Total Transfer Capability
UCPTE	Union for the Co-ordination of Production and Transmission of Electricity
UCTE	Union for the Co-ordination of Transmission of Electricity
UFLS	Under-Frequency Load Shedding
UI	Unscheduled Interchange
USAID	U.S Agency for International Development
UVLS	Under-voltage Load Shedding
VT	Voltage Transformer
WAPDA	Water and Power Development Authority
WECC	Western Electricity Coordinating Council
ZVRT	Zero-Voltage Ride-Through

Definitions

Active Power	The real component of the apparent power at fundamental frequency, expressed in watt or multiples thereof (e.g. kilowatt (kW) or megawatt (MW))
Alert State	The system state where the system is within operational security limits, but in case of occurrence of a contingency, the system is driven to a state where the available remedial actions are not sufficient to keep the system in the normal state
Already Allocated Capacity	The capacity which was allocated previously in the planning stage to the participant
Ancillary Services	In relation to power system (or grid) operation, the services necessary to support the power system (or grid) operation in maintaining power quality, reliability and security of the grid (e.g., Active power support for load following, reactive power support, black start, etc.)
Apparent Power	The product of voltage and current at fundamental frequency. It is usually expressed in kilovolt-amperes (kVA) or megavolt-amperes (MVA) and consists of a real component (active power) and an imaginary component (reactive power)
Automatic Voltage Regulator	A continuously acting automatic excitation control system to control the voltage of a generating unit measured at the generator terminals
Available Transfer Capability	The transfer capability of the inter-control area transmission system available for scheduling commercial transactions (through long term open access, medium term open access and short term open access) in a specific direction, taking into account the network security
Balancing	All actions and processes, on all timelines, through which operators ensure, in a continuous way, to maintain the system frequency within a predefined range, and to comply with the amount of reserves needed
Blackout State	The system state where the operation of part or whole of the transmission system is terminated and hence loss of electric power
Capacitor	An electrical facility provided for generation of reactive power
Common Grid Model	A cross-border data set agreed between various operators describing the main characteristic of the power system (generation, loads and grid topology) and rules for changing these characteristics during the capacity calculation process
Congestion	A situation where the demand for transmission capacity exceeds the designed transfer capability
Connection Point	A point at which a plant and/or apparatus connects to the transmission/ distribution system
Contingency	The identified and possible or already occurred fault of an element, including not only the transmission system elements, but also significant grid users and distribution network elements if relevant for the transmission system operational security that cannot be predicted in advance. In this case, scheduled outages need not to be considered as a contingency and hence an “old” lasting contingency can be considered as a scheduled outage. However, in practice all the outages are treated as contingency
Contingency Analysis	Computer based simulation of contingencies from the contingency list
Contingency List	The list of contingencies to be simulated in the contingency analysis in order to test compliance with the operational security limits before or after contingency takes place

Control Area	An electrical system bounded by interconnections (tie lines), metering and telemetry which controls its generation and/or load to maintain its interchange schedule with other control areas within limits and contributes to frequency regulation of the synchronously operating system
Data Acquisition System	A system provided to record the measurement of pre-selected system parameters and sequence of operation in time of the equipment's/relays
Demand	The demand of active power in MW and reactive power in MVAr of electricity unless otherwise specified
Demand Facility	A facility which consumes electrical energy and is connected at one or more connection points to the network;
Demand Response	To initiate demand reduction from the consumers based on predefined contract for managing power system security. Reduction in demand may be in response to alleviating a system contingency or low frequency or high imbalance charges due to over-drawal by the utility at low frequency, or in response to congestion charges being incurred by the utility, for which such consumers could be given a financial incentive or lower tariff
Dispatch Schedule	The ex-power plant net MW and MWh output of a generating station, scheduled to be exported to the Grid from time to time
Disturbance	An unplanned event that may cause the transmission system to deviate from normal state
Disturbance Recorder	A device provided to record the behaviour of the pre-selected digital and analog values of the system parameters during an event
Dynamic Stability	Stability of the system studied over a longer time frame. It is also a common term including the rotor angle stability, frequency stability and voltage stability
Emergency Limits	Emergency thermal ratings and emergency voltage limits represent equipment limits that can be tolerated for a relatively short time which may be for few minutes or an hour or two depending on design of the equipment
Emergency State	The system state where operational security limits are violated and at least one of the operational parameters is outside of the respective limits
Event	An unscheduled or unplanned occurrence on a grid including faults, incidents and breakdowns
Expected Un-Served Energy	Expected un-served energy is a measure of energy that is not supplied in expected terms over the year. It is generally expressed in GWh per year
Ex-Power Plant	Net MW/MWh output of a generating station, after deducting auxiliary consumption and transformation losses
Extra High Voltage	As per IEC60038, Extra High Voltage is defined as the voltage above 220 kV. However, Indian electricity Rules 1956 defines Extra high voltage as the voltage exceeding 33, 000 volts under normal conditions
Fault	All types of short-circuits: single-, double- and all 3-phases, with or without earth contact. It means further a broken conductor, interrupted circuit, or an intermittent connection, resulting in a permanent non-availability of the affected transmission system element
Fault Locator	A device provided to the transmission line to measure/indicate the distance at which a line fault may have occurred
Firmness	A guarantee that cross-zonal capacity rights will remain unchanged and that a compensation is paid if they are nevertheless changed

Flexible Alternating Current Transmission System (FACTs)	A power electronics based system and other static equipment that provide control of one or more AC transmission system parameters to enhance controllability and increase power transfer capability
Forced Outage	An outage of a generating unit or a transmission facility due to a fault or other reasons which has not been planned
Generating Company	Any company or body corporate or association or body of individuals, whether incorporated or not, or artificial juridical person, which owns or operates or maintains a generating station
HVDC System	An electrical power system which transfers energy in the form of high voltage direct current (100 kV and above) between two or more AC buses. A HVDC system comprises at least two HVDC converter Stations with DC transmission lines or cables between the HVDC converter stations. In case of a back-to-back system the HVDC system comprises only one HVDC converter Station with direct DC circuit connection between the pair of HVDC converter units. A HVDC system has at least two interface points
Individual Grid Model	A data set describing power system characteristics (generation, load and grid topology) and related rules to change these characteristics during capacity calculation, prepared by the responsible operators, to be merged with other individual grid model components in order to create the common grid model
Inertia	The fact that a rotating rigid body such as an alternator maintains its state of uniform rotational motion and its angular momentum is unchanged, unless an external torque is applied. In the context of this code, this definition refers to the technologies for which alternator speed and system frequency are coupled
Island Operation	The independent operation of a the network that is isolated after its disconnection from the interconnected system, having at least one generating module supplying power to this network and controlling frequency and voltage
Load	The MW/MWh/MVAr/MVArh consumed/connected to the system by a utility/ installation
Loss of Load Probability	The risk associated with having insufficient generation to meet the forecasted load demand. It is generally expressed as a percentage
Nominal Frequency	The rated value of the system frequency
Normal Limits	Normal thermal ratings and normal voltage limits represent equipment limits that can be sustained on continuous basis
Normal State	The system state where the system is within operational security limits in the n-situation and after the occurrence of any contingency from the contingency list, taking into account the effect of the available remedial actions
N-Situation	The situation where no element of the transmission system is unavailable due to a fault
N-1 Situation	The situation where one element of the transmission system is unavailable due to a fault
Observability Area	An operator's own transmission system and the relevant parts of distribution networks and neighboring operators' transmission systems, on which operator implements real-time monitoring and modeling to ensure operational security in its responsibility area
On Load Tap Changer (OLTC)	A device for changing the tap of a winding, suitable for operation while the transformer is energised or on load

On Load Tap Changer Blocking	An action that blocks the on load tap changer[s] from changing automatically generally during a low voltage event in order to stop transformers from further tap changes for voltage correction which may lead to voltage instability
Operating Range	The operating range of frequency and voltage as specified under the operating guidelines
Operational Reserves	The spinning and non-spinning reserves that are accessible in a control area
Power Factor	The ratio of active power to apparent power
Power System	All aspects of generation, transmission, distribution and supply of electricity and includes one or more of the following, namely: • Generating stations; • Transmission or main transmission lines; • Sub-stations; • Tie-lines; • Load dispatch activities; • Mains or distribution mains; • Electric supply lines; • Overhead lines; • Service lines;
Power System Stabiliser	An additional functionality of the AVR of a synchronous power generating module with the purpose of damping power oscillations
Pump-Storage	A hydro unit in which water can be raised by means of pumps and stored, to be used later for the generation of electrical energy
Reactive Power	The imaginary component of the apparent power at fundamental frequency, usually expressed in kVAr or MVAr
Reactor	An electrical facility specifically designed to absorb reactive power
Remedial Action	Any measure applied by an operator or several operators, manually or automatically, in order to maintain operational security
Requester Pays Principle	The requester of the services pays for the cost of the service. In general, if system operator(s) calls for action bear(s) all costs and benefits from the participating generator(s) or other ancillary services participant, without being compensated by other system operator for example, the system operator requesting for re-dispatch measures, will pay the costs for these measures
Responsibility Area	A coherent part of the interconnected transmission system including interconnectors, operated by a single operator with connected demand facilities, or power generating modules, if any
Restoration	The system state in which the objective of all activities in transmission system is to re-establish the system operation and maintain operational security after a blackout
Restoration Plan	The sum of all technical and organisational measures to be undertaken to restore the system back to normal state
Scenario	The forecasted status of the power system for a given timeframe
Schedule	A reference set of values representing the generation, consumption or exchange of electricity between actors for a given time period
Scheduled Contingency	The scheduled contingencies are defined as an outage state of an element due to maintenance (both planned and emergency)

Set point	A target value for any parameter typically used in control schemes
Short Circuit Ratio	To quantify the strength of the AC system. In general, the concept of Short Circuit Ratio is used at the converter bus of an HVDC system. It is the ratio of the short circuit MVA of the ac system at the ac bus to the rated dc power at that bus. It is essentially a measure of the therein impedance of the ac system
Single Contingency	Also known as N-1 event and is defined as out of N elements, 1 element is under contingency. Operators of interconnected systems are obliged to monitor the N-1 principle not only for their own grid but also for the tie lines to neighbouring grids
Spinning Reserve	Part loaded generating capacity synchronised to the system with additional capacity available and is ready to provide increased generation at short notice pursuant to dispatch instruction or instantaneously in response to a frequency drop
State Estimation	The methodology and algorithms used to calculate a reliable set of measurements defining the state of the transmission system out of the redundant set of measurements
Synchronous Area	An area covered by interconnected operators with a common system frequency in a steady operational state
System Frequency	The electric frequency of the system that can be measured in all parts of the synchronous area under the assumption of a coherent value for the system in the time frame of seconds, with only minor differences between different measurement locations
System or special Protection Scheme	The set of coordinated and automatic measures designed to ensure fast reaction to disturbances and to avoid the propagation of disturbances in the transmission system
System State	The operational state of the transmission system in relation to the operational security limits: Normal, Alert, Emergency, Blackout and Restoration System States are defined
Time Block	Block of 15 minutes each (or as the case may be) for which Special Energy Meters record values of specified electrical parameters with first time block starting at 00.00 Hrs
Topology	Necessary data about the connectivity of the different transmission system or distribution network elements in a substation. It includes the electrical configuration and the position of circuit breakers and isolators
Total Transfer Capability	The amount of electric power that can be transferred reliably over the inter-connected transmission system from one area to another under a given set of operating conditions
Transmission Reliability Margin	The amount of margin kept in the total transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions
Un-Scheduled Contingency	The un-scheduled contingency or contingencies is defined as an outage state due to fault or unforeseen event. This event is a probabilistic event in which it cannot be forecasted in advance
Unscheduled Interchange	In a time block for a generating station or a seller means its total actual generation minus its total scheduled generation and for a beneficiary or buyer means its total actual drawal minus its total scheduled drawal
Voltage Stability	The ability of a transmission system to maintain acceptable voltages at all buses in the transmission system under N-situation and after being subjected to a disturbance

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Foreword

South Asia is expected to remain the fastest growing region in the world and has been resilient to global turbulence in 2016. The countries in South Asia are planning to address their issues like power shortages, reliance on fossil fuels, and increasing electricity demand with Cross-Border Electricity Trade (CBET). As South Asia remains one of the least integrated regions in the world, therefore it has a huge scope to enhance its energy security by engaging in significant levels of power trading of themselves. The region is growing rapidly (at per capita GDP growth rate of six percent), which can be sustained only with increased and improved access to energy. However, each of the countries in South Asia is struggling with issues such as power shortages, high reliance on fossil fuels etc.

In recent years, there have been several positive developments in the region: the signing of the South Asian Association for Regional Cooperation (SAARC) Framework on Energy Cooperation; the signing of the India-Nepal power trade agreement; the signing of agreements to enhance the India- Bangladesh transmission links from 500 MW to L000 MW; and the signing of power purchase agreements between the Nepali Government and Indian private sector developers to develop export-oriented large hydro power plants. These recent developments are a strong signal that the region is finally ready to have a regional power grid.

With more number of cross-border power transmission interconnection, the SA leads towards integrated regional power system which requires harmonization of regulations, grid codes, standards, operating procedures for safe, reliable and integrated operation, planning of a South Asia Regional Power system. In fact under SAARC, SAARC regulators have identified the harmonization of grid codes and standards is one of the key area for advancing CBET in SA region as well as implementation of SAARC Framework agreement on Energy Cooperation.

To harmonize/coordinate grid codes, standards and operating procedures, SARI/EI had commissioned a study under Task Force-2 on Harmonisation of grid codes, operating procedures and standards to facilitate/promote cross-border electricity trade in the south Asia region which is working on “Advancement of Transmission System Interconnection”. The study report on “Harmonization of Grid Codes, Operating Procedures, and Standards to Facilitate/ Promote Cross-Border Electricity Trade in the South Asia Region-Framework Grid code guidelines” has been prepared based on a detailed review/analysis of the grid codes of South Asian Countries, Analysis of international best practices/ experiences over a period of two years.

I am glad that the report on “Harmonisation of Grid Codes, Operating Procedures, and Standards to Facilitate/ Promote Cross-Border Electricity Trade in the South Asia Region-Framework Grid code guidelines” has been finalized which provides the Framework Grid Code Guidelines (FGCG) for cross-border electricity trade in South Asia. The study has also recommended to create a Regional Technical Institutions/Body such as South Asia forum of transmission system utilities of SACs or South Asian Forum of Transmission Utility (SAFTU), which shall be mandated for coordinated, reliable, and secure operation of the interconnected transmission network as well as for coordinated system planning and integrated system/network development and grid code harmonization.

I would like to commend the laudable work done by the Technical Team and Task Force-2 Members (SARI/EI/IRADe Project Secretariat, SARI/EI Consultant M/s PRDC, Bangalore) for preparing this report and formulating concrete and actionable recommendations. I also appreciate the efforts being made to promote cross-border electricity trade in the region and would like to thank Mr. V. Kharbanda and Mr. Rajiv Ratna Panda for taking various initiative and studies under SARI/EI. I am confident that this framework grid code guidelines and its recommendation will be very useful for the SAARC Member States and the South Asian Countries’ Institutions to take forward the activity of Integration and formation of regional power Grid in South Asia formation and its integrated system planning and operation

Mr. Ali Haider Altaf
Director, ETS, SAARC, Kathmandu

FOREWORD

The USAID South Asia Regional Initiative for Energy Integration (SARI/EI) program advocates energy security through cross-border electricity trade (CBET), clean energy access and energy markets development in the South Asia region. The region has witnessed a per capita GDP growth rate of more than six percent in the recent past. In order to sustain this growth, provide opportunities for entrepreneurships, and continue to develop new job opportunities, it is imperative that the countries in the region have access to clean energy. However, existing power shortages and high reliance on fossil fuels, along with the rapidly increasing electricity demand are threating to undermine economic progress.

South Asia has a diverse range of energy resources with a large potential for hydropower, which is a clean energy source. Systemic development of hydropower plants, along with transmission infrastructure and a market based regional power trading system will help to optimize utilization of regional energy resources.

Each South Asian country is governed by its own policy, regulatory and legal frameworks and have specific technical standards, codes and operating procedures for maintaining its electrical grid. Therefore, it is important to harmonize these codes, technical standards and operating procedures for promoting CBET in the region.

With this in mind, the Task Force 2 was established under the program with representation from each of the South Asian Governments focusing on issues related to the advancement of transmission system interconnectivity in South Asia, including harmonization of technical standards and procedures to facilitate cross border electricity trade. This report "Harmonization/Coordination of grid codes, operating procedures and standards for promoting Cross-Border Electricity Trade in the South Asian region: Framework Grid code Guidelines" is a product of the combined efforts of the Task Force 2 and SARI/EI Team.

We are delighted that this report is now complete and details the implementation framework for grid codes. The report also recommends establishing the South Asian Forum of Transmission Utilities (SAFTU). Various regional power pools around the world have followed a similar process and have successfully established regional technical forums/institutions for harmonization of grid codes and technical standards. Such a structure in South Asia will go a long way towards institutionalizing and standardizing common technical practices and procedures and make for more effective and cost saving energy trade and transmission for all the neighboring countries in South Asia.

I would like to take this opportunity to thank the excellent work done by Task Force 2 members, the SARI/EI Project Secretariat at IRADe, and the SARI/EI Consultants M/s PRDC, Bangalore for preparing this very valuable report. I am confident that the recommendations of this report will be very useful for the energy stakeholders from the different South Asian countries to advance the task of integration of regional power grids in South Asia.

Thank you

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Foreword

South Asia Regional Initiative for Energy Integration (SARI/EI), a program of United States Agency for International Development (USAID) being implemented by Integrated Research and Action for Development (IRADe), aims to promote the integration of energy systems and to enhance Cross-Border Electricity Trade (CBET) among the South Asian countries. We began this journey four years ago at IRADe. To address these issues, we at SARI/EI/IRADe constituted three dedicated task forces represented by government-nominated members from South Asian countries headed by a Project steering committee. Twenty-eight members from these countries have been working together for the last four years.

The different sets of electricity regulation, policy, and technical frameworks in the South Asian Countries (SACs), are perceived to be a challenge for the long-term success of CBET. The existing regulatory frameworks is not necessarily developed to address issues related to CBET. International experience also suggests that to reach high levels of CBET on a sustainable basis need transparent and environment-friendly policy from each country and common regulatory frameworks among the participating member states. Therefore, a stable, transparent regional policy, regulatory and technical framework is important for the success of CBET. SARI/EI had published the Regional Regulatory Guidelines (RRG 2015), which addresses the thorny aspects of cross-border electricity trade by looking at issues such as licensing, fair rules for non-discriminatory open access, transmission pricing, transmission planning, settling the imbalance by energy accounting and scheduling, harmonizing of grid codes viz. voltage and frequency standards etc. SARI/EI also published a report on "Suggested Changes/Amendments in Electricity Laws, Regulations and Policies of South Asian Countries for Promoting Cross-Border Electricity Trade in the South Asian Region".

With more number of cross border power transmission interconnections, the SA could move towards an integrated regional power system which requires harmonization of regulations, grid codes, standards, operating procedures for secure, safe, reliable integrated operation and planning. To harmonize/coordinate grid codes, standards and operating procedures, SARI/EI had commissioned a study under Task Force-2 on Harmonisation of grid codes, operating procedures and standards to facilitate/promote cross border electricity trade in the South Asia region.

I am glad that the report on "Harmonisation of Grid Codes, Operating Procedures and Standards to Facilitate/Promote Cross-Border Electricity Trade in the South Asia Region" has been finalised which provides the Framework Grid Code Guidelines (FGCG) for cross-border electricity trade in South Asia. The study has also recommended to create a Regional Technical Institutions/Body such as South Asia forum of transmission system utilities of SACs or South Asian Forum of Transmission Utility (SAFTU), which shall be mandated for coordinated, reliable and secure operation of the interconnected transmission network.

I would like to sincerely thank the Technical Team at SARI/EI/IRADe Project Secretariat, the members of Task Force-2 and the Consultant M/s PRDC, Bangalore for preparing this high quality report with a Framework on Grid Code Guidelines (FGCG) along with concrete and actionable recommendations for implementation. I am sure that this framework grid code guidelines and its recommendation will be very useful to take forward the activity of Integration and formation of regional power Grid in South Asia.

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Message

The eight SAARC countries (Afghanistan, Bangladesh, Bhutan, India, Maldives, Nepal, Pakistan and Sri Lanka) comprise one of the fastest growing economies of the world. This region is also home for over one-fifth of the world's population. The average annual growth rate of 6% as measured by GDP per capita shows the economic advancement of these countries. In order to boost this economic progress and help each other grow, the SAARC countries have taken initiatives to promote regional cooperation in power sector and cross border electricity trade (CBET). A total of 2300MW power trade is currently taking place in South Asia. Bangladesh is importing 600MW electricity from India and has taken steps to increase this amount to 1160MW. The seasonal diversity of electricity demand in this region has made all the countries aware of the benefits of CBET. Recently the South Asian countries have signed the Framework Agreement of Energy (Electricity) Cooperation and a Power Trade Agreement (PTA) has also been signed between India and Nepal. These events will accelerate the CBET and regional cooperation for power sector development in this region.

As the CBET is emerging in the South Asian region, the emphasis of an integrated regional power system is being recognized. In order to plan a safe, reliable and integrated operational South Asian regional power system, harmonization of regulations, grid codes and standards are needed. SARI/EI had commissioned a study under Task Force-2 on harmonization of grid codes, operating procedures and standards to facilitate and promote CBET in the South Asian region.

I would like to congratulate SARI/EI for the completion of the report on 'Harmonization of Grid Codes, Operating Procedures and Standards to Facilitate/Promote Cross Border Electricity Trade in the South Asia Region'. This report provides the Framework Grid Code Guidelines (FGCG) for CBET in South Asia. This study has recommended to form Regional Technical Institutions/Body such as South Asia forum of transmission system utilities of SACs or South Asian Forum of Transmission Utility (SAFTU), which shall be mandated for coordinated, reliable and secure operation of the interconnected transmission network as well as for coordinated system planning and integrated system development and grid code harmonization.

The regional cooperation for power sector development and CBET will benefit all the countries of the South Asian region. This can lead to a sustainable future for the SAARC countries. I would like to convey my heartiest thanks to the technical team at SARI/EI/IRADe project secretariat, Task Force-2 team members and consultant M/s PRDC, Bengaluru for preparing this high-quality report and coming up with the Framework Grid Code Guidelines which will be instrumental in building an integrated regional power grid in South Asian region for regional cooperation in power sector and CBET.

Mr. Mohammad Hossain
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Preface

Cross-Border Electricity Trade (CBET) in South Asia is currently being undertaken in the form of bilateral trade and is limited between India-Nepal; India-Bangladesh and India-Bhutan. Policy and Regulatory Provisions, Institutional frameworks and few other aspects promoting/facilitating CBET exist in some South Asian Countries (SACs) but are not exhaustive in nature.

The SACs envisages a manifold increase in the quantum of CBET by the end of next decade. This scenario is rapidly changing with several new transmission interconnections being proposed across South Asian Countries which will enable greater Integration of Power Systems of SACs. Such Integration shall also enable trading on a multi-lateral basis wherein two countries having no common border could trade electricity through a third country acting as transit route.

During the 18th SAARC Summit held on 26-27 November 2014 at Kathmandu, eight member states of SAARC countries concluded the historic Framework Agreement of Energy (Electricity) Cooperation. Further, the historic Power Trade Agreement (PTA) signed between India-Nepal, opens up whole range of new possibility for trade of electricity between Nepal-India and also gives an access to Nepal Power Developers to Indian Power Market. India-Bangladesh and India-Bhutan are taking steps to increase quantum of CBET in manifold.

For the smooth, optimal, secure and reliable power system operation of CBET across the SA nations, the grid codes, power system operating procedures, protection code, metering code, connection code, planning code, system security, scheduling and dispatch, frameworks, open access needs to be harmonised/ coordinated.

Considering that the volume of electricity trade to increase manifold in future and importance of secure and reliable grid to operate in South Asia Region across South Asian Countries, SARI/EI Task force 2 Committee represented by country nominated Members from Energy/Power/Economy Ministries, Transmission Utilities etc.; commissioned a study on Harmonisation of grid codes, operating procedures and standards to facilitate/promote CBET in the south Asia region. This grid code report covering Framework Grid Code Guidelines (FGCG) provides basic design criteria and operational rules and responsibilities to be followed by the Generating stations, Transmission utilities, Distribution utilities and traders. The objective of harmonisation of grid code is to arrive at a practical working arrangement for secure and reliable grid operation, and it should not be construed as an attempt to impose a uniform grid code.

Operating an integrated electricity grid in South Asia is essentially a coordination issue. Keeping in view of the international experiences and considering the technical complexity involved with respect to grid code harmonisation and integrated planning and operation of a regional power system in South Asia, the study has recommended to create a Regional Technical Institutions/Body such as South Asia forum of transmission system utilities of SACs or South Asian Forum of Transmission Utility (SAFTU), which shall be mandated for coordinated, reliable and secure operation of the interconnected transmission network as well as for coordinated system planning and integrated system/network development and grid code harmonisation. (SAFTU) will be an independent, regional as well as technical and will provide technical support and inputs to the South Asia Forum of Electricity Regulators (SAFER) or any other Regional Regulatory Institutional Mechanism in South Asia on the matter related to grid code guidelines, harmonisation of grid codes, development of standards, integrated planning and operation of a regional power system etc.

I hope this report on “Harmonisation of Grid Codes, Operating Procedures and Standards to Facilitate/ Promote Cross-Border Electricity Trade in the South Asia Region: Framework Grid Code Guidelines” will be very useful for South Asian Countries to take forward the process of coordination/harmonisation of grid codes, operating procedures and standards of South Asian Countries for Promoting CBET.

V. K. Kharbanda,
Project Director, SARI/EI/IRADe

Context

Electric Power System is a large, complex system involving many entities executing their respective activities and responsibilities. With the multi-stakeholder perspective like the generation, transmission and distribution licensees, system operators, traders and other participants in system, the stakeholders should function in proper co-ordination with each other; follow the regulations, standards and procedures for the safe and reliable operation of the grid. A legal, regulatory and institutional framework is essential to implement and monitor the grid which is provided by the Electricity Act, Electricity Policy and Electricity Grid Code.

Grid code is a technical document containing rules, procedures, guidelines, criteria and responsibilities to be complied by the users, owners and operators of the transmission system of a country. Grid codes are approved by a regulatory body in exercise of powers conferred to it under the relevant electricity act/ legislation. Grid codes provide basic design criteria and operational rules and responsibilities to be followed by the generating stations, transmission utilities, distribution utilities and traders.

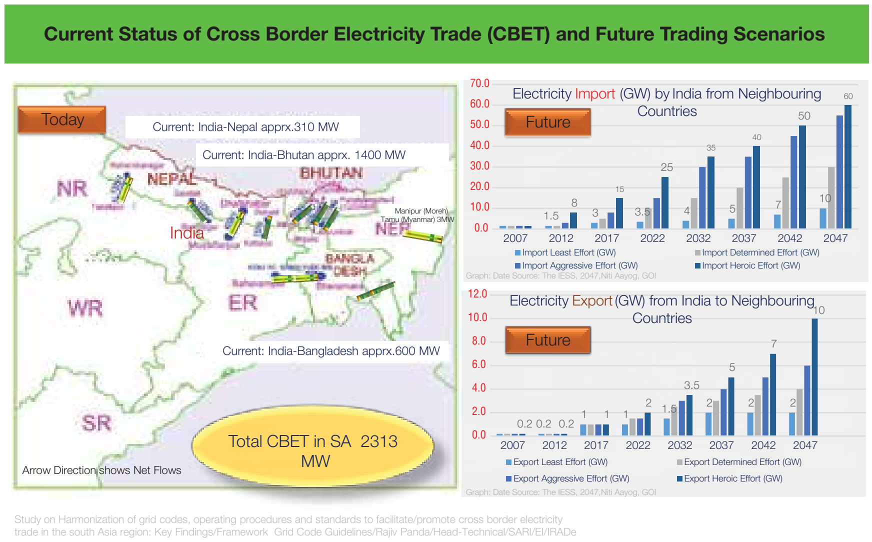


Figure 1: Current Status of Cross-Border Electricity Trade and Future Trading Scenarios (Source: IESS)

There are many rules and criteria in every grid code dealing with generation, transmission, distribution, protection, metering, maintenance, buying and selling of power, ancillary services, etc. Electricity Grid Code document of a country depends on the past practices of its electricity sector, present hierarchical structure of its electricity sector, energy sources available and its legal, technical and commercial aspects etc.

Many common specifications appear in grid codes of various countries. Different sections of the grid code will be of varying significance to the generation, transmission and distribution utilities. Some of the rules may be for promoting competitive environment for generators whereas some may be critical for the operation/maintenance of generating plant. Therefore it is essential that while interconnecting two transmission systems, the respective grid codes have to be compared and reviewed to understand the underlying principles of individual systems and then harmonise the relevant rules to suit cross-border interconnection and trading. Transmission System Operators (TSOs) of all the member countries of a planned regional grid interconnection should first establish a common framework for preparation and implementation of operating guidelines and procedures, maintenance schedules, exchange of data, dispute settlement, power exchanges, electricity market mechanisms etc. Therefore, harmonisation of the grid codes is an important step towards streamlining cross-border power trade. Currently the cross border electricity trading among South Asian Countries is around 2313 MW, however going in future the trading expected to increase significantly (Fig. 1).

The SAARC Inter-Governmental Framework Agreement (IGFA) for Energy Cooperation, signed by Foreign Ministers of the eight member states provides a strong basis for ensuring consistency in certain identified areas/articles of IGFA which is as follows:

Article 7: Planning of Cross-border interconnections: *Member States may enable the transmission planning agencies of the Governments to plan the cross-border grid interconnections through bilateral/ trilateral/mutual agreements between the concerned states based on the needs of the trade in the foreseeable future through studies and sharing technical information required for the same.*

Article 8: Build, Operate and Maintain: *Member States may enable the respective transmission agencies to build, own, operate and maintain the associated transmission system of cross-border interconnection falling within respective national boundaries and/or interconnect at mutually agreed locations.*

Article 9 (Transmission Service Agreements): *Member States may facilitate authorized Buying and Selling of Entities to enter into transmission service agreements with the transmission service providers for the purpose of cross-border electricity trade.*

Article 10: Electricity Grid Protection System: *Member States shall enable joint development of coordinated network protection systems incidental to the cross-border interconnection to ensure reliability and security of the grids of the Member States.*

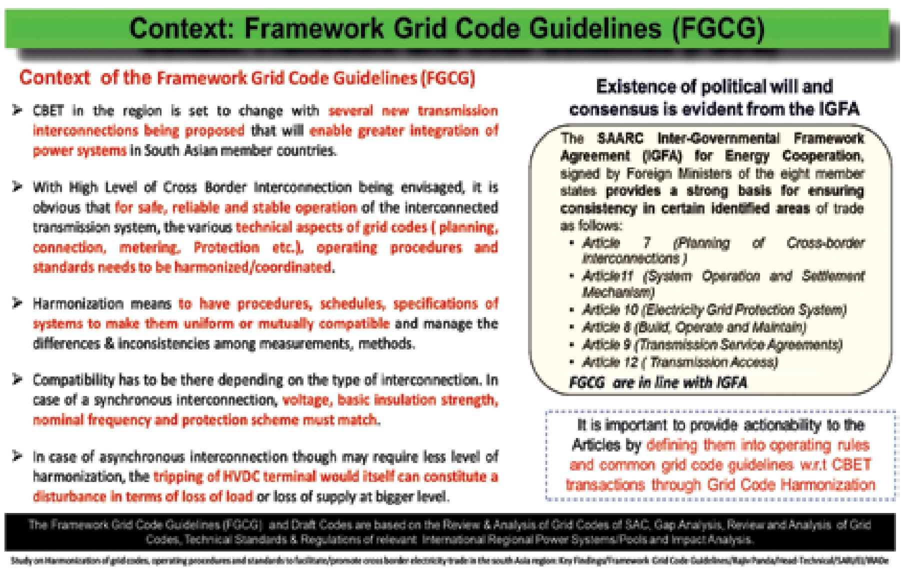


Figure 2: Context of the Framework Grid Code Guidelines

Article 11: System Operation and Settlement Mechanism: *Member States shall enable the national grid operators to jointly develop coordinated procedures for the secure and reliable operation of the inter-connected grids and to prepare scheduling, dispatch, energy accounting and settlement procedures for cross-border trade.*

It is important to provide action ability to the Articles of the SAARC Inter-Governmental Framework Agreement (IGFA) for Energy Cooperation by defining them into operating rules and common grid code guidelines w.r.t CBET transactions through Grid Code Harmonisation.

The government of Nepal and the government of the republic of India have signed agreement on electric power trade, cross-border transmission interconnection and grid connectivity (commonly referred as Power Trade Agreement). The Article-II of the above agreement states that "The Parties shall mutually work out a coordinated procedure for secure and reliable operation of the national grids interconnected through cross-border transmission interconnection(s) and prepare scheduling, dispatch, energy accounting, settlement and procedures for cross-border power trade and unscheduled interchange.

In the above context (Fig. 2), SARI/EI had commissioned a study on Harmonisation of grid codes, operating procedures and standards to facilitate/promote cross border electricity trade in the South Asia region under its Task Force-2 which is working on "Advancement of Transmission System Interconnection". The report was finalized by September, 2016 after a two years of the detailed and extensive deliberation and analysis among task forces members/technical team at SARI/EI and various stakeholders and based on interaction of the SARI/EI technical delegation to South Asian Countries.[1] The key findings of the study was also presented in the second and third meeting of SAARC Energy Regulators meeting.[2] The combined report of Task Force-2 is very comprehensive and Task Force-2 Report with respect this study is being published in three volumes which covers the findings of the analysis of existing Grid Codes of South Asian countries, findings of the Gap analysis, findings of review and analysis of the grid codes, technical standards, regulations of the International regional power pools, international best practice, impact analysis based on the review and analysis of the international power pools and regional power systems. This volume of the Task Force-2 report with respect to the study on Harmonisation of grid codes, operating procedures and standards to facilitate/ promote cross border electricity trade in the South Asia region provides the Framework Grid Code Guidelines (FGCG) for cross-border electricity trade in South Asia which can be adopted/adapted and implemented by the relevant authorities of South Asian Countries which is one of the output of the TF-2 study on Harmonisation of grid codes, operating procedures and standards to facilitate/promote cross border electricity trade in the South Asia region. Framework Grid Code Guidelines (FGCG) and Draft Cross Border Grid Codes (CBGC) are in line with overall intent of SAARC framework agreement on Energy (Electricity) Cooperation with a view to facilitate the implementation of various articles of SAARC framework agreement on Energy (Electricity) Cooperation.

[1] http://www.irade.org/Brief%20Report%20on%20SARI-EI%20Technical%20Delegation%20to%20Bhutan-6th-7th%20April,%202016%20for%20Grid%20Code%20Haromonization..pdf
http://www.irade.org/Brief%20Report%20on%20SARIEI%20Technical%20Delegation%20to%20Bangladesh%20on%20the%20Study%20on%20Harmonization%20of%20Grid%20Codes-19th%20April,2016.pdf

[2] http://sari-energy.org/wp-content/uploads/2016/09/Key-Findings-on-the-Study-on-Harmonization-of-Grid-Codes-Operating-Procedures-Standards-to-Facilitate-Promote-CBET-in-SA-by-Rajiv-Ratna-Panda-Head-TechnicalSARI-EI-IRADe-3rd-SAARC-Regulators-Meeting.pdf
http://sari-energy.org/wp-content/uploads/2017/03/Brief-Report-on-SARIEI-Delegation-to-3rd-Meeting-of-SAARC-Energy-Regulators.pdf
http://sari-energy.org/wp-content/uploads/2016/05/Brief-Report-on-SARI-EI-Delegation-to-the-2nd-Meeting-of-SAARC-Energy-Regulators-Feb-2016-2.pdf

Purpose of the Framework Grid Code Guidelines

Operating an integrated electricity grid in South Asia is essentially a coordination issue. Harmonisation means adjustment of differences and inconsistencies among measurements, methods, procedures, schedules, specifications, or systems to make them uniform or mutually compatible. Compatibility has to be there depending on the type of interconnection. In case of a synchronous interconnection, voltage, basic insulation strength, nominal frequency and protection scheme must match. In case of asynchronous interconnection, the two sides have to worry less about each other as the fault on one side is not passed on to the other. Nevertheless, the tripping of High Voltage Direct Current (HVDC) terminal would itself constitute a disturbance in terms of loss of load or loss of supply.

The interconnection between India-Bhutan and India-Nepal is on AC system whereas between India-Bangladesh is on HVDC back-to-back. However, in future, AC interconnection would be more feasible between India and Bangladesh. In case of Pakistan, in view of difference in voltage level, the interconnection may be with HVDC back-to-back whereas in case of Sri Lanka, it would be on HVDC due to sea crossing and due to other Technical-Economic Consideration.

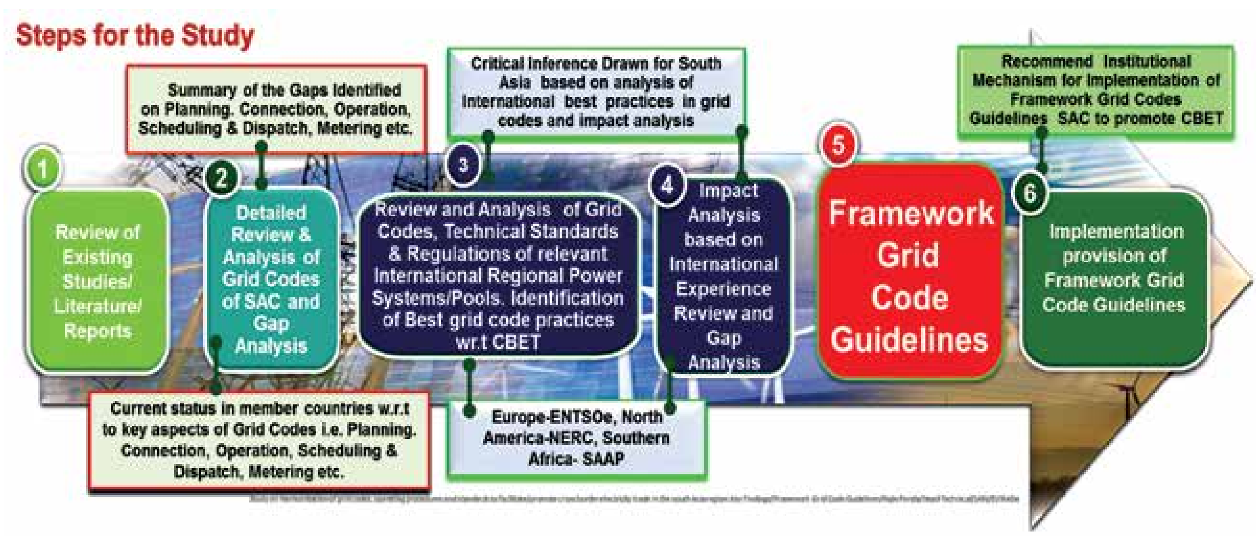


Figure 3: Steps Followed in the Study

Irrespective of nature of interconnection, there has to be real-time communication through hotline, data transfer and cooperation between the grid operators. Grid details have to be shared and the two grid operators have to prepare joint emergency response and recovery procedures. Mutual trust between the grid operators is a must. In this direction, Article 5 of the SAARC Framework Agreement on Energy (Electricity) Cooperation stipulated that “Member States shall share and update technical data and information on the electricity sector in an agreed template”. It may be stressed here that the objective of harmonisation is to arrive at a practical working arrangement for secure, reliable and integrated regional grid operation, and it should not be construed as an attempt to impose a uniform grid code. The Framework Grid Code Guidelines (FGCG) is the outcome of the two years of rigorous study through the detailed and comprehensive Review and Analysis of Grid Codes of South Asian Countries, Gap Analysis, Review and Analysis of Grid Codes, Technical Standards and Regulations of relevant International Regional Power Systems/ Pools and Impact Analysis. The steps followed in the study to arrive at FGCG is mentioned in Figure 3. The main purpose (Fig. 4) of the FGCG: a) Establish a clear technical framework and grid code

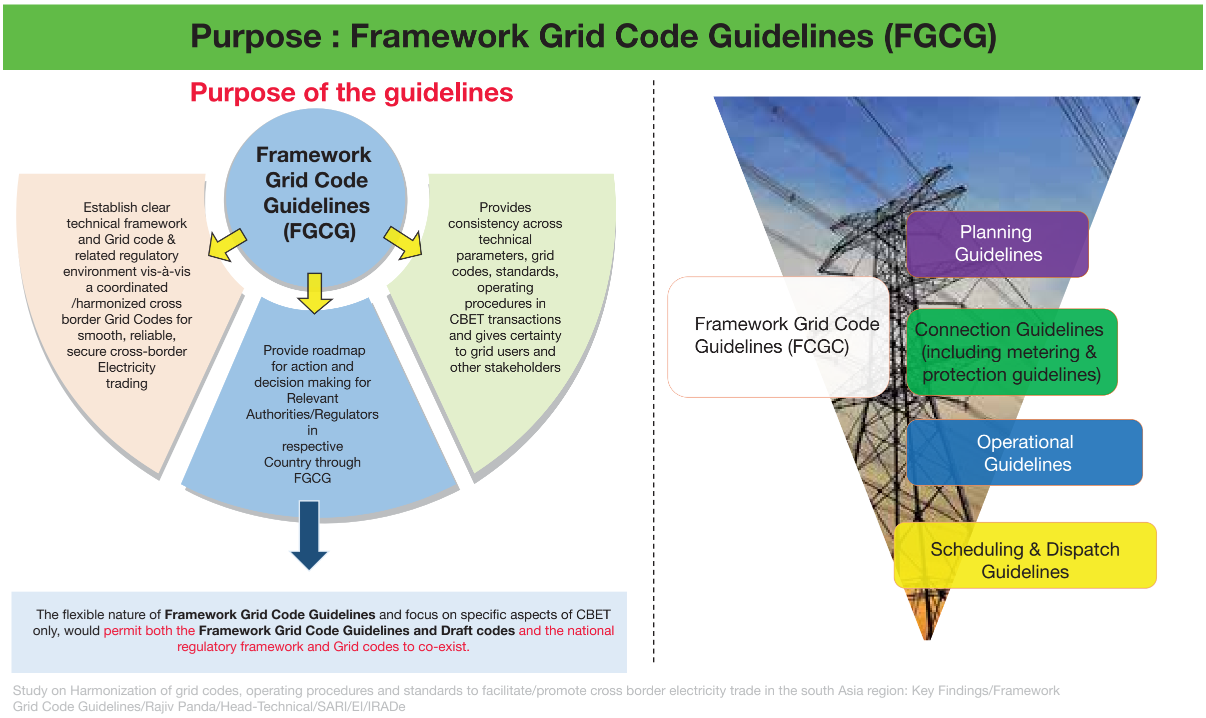
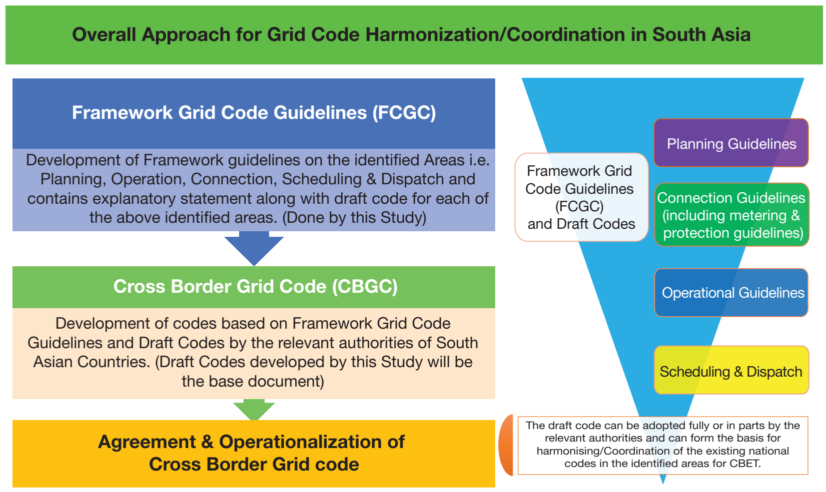


Figure 4: Purpose of the Framework Grid Code Guidelines

and related regulatory environment vis-à-vis a coordinated/harmonised cross-border Grid Codes for smooth, reliable, secure cross-border Electricity trading; b) Provide roadmap for action and decision making for Relevant Authorities/Regulators in respective Country through Framework Grid Code Guidelines; c) Provides consistency across technical parameters, grid codes, standards, operating procedures in CBET transactions and gives certainty to grid users and other stakeholders.

Implementation Framework of Grid Code Guidelines

In the South Asian region, all the member countries except Afghanistan, Maldives and Nepal have the regulatory authority for electricity sector. The grid code is also available in all the member countries except Afghanistan and Maldives. This Framework Grid Code Guidelines (FGCG) and draft cross border grid codes are not intended to replace the existing national grid codes for non-cross border issues but to harmonise/coordinate the critical issues concerning only the cross border trade. SARI/EI Task force-2 has also suggested the same. The overall approach for Grid Code Harmonisation/Coordination in South Asia followed in this study are mentioned in the Figure 5.



Study on Harmonization of grid codes, operating procedures and standards to facilitate/promote cross border electricity trade in the south Asia region: Key Findings/Framework Grid Code Guidelines/Rajiv Panda/Head-Technical/SARI/EI/IRADe

Figure 5: Approach for Grid Code Harmonisation in South Asia

It is envisaged that the FGCG and draft codes would be agreed between the regulatory entities of SAC, initially; these will be non-binding in nature and may not have a formal legal status. The FGCG and draft codes focuses only on the specific aspects of CBET that would permit both the FGCG and draft codes and the national electricity grid code framework to co-exist for a reasonable period of time. Gradually, a legal effect shall be provided to these guidelines through a structured framework.

Implementation of these FGCG will require consensus building and hence, will need to be facilitated through a strong institutional sponsor. SARI/EI Task Force-1 has recommended establishing South Asian Forum of Electricity Regulators (SAFER) to manage this process in close coordination with various regional bodies, transmission utilities including the proposed regional electricity regulatory authority, the South Asia Association for Regional Cooperation (SAARC) secretariat, technical committees and forums in the area of facilitating Cross-Border Electricity Trade (CBET).

The following approach is proposed in order to ensure this transition:

Step 1: The FGCG and draft codes may be adopted by the SAFER or any other regional regulatory institutional mechanism in South Asia in this regard and can recommend to the national regulators in South Asian countries for adoption as a non-binding framework guiding grid code harmonisation/coordination for Cross-Border Electricity Trade.

Step 2: For adoption of the FGCG and draft codes by each of regulatory agencies in the member countries in the South Asian region for the purpose of cross-border energy trading in their grid code, national electricity regulators may need to identify specific changes that are required in the national grid codes. While identifying such changes for modifying the grid code, they can adopt the proposed guidelines in toto or in parts as appropriate.

Step 3:

a) Existing National Electricity Grid Code Regulations may be updated or modified based on the FGCG and draft codes to ensure full consistency.

b) Additional studies/reviews undertaken in due course can contribute in defining the national grid code regulations in a more detailed form, eventually leading to the updating of FGCG and draft codes if needed.

Step 4: FGCG and draft codes are updated and adopted for governing cross-border trade transactions (binding nature). The legal effect could gradually be increased by adoption through the national country governments/regulatory authorities through the national grid code regulations as shown in Figure 6.

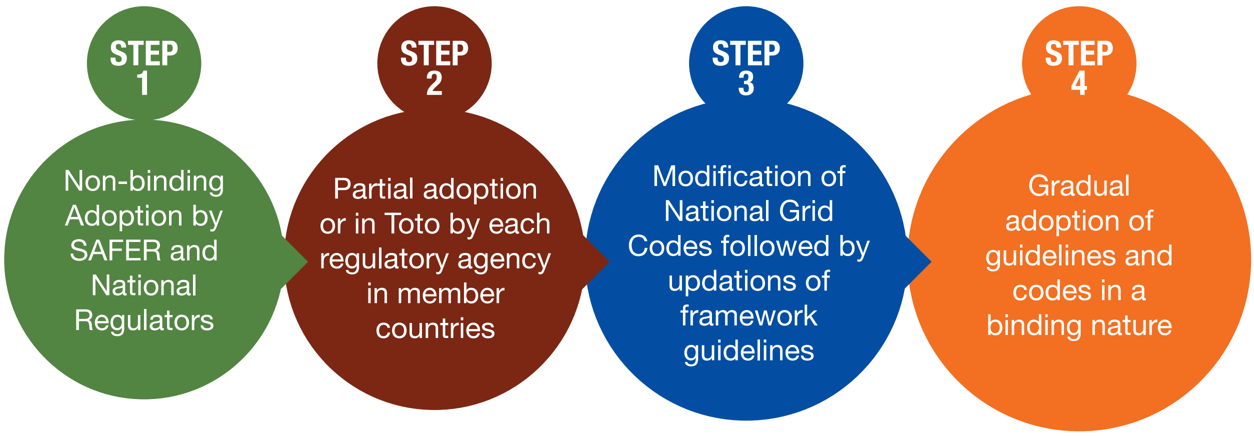
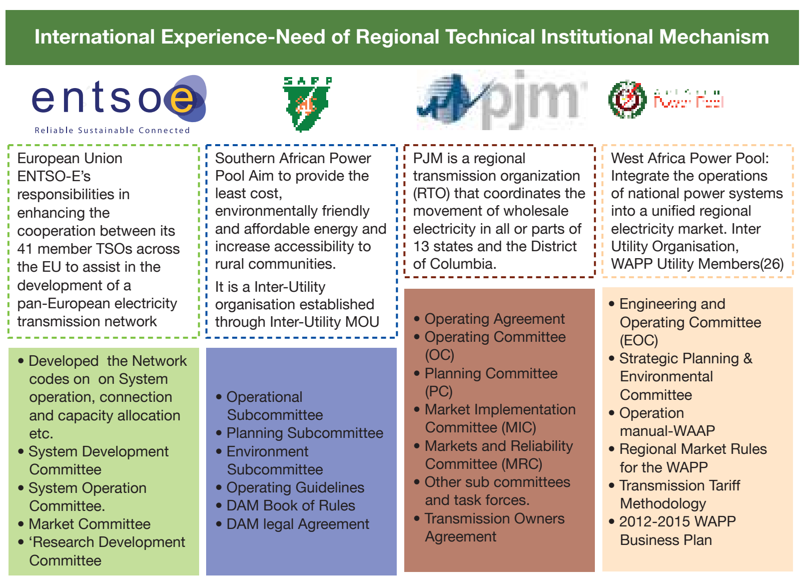


Figure 6: Procedure for Implementation of Framework Grid Code Guidelines

Keeping in view of the international experiences and considering the technical complexity involved with respect to grid code harmonisation and integrated planning and operation of a regional power system in South Asia, **it is suggested to create a Regional Technical Institutions/Body such as South Asia forum of transmission system utilities of SACs or South Asian Forum of Transmission Utility (SAFTU), which shall be mandated for coordinated, reliable and secure operation of the interconnected transmission network as well as for coordinated system planning and integrated system/network development and grid code harmonisation. South Asia Forum of Transmission Utility (SAFTU) will be an independent, regional as well as technical and will provide technical support and inputs to the SAFER**[3] **(or any other Regional Regulatory Institutional Mechanism in South Asia)** on matter related to grid code guidelines, harmonisation of grid codes, development of standards, integrated planning and operation of a regional power system etc. (More details about SAFTU is attached as Annexure-2).



Study on Harmonization of grid codes, operating procedures and standards to facilitate/promote cross border electricity trade in the south Asia region: Key Findings/Framework Grid Code Guidelines/Rajiv Panda/Head-Technical/SARI/EI/IRADe

Figure 7: International Experience-Need of Regional Technical Institutional Mechanism in South Asia

[3] South Asia Forum of Electricity Regulators (SAFER) was recommended by TF-1 study on Regional Regulatory Guidelines. The objective of SAFER is ties and programs in the area of facilitating cross border electricity trade. SAFER Objectives: "Forum focused to work towards a consistent and harmonized/coordinated regulatory framework for CBET within the South Asian nations

Preamble of Framework Grid Code Guidelines

1.1 These Framework Grid Code Guidelines (FGCG) apply to CBET among the South Asian Countries.

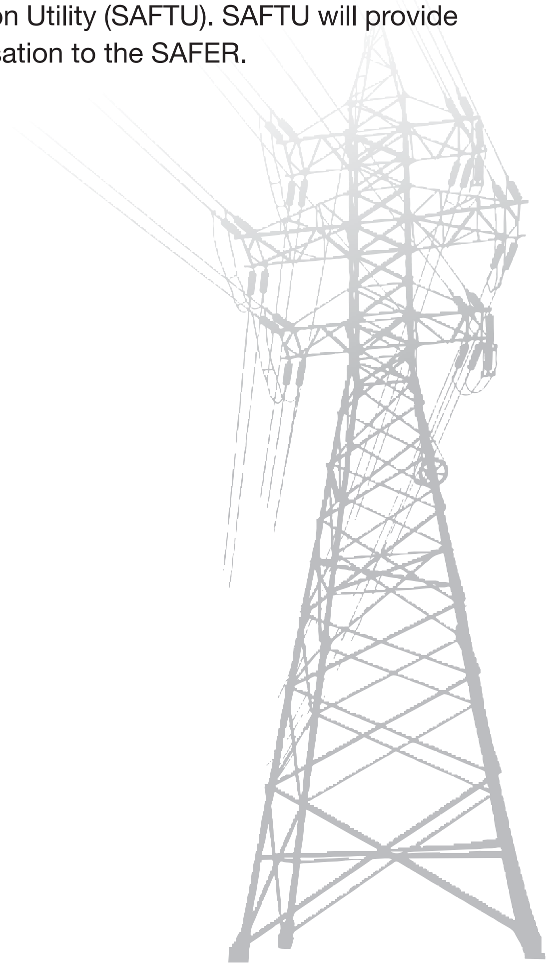
1.2 These FGCG are non-binding in nature and are aimed to provide the national regulators of SAC with a consistent set of guidelines applicable to CBET.

1.3 The FGCG deal only with limited areas where a need for such common guidelines has been felt by the SAC and are not meant to be comprehensively dealing with all matters related to CBET. For all other purposes, the respective Grid Code Guidelines shall apply.

1.4 SAFER[4] shall be the institutional body working towards enabling the guidelines and facilitating the required changes to be made in the Grid Code Framework. Such an entity shall work in close coordination with the SAARC secretariat and various bodies under the same.

1.5 In countries where regulators do not exist, the responsibilities shall rest with the relevant ministry and/or empowered entity for specific issues.

1.6 Considering the technical complexity in framing grid code, harmonisation and for integrated system planning and operation, this study has suggested to create a Regional Technical Institutions/Body such as South Asian Forum of Transmission Utility (SAFTU). SAFTU will provide technical support and inputs in farming grid code, harmonisation to the SAFER.



[4] South Asia Forum of Electricity Regulators (SAFER) suggested by SARI/EI Task Force -1 Or any other appropriate Regional Regulatory Institutional Mechanism. Now since SAARC Council of Experts of Energy Regulators-Electricity (CEERE) is proposed to be formed - CEERE may adopt the FGCG as a base for further Implementation and harmonisation/coordination.

Framework of Grid Code Guidelines

High Level of Cross-Border Interconnection are being envisaged and planned, therefore it is obvious that for safe, reliable and stable operation of the interconnected transmission system, the various technical aspects of grid codes, operating procedures and standards needs to be harmonised/ coordinated. Compatibility has to be there depending on the type of interconnection. The Framework Grid Code Guidelines (FGCG) has been prepared by analysing the existing grid codes of all the countries in South Asian Region and the international grid codes where significant cross-border trade is taking place. The summary of the overview of grid codes of South Asian Region, Gap Analysis and the significant take away from the international grid codes are summarised in Annexure-1.

Taking all considerations into account, the four major grid code guidelines are framed. A brief summary of the grid code guidelines is presented in Figure 8.

Planning Guidelines

- It provides information and stipulates the various criteria to be adopted, for planning and development of Interconnected transmission system

Connection Guidelines

- It specifies a minimum of technical, design and operational plant criteria to be compiled with by the existing and prospective users.
- It includes the meter placement, compliance of meters according to standards in terms of accuracy levels, accessibility of the meters, maintenance responsibility of meters etc.,
- It covers the general protection guidelines to be followed for the generator, transmission licensees.

Operation Guidelines

- It contains details for high level operational procedures for example demand control, operational planning and data provision

Scheduling and dispatch Guidelines

- It describes the procedures to be adopted for scheduling and dispatch of generation and allocation of power drawl.

Figure 8: Summary of Guidelines

In order to preserve the consistency, the FGCG are prepared similar to standard grid code document and distinctive numbering is given for each guideline to facilitate adoption of these guidelines *in toto* or in parts by the relevant authorities as Cross-Border Grid Codes.

I-PLANNING

Rationale: In line with Article 7 of the SAARC framework agreement for energy cooperation (electricity) as regard to planning of cross-border interconnections, it is suggested that the master plan must be prepared for each of the cross-border links between the countries. The master plan can be for bi-lateral transaction or multilateral transactions and can eventually cover the entire region. However, it is intended that the master plan shall cover a horizon of next 10 to 20 years.

PC 1. INTRODUCTION

PC 1.1 The Planning Guidelines specify the philosophy and procedures to be applied in planning of interconnected cross-border grids.

PC 1.2 In line with Article 7 of the SAARC Framework Agreement for Energy Cooperation (Electricity) (SAFEC-E), Member Countries may enable the transmission planning agencies of the governments to plan the cross-border grid interconnections through bilateral/trilateral/mutual agreements between the concerned countries based on the needs of the trade in the foreseeable future through studies and sharing technical information required for the same.

PC 1.3 With stabilisation of trade and to facilitate robust operation of the grid, it may be necessary to create the planning body to facilitate overall planning of the SAARC interconnections.

PC 2. OBJECTIVE

PC 2.1 Objectives of the planning guideline are

a. To specify the principles, procedures and criteria which shall be used in the planning and development of the cross-border interconnections,

b. To promote co-ordination amongst all participants in any proposed development of the cross-border interconnections,

c. To provide methodology and information exchange amongst participants in the planning and development of the cross-border interconnections;

PC 2.2 The criteria detailed herein are primarily meant for planning of all new cross-border ties and also to review and strengthen the existing cross-border links of 400 kV, 765 kV levels and HVDC link (and also a portion of 220 kV and sub-transmission system which would facilitate cross-border power transfer) that impact the South Asian country’s cross boundary power flow. In case congestion is anticipated till the implementation of the additional system, suitable defence mechanisms may have to be put into place.

PC 2.3 The intended guideline provides the necessary criteria for transmission planning of cross-border link and outlines the coordination among planning agencies. The need for an efficient and coordinated cross-border exchange of electrical power is attempted to be fulfilled in this guidelines. The interconnected countries can act as one huge grid. Therefore, there shall be a uniform approach for planning the reliable interconnected system.

PC 3. APPLICABILITY

PC 3.1 The planning guidelines shall apply to planning agencies, transmission utilities and other entities involved in the developing or using of the cross-border interconnections.

PC 4. PLANNING PHILOSOPHY

PC 4.1 The Master Plan shall form the basis for planning of the interconnected network among the member countries. A major collaborative planning effort will be needed to bring together the existing grids of the member countries and the planned regional super-grid. Towards this end, member countries may enable the transmission planning agencies of the respective governments to prepare master plan for the cross-border grid interconnections through bilateral/trilateral/mutual agreements between the concerned member countries in the interim. The planning body may be set up under the aegis of SAARC or any other appropriate institutional mechanism shall undertake the responsibility of preparing the plan in the future.

PC 4.2 The master plan shall be formulated with the planning horizon of at least 10 years, considering requirement of energy trade with existing and proposed interconnections. It shall be reviewed every alternative year and consider all scenarios that could be possible in the next 10 years on rolling basis, by forecasting both demand and generation. In formulating the master plan, the transmission requirements for evacuating power from renewable energy sources intended for cross-border trade during surplus scenario shall also be taken care of.

PC 4.3 All the stakeholders shall furnish to the authorised transmission agencies/planning agencies, the desired planning data from time to time to enable the formulation and finalisation of its plan. As the cross-border interconnection is expected to cater for the long term requirements of member countries, sufficient forecasting of demand and generation shall be carried out so as to make available the requisite transmission capacity, and minimise situations of congestion and stranded assets.

PC 4.4 The system peak demands shall be estimated based on the latest survey reports. However, the same may be moderated based on actual load growth of past three (3) years. The load demands at other periods (seasonal variations and minimum loads) shall be derived based on the annual peak demand and past pattern of load variations.

PC 4.5 From practical considerations, the load variations over the year shall be considered as under:

a. Annual Peak Load
b. Seasonal variation in Peak Loads for Winter, Summer and Monsoon
c. Seasonal Light Load (for Light Load scenario, motor load of pumped storage plants shall be considered)

PC 4.6 Reactive power plays a critical role in EHV transmission system management and hence forecast of reactive power demand on a system-wide basis is as important as active power forecast. This forecast would obviously require adequate data on the reactive power demands as well as the projected plans for reactive power compensation. Further, in the AC interconnection (synchronous), the reactive power flow shall be minimised and shall be operated within 0.97 lead/lag power factor at connection point and within permissible voltage variation.

PC 4.7 The load-generation scenarios shall be worked out so as to reflect in a pragmatic manner due to typical daily and seasonal variations in load demand and generation availability which impact the cross border power flow. However, when looking far ahead, it becomes increasingly difficult to remain accurate. Thus, the objective of these scenarios is to construct contrasting future developments that differ enough from each other to capture a realistic range of possible future pathways that could challenge the grid. The scenarios may consider the following factors shown in Table 1.1.

Table 1.1: Factors to be considered in scenario definition

Characteristic	Factors
Technical parameters	Plant Efficiency Availability Reserves Share of non-dispatchable generation Scheduled maintenance Ramping and start-up costs
Economical parameters	Economic growth Fuel cost
Generation scenarios for different generation types	Capacity Efficiency Flexibility Location Planned outage schedule Renewable production Wind/solar profiles or cold/heat spell
Demand scenarios	Economic growth Evaluation of demand per sector Load diversity Load Management Climate (e.g., Wind, temperature, humidity) Season (e.g., Winter, summer) Population
Exchange pattern	Inter-region and inter-country fixed flows

PC 4.8 The master plan shall include to the extent possible all the scenarios. On the basis of the plans prepared, the necessary interconnected lines and sub-stations shall be implemented.

PC 4.9 The master plan shall also include the appropriate communication system for the cross-border sub-stations along with the real-time data transfer/communication.

PC 4.10 The master plan shall consider all the criteria specified in these guidelines. The planning criteria specified in these guidelines shall also be relevant for specific bilateral or multilateral cross-border interconnections which may not be part of the master plan.

PC 5. TRANSMISSION PLANNING CRITERION

PC 5.1 The planning criteria shall be based on the security philosophy which mandates the system parameters and loading of system elements shall remain within prescribed risk level limits. A risk level shall be defined which shall aid in the assessment of need for cost-effective remedial actions.

{Considering the operation of a power system from the point of view of risk management implies the definition of a risk level that should be respected for any kind of events. This risk level is assessed by a reference value of the product "Event probability x Expected loss". The greater the probability of an event occurrence, the lower should be the expected loss. The loss may be defined either by a financial loss or more commonly for a power system in terms of a potential demand reduction or energy loss. The cost of risk associated to an event 'i' is quantified by the following formula:

$$C_i = R_i\, U$$

Where,

U is the estimated cost of non-fed energy.

R_i is the risk associated with event i and is calculated as $R_i = P_i*S_i*f_i R_i = P_i*S_i*f_i$

P_i is the likelihood of the event i for a given unit of time.

S_i is the severity associated to the event i and depends on the restitution time.

f_i is the frequency of exposure associated to the event i.

Based on these definitions, planner shall have to consider all those remedial actions which have a total effective cost lower than the cost of the risk.}

PC 5.2 Permissible normal and emergency limits

a. The loading limit of a transmission line shall be its thermal loading limit (with appropriate compensation to limit voltage drop and angular separation). The thermal loading limit of a line is determined by design parameters based on ambient temperature, maximum permissible conductor temperature, wind speed, solar radiation, absorption coefficient, emissivity coefficient etc.

b. Design ambient temperature, solar radiation, wind velocity etc., may be considered as per mutual agreement in such a manner to leave operational margin for additional loading.

{The thermal loading limit of a line is determined by design parameters based on ambient temperature, maximum permissible conductor temperature, wind speed, solar radiation, absorption coefficient, emissivity coefficient etc. In South Asia, all the above factors and more particularly ambient temperatures are different and vary considerably during various seasons of the year. Thus, the ambient temperature and other factors are to be fixed for planning purposes, thereby permitting margins during operation.}

c. The loading limit for an inter-connecting transformer (ICT) shall be its name plate rating. However, during planning, a 20% margin shall be kept in the transformer loading limits. The emergency thermal limits for the purpose of planning shall be 100% of the rated thermal limits of the equipment and any overload limits (example: 5% or 10% overload for short period of time) can be considered during the operational time frame.

d. The steady state voltage shall be as shown in Table 1.2. However, at the planning stage a margin may be kept in the voltage limits.

Table 1.2: Permissible voltage limits

	Normal (Planning)	Normal (operational)	Emergency
Voltage (400 kV, 500 kV & 765 kV)	± 3%	± 5%	±10%

{The 2% margin made available at the operational timeframe is in line with CEA's manual on transmission planning criteria which states that "At the planning stage, a margin of about 2% may be kept in the voltage limits"}

e. The temporary over voltage limits due to sudden load rejection shall be:

i 765 kV system 1.4 p.u. peak phase to neutral

ii 500 kV and 400 kV system 1.5 p.u. peak phase to neutral

{Adopted from CEA's manual on transmission planning criteria}

f. The switching over voltage limits shall be:

i 765 kV system 1.9 p.u. peak phase to neutral

ii 500 kV and 400 kV system 2.5 p.u. peak phase to neutral

{Adopted from CEA's manual on transmission planning criteria}

g. The nominal frequency shall be 50 Hz. The steady state frequency limits shall be +0.05 Hz to -0.1 Hz, i.e. from 49.9 Hz to 50.05 Hz. The instantaneous frequency limits shall be ±0.8 Hz.

{The nominal frequency is that followed by all South Asian countries. The steady state frequency limits is that stated in Indian Grid Code. The instantaneous frequency limits is adopted from the European Grid Code.}

h. Rating of equipment shall be able to withstand the designed fault currents.

i. Minimum short-circuit currents shall be assessed in bus-bars where a HVDC installation is connected. Short Circuit Ratio (SCR) at the converter terminals shall be greater than 3.

{CEA's transmission planning criteria states that "The ratio of fault level in MVA at any of the convertor station (for conventional current source type), to the power flow on the HVDC bi-pole shall not be less than 3.0 under any possible load-generation scenarios."}

j. Planned maximum sub-transient short circuit fault levels shall not be greater than 80% of equipment ratings.

{The 20% margin is set to take care of the increase in short-circuit levels as the system grows.}

k. The line to earth voltage during single line to earth faults should not rise above 80% of the rated line to line voltage.

PC 5.3 Reliability Criteria

a. Criteria for system with no contingency ('N-0')

i The system shall be tested for all the load-generation scenarios.

ii For the planning purpose all the equipment's shall remain within their normal thermal loadings and voltage ratings.

iii The angular separation between adjacent buses shall not exceed 30 degree i.e., the stability margin is above 50%.

{This is adopted from CEA's reliability criteria for transmission planning.}

iv In order to avoid a voltage collapse, studies shall ensure that the reactive power output of generators and compensation equipment in the area do not exceed their continuous rating and generator terminal voltage does not exceed its admissible range.

v Voltage step resulting from capacitor/reactor switching shall not exceed 3.0%.

{This criterion is observed in SAPP planning criteria and adopted in order to maintain the system within stable limits.}

b. Criteria for single contingency ('N-1')

Steady State

i All the equipment in the transmission system shall remain within their normal thermal and voltage ratings after a disturbance involving loss of any one of the following elements (called single contingency or 'N-1' condition), but without load shedding/ rescheduling of generation:

- Outage of a 400 kV single circuit,
- Outage of a 400 kV single circuit with Fixed Series Capacitor (FSC),
- Outage of an Inter-Connecting Transformer (ICT),
- Outage of a 765 kV single circuit,
- Outage of one pole of HVDC bi-pole[$];

ii The angular separation between adjacent buses under ('N-1') conditions shall be permitted up to 30 degree i.e., the stability margin is kept at 50%.

iii The system shall be capable of withstanding the loss of most severe single system in feed without loss of stability.

Transient State

iv The system shall be able to survive a permanent three phase to ground fault on a 765 kV line close to the bus to be cleared in 100 ms.

v The system shall be able to survive a permanent single phase to ground fault on a 765 kV line close to the bus. Accordingly, single pole opening (100 ms) of the faulted phase and unsuccessful re-closure (dead time 1 second) followed by 3-pole opening (100 ms) of the faulted line shall be considered.

vi The system shall be able to survive a permanent three phase to ground fault on a 500 kV or 400 kV line close to the bus to be cleared in 100 ms.

vii The system shall be able to survive a permanent single phase to ground fault on a 500 kV or 400 kV line close to the bus. Accordingly, single pole opening (100 ms) of the faulted phase and unsuccessful re-closure (dead time 1 second) followed by 3-pole opening (100 ms) of the faulted line shall be considered.

viii The system shall be able to survive a fault in HVDC convertor station, resulting in permanent outage of one of the poles of HVDC Bipole[$].

ix **Contingency of loss of generation:** The system shall remain stable under the contingency of outage of single largest generating unit or a critical generating unit (choice of candidate critical generating unit is left to the transmission planner).

x An N-1 contingency shall not lead to a cascading tripping.

c. Criteria for second contingency ('N-1-1')

i All the equipment in the transmission system shall remain within their normal thermal and voltage ratings after a disturbance involving loss of any one of the following contingency outages, at least after rescheduling of generation but without load shedding:

- Outage of a 400 kV single circuit with TCSC,
- Outage of a second circuit of 400 kV double circuit line with first circuit already under outage,
- Outage of a 765 kV single circuit line with series compensation;

ii Under the scenario where one contingency has already happened, the system may be subjected to one of the following subsequent contingencies:

- The system shall be able to survive a temporary single phase to ground fault on a 765 kV line close to the bus. Accordingly, single pole opening (100 ms) of the faulted phase and un-successful re-closure (dead time 1 second) shall be considered.
- The system shall be able to survive a permanent single phase to ground fault on a 400 kV line close to the bus. Accordingly, single pole opening (100 ms) of the faulted phase and unsuccessful re-closure (dead time 1 second) followed by 3-pole opening (100 ms) of the faulted line shall be considered.

iii In the 'N-1-1' contingency condition as stated above, if there is a temporary fault, the system shall not lose the second element after clearing of fault but shall successfully survive the disturbance.

iv In case of permanent fault, the system shall lose the second element as a result of fault clearing and thereafter, shall asymptotically reach to a new steady state without losing synchronism. In this new state the system parameters (i.e. voltages and line loadings) shall not exceed emergency limits; however, there may be requirement of load shedding/rescheduling of generation so as to bring system parameters within normal limits.

v Any one of these events defined above shall not cause:

- Loss of supply
- Prolonged operation of the system frequency below and above specified limits
- Unacceptable high or low voltage
- System instability
- Unacceptable overloading of equipment;

vi Suitable System Protection Schemes may be planned, either for enhancing transfer capability or to take care of contingencies beyond that indicated above.

{Outage of one pole of HVDC: Though this may not be possible if only one cross border link is planned. In such a case, the outage of poles needs to be taken care of by special protection mechanism for reducing equivalent demand/generation so as not to threaten the security. However, this criterion is applicable when multiple cross-border links are planned and in case of outage of one pole of HVDC bipole, the other cross-border links shall take care of additional loadings.}

{Usually, perturbation causes a transient that is oscillatory in nature, but if the system is stable the oscillations will be damped. The system is said to be stable in which synchronous machines, when perturbed, will either return to their original state if there is no change in exchange of power or will acquire new state asymptotically without losing synchronism.}

{The criteria for single and second contingency have been adopted from CEA's transmission planning criteria}

PC 5.4 Planning margins

a. New transmission lines emanating from a power station to the nearest grid point may be planned considering overload capacity of the generating stations in consultation with generators.

b. The new transmission additions required for cross-border transmission may be planned keeping a margin of at least 15% in the thermal loading limits of lines and transformers.

{This margin of 15% is adopted from CEA's transmission planning criteria wherein it is stated that "the margins in the interregional links may be kept as 15%."}

c. At the planning stage, a margin of about ±2% may be kept in the voltage limits as compared with normal voltage limits of ±5% and thus the voltages under load flow studies (for 'N-0' and 'N-1' steady-state conditions only) may be maintained within the limits given below:

i For 765 kV level, a maximum of 788 kV and a minimum of 742 kV

ii For 500 kV level, a maximum of 515 kV and a minimum of 485 kV

iii For 400 kV level, a maximum of 412 kV and a minimum of 388 kV

{The limits are adopted from CEA's transmission planning criteria.}

d. In planning studies all the transformers may be kept at nominal taps and On Load Tap Changer (OLTC) may not be considered. The effect of the taps shall be kept as operational margin.

e. For the purpose of load flow studies at planning stage, the nuclear generating units shall normally not run at leading power factor. To keep some margin at planning stage, the reactive power limits (Q_{max} and Q_{min}) for generator buses may be taken as:

   i Thermal Units: Q_{max} = 40% of $P_{max,}$ and Q_{min} = (-) 10% of P_{max}

   ii Nuclear Units: Q_{max} = 40% of $P_{max,}$ and Q_{min} = (-) 0% of P_{max}

   iii Hydro Units: Q_{max} = 50% of $P_{max,}$ and Q_{min} = (-) 20% of P_{max}

{In a very large interconnected grid, there can be unpredictable power flows in real time due to imbalance in load-generation balance in different pockets of the grid. This may lead to overloading of cross-border transmission elements during operation, which cannot be predicted in advance at the planning stage. This can also happen due to delay in commissioning of a few planned transmission elements, delay/abandoning of planned generation additions or load growth at variance with the estimates. Such uncertainties are unavoidable and hence some margins at the planning stage may help in reducing impact of such uncertainties. However, care needs to be taken to avoid stranded transmission assets.}

PC 6. GENERATION PLANNING CRITERION

{Generation planning criterion shall be followed if the synchronous cross-border link is envisaged. It is to be noted that each of the countries is free to use their own generation planning guidelines and reliability levels but these guidelines are intended as a reference only. However, it would be desirable to carry out adequacy assessment to estimate the cross-border power flow and shall be included in the master plan.}

PC 6.1 The sharing of capacity between different interconnected areas allows each area to maintain the desired level of reserve with a lower amount of internal installed capacity (and consequently with lower costs) compared to the isolated operation.

PC 6.2 The key objective of the generation expansion planning activity is to develop a long range least-cost generation expansion plan for the period of 10/20 years to find the deficit and surplus among the member countries while taking into account government policies, identified constraints and reliability criteria.

PC 6.3 The adequacy analysis will determine the required amount of planning reserves in each country while maintaining the required reliability level as per country grid codes. Harmonised adequacy methodology shall be adopted to determine the contribution for cross-border exchanges to individual system adequacy/reliability. Such models shall consider the limited capacities between areas of the interconnected grid and properly evaluate the potential support provided by the interconnections to each area.

PC 6.4 Adequacy assessment shall provide an estimation of the expected cross-border flows. Adequacy analysis shall be performed by using multi-area reliability models for cross-border energy exchange considering the time shift and seasonal variations.

PC 6.5 Methodology

a. To estimate the generating system reliability and to identify deficiency/surplus in the generation capabilities while meeting the projected load;
b. Most common reliability indices for reliability analysis are: Loss of Load Probability (LOLP), Loss of Load Expectation (LOLE) and Expected Un-served Energy (EUE);
c. To run a probabilistic simulation of the operation of the generating system in such a way as to minimise total system production costs;
d. To determine the present worth of production costs (fuel costs, and operation and maintenance costs) and investment cost;

e. To find the advantages/impacts of interconnections with reference to each country;

PC 6.6 Load Profile and Forecast

a. Analyzing annual hourly load profiles is an important aspect of generation planning to capture the hourly and seasonal variation in the load. The hourly loads are used to construct the monthly/yearly load curves which are one of the key inputs to generation planning. The historical monthly load curves are used for planning the future years. The assumption is that the future monthly/seasonal load variations would be very similar to the past ones.
b. The historical load profiles will be extrapolated with future load forecast values.
c. If the historical load profile has the load shedding (demand restriction) incidents, planning model shall alter the load profile considering the unrestricted load patterns.
d. Load forecast studies may be performed using both bottom-up approach (end use method) and top-down approach (econometric approach) for next 10/20 years. Based on the principle and data availability, econometric methods are preferable. This is due to high accuracy for econometric methods as econometric data on country level is available at reasonable accuracy.

PC 6.7 Environmental Criteria

a. Emissions and wastes associated with the thermal power plants shall be considered in the model
b. The emission requirements for power plants have been based on the Environmental Quality Standards specific to respective country.
c. Adverse environmental and social impacts associated with dams and reservoirs shall be considered in planning model.

PC 6.8 Reliability Criteria

a. The reliability criterion determines the timing of new capacity additions required in the future while meeting country demand and plan for imports and exports with other countries.
b. Expected Un-served Energy
c. The LOLP of 0.2% or lower shall be considered in planning exercise while assessing cross-border line flows.

PC 6.9 Existing and Committed Generation Units

a. The possible commissioning schedule and capital and operational cost data of the identified new conventional projects shall be considered. These projects were then ranked in terms of economic costs including their capital and O&M costs, so as to select the least cost projects considering their earliest possible commissioning dates.

PC 6.10 Import and Exports

a. The availability of capacity and energy from planned imports and exports shall be considered.
b. If required, imports and exports shall be considered in planning for future years.
c. Each country shall provide its inputs regarding planned import/export of power for the purpose of planning interconnections.
d. The transmission planning group would take inputs from respective governments, traders, power exchange etc., and assess the broad market trend of cross-border trade while planning interconnections.

PC 6.11 Considering the impact of renewable energy sources

a. Renewable energy sources shall be accounted in the master plan as penetration of these sources is very high in some of the member countries and it impacts the availability of generation and transmission to some extent.

b. A detailed assessment of demand profile which shall be performed to optimally utilise the renewable energy with interconnections.

PC 7. PLANNING DATA

PC 7.1 Under this Planning Guidelines, the entities of member countries, system operators, generation and demand facilities are to furnish all necessary and relevant data for carrying out planning studies.

PC 7.2 "Network stress tests" shall be performed on each planning case and specific technical planning criteria shall be followed on the basis of long term engineering practice. The criteria cover both kind of contingencies chosen as "proxies" for hundreds of other events that could happen to the grid, and the adequacy criteria relevant for assessing overall behaviour of the transmission system. The behaviour of the grid when simulating the contingencies indicates the "health" and robustness of the system. A power system that fails in one of these tests is considered "unhealthy" and steps shall be taken so that the system will respond successfully under the tested conditions. Several planning cases are thus assessed in order to identify how robust the various reinforcements are, based on one or more of the following power system studies:

a. Power Flow Studies

b. Short Circuit Studies

c. Stability Studies (including transient stability and voltage stability)

d. EMTP studies (for switching overvoltages, insulation coordination, etc.)

PC 7.3 Contingency List

a. A contingency list shall be prepared and followed for system reliability studies. The list shall include both high and low probability contingencies and necessary remedial actions may be pre-established and documented for each contingency (if required) based on simulation results. It shall be ensured that the observability area for modeling and study includes, apart from the responsibility area, a wider boundary covering all relevant elements and connections of the neighbouring responsibility area. Both scheduled contingency and un-scheduled contingency shall be defined.

b. The contingencies shall be classified under the following three categories:

i Normal Contingencies: During disturbances leading to single contingency condition (N-1), it is required that all the system parameters like frequency, voltage and loading shall remain within permissible limits. These include loss of a single element, which can be a

- Line
- Tie-line
- HVDC link
- Generation Unit (largest unit)
- Transformer (including Phase Shifting Transformer)
- Large voltage compensation installation

ii Exceptional Contingencies: These contingencies are considered depending on its own risk assessment in order to prevent cascading effects and to comply with the "no cascading with impact outside my borders" criterion. The exceptional type of contingency comprises the loss of the following elements:

- N-1 double circuit line: A double circuit line refers to two lines on the same tower over a long distance. The consideration of distance is left to the appreciation of planners.
- N-1 bus bar: The contingency can occur due to the failure of a breaker or internal lack of insulation, fault of protection devices, etc.
- N-2 units (common mode on ancillary services, etc.).

iii Out of Range Contingencies: The out of range type of contingency comprises losses of elements with a very low likelihood

- N-2 for lines,
- A total sub-station with more than a bus bar,
- A total power plant with more than two units,
- A tower with more than 2 lines,
- Severe power swinging or oscillations, etc.

c. For normal contingencies and exceptional contingencies, N-1 simulations may be mandatory, including in operational time frame also. The out of range contingencies need not to be considered for cross-border planning. The contingency list to be used for N-1 security calculations includes both internal and external events.

d. In the asynchronous interconnection (HVDC back-to-back or HVDC Bi-pole), it may be necessary to define the contingency (Loss of one pole, convertor, convertor transformer, filter banks, etc.) which results in reduction in power flow.

e. However, after suffering one contingency, grid remains vulnerable to experience second contingency (N-1-1), although this may be less probable. But occurrence of such an event could load the system to its emergency limits. To bring the system parameters back within their normal limits, remedial actions like load shedding/re-scheduling of generation may have to be applied either manually or through automatic System Protection Schemes (SPS). Such measures shall generally be applied within reasonable time after the disturbance.

{In general, a contingency is defined as the outage of an element that cannot be predicted in advance. In that case, a scheduled outage need not to be considered as a contingency so also an "old" lasting contingency which can be considered as a scheduled outage. However, in practice all the outages are treated as contingency.

In general, a single contingency is described as an N-1 event and is defined as out of N elements, 1 element is under contingency. Operators of interconnected systems are obliged to monitor the N-1 principle not only for their own grid but also for the tie lines to neighbouring grids. This is called the Responsibility Area of the Operator.

Due to the increased interconnections, the assessment of security is more inter-dependent. This mandates the system operator to take into account the influence of the surrounding grid on its responsibility area. Each system operator needs to periodically analyse, by numerical calculations, the external transmission network which influences its responsibility area. An external contingency list is prepared that includes all the elements of surrounding areas that have an influence on its responsibility area higher than a certain value, called the contingency influence threshold. Each system operator has to take into account the elements of this external contingency list in its contingency analysis.

It is necessary to model the external grid enough to guarantee accurate estimations in the responsibility area, when performing the N-1 analysis of the elements of the external contingency list. That means that not only the branches of the external contingency list have to be modelled but other surrounding branches, with lower influence on the responsibility area, have to be a part of the model. This will ensure correct simulations of the effects of outages in the neighbouring regions. All the external elements with an influence on the responsibility area higher than a certain value, called the observability influence threshold, constitute the external observability list. This defines the observability area.

To adhere with the N-1 principle, the planner (or system operator) simulates the possible cascading effects of a contingency with its impact, and checks:

- Whether critical system parameters of voltage, loadings are violated
- In extremis, whether the contingency could be propagated at least till the boundary
- The potential unbalancing of the system frequency and also the deterioration of voltage for neighbouring operators}.

PC 7.4 Generation dispatching and modelling

a. For planning of new cross-border transmission lines and sub-stations, the peak load scenarios corresponding to summer, monsoon and winter seasons may be studied. Further, the light load scenarios may also be carried out as per requirement.
b. For evolving transmission systems for integration of wind and solar generation projects, high wind/solar generation injections may also be studied in combination with suitable conventional dispatch scenarios. In such scenarios, the internal conventional generating station of the RES purchasing country may be backed-down so that impact of wind generation on the grid is minimal.
c. In case of thermal units (including coal, gas/diesel and nuclear based) the minimum level of output (ex-generation bus, i.e. net of the auxiliary consumption) shall be taken as not less than 70% of the rated installed capacity. If the thermal units are encouraged to run with oil support, they may be modeled to run up to 25% of the rated capacity.

PC 7.5 Power system model for simulation studies

a. Every element participating in the system power flow directly or indirectly shall be modeled, down to 400 kV (or 500 kV) and secondary side of the 400 kV (or 500kV) sub-station. In case of relevance, a suitable portion of 220 kV or 230 kV or sub-transmission systems may be considered if it impacts the cross border power flow.
b. The generating units that are stepped-up at 132 kV or 110 kV may be connected at the nearest 400 kV (or 500 kV) bus through a 400/132 kV transformer for simulation purpose with appropriate fault level. The generating units smaller than 50 MW size within a plant may be lumped and modelled as a single unit, if total lumped installed capacity is less than 200 MW.
c. Modelling of smaller generating units may also be considered, if required
d. Load may be lumped at 400/220 kV level.
e. In the absence of reactive power data of load demands, the load power factor may be taken as 0.95 lag during peak load condition and 0.98 lead during light load condition (worst case condition). Adequate reactive compensation shall be provided in the downstream system to reflect the power factor on the interface points.
f. The generating unit shall be modelled to run as per their respective capability curves. In the absence of capability curve, the reactive power limits (Qmax and Qmin) for generator

buses can be taken as:

i Thermal Units: Q_{max} = 40% of P_{max}, and Q_{min} = (-) 10% of P_{max}

ii Nuclear Units: Q_{max} = 40% of P_{max}, and Q_{min} = (-) 0% of P_{max}

iii Hydro Units: Q_{max} = 50% of P_{max}, and Q_{min} = (-) 20% of P_{max}

g. It shall be mandated that all the generators to provide technical details such as machine capability curves, generator, exciter, governor, PSS parameters etc., for modelling of their machines for steady-state and transient-state studies.

h. The modelling shall include the out of service elements too.

PC 7.6 Data for short circuit studies

a. The short circuit studies shall be carried out using the classical method with flat pre-fault voltages and sub-transient reactance (“Xd”) of the synchronous machines.

b. MVA rating of all the generating units in a plant may be considered for determining maximum short-circuit level at various buses in system. This short-circuit level may be considered for cross-border sub-station planning.

c. Vector group of the transformers shall be considered for the short circuit studies considering asymmetrical faults. Inter-winding reactances in case of three winding transformers shall also be considered. For evaluating the short circuit levels at a generating bus, the unit and its generator transformer shall be represented separately.

d. Short circuit level both for three-phase to ground fault and single-phase to ground fault shall be calculated.

e. The short-circuit level in the system varies with operating conditions. It may be low for light load scenario compared to a peak load scenario, as some of the plants may not be on-bar. For getting an understanding of system strength under different load-generation/ export-import scenarios, the MVA of only those machines shall be taken which are on bar in that scenario.

PC 8. DATA FOR GENERATION PLANNING

PC 8.1 Load data

a. Historical hourly load data

b. Load forecast

PC 8.2 Existing Imports/Exports

a. Capacity of the interconnections

b. Transmission losses

c. Monthly energy and capacity available

PC 8.3 Existing base and peak hydro data

a. Unit installed capacity, auxiliary consumption

b. Water availability

c. Firm and average monthly capacity and energy available

d. Unit forced outage and maintenance rates

e. Retirement/rehabilitation plan of current generating units

PC 8.4 Existing Thermal Data

a. Unit installed capacity, auxiliary consumption

b. Fuel availability

c. Unit forced outage and maintenance rates
d. Retirement/rehabilitation plan of current generating units

PC 8.5 Committed and Future System

a. Committed and planned imports: Capacity of the interconnections; Transmission Losses; Monthly energy and capacity available; and Fixed and variable tariff, O&M cost if any.
b. Committed and planned base and peak hydro data: Technical characteristics, O&M costs, firm and average monthly capacity and energy available, capital cost data, gestation periods, cash flows, construction period.
c. Committed and planned thermal data: Technical characteristics, fuel characteristics, O&M cost data, capital cost data, gestation periods, cash flows, construction period.
d. Future other supply options available.

PC 9. ADDITIONAL PLANNING GUIDELINES

PC 9.1 **Reactive power compensation:** Requirement of reactive power compensation like shunt capacitors, shunt reactors (bus reactors or line reactors), static VAr compensators, STATCOM, fixed series capacitor, variable series capacitor (thyristor controlled) or other FACTS devices shall be assessed through appropriate studies for cross-border transactions. This compensation shall be provided by the respective entities within a country and import of reactive power shall be avoided to the extent possible.

PC 9.2 Cross-Border Sub-station planning criteria

a. The maximum short-circuit level on any new sub-station bus shall not exceed 80% of the rated short circuit capacity of the sub-station equipment. The 20% margin is intended to take care of the increase in short-circuit levels as the system grows.
b. Rating of the various sub-station equipments shall be such that they do not limit the loading limits of connected transmission lines.
c. Effort shall be made to explore possibility of planning a new sub-station instead of adding transformation capacity at an existing sub-station. The maximum transformation capacity for different voltage levels shall be:
    - For 765 kV, 6000 MVA
    - For 500 kV and 400 kV, 1500 MVA

d. While augmenting the transformation capacity at an existing sub-station or planning a new sub-station, the fault level of the sub-station shall also be kept in view. If the fault level is low, the voltage stability studies shall be carried out.
e. Size and number of interconnecting transformers (ICTs) shall be planned in such a way that the outage of any single unit would not overload the remaining ICT(s) or the underlying system.

PC 9.3 Additional criteria for wind and solar projects

a. Planning studies shall consider the impact of wind and solar while planning the cross-border flows. The capacity factor shall be calculated for the purpose of maximum injection to plan the evacuation system.
b. The 'N-1' criteria may not be applied to the immediate connectivity of wind/solar farms with the grid i.e., the line connecting the farm to the grid and the step-up transformers at the grid station.
c. As the generation of energy at a wind farm is possible only with the prevalence of wind, the thermal line loading limit of the lines connecting the wind machine(s)/farm to the nearest grid point may be assessed considering the probable wind speed.

d. The wind and solar farms shall maintain a power factor of 0.98 (absorbing) at their grid interconnection point for all dispatch scenarios by providing adequate reactive compensation and the same shall be assumed for system studies.

PC 9.4 Guidelines for planning HVDC transmission system

a. The ratio of fault level in MVA at any of the convertor station (for conventional current source type), to the power flow on the HVDC bi-pole (SCR) shall not be less than 3.0 under any of the load-generation scenarios or contingencies.

b. In areas where multiple HVDC bi-poles are feeding power (multi in-feed), appropriate studies shall be carried at planning stage so as to avoid repetitive commutation failures.

PC 9.5 Guidelines for voltage stability

a. These studies may be carried out using load flow analysis program by creating a fictitious synchronous condenser at critical buses which are likely to have wide variation in voltage under various operating conditions, i.e., bus is converted into a PV bus without reactive power limits. By reducing desired voltage of this bus, MVAr generation/absorption is monitored. Each bus shall operate above Knee Point of Q-V curve under all normal as well as the contingency conditions. The system shall have adequate margins in terms of voltage stability.

PC 9.6 Remedial Actions

a. Remedial actions shall be established for normal, severe and rare contingencies on the basis of cost analysis.

b. Remedial actions for power flow issues:

   i Network re-configuration

   ii Use of phase shifting transformers

   iii Use of compensating equipments including FACTs controllers

{The system shall be planned to operate within permissible limits both under normal as well as after more probable credible contingencies as detailed in these regulations. However, the system may experience extreme contingencies which are rare, and the system may not be planned for such rare contingencies. To ensure security of the grid, the extreme/rare but credible contingencies should be identified from time to time and suitable defence mechanism may be worked out to mitigate their adverse impact.

Remedial action is any measure applied by a system operator or several operators, manually or automatically, in order to maintain operational security. Remedial action may be curative or preventive by nature. Curative remedial actions are implemented after a contingency in order to quickly relieve constraints on the system. They have to be defined in advance and their efficiency shall have been previously proven by simulation. Curative remedial actions are generally defined in operational planning in compliance with real-time operational constraints. Preventive remedial actions on the other hand are decided and implemented in advance. In those cases, curative remedial actions are not efficient or do not exist. Preventive measures have to be taken in order to restore margins on the risk level. Obviously, combinations of preventive and curative remedial actions are possible, each of them having different consequences on the risk management. It is up to the operator to ensure full efficiency of preventive or curative remedial actions. But it is not mandatory to cope with the failure of the remedial actions. The N-1 principle guarantees that the loss of any set of elements of the network is compatible with the operational criteria of the system, taking into account available remedial actions.}

II - CONNECTION

Rationale: The connectivity guidelines in line with Articles 8, 9 and 10 of the SAARC framework agreement for energy cooperation (electricity) detail the connection of generator, deal with network connectivity and protection issues in detail and elaborate on the communication framework and exchange of data among the countries. The technical requirements covered in the connectivity code shall include, but not be limited to, frequency and voltage requirements, short circuit current requirements, reactive power requirements, responsibility and ownership, protection and control and metering requirements.

CC 1. INTRODUCTION

CC 1.1 The aim of the connection guidelines is to have effective connectivity of transmission system of member countries and also the generation plants with transmission in the vicinity of cross-border interconnection so as to ensure reliability and safety of the system elements and to facilitate secure grid operation by equitable treatment of all existing and new users. In order to comprehensively meet the requirements for grid connectivity, the connection guidelines shall apply to all system elements having impact on the cross-border power flow but limited to two levels beneath the point of interconnection called observability area.

CC 1.2 The connection guidelines, as a framework covering all relevant cross-border aspects of generation and demand connections is intended to ensure equitable treatment of all users by maintaining a consistent set of requirements for generator owners, transmission operators and distribution network operators, who intend to connect with cross-border links. Any generator or distribution network operator who is outside the boundary limit of two level beneath the point of interconnection, for him the respective country's connection code shall apply.

CC 2. OBJECTIVE

CC 2.1 The connection guidelines are aimed at setting out clear and objective requirements for entities to interconnect with cross-border links. Respective authorities at the interconnection point shall ensure:

a. Safe operation, integrity and reliability of the grid
b. Basic rules for connectivity are complied with in order to treat all users in a non-discriminatory manner.
c. Any new or modified connections, when established, shall neither suffer unacceptable effects due to its connectivity to the Inter-Transmission utility nor impose unacceptable effects on the system of any other connected user.
d. Any person seeking a new connection to the grid is required to be aware, in advance, of the procedure for connectivity to the Inter-Transmission utility and also the standards and conditions his system has to meet for being integrated into the grid.

CC 3. PROCEDURE FOR CONNECTION

CC 3.1 Transmission company, new power generating modules/new demand facilities and new distribution network connections intending to seek cross-border interconnection shall submit an application on standard format to respective authority mentioned in the grid code or any other relevant regulations.

CC 3.2 The procedure for new connection relevant to cross-border shall consist of an installation document. Based on an installation document obtained from the relevant system operator or the designated agency, the owner of the site shall fill in the required information and submit it to the relevant system operator or the designated agency.

CC 3.3 The content of the installation document shall be defined by the relevant system operator or the designated agency and shall seek at least the following information:

a. Location at which the connection is made;
b. Date of the connection;
c. Maximum capacity of the installation in MW;
d. Type of primary energy source;
e. Type of generating unit
f. Detailed technical data of the connection components with relevance to the network connection, that is defined by the connection point;
g. Studies demonstrating expected steady-state and dynamic performance;
h. The contact details of the owner and the installer and their signatures;
i. Manufacturer equipment certificates used in the site installation.

CC 3.4 The joint planning committee of the respective national transmission utilities shall provide clearance for new or modified arrangement of connection with the cross-border links.

CC 4. CONNECTION AGREEMENT

CC 4.1 The connection agreement shall be mandatory between the applicant and the national transmission utility of the country in which the applicant is situated and also between the national transmission utilities of the member countries where cross-border link is situated.

CC 5. IMPORTANT TECHNICAL REQUIREMENTS FOR CONNECTIVITY TO THE GRID

CC 5.1 The connection guidelines shall identify standard minimum requirements that shall be complied with the respective countries connection code(s) and shall define the requirements in relation to the relevant system parameters in order to contribute to secure system operation of grid users including:

a. Reactive power requirements
b. Data and communication facilities
c. Event recording instruments including real-time data gathering with time stamping
d. Cyber security
e. Schedule of cross border assets of member country grid

CC 5.2 At the inter-connection point, there are other additional parameters also to be considered,

a. Frequency and voltage parameters
b. Short-circuit fault levels
c. Metering system
d. Protection devices
e. Simulation models

CC 5.3 Reactive power requirements

a. Respective country power authority need to ensure that reactive power requirements is kept at bare minimum (within lead/lag 0.97 power factor and operated within the grid code voltage level) with adjacent synchronously connected member's power system so that voltage profile is within the stipulated limits. Reactive power compensation shall be provided by the user connected at the synchronous area where needed, to take care of reactive power needs of transmission system and the loads.

b. The relevant country's power authority shall regularly monitor the status in this regard. Generators who intend to sell power through the cross-border links shall comply with their respective country regulation if it is connected beyond the observability area. If the cross-border links is through synchronous interconnection (AC link), then the reactive power flow on the links shall be limited to 0.97 lead or lag at the point of interconnection on either side of the link. In case of HVDC link or asynchronous link, the voltage is to be maintained within the limit by the respective transmission agencies to prevent mal-operation of the HVDC links.

CC 5.4 Data and Communication Facilities

a. Reliable and efficient speech and data communication systems, with adequate redundancy of communication links, shall be provided to facilitate necessary communication and data exchange, and supervision/control of the cross-border interconnection by the respective system operators in each of the country, under normal and abnormal conditions with defined time stamping in accordance and agreement of all affected parties to ensure the operational security of the system. Systems shall be provided to telemeter power system parameter such as power flow, voltage and status of switches/transformer taps etc., in line with control centre interface requirements and other guidelines made available by respective system operators of each country. The associated communication system to facilitate data flow up to appropriate data collection point and onward to the respective system operator's control centre, shall also be established by the respective countries in their area of jurisdiction.

b. A hotline, with a backup needs to be established to facilitate voice communication between the system operators of the two countries. A voice recording system, with facility of archival, retrieval and playback would also be necessary on the hotlines so as to record all conversations on the hotline.

c. Data transfer between power station and system operator for observable area:

   i Generation schedules of the power station (in advance, e.g. day ahead and changes of the schedules immediately)

   ii Position signals of switchgear of the generator connection to the extent necessary for system operation

   iii Tap-changer position of the transformer if necessary for system operation

   iv Actual values of active and reactive power (net values), frequency and voltage at sampling time of 4 sec or as appropriate based on the SCADA connectivity

   v Protection commands (if applicable)

   vi Water level (hydro units) if necessary for system operation

   vii Notification on tripping onto auxiliary supply

   viii Notification on activation of speed control

   ix Available secondary control capacity (if applicable)

   x Information on restrictions on active and reactive power supply capability etc.

d. Data transfer between system operators to power station:

   i. In case of a generating station in the observable area

      - (de-)activation of primary/secondary control
      - Regulator signals for secondary control
      - If applicable, signals for tertiary regulation
      - Requested reactive power output or voltage (HV-side)

ii. Position signals of switchgear and measured values in the sub-station to the extent it is individually agreed

iii. Alert signals indicating emergency states etc.

e. It is recommended that all relevant information shall be exchanged between the cross-border interconnected countries through communication data channels, preferably on a common platform, in accordance with the grid code.

CC 5.5 **System recording instruments:** Recording instruments such as data acquisition system/ disturbance recorder/event logging facilities/Phasor monitoring units/fault locator (including time synchronisation equipment) shall be provided and shall always be kept in working condition at the synchronous area for recording of dynamic performance of the system. All users shall provide all the requisite recording instruments and shall always keep them in working condition.

CC 5.6 **Responsibilities for safety:** The concerned transmission asset owners shall ensure that all safety requirements for equipment and personnel as specified in the relevant technical standards of the concerned member country are fully complied with at all times.

CC 5.7 **Cyber security:** All member countries shall have in place, a cyber-security framework to identify the critical cyber assets and protect them so as to support reliable operation of the grid.

CC 5.8 **Schedule of maintenance of assets:** Maintenance activities shall be carried out by relevant owner/operator of the member country system. The concerned national transmission utilities shall mutually decide the maintenance procedure and time and coordinate the maintenance activity to minimise outage time at the initial stage. In long term the independent authority or coordination forum can be identified to monitor and permit the outage. The designated transmission agencies are only authorised to carry out the maintenance work.

CC 6. ADDITIONAL CONNECTION GUIDELINES

CC 6.1 **Frequency:** Frequency is a system-wide matter and frequency management and maintaining frequency within required ranges are thus cross-border issues.

a. User shall be capable of staying connected to the network and operating within the frequency ranges and time periods, wider frequency ranges or longer minimum times for operation can be agreed between the relevant network operator in coordination with the concerned system operator and the users.

b. User shall be capable of automatic disconnection at specified frequencies, if required by the relevant operator. Terms and settings for automatic disconnection shall be agreed between the relevant operator and the user.

c. Recommended frequency band of operation of synchronised interconnection shall be within 49.9 Hz to 50.05 Hz but all the connecting equipment shall withstand the frequency profile as in Table 2.1.

Table 2.1: Frequency limits for equipment

Frequency	Time period for operation
47.5 Hz – 48.5 Hz	90 minutes
48.5 Hz – 49.0 Hz	To be defined by each system operator, but not less than the period for 90 minutes
49.0 Hz – 51.0 Hz	Unlimited
51.0 Hz – 51.5 Hz	30 minutes

{The frequency profile is adopted from European Grid Code. It may be required that all equipment shall comply with these frequency limits since having a uniform frequency profile among all interconnected countries ensures security and stability of all interconnected equipment.}

CC 6.2 Voltage

a. Transmission connected user shall ensure that their connection to the network does not result in a level of distortion or fluctuation of the supply voltage on the network, at the connection point, exceeding that allocated to them, under the conditions and within the legal framework approved by the relevant concerned authority in accordance with their grid code.
b. In case of a deviation of the network voltage at the connection point from its nominal value, the user shall ensure that its equipment at the connection point site is capable of withstanding the voltage range at the connection point. The establishment of the reference nominal voltage shall be subject to coordination between the adjacent system operators in synchronous area.
c. If there is any deviations in the prescribed voltage limits, the user shall undertake automatic disconnection if the equipment life is threatened subject to prior approval from the respective system operator. The terms and settings for automatic disconnection shall be agreed between the relevant system operator and the user.
d. At the point of interconnection, acceptable range of operating voltages shall be ±5% for 400 kV and above transmission voltage levels but all the connected equipment shall withstand the voltage variation of ±10%.

{As all the countries except Pakistan have operating voltage range of ±5%, the same can be adopted for cross-border energy transfer limits. However, a margin of 10% withstanding capacity is set considering safety of equipment.}

CC 6.3 **Short-Circuit Fault Levels**

a. Based on the rated short-circuit withstand capability of its equipment, the relevant system operator shall define the maximum short-circuit current at the connection point that the equipment shall be capable of withstanding.
b. The relevant system operator shall deliver to the user an estimate of the minimum and maximum short-circuit currents at the connection point as an equivalent of the network.
c. As soon as possible (less than a week), the relevant system operator shall inform the user for an unplanned/planned event of the changes above a threshold in the maximum short-circuit current that it shall be able to withstand from its network and vice versa.
d. The coordination forum or the planning committee (as per planning guidelines) shall model the entire transmission system and provide short circuit level of the interconnecting sub-station of cross-border link for various possible scenarios and the same shall be communicated to the respective designated transmission agencies.

CC 6.4 **Protection and Control**

a. The installation of necessary protection and backup protection equipment within its transmission system shall be mandated in order to efficiently and effectively protect transmission system elements and to coordinate with the protection of the equipment of significant grid users, from effects of faults in the transmission system.
b. All necessary protection and backup protection equipment shall be installed within the system in order to automatically prevent disturbance propagation which can endanger the operational security of the interconnected transmission system.

CC 6.5 Maintenance and Testing

a. Each transmission owner and any distribution provider that owns a transmission protection system and each generator owner that owns a generation or generator interconnection facility protection system shall have protection systems in consultation with national transmission company or the co-ordinated forum. The program shall include:

i Maintenance and testing intervals and their basis.

ii Summary of maintenance and testing procedures.

CC 6.6 Disturbance Recording

a. Each transmission owner and generator owner is required to install Disturbance Monitoring Equipment (DMEs) within the observability area that meets the following requirements:

i Internal clocks in DME devices shall be synchronised to within 2 milliseconds or less of common time scale like Indian Standard Time (IST) scale.

ii Recorded data from each disturbance shall be retrievable up to ten calendar days.

CC 6.7 The transmission owner and generator owner shall each maintain and report on request, the following data on the DMEs installed to meet that region's installation requirements:

a. Type of DME (sequence of event recorder, fault recorder, or dynamic disturbance recorder)
b. Make and model of equipment
c. Installation location
d. Operational status
e. Date last tested
f. Monitored elements, such as transmission circuit, bus section, etc.,
g. Monitored devices, such as circuit breaker, disconnect status, alarms, etc.,
h. Monitored electrical quantities, such as voltage, current, etc.,

CC 6.8 The transmission owner and generator owner shall archive all data recorded by DMEs for identified events for at least three years.

CC 6.9 Each transmission owner and generator owner having DMEs shall have maintenance and testing program for those DMEs that includes:

a. Maintenance and testing intervals and their basis.
b. Summary of maintenance and testing procedures.

CC 7. METERING REQUIREMENTS

CC 7.1 With regard to cross-border context, few of the requirements for metering equipment shall be made mandatory in the agreement:

a. For billing purposes, Watt-hour meters are recognised as the official source of meter information.
b. Metering devices shall be capable of collecting and storing information for intervals required by the service provided and as mutually agreed upon by the parties involved.
c. Any generation unit participating in cross border is required to have independent metering devices that are capable of recording generation net MWh output. When metering limitations require variance from this standard, the metering system shall be mutually agreed upon by the parties involved.

CC 7.2 Bi-directional meters shall be installed at the connection point between the transmission connected grid of the participating countries, between the transmission grid and the generator and between the transmission connected grid and the distributor to measure the following:

a. Active energy for export and import
b. Reactive energy for export and import

CC 7.3 The metering shall record the following:

a. Bus voltage
b. Frequency
c. MW
d. MWh
e. MVAr
f. Current
g. Any other facilities as agreed in the connection agreement

CC 8. METERING STANDARDS

CC 8.1 For cross-border activities, it is recommended that the minimum standard of accuracy of meters shall comply with the latest IEC standards. The IEC standards are mentioned below for each equipment meter.

CC 8.2 Voltage Transformer

a. The minimum standard of accuracy of the voltage transformer shall confirm to the latest relevant IEC Standard and be as follows:
   i For cross-border power transfer at the interconnecting sub-stations, the accuracy shall be 0.2%
   ii For generators, including IPPs, with total installed capacity exceeding 5 MW, the accuracy shall be 0.2%;
   iii For distributors and HV consumers with power transfer greater than 5 MW, the accuracy shall be 0.2%;

b. The secondary burden of voltage transformer shall be maintained between 25% and 100% of rated values.

{This criteria is specified in Nepal Grid Code in accordance with the governing IEC standards}

c. The check meter shall be supplied from a secondary core separate from the one feeding supply to the main meter.

CC 8.3 Current Transformer

a. The minimum standard of accuracy of the current transformer shall conform to the latest relevant IEC standard and be as follows:
   i For cross-border power transfer at the interconnecting sub-stations, the accuracy shall be 0.2%;
   ii For generators, including IPPs, with total installed capacity exceeding 5 MW, the accuracy shall be 0.2%;
   iii For distributors and HV consumers with power transfer greater than 5 MW, the accuracy shall be 0.2%;

b. The secondary burden of the current transformer shall be maintained between 25% and 100% of rated values.

{This criteria is specified in Nepal Grid Code in accordance with the governing IEC standards}

c. The check meter shall be supplied from a secondary core separate from the one feeding supply to the main meter.

CC 8.4 Main and Check Meters

a. Meters shall be of three-element, 3-phase, 4-wire, Wye-connection, bi-directional digital type having facility for local and remote communication. The transmission medium may be of any type but shall be free of data loss during transmission.

b. The minimum standard of accuracy of meters shall comply with the latest IEC standards and be as follows:

   i For cross-border power transfer at the interconnecting sub-stations, the accuracy shall be 0.2%;

   ii For generators, including IPPs, with total installed capacity exceeding 5 MW, the accuracy shall be 0.2%;

   iii For distributors and HV consumers with power transfer greater than 5 MW, the accuracy shall be 0.2%;

{Draft Nepal Grid Code provides accuracy of 0.1% but in other SA countries it is 0.2%. Based on the availability and requirement, 0.1% accuracy can be chosen at a later date.}

c. The burden of meters shall be maintained between 25% and 100% of rated values.

d. A cumulative record of the parameters measured shall be available on the meter. The loss of auxiliary supply to the meter shall not erase these records. Separate record shall be provided for each measured quantity and direction. The meter shall have super capacitor for memory storage in addition to internal battery.

e. All metering systems shall be capable of electronic data transfer through dedicated telephones or the Grid Owner's communication channels.

CC 8.5 Accuracy Class of Meters

a. The minimum metering accuracy for each measuring device is defined by prevailing IEC standards. In case where standards differ, the most restrictive criteria take precedence.

b. The accuracy class of all billing devices shall be accurate within ±0.2% of full scale.

CC 9. OWNERSHIP AND LOCATION OF METERS

CC 9.1 It is recommended that Energy Accounting and Audit functions shall be carried out by coordinating forum or the planning committee (as per planning guidelines) or separate agency as required. All main energy meters for interconnection shall be owned by Government designated Transmission licensee in whose premises the meter is located and the check meters shall be owned by the other member country licensee. For any future addition/replacement of the meters, the concerned agencies shall provide and install the same.

CC 9.2 Table 2.2 indicates the position of the interconnected energy accounting and billing meter across member countries.

Table 2.2: Location of meters

Sl. No	Stages	Main meter	Check meter	Standby meter
1.	Generating station not directly connected to the Transmission system	On all outgoing feeders	On all outgoing feeders	H.V side of the generator transformers H.V side of all station auxiliary transformers
2.	Transmission connected	At both ends of the interconnected transmission line. Meters at both ends shall be considered as main meters for respective licensees.	-	There shall be no separate standby meter. Meter installed at other end of the line in case of two different licensees shall work as standby meter.

CC 10. INSTALLATION, OPERATION, TESTING AND MAINTENANCE OF METERS

CC 10.1 In accordance with the connection agreement among all the member countries, participated generating company or licensee, as the case may be, shall examine, test and regulate all meters before installation and only meters of relevant accuracy class shall be installed and shall submit to the concerned transmission licensee for approval of engineering design for energy accounting and billing meter, proposed location of metering equipment and ancillaries complete with wiring, installation drawings and bill of materials. The proposed metering location shall be adjacent to tele-metering, communication and data logging equipment.

CC 10.2 The main energy meters shall be used for billing provided they have been in continuous service throughout the month. If any one or more main meters have been removed from service for repairs or have not registered energy supply for any duration of time, the reading of the corresponding check meter or meters shall be taken as basis for billing.

CC 10.3 When carrying out maintenance, testing or auditing, prior notice shall be given to users in accordance with their member country rules and regulations. User's or his authorised representative's signature shall be obtained to certify the meter readings before and after testing. The concerned Transmission licensee shall maintain all metering systems according to a planned program and shall keep all test results, maintenance records and sealing records in respect of all items tested/inspected. On request, relevant information shall be made available to the user.

CC 10.4 The operation, testing and maintenance of all types of meters shall be carried out by the designated transmission agency of the country.

CC 10.5 Access to Meter

a. To enable the execution of its obligation, the relevant authorities shall, after giving prior notice and reason, have access to the Licensees' and Users' facilities and metering equipment.
b. Each equipment owner/user of the premises where the meter is installed shall provide/ authorise access to at all times, and where metering equipment has been installed in a restricted area, the two parties (member countries) shall agree on a procedure for the licensee to gain access for installation, testing, commissioning, reading and recording and maintenance of meters.
c. The designated transmission agency shall give permission for the relevant authorities to installing, testing, commissioning, reading and recording and maintenance of meters.

CC 10.6 Sealing of Meters

a. After completing the installation, the representatives of concerned entity, designated transmission licensee or generating company as observers, shall lock and seal the meter and tamper proof, with no possibility of any adjustments at site, except for a restricted clock operation.
b. A tracking and recording software for all new seals shall be provided by the manufacturer of the meter so as to track total movement of seals starting from manufacturing, procurement, storage, record keeping, installation, and series of inspections, removal and disposal.
c. Seal shall be unique for each member country and name or logo of the member country shall be clearly visible on the seals.
d. Only the patented seals (seal from the manufacturer who has official right to manufacture the seal) shall be used.
e. Polycarbonate or acrylic seals or plastic seals or holographic seals or any other superior seal shall be used.
f. Lead seals shall not be used in the new meters. Old lead seals if any shall be replaced by new seals in a phased manner and the time frame of the same shall be submitted by the licensee to the appropriate commission for approval.

CC 10.7 Removal of seals from meters: Seal of the energy meter shall be removed only by the participating licensee who owns the meter, at the cross border. Whenever seal of the interface meter have to be removed for any reason, advance notice shall be given to other member country for witnessing the removal of seals and resealing of the interface meter. The breaking and re-sealing of the meters shall be recorded by the party, who carried out the work, in the meter register, mentioning the date of removal and resealing, serial numbers of the broken and new seals and the reason for removal of seals. No concerned user shall tamper with, break or remove the seal under any circumstances. Any tampering, breaking or removing the seal from the meter shall be dealt with as per relevant provisions of the Act.

CC 10.8 Safety of meter: The concerned user shall be responsible to take precautions for the safety of the energy meter installed in his premises belonging to the generating company or the licensee. Licensee shall be responsible for the safety of the energy meter located outside the premises of the consumer.

CC 10.9 Meter Reading and Recording

a. Meter reading and recording functions shall be carried out by coordinating forum or the planning committee (as per planning guidelines) or separate agency as required.
b. All countries shall have the provision to transfer the meter readings which are connected at transmission connection point to respective authorities through data communication channels.
c. The backup meters shall be provided in case of primary meter failure, the level of accuracy for the backup meter shall be as per the agreement.
d. Any generation unit participating in the energy market is required to have independent metering devices that are capable of recording generation net MWh output.

CC 11. METER FAILURE OR DISCREPANCIES

CC 11.1 Whenever difference between the readings of the main meter and the check meter for any month is more than 0.5%, the following steps shall be taken:

a. Checking of CT and VT connections;

b. Testing of accuracy of interface meter at site with reference to standard meter of accuracy class higher than the meter under test

c. If the difference exists even after such checking or testing, then the defective meter shall be replaced with a correct meter.

CC 11.2 In case of conspicuous failures like burning of meter and erratic display of metered parameters and when the error found in testing of meter is beyond the permissible limit of error provided in the relevant standard, the meter shall be immediately replaced with a correct meter.

CC 11.3 In case where both the main meter and check meter fail, at least one of the meters shall be immediately replaced by a correct meter.

CC 11.4 Billing for the Failure Period

a. The billing for the failure period of the meter shall be done as per the procedure laid down by the appropriate commission.

b. Readings recorded by main, check and standby meters for every time slot shall be analysed, cross checked and validated by the appropriate authority. The discrepancies, if any, noticed in the readings shall be informed by the appropriate authority in writing to the energy accounting agency for proper accounting.

CC 11.5 **Anti-tampering features:** The meters shall be provided with such anti-tampering features as per the Standards on Installation and Operation of meters given in the schedule.

CC 11.6 **Quality assurance of meters:** The licensee shall ensure that all type, routine and acceptance tests are carried out by the manufacturer in compliance with the requirement of the relevant IEC as the case may be.

CC 12. ADDITIONAL REQUIREMENTS FOR METERS

CC 12.1 Calibration and Periodical Testing of Meters

a. All new or replacement metering equipment shall be tested and calibrated annually as per prevailing IEC standards or the guidelines in the member country, jointly by the concerned agencies. The cost of testing/calibration of the energy meters shall be borne by the respective owner of the metering equipment.

b. Meters shall be tested and recalibrated at least once every two years as per the agreement among member countries.

c. The designated transmission agency shall take the responsibility of testing, calibrating and shall maintain the equipment to work within the prescribed limits. This shall be authorised by the coordinating forum or the planning committee (as per planning guidelines) or separate agency as required.

CC 12.2 Additional Meters

a. In addition, any meter which may be placed for recording the electricity consumed by the consumer at the interconnection point, the designated licensee may connect additional meters, maximum demand indicator or other apparatus as he may deem fit for the purposes of ascertaining or regulating either the quantity of electricity supplied to the consumer, or the number of hours during which the supply is given, or the rate per unit of time at which energy is supplied to the consumer, or any other quantity or time connected with the supply to consumer.

b. Provided further that, where the charges for the supply of energy depend wholly or partly upon the reading or indication of any such meter, indicator or apparatus as aforesaid, the licensee shall, in the absence of an agreement to the contrary, keep the meter, indicator or apparatus correct.

CC 13. PROTECTION REQUIREMENTS

Requirements for Generator

CC 13.1 The relevant network operator shall define the schemes and settings necessary to protect the network taking into account the characteristics of the power generating modules. Protection schemes relevant for the power generating module and the network and settings relevant for the power generating module shall be coordinated and agreed between the relevant network operator and the power generating facility owners. The protection schemes and settings for internal electrical faults shall be designed not to jeopardise the performance of a power generating module.

CC 13.2 Electrical protection of the power generating module shall take precedence over operational controls taking into account system security, health and safety of staff and the public and mitigation of the damage to the power generating module.

CC 13.3 Protection schemes shall protect against the following aspects:

a. External and internal short circuit;
b. Asymmetric load (negative phase sequence);
c. Stator and rotor overload;
d. Over-/under-excitation;
e. Over-/under-voltage at the connection point;
f. Over-/under-voltage at the alternator terminals;
g. Inter-area oscillations;
h. Inrush current;
i. Asynchronous operation (pole slip);
j. Protection against inadmissible shaft torsions (for example, sub-synchronous resonance);
k. Power generating module line protection;
l. Unit transformer protection;
m. Backup schemes against protection and switchgear malfunction;
n. Over fluxing;
o. Inverse power;
p. Rate of change of frequency; and
q. Neutral voltage displacement

CC 13.4 Any changes to the protection schemes relevant for the power generating module and the network and to the setting relevant for the power generating module shall be agreed between the network operator and the power generating facility owner and be concluded prior to the introduction of changes.

Requirement for Demand Facilities

CC 13.5 The relevant operator shall define the settings necessary to protect the network while respecting the characteristics of the transmission connected demand facility or transmission connected distribution network. Relevant protection schemes and settings shall be agreed between the relevant operator and the demand facility owner.

CC 13.6 Electrical protection of the transmission connected demand facility or transmission connected distribution network shall take precedence over operational controls while respecting system security, health and safety of staff and the public as well as mitigation of the damage to the demand facility.

CC 13.7 Protection scheme devices may cover the following aspects:

a. External and internal short circuit;
b. Over- and under-voltage at the connection point;
c. Over- and under-frequency;
d. Demand circuit protection;
e. Unit transformer protection; and
f. Backup schemes against protection and switchgear malfunction.

CC 13.8 Simulation Model

a. All users shall fulfil the following requirements related with regard to the simulation models or equivalent information:
   i Steady and dynamic states, including 50 Hz component;
   ii Electromagnetic transient simulations at the connection point;
   iii Structure and block diagrams.

b. Simulation studies shall be carried out by the coordinating agency or planning committee (as per planning guidelines) and the relevant details shall be furnished by the designated transmission agencies of member countries that are connected through interconnection point.

Requirement for Transmission Owner

CC 13.9 Each transmission owner shall provide fault recording capability for the following elements at facilities where fault recording equipment is required to be installed:

a. All transmission lines
b. Autotransformers or phase-shifters connected to busses
c. Shunt capacitors, shunt reactors
d. Individual generator line interconnections
e. Dynamic VAR devices
f. HVDC terminals

CC 13.10 Each transmission owner shall have fault recording capability that determines the current zero time for loss of system transmission elements.

CC 13.11 Each generator owner shall provide fault recording capability for generating plants connected through a Generator Step Up (GSU) transformer to a system element unless fault recording capability is already provided by the transmission owner.

CC 13.12 Each transmission owner and generator owner shall record for faults, sufficient electrical quantities for each monitored element to determine the following:

a. Three phase-to-neutral voltages. (Common bus-side voltages may be used for lines.)
b. Three phase currents and neutral currents.
c. Polarising currents and voltages, if used.
d. Frequency.
e. Real and reactive power.

CC 13.13 Each transmission owner and generator owner shall provide fault recording with the following capabilities:

a. Each fault recorder's record duration shall be a minimum of one (1) second.

b. Each fault recorder shall have a minimum recording rate of 16 samples per cycle.
c. Document additional triggers and deviations from the settings when local conditions dictate.

{The capability of fault recorder has been adopted from NERC Grid Code with the intent to ensure that adequate disturbance data is available to facilitate system event analyses.}

CC 13.14 Each member country's transmission company shall establish its area's requirements for Dynamic Disturbance Recording (DDR) capability that records dynamic disturbance information with consideration of the following facilities/locations:

a. Major load centres
b. Major generation clusters
c. Major voltage sensitive areas
d. Major transmission interfaces
e. Major transmission junctions
f. Elements associated with operating limits
g. Major EHV interconnections between operating areas

CC 13.15 They shall specify that DDRs installed after the approval of this standard function as continuous recorders.

CC 13.16 They shall establish the requirements such that the following quantities are monitored or derived where DDRs are installed:

a. Line currents for most lines such that normal line maintenance activities do not interfere with DDR functionality.
b. Bus voltages such that normal bus maintenance activities do not interfere with DDR functionality.
c. As a minimum, one phase current per monitored element and two phase-to-neutral voltages of different elements with one of the monitored voltages shall be of the same phase as the monitored current.
d. Frequency.
e. Real and reactive power.

CC 13.17 They shall specify its DDR requirements including the DDR setting triggers to the transmission owners and generator owners. Each transmission owner and generator owner who receives a request from the relevant national transmission company to install a DDR shall acquire and install the DDR and shall mutually agree on an implementation schedule.

CC 13.18 Each transmission owner and generator owner shall establish maintenance and testing program for standalone DME (equipment whose only purpose is disturbance monitoring) that includes:

a. Maintenance and testing intervals and their basis.
b. Summary of maintenance and testing procedures.
c. Monthly verification of communication channels used for accessing records remotely.
d. Monthly verification of time synchronisation.
e. Monthly verification of active analog quantities.
f. Verification of DDR and DFR settings in the software every six (6) years.
g. A requirement to return failed units to service. If a DME device is to be kept out of service for an extended period, the owner shall keep a record of the efforts aimed at restoring the DME back to service.

III - OPERATION

Rationale: In order to enable secure and reliable operation of the interconnected grid, the operational guidelines is intended to cover all necessary aspects relevant to outage planning, operational security analysis, frequency control and handling of reserves and the emergency operational procedures. In addition to above, the operation code also covers operational security aspects pertaining to power system states, frequency control management, voltage and reactive power management, short circuit management, power flow management, contingency analysis and stability management.

OC 1. INTRODUCTION

OC 1.1 The Operating Guideline specifies the philosophy and procedures to be applied in the interconnected operation of cross-border Power grids.

OC 2. OPERATING PHILOSOPHY

OC 2.1 The objective is to facilitate trading in electricity between the participating SAARC Member Countries through reliable, secure and stable operation of the cross-border links connecting the participating countries. The mode of interconnection between the two countries would be decided through mutual agreement between the SAARC Member Countries. Asynchronous mode of interconnection offers the advantage of controlled power flow across the cross-border link and it also prevents disturbances in one country affecting the other. The participating SAARC Member Countries agree to abide by this guideline for reliable, secure and stable operation of the cross-border interconnections.

OC 2.2 The operating procedures followed by the respective countries shall be retained to the extent that it would not interfere with the cross-border transaction. If any provision impacts cross-border trade then the regulations given in this guidelines would be applicable so as to ensure compliance with the requirement of the cross-border operational procedures.

OC 2.3 The guideline is framed considering the following objectives to ensure system security:

a. To ensure secure system operation and scheduled power flow of the cross-border link by the system operator of each of the member country following applicable rules.
b. To establish design and documentation requirements for automatic under-frequency load shedding programs in order to arrest declining frequency, assist recovery of frequency following under-frequency events and provide last resort system preservation measures.
c. Provide system preservation measures in an attempt to prevent system voltage collapse or voltage instability by implementing an under-voltage load shedding program.
d. To ensure that system protection is coordinated among operating entities.
e. To ensure that all special protection systems are properly designed, meet their performance requirements, and are coordinated with other protection systems.
f. To ensure that maintenance and testing programs are developed and mal-operations are analyzed and corrected.
g. To ensure that disturbance monitoring equipment is installed and that disturbance data is reported in accordance with regional requirements to facilitate analyses of events.
h. To ensure that adequate disturbance data is available to facilitate system event analyses.

OC 2.4 Equipment protection is used to protect transmission system assets from faults. System protection schemes are used to detect abnormal system conditions and take predetermined corrective actions to preserve system integrity and provide acceptable system performance, in a coordinated way. System protection schemes are nowadays widely used by operators in most synchronous areas and hence included in operation guideline also.

OC 3. SYSTEM SECURITY ASPECTS

OC 3.1 No important element of the interconnected grid shall be deliberately opened or removed from service at any time, except

a. Under an emergency, and conditions in which such isolation would prevent a total grid collapse and/or would enable early restoration of power supply
b. For safety of human life
c. When serious damage to costly equipment is imminent then isolate the equipment by suitable disconnection without endangering security of the system
d. Such isolation is to be specifically instructed after mutual agreement of the System Operators of the two countries through specific messages exchanged to this effect.

OC 3.2 The list of such important grid elements on which the above stipulations apply shall be prepared and published in advance. In case of opening/removal of any important element of the grid under an emergency situation, the same shall be communicated to all affected entities at the earliest possible time after the event.

OC 3.3 Any tripping, whether manual or automatic, of any of the identified important grid elements of interconnected grid shall be precisely intimated as soon as possible to all the affected regional heads. The reason (to the extent determined) and the likely time of restoration shall also be intimated. All reasonable attempts shall be made for the elements' restoration as soon as possible.

OC 3.4 If there is any prolonged outage of power system elements, which is causing or likely to cause danger to the grid or sub-optimal operation of the grid, then the same shall be regularly monitored by the respective regional heads. Such outages shall be reported to the other regional heads and restoration plans of such elements shall be undertaken within a specified time period.

{The regional heads defined for these guidelines include the head of designated transmission company or head of the system operator of specified country or head of the regional co-ordination forum or head of coordination forum}

OC 3.5 For each element in its transmission system, the operator shall define operational security limits. Based on these limits, the operator shall classify the current operating condition of its transmission system under one of the following five states in real time:

a. Normal state
b. Alert state
c. Emergency state
d. Black out state
e. Restoration

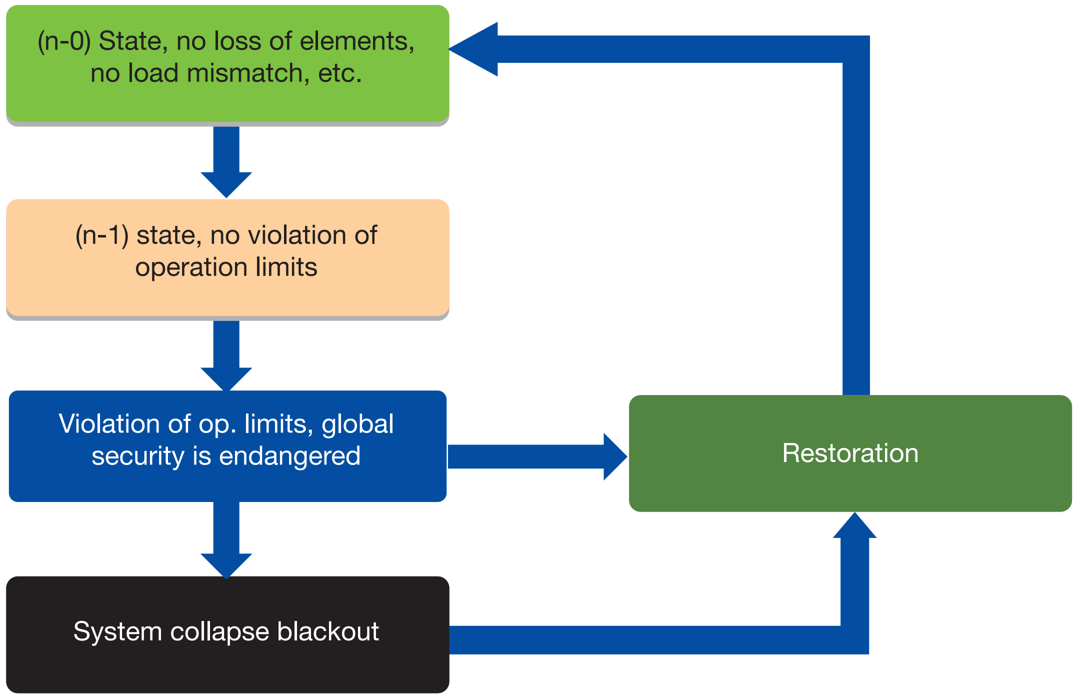


Figure 3.1: System Operating States

OC 3.6 The determination of the system operation state shall be done continuously by monitoring the parameters against pre-set criteria and performing contingency analysis in real time if required.

{To analyse the security of a power system during operation, it is beneficial to classify the operating conditions into five states: normal, alert, emergency, blackout (extreme emergency) and restoration.

In the normal state, all system variables are within the normal range and no equipment is being overloaded. The system operates in a secure manner and is able to withstand a contingency without violating any constraints.

If the security level falls below a certain limit of adequacy or if a possibility of disturbance increases due to any external factor, the system enters alert state. In this state, all system variables remain within acceptable limit and all constraints are still satisfied. However, the system has weakened to a level where an additional contingency may push the system to emergency state. If the disturbance is very severe, the system could directly fall into the blackout state. Preventive action is to be taken to restore system to normal state.

The system enters emergency state if a severe disturbance occurs and the system is in alert state. Here, the voltages at many buses are low and/or equipment loadings exceed short-term emergency ratings. The system still remains intact and can be restored to alert state by initiating emergency control actions.

If the above actions are not applied or are ineffective, the system results in cascading outages and possibly a shutdown of a major portion of the system i.e. blackout or brown outs. Control actions such as load shedding is undertaken to save as much of the system as possible from a widespread blackout.

The restoration state represents a condition in which control actions are being taken to reconnect all the facilities and to restore the system load. The system may transit from this state to alert or normal state, depending on the system conditions.}

OC 3.7 All generating units shall follow the grid code guidelines of their respective countries. However, it shall be mandated that all thermal and hydro generating units, that have the capability to impact the grid considerably, shall be equipped with tuned PSS for effective damping of oscillations. All units shall have their AVRs in operation. Provision of protection and relay settings shall be coordinated periodically.

OC 3.8 Adequate operating reserves (Spinning/Contingency/Stand-by) shall be made available for use during contingency conditions and large demand variation conditions in case of synchronous interconnection. The cross-border links shall facilitate in the primary reserve process. However, it is desirable that adequate control be established to restore the power flow to the scheduled level within a block period (15 minutes).

{The operational control actions are performed in following successive steps, each with different characteristics and qualities, and all depending on each other.

Primary Control

The objective of primary control is to maintain a balance between generation and demand within the synchronous area. This control action is used after a disturbance or incident to only stabilise the frequency at a stationary value, in the time-frame of seconds, and not to restore the frequency and the power exchanges back to its reference values. This control is triggered when the frequency deviation exceeds ±20 mHz.

Secondary Control

The objective of secondary control is to maintain a balance between generation and demand within each control area/block as well as the system frequency within the synchronous area in the time-frame of seconds up to typically 15 minutes after an incident. Secondary control makes use of a centralised and continuous automatic generation control and is based on secondary control reserves that are under automatic control.

After 30 seconds at the latest, the secondary controller shall initiate corrective control actions and shall correct the Area Control Error as quickly as possible, within 15 minutes at the latest.

Tertiary Control

Tertiary control uses tertiary reserve that is activated manually or scheduled to activate periodically by the operators in case of observed or expected sustained activation of secondary control. It is primarily used to free up the secondary reserves in a balanced system situation, but it is also activated as a supplement to secondary reserve after larger incidents to restore the system frequency and consequently free the system wide activated primary reserve.}

OC 3.9 Procedures shall be developed to recover from partial/total collapse of the grid and shall be periodically updated in accordance with the requirements given under Section OC 9. These procedures shall be followed by all the users to ensure consistent, reliable and quick restoration.

OC 3.10 Each regional head shall provide and maintain adequate and reliable communication facility internally and with other heads to ensure exchange of data/information necessary to maintain reliability and security of the grid. Wherever possible, redundancy and alternate path shall be maintained for communication along important routes.

OC 3.11 The system security limits shall be fixed as shown in Table 3.1.

Table 3.1: Recommended operating limits for cross-border interconnection

	Normal	Alert	Emergency
Voltage (400, 500 & 765 kV)	± 5%	± 5%	± 10%
Frequency – for synchronously interconnected system	Nominal: 50 Hz Steady state limits: +0.05 Hz to -0.1 Hz Instantaneous limits: ± 0.8 Hz	Exceeds steady state limits for up to 10 mins	Exceeds steady state limits for >10 mins up to 20 mins
Equipment loading	Within limits	Within limits	Exceeds limits of short term overload

{The alert state trigger for frequency exceeding steady state limits is followed in NERC Grid Code to ensure close frequency monitoring and to avoid possible system collapse.}

OC 3.12 Scope of contingencies shall be defined and automated simulations shall be implemented to the extent possible.

{Incorporation of contingency studies during operational planning time horizons will ensure increased preparedness of the system operator.}

OC 3.13 In the initial development process, it is recommended to plan for Special Protection System (SPS) to prevent cascading with the outage of cross-border links. The SPS can be planned with hard-wired control either to demand facility or generation facility to limit the unintended power flow leading to overloads or drop in frequency.

OC 3.14 The ancillary services required for maintaining and dispatching reserves with the help of governor/primary response, secondary response/tertiary reserves, contingency reserves and load shedding contract shall be defined.

OC 3.15 Due to the high potential of wind and solar generation in the South Asian countries, these generations shall be included in the operation and dispatch assessment studies. All efforts shall be made to evacuate the available solar and wind power and these generations shall be treated as a must-run station, unless instructed otherwise by respective operators on consideration of grid security.

OC 3.16 System protection functions shall be analysed relying on network calculations, considering correct and incorrect functioning. If unacceptable consequence is anticipated, functionality and redundancy of the system protection scheme have to be accordingly adjusted to fulfil operational security requirements. The functionality and system state status have to be monitored, communicated and coordinated between neighbouring operator and other parties affected by the system protection.

OC 3.17 The protection strategy and concepts shall be reviewed every five years and when necessary, protection functions shall be adapted to ensure the correct functioning of the protection and maintaining of operational security. After every protection operation even if the impact is outside of its own responsibility area, each operator shall assess whether the protection system in its area worked as planned and shall undertake corrective actions if necessary.

OC 3.18 Protection shall be operated with set-points that ensure reliable, fast and selective fault clearing, including backup protection for fault clearing in case of malfunction of the main protection system.

Criteria for Protection Set-Points

OC 3.19 Protective relay settings shall not limit transmission loadability nor interfere with system operators' ability to take remedial action to protect system reliability and, be set to reliably detect all fault conditions and protect the electrical network from these faults.

OC 3.20 Each transmission owner, generator owner, and distribution provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability.

OC 3.21 Each transmission owner, generator owner, and distribution provider that sets transmission line relays within the vicinity of observable area shall provide an updated list of the circuits associated with those relays to its regional entity at least once each calendar year, to allow the compilation of a list of all circuits that have protective relay settings that limit circuit capability.

OC 3.22 Any changes to the protection schemes, relevant for the demand facility and the network, as well as to the setting relevant for the demand facility, shall be agreed between the relevant operator and the transmission connected demand facility owner.

{At the connection point, respective agency shall be vested to prepare and review protection schemes according to the adopted standards in line with Article 10 of SAARC Framework Agreement for Energy Cooperation (Electricity) which states that member countries shall enable joint development of coordinated network protection systems incidental to the cross-border interconnection to ensure reliability and security of the grids of the Member Countries.}

OC 4. DEMAND ESTIMATION FOR OPERATIONAL PURPOSES

{The present guidelines are for information purpose only and if relevant the same can be adopted in the respective country's grid codes}

OC 4.1 The existing demand estimation procedure as per the grid code of the respective member country can continue for daily/weekly/monthly/yearly basis for current year for load generation balance planning.

OC 4.2 Each region shall carry out its own demand estimation from the historical data and weather forecast data from time to time. All necessary data and information shall be provided by relevant entities as required for demand estimate. The monthly estimated demand shall be shared with the operation planning authorities.

OC 4.3 Based on the demand estimation for operational purposes on a daily/weekly/monthly basis, mechanisms and facilities shall be created at the earliest to facilitate on-line estimation of cross-border power flow for each 15 minutes block.

OC 4.4 Each region shall take into account the wind energy forecasting to meet the active and reactive power requirement.

OC 5. CONGESTION MANAGEMENT

OC 5.1 This section is concerned with the provisions to be made by the member countries to effect a reduction of demand/generation in the event of insufficient generating capacity/demand, and inadequate transfers from external interconnections, or in the event of breakdown or congestion in cross-border transmission system or other operating problems (such as frequency, voltage levels beyond normal operating limit, or thermal overloads, etc.) or over drawing of power beyond the limits.

OC 5.2 Commercial principles for congestion management need to be developed in order to facilitate cross-border transactions. Transmission agencies shall be responsible to continuously monitor and adopt curative measures, as and when required.

OC 5.3 Till the establishment of such principles, congestion relieving mechanisms based on the market shall be taken up. For long-term commitments of cross-border power flow, re-dispatch and counter flow measures may be followed. For medium- and short-term commitments, load curtailment shall be the last resort, after all other available measures are exhausted.

OC 5.4 The respective member country utilities shall also formulate and implement state-of-the-art demand management schemes for automatic demand management like rotational load shedding, demand response (which may include lower tariff for interruptible loads) etc., to reduce drawing above the schedule in the cross-border links.

OC 5.5 The frequency thresholds of 49.5 Hz can be defined for automatic shedding of loads for the synchronous cross-border links. The loads should be classified in four groups, loads for scheduled power cuts/load shedding, loads for unscheduled load shedding, loads to be shed through under-frequency relays/df/dt relays and loads to be shed under any SPS. All manual load shedding shall be coordinated between operators and demand facilities. This load shedding shall be maintained by the respective country authorities without affecting the grid security.

OC 6. PERIODIC REPORTS

OC 6.1 A monthly report covering performance of the interconnected grid pertaining to cross-border transaction shall be prepared and made available to all entities.

OC 6.2 A weekly report covering performance of grid in previous week shall be prepared. Such weekly report shall be available on a common platform for at least previous 12 weeks.

OC 6.3 The weekly reports shall contain the following:

a. Frequency profile
b. Voltage profile of cross-border sub-stations
c. Major generation and transmission outages
d. Transmission constraints
e. Instances of persistent/significant non-compliance
f. Instances of congestion in transmission system
g. Instances of inordinate delays in restoration of critical transmission elements and generating units

OC 6.4 A daily report covering the performance of the cross-border transaction shall be prepared which shall also include the variable power generation (wind and solar) and injection in to grid.

OC 6.5 An elaborate quarterly report shall also be prepared which shall bring out the system constraints, reasons for not meeting the requirements, if any, of security standards and quality of service, along with details of various actions taken by different persons, and the persons responsible for causing the constraints.

OC 7. OPERATIONAL LIAISON

OC 7.1 This section sets out the requirements for the exchange of information in relation to operations and/or events on the total interconnected system which have had or will have an effect on the significant grid users.

OC 7.2 The data shall be categorised under the following classifications:

a. Structural data
b. Scheduled data
c. Forecasting data
d. Real-time data
e. Individual instructions by operators

OC 7.3 The common proposal for data exchange shall include sufficient information on who is responsible for exchange of what data, containing how much detail, at what frequency and in what format along with the need for time stamping. An overview of data exchange is tabulated in Table 3.2. The operator can choose the data required based on the specific task.

Table 3.2: Data exchange

Data to be exchanged between operators for cross-border links observable area	
General structural information	Sub-stations' regular topology and other relevant data by voltage level Transmission lines Transformers connecting the DSOs, demand facilities or power generating facilities Maximum and minimum active and reactive power of power generating modules Phase-shifting transformers High voltage DC lines Reactors, capacitors and static VAR compensators Operational security limits Type of regulation concerning tap changers Voltage regulation range Regarding HVDC lines and FACTS devices, the dynamic models of the device and its associated regulation suitable for large disturbances Topology of transmission system $\geq$ 400 kV Model or equivalent of transmission system <400 kV having significant impact on its transmission system Protection set-points of the lines included as external contingencies in neighbouring operator's contingency lists
Generator specific structural data for dynamic stability analysis	Electrical parameters of the alternator suitable for dynamic stability analysis, including total inertia Protection models Step up transformer description Minimum and maximum reactive power Prime movers and excitation system models suitable for large disturbances
Scheduled data	The forecasted aggregate sum by primary energy source of injection and withdrawal in every node of the transmission system for different timeframes
Real-time data between all other operators via an IT tool	Frequency Frequency restoration control error or an equivalent parameter Measured active power exchanges between LFC areas Aggregated generation in feed System state Set-value of the FR controller Power exchange via the virtual tie-lines

Data to be exchanged between operators for cross-border links observable area	
Real-time data only between operators within its observability area	Actual sub-station topology Active and reactive power in line bay, including transmission, distribution and lines connecting significant grid user Active and reactive power in transformer bay, including transmission, distribution and significant grid user connecting transformers Active and reactive power in power generating facility bay Regulating positions of transformers, including phase-shifting transformers Measured or estimated bus-bar voltage Reactive power in reactor and capacitor bay or from a static VAR compensator Restrictions on active and reactive power supply capabilities with respect to the observability area
Data to be provided to transmission operators by distribution operators of each transmission connected distribution system in the observable area	
Structural information (every 6 months)	Sub-stations by voltage Lines that connect the sub-stations Transformers from the sub-stations Significant grid users Reactors and capacitors connected to the sub-stations Total aggregated generating capacity, the related information concerning the frequency behaviour and best possible estimate of power generating modules, by primary energy source
Real-time data	Actual sub-station topology Active and reactive power in line bay Active and reactive power in transformer bay Active and reactive power injection in power generating facility bay Tap positions of transformers connecting to the transmission system Bus-bar voltages Reactive power in reactor and capacitor bay Best available data for aggregated generation in the DSO area Best available data for aggregated consumption in the DSO area
Data to be provided to operators by owners of each generation facility directly to the transmission network in the observable area	
Structural data	General data, including installed capacity and primary energy source Data for short-circuit calculation FCR, FRR and RR data for power generating facilities offering or providing this service Protection data Voltage and reactive power control capability Data and models necessary for performing dynamic simulation Power generating facility transformer data for generators Turbine and power generating facility data including time for cold and warm start for generators Data necessary for restoration of generators
Scheduled data	Day-ahead and intra-day basis of its active power output and active power reserves amount and availability and its scheduled unavailability or active power capability restriction Any forecasted restriction in the Reactive Power control capability

Data to be exchanged between operators for cross-border links observable area	
Real time data	Position of the circuit breakers at the connection point or another point of interaction agreed with the operator Active and reactive power at the connection point or another point of interaction agreed with the operator In the case of power generating facility with consumption other than auxiliary consumption, net active and reactive power
Data to be provided to operator by owners of interconnectors and other lines connected directly to the transmission network	
Structural data	HVDC owners to provide: • Name plate data of the installation • Transformers data • Data on filters and filter banks • Reactive compensation data • Active power control capability • Reactive power and voltage control capability • Active or reactive operational mode prioritisation if it exists • Frequency response capability • Dynamic models for dynamic simulation • Protection data • Fault ride through capability AC line and interconnector owners to provide: • Name plate data of the installation • Electrical parameters • Associated protections
Scheduled data	HVDC owners to provide: • On a day-ahead and intra-day basis, its active power schedule and active power reserves and availability • Without delay its scheduled unavailability or active power restriction • Any forecasted restriction in the reactive power or voltage control capability AC line and interconnector owners to provide the scheduled unavailability or active power restriction data
Real-time data	Position of the circuit breakers Operational status Active and reactive power
Data provided to operator by transmission facilities directly connected to transmission networks in the observable area	
Structural data	Electrical data of the transformers connected to the transmission system Characteristics of the load of the demand facility Characteristics of the reactive power control Its behaviour at the voltage ranges
Schedule data	Scheduled active and forecast reactive consumption on a day-ahead and intraday basis, including any changes of these schedules or forecast Any forecast restriction in the reactive power control capability Minimum and maximum power to be curtailed in demand response

Data to be exchanged between operators for cross-border links observable area	
Real-time data	Active and reactive power at the connection point Minimum and maximum power to be curtailed
Data provided to operator by transmission facilities directly connected to distribution networks or aggregators within the observable area	
Structural data	Structural minimum and maximum active power available for demand side response, and the maximum and minimum duration of any potential usage of this power for demand side response
Scheduled data	Forecast of unrestricted active power available for any planned demand side response
Real-time data	Active and reactive power at the connection point Confirmation that the estimated actual values of demand response are applied

OC 7.4 Neighbouring operators shall exchange the protection set-points of the lines included as external contingencies in neighbouring operators contingency lists to allow protection coordination between the different transmission systems.

OC 7.5 A generator operator or transmission operator shall coordinate new protective systems and changes as follows.

a. Each generator operator shall coordinate all new protective systems and all protective system changes with its transmission operator.

b. Each transmission operator shall coordinate all new protective systems and all protective system changes with neighbouring transmission operators and balancing authorities.

OC 7.6 Each generator operator and transmission operator shall have and provide upon request evidence that could include but is not limited to, revised fault analysis study, letters of agreement on settings, notifications of changes, or other equivalent evidence that will be used to confirm that there was coordination of new protective systems or changes.

OC 7.7 A generator operator or transmission operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the protection systems of others:

a. Each generator operator shall notify its transmission operator in advance of changes in generation or operating conditions that could require changes in the transmission operator’s protection systems.

b. Each transmission operator shall notify neighbouring transmission operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other transmission operators’ protection systems.

OC 7.8 Each transmission operator shall coordinate protection systems on major transmission lines and interconnections with neighbouring generator operators and transmission operators.

OC 7.9 Each transmission operator shall monitor the status of each special protection system in their area, and shall notify affected transmission operators of each change in status.

OC 7.10 Each transmission operator shall have and provide upon request evidence that could include but is not limited to, documentation, electronic logs, computer printouts, or computer demonstration or other equivalent evidence that will be used to confirm that it monitors the special protection systems in its area.

OC 7.11 Each transmission operator and balancing authority shall have and provide upon request evidence that could include but is not limited to, operator logs, phone records, electronic-notifications or other equivalent evidence that will be used to confirm that it notified affected transmission operator and balancing authorities of changes in status of one of its special protection systems.

OC 7.12 Each transmission owner and generator owner shall provide Sequence of Event (SOE) recordings installed pursuant to CC13 guidelines.

OC 7.13 Each generator operator and transmission operator shall notify reliability entities of relay or equipment failures as follows:

a. If a protective relay or equipment failure reduces system reliability, the generator operator shall notify its transmission operator and host balancing authority. The generator operator shall take corrective action as soon as possible.
b. If a protective relay or equipment failure reduces system reliability, the transmission operator shall notify its regional head and affected transmission operators and balancing authorities. The transmission operator shall take corrective action as soon as possible.

OC 7.14 The transmission owner and distribution provider that own a transmission protection system and the generator owner that owns a generation unit or generator interconnection facility protection system shall each retain data on its protection system mal-operations and each accompanying corrective action plan until the corrective action plan has been executed or for 12 months, whichever is later. The compliance monitor shall retain any audit data for three years.

OC 7.15 The transmission owner, any distribution provider that owns a transmission protection system, and the generator owner shall each provide to its regional entity, documentation of its mal-operations analyses and corrective action plans according to the regional entity's procedures.

OC 7.16 All necessary communication and data sharing shall happen over a common platform. Having a common platform for updations, storage and exchange will lead to a simplified and transparent liaising process.

OC 8. OUTAGE PLANNING

OC 8.1 This section in general sets out the procedure for preparation of outage schedules for the elements of the interconnected grid in a coordinated and optimal manner keeping in view the system operating conditions and the balance of generation and demand.

OC 8.2 The generation output and transmission system shall be adequate after taking into account the outages to achieve the security standards.

OC 8.3 The outage planning of run-of-the-river hydro plant, wind and solar power plant and its associated evacuation network shall be considered to extract maximum power from these renewable sources of energy. Outage of wind generator shall be planned during lean wind season, outage of solar, if required during the rainy season and outage of run-of-the river hydro power plant in the lean water season.

Outage Planning Process

OC 8.4 An outage coordination region shall be formed by grouping responsibility areas based on the extent of interconnection, for an efficient coordination. The set of power system assets which influence two or more system operator while being out of operation are identified as relevant assets. Of these, those which are considered to have a major influence on the operational management of the neighbouring systems are identified as critical assets. The outage coordination planning takes all relevant assets into account.

OC 8.5 The operational planning shall be split into three time horizons, namely the long-term (a year ahead), the medium-term (monthly reassessment) and the short-term planning (week ahead). In order to coordinate possible congestions and other matters, a weekly teleconference call may be organised to share operational information. The coordinated availability plan shall have the following details for each relevant element:

a. Availability status, which may be one of the following three states:
   i Available: The relevant asset is capable of and ready for providing service, whether or not it is actually in operation.
   ii Unavailable: The relevant asset is not capable of or ready for providing service;
   iii Testing: The capability of the relevant asset for providing service is being tested. This status may be used only during time periods between first connection and final commissioning or immediately after maintenance.
b. Reason for unavailability
c. Conditions that need to be fulfilled before making asset unavailable
d. Restoration time

OC 8.6 A draft outage plan shall be prepared taking into account the available resources in an optimal manner and to maintain security standards. This will be done after carrying out necessary system studies. Whenever incompatibilities are identified, the coordination process is reassessed. The outage plan shall then be finalised for implementation.

OC 8.7 The above annual outage plan shall be reviewed on quarterly and monthly basis in coordination with all parties concerned, and adjustments shall be made as and when required.

OC 8.8 In case of emergency in the system, viz., loss of generation, break down of transmission line affecting the system, grid disturbances, system isolation, the studies may be conducted again before clearance of the planned outage.

a. The outage plan may be deferred in case of grid disturbances, taking into account the statutory requirements.

OC 8.9 Annual outage plan shall be prepared in advance for the financial year and reviewed during the year on quarterly and monthly basis. All users shall follow these annual outage plans. If any deviation is required the same shall be accommodated with prior permission of concerned authorities.

OC 8.10 Quarterly and half-yearly reports shall be submitted to the relevant authorities indicating deviation in outages from the plan along with reasons. These reports shall also be put up on a website.

OC 9. RECOVERY PROCEDURE

OC 9.1 Restoration of the cross-border interconnection shall be carried out as soon as the conditions permit. The restoration process shall be supervised by respective system operator, in co-ordination with the system operator of other neighbouring country. Any tripping, either manual or automatic, shall be communicated immediately by the system operator who detects such an event to their counterpart in another country.

OC 9.2 Detailed plans and procedures for restoration of the grid under partial/total blackout shall be developed and reviewed/updated annually.

OC 9.3 Detailed plans and procedures for restoration after partial/total blackout of each user's system within member country will be finalised by the concerned user in coordination with the operator. The procedure will be reviewed, confirmed and/or revised once every subsequent year. Mock trial runs of the procedure for different subsystems shall be carried out by the users at least once every six months. Diesel generator sets for black start would be tested on weekly basis and test report shall be sent to on quarterly basis for the assets in the observable area.

OC 9.4 List of generating stations with black start facility, inter-country ties, synchronising points and essential loads to be restored on priority, shall be prepared.

OC 9.5 All communication channels required for restoration process shall be used for operational communication only, until the grid normalcy is restored. Each significant grid user shall have at least one redundant voice communication system to exchange the necessary information for restoration plan, which shall have backup power supply for at least 24 hours and shall be prioritised.

OC 9.6 Operators have to know the status of components of their power system after a blackout before starting the restoration process. This process shall be started only after the grid reaches a stabilised situation.

OC 9.7 Respective system operator shall coordinate the frequency management within a synchronous area. A common entity shall be appointed as the resynchronisation leader who shall bear the onus for coordinating with the regional heads during the resynchronisation process of two neighbouring areas.

OC 9.8 During the re-energising processes, following considerations are taken into account:

a. Each operator has to develop proper re-energisation procedures, at least by simulation or offline calculations.
b. Each operator has to evaluate the number of units capable of black start and islanded operation to contribute to the restoration and to get knowledge of units in house load operation.
c. Operators have to know the status of the component of their power system after a blackout.
d. During re-energisation, the relevant region's load frequency secondary control is switched to frequency control mode while the other load frequency secondary controllers remain in frozen control state.
e. The consumption and production are balanced by the re-synchronisation leader with the aim of returning near to 50 Hz, with a maximum tolerance of ±200 mHz, under the coordination of the area's regional head.
f. The operator shall re-energise the shed load when system frequency is not below 49.8 Hz, keeping a generation margin sufficient at least to cope with the next block of load to re-energise. The process of re-energising customers shall be done stepwise in block loads of maximum size defined by the operator with respect to the load of his grid.
g. The operator shall coordinate the reconnection of generators tripped due to abnormal frequency excursion.
h. The re-synchronisation leader of the concerned areas and in collaboration with the two regional heads of their respective areas will apply the required actions in order to operate the re-synchronisation under the following criteria:
    - i Both systems shall be in a stable state and both frequencies must be near to 50 Hz to re-synchronise as securely as possible.
    - ii Use of 400 kV line(s) of high loadability
    - iii Make provisions for closing immediately a second line that is electrically close to the first line.

iv To choose, by preference, a line for synchronisation not in the vicinity of large thermal units in operation.

OC 9.9 The re-synchronisation leader gives orders to regional heads for actions in the proper direction to minimise the frequency and voltage deviation between both areas just at the time of re-synchronisation.

OC 10. EVENT INFORMATION

OC 10.1 This section deals with reporting procedures in respect of events in the system to all users.

OC 10.2 Any of the following events shall require reporting:

a. Violation of security standards
b. Grid indiscipline
c. Non-compliance
d. System islanding/system split
e. Regional black out/partial system black out
f. Protection failure on any element on the "agreed list" of the interconnected systems
g. Power system instability

OC 10.3 Each operator shall provide the following information in due time for the purposes of System Defence Plan procedures and Restoration Plan procedures:

a. To neighbouring operators:
   i The extent and borders of the synchronised region or synchronised regions to which its responsibility area belongs
   ii Restrictions to operate synchronised region
   iii Active and reactive power limits at interconnectors
   iv Other technical or organisational restrictions

b. To the regional head:
   i Restrictions to maintain islanded operation
   ii The available additional load and generation
   iii The availability of operational reserves

c. To transmission connected distribution systems:
   i The system state of its transmission system
   ii Limits of active and reactive power, block loading, tap and circuit breaker position at the connection points
   iii Information on the current and planned status of power generating modules connected to the DSO
   iv All necessary information leading to further coordination with distribution connected parties

OC 10.4 All oral notifications may be backed up with appropriate written reports, together with the following details of event:

a. Time and date of event
b. Location
c. Plant and/or equipment directly involved
d. Description and cause of event

e. Antecedent conditions of load and generation, including frequency, voltage and the flows in the affected area at the time of tripping including weather condition prior to the event
f. Duration of interruption and demand and/or generation (in MW and MWh) interrupted
g. All relevant system data including copies of records of all recording instruments including disturbance recorder, event logger, DAS etc.
h. Sequence of trippings with time
i. Details of relay flags
j. Remedial measures

OC 11. COORDINATION BETWEEN SYSTEM OPERATORS

OC 11.1 Different coordination forums shall be constituted to facilitate smooth operation of the cross-border links among the member countries.

a. **Operation and Protection Coordination Forum:** The Operation and Protection Coordination Group would have members from the system operators of participating countries and protection team of respective transmission companies to look into various aspects associated with the operation of the cross-border links, including any protection coordination issues. The group would meet once every calendar quarter.
b. **Commercial Coordination Forum:** The Commercial Coordination Group would have members from the system operators of the participating countries along with other stakeholders to look into all commercial aspects related to the operation of the cross-border links. The group would meet once every calendar quarter.

OC 11.2 In addition to the above coordination forums, the transmission system owners of the respective countries may coordinate with each other for various aspects pertaining to the O&M of the transmission assets in their respective jurisdiction.

IV - SCHEDULING & DISPATCH

Rationale: While making guidelines for scheduling and dispatch procedures the code must encompass the requirements for establishment of scheduling processes, provision of information to other country system operators, day-ahead scheduling procedure, intra-day scheduling/revision procedure, sharing of information on schedules with other trading countries and standardised scheduling intervals for cross-border trade. It shall enable non-discriminatory access to the respective transmission grids for purpose of cross-border trade in line with Article 12 of SAARC framework agreement for energy cooperation (electricity) and include procedure for calculation of TTC, ATC along with reliability margins and the regulations for mechanism for forward capacity allocation and congestion relieving mechanism.

SDC 1. INTRODUCTION

SDC 1.1 For effective power transfer and to facilitate cross-border power trade, computation of the Available Transfer Capability (ATC) plays a vital role. While calculating the ATC, system operator shall consider the technical limit imposed by the system components, the thermal line limits, bus voltage limits and stability limit. The ATC is arrived at after deducting transmission reliability margin (TRM) from the total transfer capability (TTC). Therefore methodology for calculation of TRM affects the final result. In order to move towards an integrated electricity market, the rules on power transfer capability forecast and congestion management across cross-border links shall be harmonised.

SDC 1.2 Power transfer capability forecast and congestion management rules set out the methods for allocating electricity interconnection capacity in annual, seasonal, monthly, day-ahead and intra-day timescales and outline the approach in which interconnection capacity will be calculated across the different transmission network zones that impact the cross-border power flow.

SDC 1.3 This guideline sets out the

a. Demarcation of responsibilities between various regional entities in scheduling and dispatch
b. Power transfer capability forecast and congestion management techniques
c. Procedure for scheduling and dispatch
d. Complementary commercial mechanisms

SDC 2. OBJECTIVE

SDC 2.1 The guidelines for cross-border power transfer capability forecast and congestion management in the day-ahead and intra-day markets shall be highlighted, including the elaboration of requirements for the establishment of common methodologies for determining the volumes of capacity simultaneously available between bidding zones.

SDC 2.2 The objective of these guidelines is to set out rules for transmission capacity forecast for cross-border exchanges in electricity and congestion management by:

a. Ensuring optimal use of the transmission infrastructure;
b. Ensuring operational security;
c. Ensuring and enhancing the transparency and reliability of information;
d. Contributing to the efficient long-term development of the electricity transmission system by accurate forecasting;

SDC 2.3 The procedures to be adopted for scheduling of the net injection/drawals of concerned entities on a day-ahead basis with the modality of the flow of information between the regional entities are covered in this guideline. The procedure for submission of requisition/ drawal schedule by participating entities is intended to enable respective system operator to prepare the dispatch schedule for each generating station and drawal schedule for each regional entity. It also provides methodology of issuing real time dispatch/drawal instructions and rescheduling, if required, to participating entities along with the commercial arrangement for the deviations from schedules, as well as mechanism for reactive power pricing.

SDC 3. DEMARCATION OF RESPONSIBILITIES

SDC 3.1 System operator of each member country shall have the control on its generation and/or load to maintain its interchange schedule with other member countries whenever required and contribute to frequency regulation of the synchronously operating system.

SDC 3.2 System operator of a member country shall take the responsibility of coordinating the scheduling of a generating station, within the country area, real-time monitoring of the station's operation in its availability declaration, or in any other way revision of availability declaration and injection schedule, switching instructions, metering and energy accounting, outage planning, etc. All generating stations shall come under any of these control areas.

SDC 3.3 Each member country grids shall be operated as power pools with their own scheduling and dispatch process, in which the respective system operators shall have the total responsibility for

a. Scheduling/dispatching of their own generation
b. Regulating the demand of its control area
c. Scheduling their drawal from the cross-border link
d. Regulating the net drawal of their control area from the cross-border link

SDC 3.4 The algebraic summation of scheduled drawal from contracts through a long-term access, medium-term and short-term open access arrangements shall provide the drawal schedule of each member country, and this shall be determined in advance on day-ahead basis. The member country entities shall regulate their generation and/or consumers' load so as to maintain their actual drawal from the cross-border grid close to the above schedule.

SDC 3.5 The member country entities shall ensure that their automatic demand management scheme acts to ensure that there is no over-drawl when frequency is 49.5 Hz or below. If the automatic demand management scheme has not yet been commissioned, then action has to be taken as per manual demand management scheme to ensure zero over-drawal when frequency is 49.5 Hz or below.

SDC 3.6 The generating stations and sellers shall be responsible for power generation/power injection generally according to the daily schedules advised to them by the system operator of respective country on the basis of the contracts/requisitions received.

SDC 3.7 The generating stations may be allowed to generate beyond the given schedule under deficit conditions as long as such deviations do not cause system parameters to deteriorate beyond permissible limits and/or do not lead to unacceptable line loading in the cross-border link. Deviations, if any, from the schedules shall be appropriately priced. In addition, deviations, from schedules causing congestion, shall also be priced accordingly.

SDC 3.8 When the frequency is higher than 50.2 Hz, the actual net injection shall not exceed the scheduled dispatch for that time block.

SDC 3.9 The coordinating member may direct the system operator to increase/decrease their drawal/ generation in case of contingencies, e.g. overloading of lines/transformers, abnormal voltages, threat to system security. Such directions shall immediately be acted upon.

SDC 3.10 All member country entities shall abide by the relevant market regulations for deviations from the schedule.

SDC 3.11 The coordinating forum shall be responsible for computation of actual net injection/drawal of on the cross-border link, 15 minute-wise, based on the above meter readings.

SDC 4. SCHEDULING AND DISPATCH

SDC 4.1 Till the development of secure cross-border scheduling mechanism, it is recommended to follow the Indian scheduling and dispatch timeline for the day-ahead schedule, as tabulated in Table 4.1 and Figure 4.1.

Table 4.1: Scheduling and dispatch timeline (all in IST)

Time	Activity
0800 hrs	Member country load dispatch centres shall compile their foreseen MW and MWh generation capabilities for the next day and submit the cross-border power transfer, i.e., from 0000 hrs to 2400 hrs of the following day to the coordinator heads.
1500 hrs	Member country load dispatch centres shall compile their foreseen load pattern for the next day and submit revised cross-border power transfer to the coordinator heads.
1800 hrs	All coordinator heads together or a scheduling authority decides the best dispatch and drawal schedule for cross-border interconnection and each coordinator head conveys the net dispatch schedule and the net drawal schedule through cross-border interconnecting to each member country load dispatch centres under its control.
2200 hrs	Any modifications in load or generation shall be brought to the notice of the coordinator head by the member country dispatch centre.

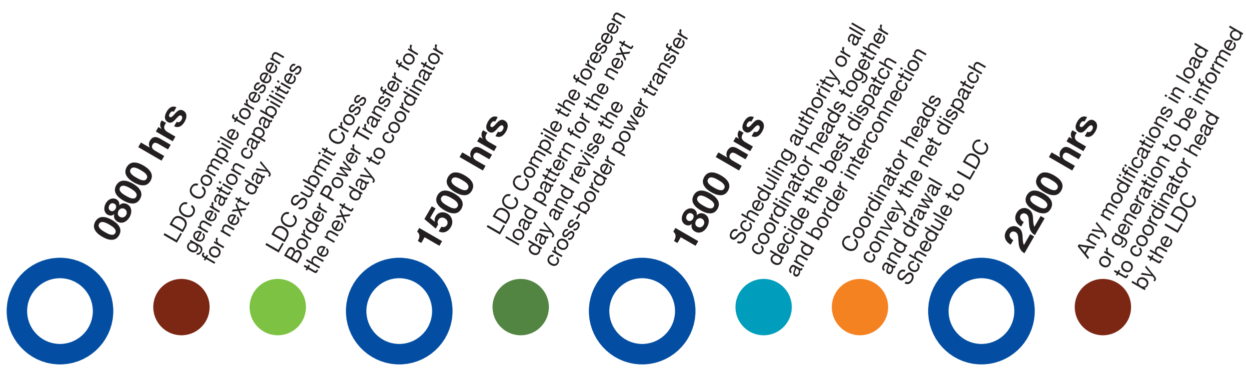


Figure 4.1: Scheduling and Dispatch Timeline

SDC 4.2 Each time block shall be for a duration of 15 minutes and a common time of Indian Standard Time (IST) can be adopted for uniformity.

SDC 4.3 Transmission losses will be apportioned between two countries based on a mutually agreed methodology.

SDC 4.4 Transmission system losses would be borne in kind by the utilities as per the quantum declared by the concerned system operator for the respective area of jurisdiction in the interim i.e., the injecting utility (seller) would have to inject more power to compensate the losses and the drawee utility (buyer) would draw less power to compensate for the losses.

This procedure can be adopted till the sound mechanism for transmission loss like charging for losses as envisaged in SDC 8 is adopted.

SDC 4.5 The (firm) power traded over the cross-border links would normally be treated as a 'must-run' and thus would not be subject to revision/curtailment except under conditions which pose a threat to the system security of either of the participating countries.

SDC 4.6 The priority of scheduling of power over the cross-border link would be long-term contracts, medium-term contracts and short-term bilateral contracts (up to 3 months) in that order.

SDC 4.7 It is initially envisaged to begin with bilateral contracts, gain experience and gradually ramp up to allow procurement/sale of power through the power exchange(s) operating in India.

SDC 5. DEVIATION SETTLEMENT

SDC 5.1 The concerned utility operating the sub-station at either end of the cross-border interconnection shall install special energy meters on all interconnections between the countries for recording of actual net MWh interchanges on a 15-minute basis and MVArh drawals. The installation, operation and maintenance of special energy meters shall be in accordance with prevailing regulations in the respective countries and through mutual agreement.

SDC 5.2 Joint weekly meter readings shall be taken and transmitted to the respective system operators by Tuesday noon so as to facilitate energy accounting.

SDC 5.3 Net import/export MWh and MVArh would be computed by each system operator for their respective ends and matched with the counterparts.

SDC 5.4 Deviation from schedule on the cross-border link will be calculated for each 15-minute time interval.

SDC 5.5 A mutually acceptable and suitable mechanism for settlement of the deviation from schedule (imbalance) on the cross-border link along with payment mechanism needs to be evolved.

SDC 5.6 Transmission charges for wheeling of power up to the international interconnection for the international trade would be borne by both the buyer and the seller as per the prevailing methodology in the respective country.

SDC 5.7 Transmission charges for the international interconnection would be payable by the market participants as per the charges mutually agreed between the participating member countries.

SDC 5.8 System operation charges would be payable to the system operators of the respective countries by the participants to the trade. Taxes, levies and other statutory duties/levies would be payable by the participants as per the prevailing laws of the land.

SDC 5.9 Any other charges levied from time-to-time by the regulator or changes in law would be payable as and when levied.

SDC 5.10 A suitable payment security mechanism for transmission charges, system operation charges and charges of imbalance would be put in place by the participating member countries.

SDC 5.11 The member states shall put into place through mutual agreement a mechanism for dispute resolution.

SDC 6. GENERAL GUIDELINES

SDC 6.1 The system operators/licensees shall publish a general scheme for calculation of the interconnection capacity for different timeframes based on the electrical and physical realities of the network.

SDC 6.2 The planning standards defined under PC 5.2 considering system security shall form an integral part of the information that system operators shall publish in open and public document. Also this document shall be submitted to the approval of respective regulators.

SDC 6.3 The relevant system operators shall calculate the interconnection capacities for the different timeframes using a common network model. The values of these interconnection capacities shall be published along with the corresponding technical assumptions.

SDC 6.4 When preparing the day-ahead grid operation, the system operator shall exchange information with neighbouring system operators including their grid topology, availability of generation units, and load flows in order to optimise the use of the overall network through operational measures.

SDC 6.5 The Total Transfer Capability (TTC), Reliability Margins and Available Transfer Capability (ATC) for the international interconnection shall be assessed by the system operators of participating countries. These would be exchanged by the system operators and the minimum of the declared limits would be considered while permitting/allowing bilateral trades to be scheduled over the cross-border links. The TTC assessed by the system operators would be reviewed periodically as and when considered necessary and the revised limits would be communicated to the counterpart immediately. The quantum of power scheduled shall not exceed the TTC limits agreed to by the system operators.

SDC 6.6 In case of congestion over the cross-border interconnection(s), agreed commercial mechanism is to be followed.

SDC 6.7 While defining optimal network parts for congestion management, system operators shall be guided by cost-effectiveness and the lowest negative impacts on system operation. In that sense, system operators shall not restrict their attention only to the borders of their own control area in order to prevent internal congestion and system operators shall avoid limiting interconnection capacity in order to solve congestion inside their own control area.

SDC 6.8 The following points shall be considered to calculate the ATC by the concerned system operator for cross-border transactions:

a. Capacity calculation timeframes;
b. Capacity calculation regions;
c. Common grid model methodology;

SDC 6.9 All system operators shall calculate cross-border capacity by considering their internal network for at least the annual, monthly, day-ahead and intra-day timeframes.

{For the day-ahead market timeframe, individual values for cross-border capacity for each day-ahead market time unit shall be calculated on the basis of the latest available information, i.e. at least two days before the day of delivery.

For the intra-day market timeframe, individual values for cross-border capacity for each remaining intra-day market time unit shall be calculated. The system operators in each capacity calculation region shall ensure that cross-border capacity is recalculated within the intra-day market timeframe based on the latest available information. The frequency of this recalculation shall take into consideration efficiency and operational security.}

SDC 6.10 The regions shall ensure long-term capacity calculations for the purpose of power transfer capability forecast and congestion mitigation.

SDC 6.11 The common grid model is the key for ATC calculation and will be a representation of the grid models of all connected areas/regions. It shall contain at least the following items:

a. The generation and load data provision methodology;
b. A definition of possible scenarios;
c. A definition of individual grid models and
d. A description of the process for merging individual grid models to form the common grid model.

{The generation and load data provision methodology shall specify which generation units and loads are necessary to provide information to their respective system operators for the purposes of capacity calculation. The information shall at least include the following:

i Information related to their technical network data, operation limits, relevant network model and topology;
ii Information related to the availability of generation units and loads;
iii Information related to the schedules of generation units; and
iv Relevant available information relating to how generation units will be dispatched}

SDC 6.12 System operators shall have the capability to manage the uncertainty during capacity assessment in a coordinated and consistent manner. The methodologies for the capacity calculation shall include the following parameters:

a. A methodology for determining the reliability margin;
b. The methodologies for determining operational security limits, contingencies relevant to capacity calculation and allocation constraints that may be applied; and
c. The methodology for determining remedial actions to be considered in capacity calculation;

SDC 6.13 Due to the complexity involved; the assessment of transfer capability from one country to another in an interconnected system is carried out with the help of simulation studies.

{Available Transfer Capability (ATC) would be defined as the Total Transfer Capability (TTC) after deducting the Transmission Reliability Margin (TRM).

ATC = TTC-TRM (Planning stage)
ATC= TTC-TRM-AAC (Operation stage)
Where,
AAC is the Already Allocated Capacity,
TTC is the Total Transfer Capability}

SDC 6.14 For calculating ATC, following are the main parameters:

a. The calculations are based upon the best available input data sets merging from the best estimates. Each system operator/transmission licensee is responsible for providing for its own network.
b. The load flow calculations are performed using a real network representation as wide as possible.
c. The system operator/transmission licensee shall exchange the input data sets in order to start from the same scenarios (base cases). The base cases have to rely on historical recorded data (snapshots of network conditions in the past) for realistic system analysis and same base cases can be adapted in order to take into account the foreseeable electric system changes.

d. Several possibilities exist on how to simulate the power exchanges between two areas. The choice has to be uniform and same shall have to be adhered by each system operator. System operator will also take into consideration the security constraints and the transmission reliability margin. The aim is always to reach the most realistic results.
e. The needs of transparency regarding the exchange of technical input data and assumptions as well as necessary co-operation in order to agree the relevant studied scenarios are outlined.
f. In determining the ATC, the following shall be considered, in particular:
   i Thermal limitations, voltage limitations and limitations conditioned by the stability of system;
   ii N-1 criterion for reliability during calculation of Total Transfer Capacity (TTC);
   iii Transmission Reliability Margin (TRM);
   iv Limitations of power system operation which are scheduled beforehand in compliance with the scheduled unavailability of elements in the network; and
   v Limitations in operation of power system which are not scheduled before and which arise from the unscheduled unavailability of elements in the network.

SDC 6.15 TTC Preparation: Cross-border transmission capacity calculations require a set of data. This set of data, called "base case", which includes a network model and input data describing load and generation patterns forecast and network topology at the studied time frame. For calculating TTC, the first step of the procedure consists of the identification of the base case for the proper simulation of the whole interconnected system operation in the targeted time frame.

a. Network Model
   i The network model shall contain a full representation of the network elements. It can be split in several geographical parts of a synchronously interconnected network and one for each of the countries connected by DC links.
   ii The studied area has to be as wide as possible to allow an accurate comprehension of physical flows distribution on tie-lines resulting from international exchanges since some important part of the power flowing from one area to another can circulate through third countries depending on the interconnection.
   iii The calculation area (i.e. the subset of the network model) for TTC assessment between two neighbouring countries will be determined case-by-case.

b. Input Data
   i Load-flow calculations have to be performed.
   ii For cross-border transmission capacity assessments, for each time frame being considered, the following input data are needed for analysis:
      - The thermal ratings of network elements as well as the electrical parameters
      - The maximum and minimum output power values for the generating units being included into the network model
      - The intended network topology at the time frame considered. The generation pattern by the means of the net injection at each node at the time frame considered
      - The load pattern by the means of the net sink at each node at the time frame considered
      - The common set of programs of cross-border transactions and the net balances of each system operator area at the time frame considered. The common set

of cross-border transactions considered in the base case relates to the best forecast for exchanges at the time frame considered

- The expected maximum power available at the time frame considered

{The base case can be built up starting from real observed operation situations and forecasts data. While the observed operation situations offer a true scenario of the electrical system behaviour, forecasts can give a better database because they include the expertise of each system operator about the expected behaviour of generation and load in its own country and the knowledge about the scheduled maintenance works on the transmission network/ generators. These two alternative views on base case construction may be combined in the following way. The base case would be built starting from a real observed situation (snapshots of the power system at selected scenarios). Then each system operator will update the information regarding his system taking into account foreseeable differences about:

- Load level, according to the demand forecasts over the time frame being analyzed
- Generation pattern based on forecasts of primary energy sources (i.e. hydro reserves, fuels availability etc.);
- Network and generation planned or forced (long lasting) outages.

The specific procedure that each system operator uses to modify the starting base case provided that these modifications are consistent at control area level (i.e. real generation limits/possibilities) and at the control block level (i.e. base case exchanges). However each system operator has to explain the nature and extent of any modification performed on the starting base case when sending to the other partners the results of modifications which shall be integrated into the common base case used for ATC computations.}

SDC 6.16 Transmission Reliability Margin (TRM): Transmission reliability margin is defined as reliable reserve which exceeds uncertainties in calculation of TTC. System operator shall choose one of the below mentioned formula based on data availability

- TRM = TTC in the base case – TTC in the worst scenario, or
- TRM = TTC with normal line ratings – TTC with line ratings lowered by 2% from normal, or
- TRM could also be calculated from probabilistic methods.

{If system operator is using probabilistic method to calculate, TRM shall also cover primary control energy exchanges in case of power plant outages, unintentional physical power flow due to load-frequency control, security reserves between system operators as well as imprecise data and metering.

TRM values may be determined as:

$TRM_i = U_r + U_e$

$TRM_{ii} = Max\ (U_{r,}\ U_e)$

Where:

TRM_i is the worst case combination that takes into account both statistical estimate and common reserve and emergency exchanges margin.

TRM_i assumes that both uncertainty margins cannot happen simultaneously.

U_r is the statistical estimate based on historic data.

U_e is the margin for common reserve and emergency exchanges.

Another approach to determine TRM could be:

$TRM_{pessimistic} = PTRM_1 + PTRM_e + PTRM_i$

$TRM_{optimistic} = Max\ (PTRM_{1,} PTRM_e) + PTRM_i$

Where,

$PTRM_1$ i.e. the unintended deviations due to primary control

$PTRM_2$ i.e. the unintended deviations due to power-frequency (secondary) control

$PTRM_e$ i.e. the common reserve and emergency exchanges to cope with unbalanced situations

$PTRM_i$ i.e. the inaccuracies in data collection and measurements}

SDC 7. CONGESTION MANAGEMENT

SDC 7.1 Relieving from congestion is an important measure for secure operation of grid. Coordinator shall regularly evaluate the congestion management methods, paying particular attention to compliance with the principles and rules established in the regulations and terms and conditions set by regulators of respective countries. Such evaluation shall include dedicated studies and shall be carried out in consultation with all market players.

SDC 7.2 System operators shall provide fair and transparent standards outlining their congestion management methods along with the associated circumstances under which it will be applied.

SDC 7.3 A corridor shall be considered congested under the following circumstances:

a. Grid voltage in the important nodes downstream/upstream of the corridor is beyond the operating range
b. The real-time power flow along a corridor is such that N-1 contingency may not be satisfied.
c. One or more transmission lines in the corridor are loaded beyond their normal limit

SDC 7.4 Whenever actual flow on the cross-border links exceeds ATC and security criteria are violated a warning notice shall be issued. The notice for congestion shall be communicated to all the regional entities.

SDC 7.5 If the power flow on the interconnections is as per the schedule, but the congestion has been caused by forced outages of a transmission line occurring after the drawal schedule has been fixed, then open access transactions shall be curtailed as a last resort after exhausting all available remedial measures, followed by revision of TTC, TRM and ATC.

SDC 7.6 Congestion charges shall be applied if violation of TTC limits persists for 2 time-blocks not counting the time-block in which warning notice was issued and no affirmative action is taken by the defaulting agency.

SDC 7.7 Congestion charge would be levied for

a. Over-drawal or under-injection in the importing control area; and
b. Under-drawal or over-injection in the exporting control area;

SDC 7.8 Congestion charge shall be withdrawn after the power flow on the affected transmission link has come down to the ATC and remains at this level for one time block.

SDC 7.9 Network congestion problems shall be addressed based on the secure and agreed market principles.

SDC 7.10 System operators shall implement appropriate co-ordination and information exchange mechanisms. These are essential for providing fair and secure access to networks within the member country internal electricity system operation. System operators shall publish all relevant data concerning cross-border transfer capacities with fully justified general scheme for calculation of the total transfer capacity and the transmission reliability margin based upon the electrical and physical realities of the network (total transfer capacities should not be net of contracted flows). Such a scheme shall be subject to approval by the regulators of the respective member countries.

SDC 8. CHARGES FOR LOSSES

{This guideline is provided considering futuristic aspect for accounting transmission losses. Till mature cross-border transaction takes place, the present accounting of losses in kind can be adopted}

SDC 8.1 In order to ensure cross-border power trade, the guidelines provide to establish an inter-transmission system operator compensation mechanism as a stable basis for the fair compensation to transmission system operators for the costs of hosting cross-border flows of electricity.

SDC 8.2 Transmission system operators shall be compensated for energy losses resulting from hosting cross-border flows of electricity. Such compensation shall be based on an estimate of what losses would have been incurred in the absence of transits of electricity.

SDC 8.3 In the long term, a fund shall be established to compensate transmission system operators for the energy losses incurred. The fund may be referred to as Cross-Border System Operator Compensation (CBSOC) Fund.

SDC 8.4 An agency shall be established comprising of representatives of all participating countries and shall be made responsible for establishing arrangements for the collection and disbursement of all payments relating to the CBSOC Fund, and shall also be responsible for determining the timing of payments. All contributions and payments shall be made as per the agreements in place. The Agency shall oversee the implementation of the CBSOC mechanism and publish report annually on the implementation of the CBSOC mechanism and the management of the CBSOC fund.

SDC 8.5 The system operators shall contribute to the CBSOC fund in proportion to the absolute value of net flows onto and from their transmission system as a share of the sum of the absolute value of net flows onto and from all transmission systems.

SDC 8.6 Transit of electricity shall be calculated, normally on 15 minutes time block, by taking the lower of the absolute amount of imports of electricity and the absolute amount of exports of electricity on interconnections between national transmission systems. The net flow of electricity shall mean the absolute value of the difference between total exports of electricity from a given region to countries which participate in the CBSOC mechanism and total imports of electricity from countries which participate in the CBSOC mechanism to the same region.

SDC 8.7 The amount of losses incurred on a transmission system shall be established by calculating the difference between:

a. The amount of losses actually incurred on the transmission system during the relevant period; and
b. The estimated amount of losses on the transmission system which would have been incurred on the system during the relevant period if no transits of electricity had occurred;

SDC 8.8 The agency shall be responsible for carrying out the loss calculation and shall publish this calculation and its method in an appropriate format.

SDC 8.9 Until such time as CBSOC mechanism has been established, system operators shall co-operate amongst themselves to carry out the tasks assigned in relation to the CBSOC mechanism.

Annexure 1: Summary of South Asian Countries Grid Code and International Grid Code

1. INTRODUCTION

Grid codes of all South Asian countries (grid codes are not available for Afghanistan and Maldives) are referred to understand technical and commercial issues concerning cross border trading in existing grid codes. A brief description about the grid codes are presented below.

Bangladesh: Bangladesh Energy Regulation Commission Electricity (BERC) approved the grid code in 2012 in exercise of the powers conferred by Section 59 of the BERC Act 2003. Power Grid Company of Bangladesh (PGCB) is the transmission licensee and is made responsible for managing and servicing the grid code.

Grid code of Bangladesh is organised into sections namely Management of the Bangladesh Grid Code, Transmission System Planning, Connection Conditions, Outage Planning, Schedule and Despatch, Frequency and Voltage Management, Contingency Planning, Cross Boundary Safety, Operational Event/Accident Reporting, Protection Metering, Communication and Data Acquisition, Tests, Numbering and Nomenclature, Data Registration, Performance Standard for Transmission and Financial Standard for Transmission.

Bhutan: Grid Code Regulation 2008 issued by Bhutan Electricity Authority (BEA) under Section 89 of the Electricity Act of Bhutan, 2001. BEA is responsible for managing and amending the grid code according to the prescribed procedure issued by the BEA. The Grid Code Regulation document is organised into sections namely Role and Responsibilities, Planning Code, Connection Conditions, Operations and Operational planning, Scheduling and Dispatch code and Management of Grid Code Regulation.

India: The Indian Electricity Grid Code (IEGC) is a regulation made by the Central Electricity Regulatory Commission (CERC) in exercise of powers under Sections 79 and 178 of the Electricity Act 2003. CERC is vested with responsibility of reviewing and modifying the IEGC. Principal IEGC regulations were enforced in 2002. It was amended in 2012 and 2014. As specified in the Act, the IEGC is prepared having regard to CEA's "Grid standards for operation and maintenance of transmission lines". Transmission Planning Criteria and guidelines issued by the CEA, CERC (Grant of Connectivity, Long-term Access and Medium-term Open Access in inter-state Transmission and related matters) Regulations-2009, CEA (Installation and Operation of Meters) Regulations-2006 and CEA (Technical Standards for connectivity to the Grid) Regulations-2007 are supplementary to IEGC. IEGC document is organised into sections namely role of various organisations and their linkages, Planning Code for inter-State transmission, Connection Code, Operating Code, Scheduling and Despatch Code and Miscellaneous.

Further, each of the States in India have their own state grid code which describes the operation of electricity sector within the respective State. State grid code addresses Generation, Transmission and Distribution aspect of the power system. The transmission aspect of the State grid code is based on the Indian Electricity Grid Code and therefore will not cause dispute/ambiguity in implementation of regulations.

Nepal: The NEA Grid Code, 2005 prepared by Nepal Electricity Authority (NEA) is an internal document and lacks the authority of the law. Hence, full compliance by non-NEA Grid Users is not assured. Until a Nepal Grid Code gets enacted, NEA shall abide by the NEA Grid Code in its entirety and endeavour to bring non-NEA parties into the purview of this Grid Code. NEA Grid Code document is organised as Grid Code Management, Grid Planning, and Performance Standards for Grid, Grid Connection Requirements, Grid Operation and Management, Scheduling and Dispatch, System Test, Grid Metering, Exemptions and Transitory Provisions and Reports.

Pakistan: The grid code of Pakistan is prepared by National Transmission and Dispatch Company (NTDC) under Article 16 of NTDC license and approved by National Electric Power Regulatory Authority (NEPRA) pursuant to Section 35 of NEPRA Act, 1997. NTDC shall establish and maintain the review panel which shall be a standing body and shall undertake the functions detailed in Section 3.3 of the grid code. The functions include: review all suggestions for amendments, submit all the agreed recommendations to NEPRA for approval and resolve any matters of dispute between NTDC and its users/code participants.

Sri Lanka: The grid code of Sri Lanka has been formulated in terms of the provisions of Clause 17(f) and 3.1 (c) of the Sri Lanka Electricity Act, No. 20 of 2009. The Public Utilities Commission of Sri Lanka (PUCSL) approves and amends the grid code as and when necessary. The grid code document is organised into sections namely Grid Planning Code, Grid Connection Code, Grid Operations Code, Generation Dispatch Code, Grid Metering Code, Planning and Operating Standards and Information and Data Exchange.

Further analysis on the critical regulations is carried out based on the similar cross-country power system to assess the impact of each of the critical regulations being followed in Europe, North America and Southern Africa and their relevance for South-Asian interconnections.

The grid code comparison is made under relevant headings for ease of understanding and for effective analysis.

2. PLANNING

CURRENT PRACTICE IN SOUTH ASIA

Transmission licensee is responsible for all transmission planning activities in Bhutan, Bangladesh, India, Pakistan and Sri Lanka, whereas in Nepal, Grid owner is responsible for the same. The planning process is as follows:

Bangladesh

A system planner is assigned by the government to prepare and submit a long-term (preferably 20 years) Power System Master Plan to the commission for Transmission and Generation expansion. The Power System Master Plan shall be updated periodically, preferably every 5 years and used as an input to the National Plan. It is not explicitly mentioned as to which are the entities to whom the planning code is applicable. However it is implied that the planning code applies to transmission licensee and distribution licensee.

The criteria to be considered for transmission planning, given in the grid code, include (N-1) contingency considering outage of single circuit. The voltage variation limits considered for planning stage is:

- +/- 5% during normal conditions
- +/- 10% during emergency conditions

Grid planning studies are carried out such that system is maintained stable during a temporary fault clearance by three-phase trip within 100 ms and followed by successful re-closure within 300 ms. Grid code also specifies that from stability perspective, the maximum fault clearance times shall be 100 ms for 400 kV and 160 ms for 220 and 132 kV faults.

Bhutan

The system operator shall prepare aggregated medium-term (5 years) and long-term (10 years) load forecasts for the overall system. System operator shall also prepare a medium-term expansion plan for the generation capacity. Ministry of Economic Affairs shall develop and periodically update the overall Power System Master Plan which includes developments for the transmission system including export transmission facilities. Based on the Power System Master Plan, other reports/criteria/guidelines issued by the ministry and data submitted from transmission users, the Transmission licensee shall carry out grid planning studies and prepare a transmission plan which shall be submitted to BEA for approval. The completion of these works in the required time frame shall be ensured by the Transmission Licensee. The planning code applies to Transmission Licensee, Generation Licensees and the Distribution Licensees connected to and/or using and involved in developing the transmission system.

The criteria considered for transmission planning, given in the grid code, include (N-1) contingency considering outage of single circuit. The transmission system should be capable of withstanding loss of most severe single system infeed. The voltage variation limits considered for planning stage is:

- +/- 5% during normal conditions
- +/- 10% during emergency conditions

Grid code specifies that transient stability should be considered in planning studies but does not mention any specific limits. Grid code of Bhutan further specifies that planning of the transmission system for export of power from the generating stations to neighbouring countries shall be discussed and reviewed with the concerned agencies of the neighbouring countries.

India

Central Electricity Authority (CEA) will formulate the perspective transmission plan once in five years and continuously update to take care of the revisions in load projections and generation scenarios. The load projections would also be carried out by the CEA with the formulations of Electric Power Survey. At present 18th EPS is in operation. The generation planning aspect is deliberated in the State Grid codes. Transmission licensee (CTU) shall provide the non-discriminatory open access for all interstate transmission lines and STU for intra-transmission lines in India. In addition, other transmission licensees in India shall also provide open access. No such regulations regarding open access are given in other grid codes.

The planning code applies to Central Transmission Utility (CTU), other transmission licensees, Inter-State Generating Station (ISGS), connected to and/or using and involved in developing the Inter-State Transmission System (ISTS). Also applicable to Generating Companies, IPPs, State Electricity Boards/ State Transmission Utility (SEBs/STUs) and/licensees, regarding generation and/or transmission of energy to/from the ISTS.

In India, outage of single circuit at 400 kV and 765 kV levels and outage of double circuit at 132 kV and 220 kV levels is considered as ‘N-1’ outage. Further, India has also introduced N-1-1 stability criterion for critical elements of the grid. The transmission system should also be capable of withstanding loss of most severe single system infeed.

Transmission planning should be such that the grid shall be able to survive

- A permanent three phase to ground fault on 765 kV or 400 kV cleared in 100 ms.
- A permanent three phase to ground fault on 220 kV or 132 kV cleared in 160 ms.
- A permanent single phase to ground fault on a 765 or 400 kV and accordingly, single pole opening (100 ms) of the faulted phase and unsuccessful re-closure (dead time 1 second) followed by 3-pole opening (100 ms) of the faulted line shall be considered.

- A fault in HVDC convertor station, resulting in permanent outage of one of the poles of HVDC bipole.
- An outage of single largest generating unit or a critical generating unit.
- A temporary single phase to ground fault on a 765 kV in a scenario where a 'N-1' contingency already has happened in the system. Accordingly, single pole opening (100 ms) of the faulted phase and successful re-closure (dead time 1 second) shall be considered.

India is the only country among the SAC whose grid code specifies different voltage variation limits for planning and operation stages. The voltage variation limits considered for planning stage is

- +/- 2% for 400 kV, 765 kV; +/- 5 to 7% for below 220 kV during normal conditions
- +/- 5% for 400 kV, 765 kV; +/- 10% for below 220 kV during emergency conditions

Transmission licensee (CTU) shall perform the reactive power compensation studies for ISTS in India.

Nepal

The System Planning Department (SPD) of NEA is responsible for Grid Planning. Based on the data collected from distribution utilities and other NEA grid users, the SPD shall prepare every year a demand forecast for the following 15-year period and to meet this demand, it shall also prepare a least cost generation expansion plan. Based on the demand and generation expansion plan, SPD shall conduct an annual review of the performance of the grid with a planning horizon of five years. Consolidating all these studies, the SPD shall review the Power System Master Plan every year. The planning code applies to System Planning Department (SPD), NEA; Grid Owner; System Operator; Generators; Distributors; any other non-NEA entity with a user system connected to the grid.

The criteria to be considered for transmission planning, given in the grid code, include (N-1) contingency considering outage of single circuit. The voltage variation limits considered for planning stage is

- +/- 5% during normal conditions
- +/- 10% during emergency conditions

Grid code specifies that transient stability should be considered in planning studies but does not mention any specific limits.

Pakistan

NTDC shall establish a planning process and submit a TSEP (Transmission System Expansion Plan) to NEPRA each year as part of the "Annual System Reliability Assessment and Improvement Report". The NTDC plan may be prepared for next 1, 3, 5 and 10 years into the future. The plan shall contain a long-term load forecast (at least for twenty years) and identify the required transmission system reinforcements/upgrading/expansion projects. All code participants shall provide necessary data to facilitate the planning process. The planning code applies to transmission licensee (NTDC), generation and distribution licensee, transmission-connected consumers and externally connected parties.

The criteria to be considered for transmission planning given in the grid code, include (N-1) contingency considering outage of single circuit. The voltage variation limits considered for planning stage is

- +/- 5% for 132 kV, +/-10% for 220 kV during normal conditions
- +/- 10% for 132 kV, +/-10% for 220 kV during emergency conditions

The grid code specifies that planning process should consider that system should be capable of surviving a permanent three phase to ground fault on 500 kV or 220 kV with a fault clearance of 100 ms.

Sri Lanka

Transmission licensee will prepare a transmission development plan for a period of ten years and update the plan at least once in two years. The planning code applies to transmission licensee, transmission system users, prospective users, and parties who are authorised to carry out distribution/ supply activities and are connected to the grid.

The criteria to be considered for transmission planning given in the grid code include (N-1) contingency considering outage of single circuit. The transmission system should be capable of withstanding loss of one generator. The voltage variation limits considered for planning stage is

- +/- 5% for 132 kV, +/-10% for 220 kV during normal conditions
- +/- 10% for 132 kV and 220 kV during emergency conditions

Grid code specifies that transient stability should be considered in planning studies but does not mention any specific limits.

INTERNATIONAL PRACTICE

EUROPE (ENTSO-E)

The Transmission System Operator (TSO) is responsible for all transmission related activities. Planning scenarios are defined to represent future developments of the energy system. The essence of scenario analysis is to come up with plausible pictures of the future. Scenarios are means to approach the uncertainties and the interaction between these uncertainties. As it can take up to 10 years to build new transmission infrastructure, the objective is to construct scenarios that look beyond the coming 10 years.

It is necessary to model the external grid wide enough to guarantee accurate estimations in the responsibility area, when performing the N-1 analysis of the elements of the external contingency list. That means that not only the branches of the external contingency list have to be modeled but also other surrounding branches, with lower influence on the responsibility area, have to be part of the model. This will ensure correct simulations of the effects of abroad outages. All the external elements with an influence on the responsibility area higher than a certain value, called the observability influence threshold, constitute the external observability list. This defines the observability area.

Large scale wind farms or other large MW-scale distributed generation plants connected to the transmission system are to be modeled in detail like any other large generating plant in the system. However, because of its low load factor, supply to any part of the transmission system should not depend on wind generation.

All TSOs are obligated to serve under an 'N-1' principle which is developed with the goal of preventing propagation of an incident. Each TSO is expected to continuously monitor and warn neighbours of any risks foreseen within the system. Awareness of impact of any domestic decision on the neighbours and Bi-multilateral coordination before any such operation is also made mandatory. Best efforts are required to set up remedial actions, even if the actions of a single TSO is insufficient. Risk assessment and coordination is the major requirement of planning criteria.

"Network stress tests" are performed on each planning case and follow specific technical planning criteria developed by ENTSO-E on the basis of long term engineering practice. The criteria cover both the kind of contingencies chosen as "proxies" for hundreds of other events that could happen to the grid, and the adequacy criteria relevant for assessing overall behaviour of the transmission system.

It is endeavoured that cascading effects across borders must be prevented by remedial actions. Preventive (before occurrence of the contingency) and curative (after occurrence) remedial actions are due to be previously prepared in operational planning stage and to be duly applied in real time. The goal of remedial actions is to fully respect the N-1 principle taking into account inter-TSOs coordination.

After a normal or exceptional type of contingency, the situation should be without constraints after implementation of remedial actions when needed. These remedial actions (preventive/curative) have to be previously assessed by numerical simulations in order to evaluate the influence of those measures on the constraints and also to prevent negative effects to neighbouring TSOs.

NERC

The planning coordinator shall perform the resource adequacy analysis annually. Each planning coordinator and each of its transmission planners shall jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the planning coordinator's planning area.

The system is modeled such that all data required for steady-state, dynamics, and short circuit studies are accurate. Following key features are mandatory for the modeling of the variable generators (generators whose source of the energy is not dispatchable, like solar, wind, etc.):

- Preliminary model data may be used for the initial feasibility study of a variable generator interconnection project.
- The best model available shall be used for the final system impact study or facilities study. These models can be user-written and require non-disclosure agreements.
- The detailed dynamic model must be accurate over the frequency range of 0.1 to 5 Hz. Time constants in the model should not be less than 5 ms.
- The detailed dynamics model must have been validated against a physical or type test.

For the planning events, when the analysis indicates an inability of the system to meet the performance requirements, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned system shall continue to meet the performance requirements.

SAPP

The entity/utility shall annually publish a five-year-ahead transmission system development plan by end December to feed into the overall SAPP transmission system development plan. The plan will indicate the major capital investments planned. Each member of SAPP shall submit a 20-year forecast for peak demand energy requirements.

The interconnected transmission system should be capable of performing reliably under a wide variety of expected system conditions while continuing to operate within specified equipment and electric system thermal, voltage and stability limits. Reliability studies examine post-contingency steady state conditions as well as stability, overload, cascading and voltage collapse conditions.

INFERENCES FOR SOUTH ASIA

For the planning process, it is essential to have a co-ordinating agency for planning the cross-border links and over a period of time formulate itself into an authority overseeing all the activities of cross-boundary transactions. However, in the interim, as in the SAPP, each country/utility shall be authorised as a designated agency by the country, shall prepare their transmission system development plan and then same can be integrated with the South Asian transmission system development plan. The South Asian transmission development plan can be prepared by the planning committee (bilateral/trilateral/mutual agreement) which is to be formed by the member countries involving entities of all interconnected regions as per Article 7 of SAARC Framework Agreement for Energy Cooperation (Electricity). This committee shall be responsible for all the planning activities of their domain.

Further, it would be necessary to prepare the Master Plan, which shall formulate with the plan for next 10 years, considering necessary system upgradations, both proposed and commissioned. It must be reviewed annually and must ensure adequacy for all scenarios that could be possible in the next 10 years, by forecasting both demand and generation considering necessary factors.

The interconnection adopted in South Asian region comprises of both asynchronous and synchronous. In the asynchronous interconnection (HVDC back-to-back or HVDC Bi-pole) it may be necessary to define the contingency (Loss of one pole, convertor transformer, filter banks, etc.) which results in reduction in power flow. In the synchronous interconnection, the criteria of N-1 or N-1-1 contingency shall be defined and adopted. For the purpose of planning the inter-state transmission system, the transmission network shall be modeled down to 220 kV level. The base case shall be attempted corresponding to load-generation scenarios (reflecting typical daily and seasonal variations in load and generation) for a 5-year time horizon.

In the interconnected transmission system, the security is interdependent and hence the observability and analysis of the neighbouring system is paramount. It is required that planner shall define the responsibility area at each of the interconnection point and consider the influence of the surround grid on the cross-border power flow. Further, to assess the impact of various scenarios, it is important to have the accurate model of the interconnected system. With the increasing penetration of variable generation (wind & solar), it would be required to adequately model the impact of these generation on the system.

The remedial actions shall be established for normal, severe and rare contingencies based on a detailed impact analysis. The remedial actions shall be preventive, curative or a combination of both, to ensure that the system limits are not violated as a result of disturbance.

3. CONNECTION

CURRENT PRACTICE IN SOUTH ASIA

In all grid codes, it is mentioned that connection code applies to all users: those who are already connected and those seeking new/modify existing connection.

Bangladesh

Any potential user seeking to establish new or modified arrangement of connection to or for use of the Transmission system shall submit an application in standard format to the transmission licensee. A connection agreement shall be signed by the applicant in accordance with the grid code. Transmission licensee is responsible for data communication (such as flow, voltage and status of switches/transformer taps etc.) through SCADA. The users who are connected to transmission system should not depend on transmission system for reactive support.

In Bangladesh, the procedure for international connection to the transmission system and the execution of agreement for the same shall be done by the Licensee in consultation with the Commission and the Line Ministry.

In Bangladesh the Meters are classified as Generation, Transmission and Distribution connected Meters. The meters follow respective country-specific meter standards. The meters placed in transmission system are owned and maintained by transmission licensees. Billing is processed by system operators. The meters shall be located at outgoing feeders of generation sub-station (common connection point). The provision to transfer the meter readings which are connected at transmission connection point to remote location through data communication channels must be available. The meter accuracy level shall be +/- 0.2%.

Maintenance works of meters is carried out by the generating company or the licensee or distribution licensee. Bangladesh grid code specifies that at each metering point associated with determination of energy exported or imported the transmission licensee shall install, own and maintain a metering system.

The transmission licensee is responsible for undertaking protection studies, coordinate with users for determination and approval of relay settings and finalise a protection coordination plan in Bangladesh. This entity is also responsible for the design, installation and maintenance of protection system.

The grid code specifies that

- Every element of the power system shall be protected by a standard protection system having the required reliability, selectivity, speed, discrimination and sensitivity.
- An additional protection as back up protection besides the main protection shall be provided.
- The user shall protect his system from faults within his site and from those originating in the grid.
- Protection system shall reliably detect faults and various abnormal conditions within the protection zone and appropriate means to isolate them.
- Circuit Breaker fail protection or Local Breaker Back up protection shall be provided.
- Bus Bar protection shall be provided. Generators should be protected from faults within the premises and in the grid.
- Each transmission line shall be provided with two sets of distance protection schemes and a backup scheme.

Bhutan

Any potential user seeking to establish new or modified arrangement of connection to or for use of the transmission system shall submit an application in standard format to the transmission licensee. A connection agreement shall be signed by the applicant in accordance with the grid code. Transmission licensee is responsible for data communication (such as flow, voltage and status of switches/transformer taps etc.) through SCADA.

It is noted that,

- The distribution licensee shall not depend upon the transmission system for reactive compensation support.
- The procedure for international connection to the transmission system and the execution of agreement for the same shall be done by the agency who has been assigned this responsibility by the Ministry.
- All transmission licensees shall submit annually to the authority by 31st March each year a schedule of transmission assets which constitute the transmission system as on 31st December of the previous year.

Bhutan grid code specifies procedures only for energy meters. The meters follow their own country-specific meter standards. The meters placed in transmission system are owned and maintained by transmission licensees. Billing is processed by system operators. The meters shall be located at outgoing feeders of generation sub-station (common connection point). The provision to transfer the meter readings which are connected at transmission connection point to remote location through data communication channels must be available. The meter accuracy level shall be +/- 0.2%.

Bhutan grid code specifies that energy meters shall be installed on all interconnections with the distribution licensees and generators and other identified points for recording of actual bilateral energy exchange and reactive energy drawls. The system operator shall be responsible for computation of actual energy export/import of each generating stations and at each distribution point. Meters are installed and owned by the licensees in whose premises the meter is installed.

The System Coordination Committee (SCC) is responsible for undertaking protection studies, coordinate with users for determination and approval of relay settings and finalise a protection coordination plan in Bhutan. This entity is also responsible for the design, installation and maintenance of protection system.

Special Protection Schemes (SPS) for operating the system closer to its limits, protection from voltage collapse, cascade tripping and tripping of important corridors shall be provided.

India

Any potential user seeking to establish new or modified arrangement of connection to or for use of the Transmission System shall submit an application in standard format to CTU. A connection agreement shall be signed by the applicant in accordance with the CERC Regulations, 2009.

It is noted that, according to Indian Grid code,

- STUs and users should not depend on ISTS for reactive power support.
- RLDCs are responsible for data communication (such as flow, voltage and status of switches/ transformer taps etc.) through SCADA.
- All utilities shall have in place, a cyber-security framework to identify the critical cyber assets and protect them so as to support reliable operation of the grid.
- The procedure for international connection to ISTS and the execution of agreement for the same shall be determined by Transmission Licensee (CTU) in consultation with CEA and Ministry of Power (MOP).
- CTU and other transmission licensees granted license by CERC shall submit annually to CERC by 30th September each year a schedule of transmission assets which constitute the Regional Grid as on 31st March of that year indicating ownership on which RLDC has operational control and responsibility.

India grid code specifies following requirements applicable to both wind and other generating stations using inverters:

- The harmonic current injections from a generating station shall not exceed the limits specified in IEEE Standard 519.
- Grid code of India specifies that the generating station shall not inject DC current greater than 0.5% of the full rated output at the interconnection point.
- The generating station in India shall not introduce flicker beyond the limits specified in IEC 61000.
- Indian grid code specifies that the measurement of harmonic content, DC injection and flicker shall be done at least once in a year in presence of the parties concerned and the indicative date for the same shall be mentioned in the connection agreement.
- Indian grid code specifies that the generating station shall be capable of supplying dynamically varying reactive power support so as to maintain power factor within the limits of 0.95 lagging to 0.95 leading.
- The generating units shall be capable of operating in the frequency range of 47.5 Hz to 52 Hz and shall be able to deliver rated output in the frequency range of 49.5 Hz to 50.5 Hz.
- CEA guidelines of India specifies that wind generating stations connected at 66 kV and above shall have
    - o Low Voltage Ride-Through Capability (LVRT). Provided that during voltage dip, units shall generate active power proportional to the retained voltage and shall maximise supply of reactive current till the time voltage starts recovering.
    - o Facility to control active power injection in accordance with a set point which shall be capable of being revised in accordance with the directions of appropriate LDC. Reduction in generation shall be done, as far as possible, by sharing it among all the units on pro-rata to their capacity and not by shutting down few units.

In India, metering code applies to all the generating companies and licensees. The meters are classified into three categories: Interface, consumer, energy accounting and audit meters. The meters shall comply with BIS (Bureau of Indian Standards). If relevant BIS are not available, it shall follow the relevant IEC Standard. The meters placed in transmission system are owned and maintained by transmission licensees. The meters used for real-time monitoring are interface meters and energy accounting meters are used for billing. Billing is processed by system operators. The meters shall be located at outgoing feeders of generation sub-station (common connection point). The provision to transfer the meter readings which are connected at transmission connection point to remote location through data communication channels must be available. Metering for transmission lines shall be done at both ends of the line between sub-stations of two different licensees. The meter accuracy level shall be +/- 0.2%.

Maintenance works of meters is carried out by the generating company or the licensee or distribution licensee. Grid code of India specifies that the Inter-State Transmission licensee, the CTU, shall install special energy meters on all interconnections between the regional entities and other identified points for recording of active and reactive power exchanges. The State grid codes specify the same for intra-state transmission licensee - the STU. The meters shall be of static type. Weekly readings of the meters located between two control areas/regional entities shall be forwarded to the RLDC for computation of net drawl/injection who will then forward it to RPC Secretariat for issuing the unscheduled interchange account.

Regional Power Committee (RPC) and its subcommittee called Protection Coordination Sub-Committee are responsible for undertaking protection studies, coordinate with users for determination and approval of relay settings and finalise a protection coordination plan in India. This entity is also responsible for the design, installation and maintenance of protection system.

The grid code specifies that

- Every element of the power system shall be protected by a standard protection system having the required reliability, selectivity, speed, discrimination and sensitivity.
- An additional protection as back up protection besides the main protection shall be provided.
- The user shall protect his system from faults within his site and from those originating in the grid.
- Protection system shall reliably detect faults and various abnormal conditions within the protection zone and appropriate means to isolate them.
- Circuit Breaker fail protection or Local Breaker Back up protection shall be provided.

Special Protection Schemes (SPS) for operating the system closer to its limits, protection from voltage collapse, cascade tripping and tripping of important corridors shall be provided. Bus Bar protection shall be provided. Generators should be protected from faults within the premises and in the grid. All generators above 100 MW of capacity shall have two independent sets of main protection schemes and a backup protection scheme. Other State grid codes specify that generators be provided a main and back up protection scheme. Clearance period will be as per connection agreement. Each transmission line shall be provided with two sets of distance protection schemes and a backup scheme. At all transmission connection sites, disturbance recording and event logging facilities along with time synchronisation facility for global common time reference shall be provided.

Nepal

Any potential user seeking to establish new or modified arrangement of connection to or for use of the transmission system shall submit an application in standard format to the Grid Owner. A connection agreement shall be signed by the applicant in accordance with the grid code. The Grid Owner is responsible for data communication (such as flow, voltage and status of switches/transformer taps etc.) through SCADA.

In Nepal, metering code applies to all the generating companies and licensees. The meters are classified as energy meters and bi-directional meters. The meters shall comply with IEC standards. The meters placed in transmission system are owned and maintained by transmission licensees.

Billing is processed by system operators. NEA grid code specifies that bi-directional meters shall be installed at all the connection points between Grid and Distributor/Generator to measure active and reactive energy exchange.

The Grid Owner is responsible for undertaking protection studies, coordinate with users for determination and approval of relay settings and finalise a protection coordination plan in Nepal. This entity is also responsible for the design, installation and maintenance of protection system.

The grid code specifies that,

- Every element of the power system shall be protected by a standard protection system having the required reliability, selectivity, speed, discrimination and sensitivity.
- An additional protection as back up protection besides the main protection shall be provided.
- The user shall protect his system from faults within his site and from those originating in the grid.
- Protection system shall reliably detect faults and various abnormal conditions within the protection zone and appropriate means to isolate them.
- Circuit breaker fail protection or local breaker back up protection shall be provided.

Generators should be protected from faults within the premises and in the grid. A minimum of one distance protection scheme and a backup scheme shall be provided. The distance protection relays shall have in-built facilities for fault locator, event recorder and disturbance recorder.

Pakistan

Any potential user seeking to establish new or modified arrangement of connection to or for use of the Transmission System shall submit an application in standard format to the transmission licensee. A connection agreement shall be signed by the applicant in accordance with the grid code.

It is noted that,

- The grid code specifies that distribution companies shall maintain a power factor of a minimum of 95% by providing reactive compensation at 132 kV and below voltage levels.
- Transmission licensee is responsible for data communication (such as flow, voltage and status of switches/transformer taps etc.) through SCADA.

In Pakistan, revenue meters are used for the purposes of billing, engineering studies and planning. The meters shall comply with IEC standards. The meters placed in transmission system are owned and maintained by transmission licensees. Billing is processed by system operators. The meters shall be located at outgoing feeders of generation sub-station (common connection point). The provision to transfer the meter readings which are connected at transmission connection point to remote location through data communication channels must be available. The meter accuracy level shall be +/- 0.2%.

Maintenance works of meters is carried out by the generating company or the licensee or distribution licensee. Pakistan grid code specifies that metering facility shall be provided at the Point of Connections between Code Participants and NTDC to record energy and maximum power (active and reactive power both) supplied to or delivered from the transmission system of NTDC for the purposes of billing, engineering studies and planning. NTDC shall install these energy meters. Meter readings shall be transmitted to the system operator for further processing.

NTDC (National Transmission and Dispatch Company) is responsible for undertaking protection studies, coordinate with users for determination and approval of relay settings and finalise a protection coordination plan in Pakistan. This entity is also responsible for the design, installation and maintenance of protection system.

The grid code specifies that

- Every element of the power system shall be protected by a standard protection system having the required reliability, selectivity, speed, discrimination and sensitivity.
- An additional protection as back up protection besides the main protection shall be provided.
- The user shall protect his system from faults within his site and from those originating in the grid.
- Protection system shall reliably detect faults and various abnormal conditions within the protection zone and appropriate means to isolate them.
- Circuit Breaker fail protection or Local Breaker Back up protection shall be provided.

Bus Bar protection shall be provided. Generators should be protected from faults within the premises and in the grid. Each transmission line shall be provided with two sets of distance protection schemes and a backup scheme. At all transmission connection sites, disturbance recording and event logging facilities along with time synchronisation facility for global common time reference shall be provided.

Sri Lanka

Any potential user seeking to establish new or modified arrangement of connection to or for use of the Transmission System shall submit an application in standard format to the Transmission licensee. A connection agreement shall be signed by the applicant in accordance with the grid code. Transmission licensee is responsible for data communication (such as flow, voltage and status of switches/transformer taps etc.) through SCADA.

In Sri Lanka, Transmission Licensee shall establish a Plant and Equipment database to ensure the schedule of assets is recorded.

Sri Lanka grid code specifies following requirements for wind generators:

- The harmonic current injections from a generating station shall not exceed the limits specified in IEEE Standard 519.
- In Sri Lanka, the generating station shall comply with IEC 61400-21 standard and P28 Engineering recommendations of UK.
- Active power regulation capability shall be provided.

In Sri Lanka, metering code applies to all licensees who are authorised to carry out distribution/ transmission activities. The meters shall comply with IEC Standards. The meters placed in transmission system are owned and maintained by transmission licensees. Billing is processed by system operators. The meters shall be located at outgoing feeders of generation sub-station (common connection point). The provision to transfer the meter readings which are connected at transmission connection point to remote location through data communication channels must be available. The meter accuracy level shall be +/- 0.2%.

The transmission licensee is responsible for undertaking protection studies, coordinate with users for determination and approval of relay settings and finalise a protection coordination plan in Sri Lanka. This entity is also responsible for the design, installation and maintenance of protection system.

The grid code specifies that,

- Every element of the power system shall be protected by a standard protection system having the required reliability, selectivity, speed, discrimination and sensitivity.
- An additional protection as back up protection besides the main protection shall be provided.
- The user shall protect his system from faults within his site and from those originating in the grid.
- Protection system shall reliably detect faults and various abnormal conditions within the protection zone and appropriate means to isolate them.
- Circuit Breaker fail protection or Local Breaker Back up protection shall be provided.
- Generators should be protected from faults within the premises and in the grid.

INTERNATIONAL PRACTICE

EUROPE (ENTSO-E)

The connection code is applicable to all users (Power Generating Modules, Demand Facility Owner or Distribution Network Operator) who are already connected as well as those seeking new/modified connection. Their network code does not apply to the small isolated systems and in the micro-isolated systems.

A user who is willing to take new connection shall demonstrate and submit sufficient evidence to the relevant network operator. The relevant network operator shall confirm the user connection as per the procedures mentioned in the network code, with the approval of National Regulatory Authority. If the user intends to modify the technical capabilities of the existing connection then he shall notify the Relevant Network Operator.

The connection agreement is signed between the relevant network operator and the user. The agreement includes relevant site and technical specifications for the Power Generating Facility or distribution network connection, like maximum import and export capabilities etc.

User shall be capable of maintaining their steady state operation at their connection point within a reactive power range specified by the relevant TSO and as per the agreement, the relevant TSO and relevant network operator determine the optimal solution for reactive power exchange.

The normal operating frequency in Europe is 50 Hz and the permissible frequency deviation at the connection point is 49 Hz to 51 Hz. Wider frequency ranges or longer minimum frequency recover times for operation can be agreed between the user and network operator in coordination with the relevant TSO. Wide range of operating voltage is agreed between the user and system operator at the connection point, any user with a connection point at 110 kV or above shall ensure its equipment is capable of withstanding without damage the voltage range at the connection point. The establishment of the reference nominal Voltage shall be subject to coordination between the adjacent TSOs. The relevant TSO shall deliver to the user an estimate of the minimum and maximum short-circuit currents at the connection point as an equivalent of the Network.

The Relevant Network Operator shall define the schemes and settings necessary to protect the network taking into account the characteristics of the Power Generating Module and Transmission connected distribution network. Schemes and settings for the different control devices of the transmission connected distribution network or transmission connected demand facility, relevant for system security, shall be agreed by the relevant TSO, and the user. Any changes to the schemes and settings of the different control devices of the transmission connected system relevant for system security shall be agreed between the relevant TSO, and the user.

Relevant TSO/DSO is responsible for operating, ensuring the maintenance of and, if necessary, developing the transmission system/distribution network in a given area and, where applicable, its interconnections with other networks and for ensuring the long-term ability of the network to meet reasonable demands for the distribution of electricity.

NERC

Connection code applies to customers (Generator Owner, Transmission Owner, Distribution Provider, and Load-Serving Entity) seeking to integrate generation facilities, transmission facilities, and electricity end-user facilities.

Any customer seeking to integrate/modify generation facilities, transmission facilities, and electricity end-user facilities shall provide the documentation to the Regional Reliability Organisation(s) and NERC Reliability Standards on the interconnected transmission systems. The connection agreement shall be signed by the applicant in accordance with the NERC Reliability Standards.

End-users connected directly to the transmission system should plan and design their systems to operate at close to unity power factor to minimise the reactive power burden on the transmission system.

The transmission system typically operates at a nominal 60 Hz with a variation of 0.05 Hz (59.95 to 60.05 Hz) at the synchronous area.

Interconnected device shall fully comply with the latest ANSI/IEEE C37 collection of standards and be capable of interrupting the maximum available fault current at that location. Automatic reclosing of the applicant's facilities is not permitted unless a special agreement is worked out with transmission owner.

Transmission owner reserves the right to specify functional specifications and relay settings to the applicant and shall review the interface protection and/or the self-contained protection schemes included with the generation before the unit will be permitted to connect to the transmission system. The applicant connecting to the transmission system are responsible for determining that the proper protective equipment meet all applicable standards, is properly installed and coordinates with transmission owner relaying.

The maintenance of facilities is the responsibility of the owner of those facilities. Planned maintenance and testing of the facilities must be scheduled and coordinated through regional operator to ensure the reliability and capability of the owner for the transmission system is maintained.

Transformers connected through transmission (EHV interchange) metering points are provided from the secondary side of all through-transmission transformers connected to the 500 kV EHV system. Generators and transformers (Radially Tapped) that are not through transmission (including unit station service transformers) and that are tapped directly on the EHV system are provided with interchange metering on the primary side of the step-up, station service or radial transformer. All metering equipments shall act in accordance with American National Standards Institute (ANSI) standards. Transmission operator is responsible for properly maintaining its metering equipment. Meter information is automatically and electronically communicated to transmission operator by the producer, host utility, or transmitter in order to ensure timely accounting and billing. Billing metering systems are capable of collecting and storing bi-directional information for intervals as determined by the parties involved. The relevant transmission operator maintains a metering database for auditing purposes.

Meter readings (active and reactive powers) shall be transmitted to the System Operator for Billing. Hourly MWh readings data must be provided to system operator daily to ensure accurate billing. The megawatt-hour (MWh) is the standard unit of service measurement. Any generation unit participating in the energy market is required to have independent metering devices that are capable of recording generation net MWh output. Backup meters of sufficient accuracy serve as a replacement for the primary metering system. The average of instantaneous values may be used as a backup source, provided mutually agreed upon accuracy is obtained and applicable standards are achieved and is capable of collecting interchange data and logically comparing data with the primary meter system. The equipment owner of the premises where the meter is installed shall provide access to the transmission system operators for installation, testing, commissioning, reading and recording and maintenance of meters.

INFERENCES FOR SOUTH ASIA

Connection code is applicable to the authorised transmission agencies for cross-border links and the associated sub-stations. For other links within the country, the respective countries connection code would be applicable.

The designated agency or the co-ordination forum or the planning committee has to provide clearance for new or modified arrangement connection with the transmission system of the cross-border links. The connection agreement shall be mandatory between the designated transmission companies of member countries for the cross-border link.

Generators who intend to sell power through the cross-border links must comply with their respective country regulation. If the cross-border links is through synchronous interconnection (AC link) then the reactive power flow on the links shall be limited to 0.97 lead or lag at the point of interconnection on either side of the link. In case of HVDC link or asynchronous link, the voltage is to be maintained within the limit by the respective transmission agencies to prevent mal-operation of the HVDC links.

Recommended frequency band of operation of synchronised interconnection shall be within 49.9 Hz to 50.05 Hz and frequency profiles shall be fixed and followed by all connecting equipments. At the point of interconnection, acceptable range of operating voltages shall be ±5% for 400 kV and above transmission voltage levels but all the connected equipment shall withstand the voltage variation of ±10%.

At the connection point, respective agency shall be vested to prepare and review protection schemes according to the adopted standards in line with Article 10 of SAARC Framework Agreement for Energy Cooperation (Electricity).

Maintenance activities shall be carried out by relevant owner/operator of that network connected system. It is recommended that independent authority in the long term and co-ordination forum in the short term be identified to monitor and permit the outage. The designated transmission agencies are authorised to carry out the maintenance work.

It is recommended that energy meters shall be provided at both sides of the connection point. IEC Standards shall be followed for the Metering. Energy Accounting and Audit functions shall be carried out by coordinating forum or the planning committee or separate agency as required and all meters for interconnection shall be owned by Government designated Transmission Licensee/CTU. The designated transmission agency shall give permission for the relevant system operator to install, testing, commissioning, reading and recording and maintenance of meters.

4. OPERATION

CURRENT PRACTICE IN SOUTH ASIA

In Bhutan, Pakistan, Nepal and Sri Lanka, system operator is responsible for the operation of power system. In Bangladesh, NLDC is responsible. In India, overall operation of the National/inter-regional grid shall be supervised by the NLDC while the RLDC would supervise the Inter-State transactions.

Bangladesh

Bangladesh Grid Code specifies that no cross boundary circuits or Generating Unit of a Generator shall be removed from service without specific release from the NLDC. Adequate operating reserves (Spinning/Contingency/Stand-by) shall be made available for use during contingency conditions and large demand variation conditions. Reserves are also included in the day-ahead despatch schedule.

The grid code specify that when the frequency rises above 51.0 Hz or falls below 49.0 Hz for Bangladesh, the generating units which were responsible for seeing frequency of the system shall decrease or increase respectively, their generating output at a rate of 2% per 0.1 Hz departure of frequency until the frequency is restored within the normal range. While preparing generation schedules, the concerned entity should consider the ramping-up/ramping-down limits of the generators. All generating units shall have an Automatic Voltage Regulator (AVR) in service. It is noted that,

- Operating frequency range is from - 49 Hz to 51 Hz
- All users, system operators, transmission licensees shall take all possible measures to ensure that the grid voltage always remains within +/-5% during normal conditions and within +/-10% during emergency conditions.

Transmission licensee is responsible for demand estimation (MW, MVAr and MWh) for daily/weekly/monthly/yearly basis. NLDC should make provisions to reduce their demand in the event of insufficient generating capacity or supply from external interconnections. During frequency level problems, the concerned entity shall give instructions to distribution licensees to decrease their drawl by a certain quantum.

The transmission licensee shall produce a yearly transmission outage program for the period July to June. He is authorised during the restoration process following a black out, to operate with reduced security standards for voltage and frequency as necessary in order to achieve the fastest possible recovery of the grid.

Bhutan

It is stated that no part of the grid shall be deliberately isolated from the rest of the National/Regional grid, except under an emergency or when such isolation is specifically instructed by system operator. The restoration process shall be supervised by the system operator, as per operating procedures separately formulated by system operator of Bhutan.

All hydro units of 10 MW and above shall have their governors in operation at all times. Adequate operating reserves (Spinning/Contingency/Stand-by) shall be made available for use during contingency conditions and large demand variation conditions. Reserves are also included in the day-ahead despatch schedule.

Grid codes specify that supplementary control for increasing or decreasing the output for all generating units, irrespective of their type and size, would be 1% per minute or as per manufacturer's limits. However, if frequency falls below 49.7 Hz, all partly loaded generating units shall pick up additional load at a faster rate, according to their capability. While preparing generation schedules, the concerned entity should consider the ramping-up/ramping-down limits of the generators. All generating units shall have an automatic voltage regulator (AVR) in service.

It is noted that,

- Operating frequency range is from - 49.5 Hz to 50.5 Hz
- All users, system operators, transmission licensees shall take all possible measures to ensure that the grid voltage always remains within +/- 5% during normal conditions and within +/- 10% during emergency conditions.
- All transmission licensee shall facilitate identification, installation and commissioning of system or Special Protection Schemes (SPS) (including inter-tripping and run-back) in the power system.
- All users under the operation control of system operator shall send information/data including disturbance recorder/sequential event recorder output.

In Bhutan Distribution licensee is responsible for demand estimation (MW, MVAr and MWh) for daily/weekly/monthly/yearly basis. System Operator and Distribution Licensees should make provisions to reduce their demand in the event of insufficient generating capacity or supply from external interconnections. During frequency level problems, the concerned entity shall give instructions to distribution licensees to decrease their drawl by a certain quantum.

Bhutan grid code specifies that if required by system operator then the distribution licensees shall provide automatic under-frequency load shedding facilities in their respective systems and details of arrangements of demand into discrete blocks to system operator. The measures taken to reduce the drawl from the transmission system shall not be withdrawn as long as the frequency/voltage remains at a low level or congestion continues unless specifically permitted by the system operator.

The system operator shall be responsible for analysing the outage plans given by all Licensees, and finalisation of the outage plan for the following calendar year. The system operator is authorised during the restoration process following a black out, to operate with reduced security standards for voltage and frequency as necessary in order to achieve the fastest possible recovery of the grid. It is required that a quarterly report shall be issued by the system operator which covers the performance of the transmission system for the previous quarter.

India

In India, all licensees, generating station/company and any other person connected with the power system operation shall comply with the directions issued by the respective RLDC/SLDC.

It is stated that no part of the grid shall be deliberately isolated from the rest of the National/Regional grid, except under an emergency or when such isolation is specifically instructed by RLDC. The restoration process shall be supervised by RLDC, as per operating procedures separately formulated by NLDC/RLDC in India.

Grid code of India does not explicitly mention about operating reserves but it specifies that all thermal generating units of 200 MW and above and all hydro units of 10 MW and above operating at or up to 100% of their Maximum Continuous Rating (MCR) shall be capable of instantaneously picking up to 105% and 110% of their MCR, respectively, when frequency falls suddenly. Any generating unit in India not complying with the above requirements shall be kept in operation only after obtaining the permission of RLDC. Accordingly, it is required that all thermal generating units of 200 MW and above and all hydro units of 10 MW and above, shall have their governors in operation at all times. Droop settings in the range of 3% to 6% and Governor dead band of ±0.03 Hz are specified.

Grid codes specify that supplementary control for increasing or decreasing the output for all generating units, irrespective of their type and size, would be 1% per minute or as per manufacturer's limits. However, if frequency falls below 49.7 Hz, all partly loaded generating units shall pick up additional load at a faster rate, according to their capability. While preparing generation schedules, the concerned entity should consider the ramping-up/ramping-down limits of the generators.

It is noted that,

- All generating units shall have an Automatic Voltage Regulator (AVR) in service. Further, a properly tuned Power System Stabiliser (PSS) should be in service.
- Operating frequency range is from - 49.9 Hz to 50.05 Hz
- All users, system operators, transmission licensees shall take all possible measures to ensure that the grid voltage always remains within +/- 5% for 400 kV, 765 KV; +/- 10% for 220 kV and below during normal and emergency conditions.
- All distribution licensees shall provide automatic under-frequency and df/dt relays for load shedding. All users, STU/SLDC, CTU/RLDC and NLDC shall facilitate identification, installation and commissioning of System or Special Protection Schemes (SPS) (including inter-tripping and run-back) in the power system.
- All users under the operation control of RLDC (in India) shall send information/data including disturbance recorder/sequential event recorder output.

In India, the grid code specifies that system operator shall make all efforts to evacuate the available solar and wind power and treat them as a must-run station except in a scenario where doing so will be against grid security or safety considerations.

The SLDCs are responsible for demand estimation (MW, MVAr and MWh) for daily/weekly/monthly/yearly basis. SLDCs shall take into account the wind energy forecasting to meet the active and reactive power requirement. SLDCs should make provisions to reduce their demand in the event of insufficient generating capacity or supply from external interconnections. It also specifies that the SLDCs/SEB/Distribution licensee shall initiate action to restrict drawl of its control area within scheduled value when the frequency falls to 49.7 Hz and shall ensure requisite load shedding is carried out to prevent over drawl when frequency is 49.5 Hz and below. Also, when frequency is above 49.7 Hz and below 50.1 Hz, each control area shall ensure the over drawl/under injection during a time block (15 minute blocks) shall not exceed 12% of scheduled value or 150 MW, whichever is lower.

According to India Grid code, SLDCs through their respective State Electricity Boards/Distribution Licensees shall formulate and implement state-of-the-art demand management schemes for automatic demand management like rotational load shedding, demand response etc., and the interruptible loads shall be categorised into four non-overlapping groups, for scheduled load shedding, for unscheduled load shedding, for shedding through under-frequency/df/dt relays and for shedding through SPS.

In India, regulations applicable during scenarios of congestion in the inter-control area transmission lines have been laid down. For each inter-control area transmission line, CTU shall declare the corresponding Total Transfer Capability (TTC), Available Transfer Capability and Transmission Reliability Margin (TRM). If the flow in an inter-control area transmission line exceeds its ATC, then NLDC/RLDC shall give a warning to involved entities and if it exceeds TTC, then applies congestion charges over and above the Unscheduled Interchange (UI) charges to the defaulting entities. The measures taken to reduce the drawl from the Transmission System shall not be withdrawn as long as the frequency/voltage remains at a low level or congestion continues unless specifically permitted by RLDC/SLDC (India).

Weekly and monthly reports covering performance of the national/integrated grid in previous week shall be prepared by NLDC, in India. Daily, weekly and quarterly reports covering the performance of the regional grid shall be prepared by each RLDC based on the inputs received from SLDCs/ Users. It is also noted that annual outage plan shall be prepared in advance for the financial year by the RPC Secretariat in consultation with NLDC and RLDC and reviewed during the year on quarterly and monthly basis. This will be done after carrying out necessary system studies and, if necessary, the outage programmes shall be rescheduled. All users, CTU, STU etc., shall follow these annual outage plans.

NLDC/RLDC is authorised to defer the planned outage in case of any of the following, taking into account the statutory requirements:

i. Grid disturbances
ii. System isolation
iii. Partial black out in a state
iv. Any other event in the system that may have an adverse impact on the system security by the proposed outage

The RLDC is authorised during the restoration process following a black out, to operate with reduced security standards for voltage and frequency as necessary in order to achieve the fastest possible recovery of the grid.

Nepal

All hydro units of 10 MW and above shall have their governors in operation at all times. Adequate operating reserves (Spinning/Contingency/Stand-by) shall be made available for use during contingency conditions and large demand variation conditions. Reserves are also included in the day-ahead despatch schedule.

The grid code specify that when the frequency rises above 50.5 Hz or falls below 49.5 Hz, the generating units which were responsible for seeing frequency of the system shall decrease or increase respectively their generating output at a rate of 2% per 0.1 Hz departure of frequency until the frequency is restored within the normal range. While preparing generation schedules, the concerned entity should consider the ramping-up/ramping-down limits of the generators.

It is noted that,

- Operating frequency range is from - 49.5 Hz to 50.5 Hz
- All users, system operators, transmission licensees shall take all possible measures to ensure that the grid voltage always remains within +/- 5% during normal conditions and within +/- 10% during emergency conditions.
- System operator should make provisions to reduce their demand in the event of insufficient generating capacity or supply from external interconnections. During frequency level problems, the concerned entity shall give instructions to distribution licensees to decrease their drawl by a certain quantum.

Nepal grid code specifies that the distributor/HV Consumer shall split the demand into discrete MW blocks for automatic load dropping and the number of such blocks shall be specified by system operator. Two groups of digital under-frequency relays shall be provided – Group A for frequency level < 49.0 Hz and Group B for frequency level < 48.0 Hz. Under-frequency settings shall be provided by system operator. Grid Owner of Nepal shall install under-frequency relays to cover about 50% of the system peak demand on feeders spread all over the distribution network to provide a reasonably uniform disconnection in the distribution system. The measures taken to reduce the drawl from the transmission system shall not be withdrawn as long as the frequency/voltage remains at a low level or congestion continues unless specifically permitted by the system operator.

In Nepal, Users/generators will interact with system operator to plan for outages of grid/generators. System operators are authorised to defer the planned outage in case of any of the following, taking into account the statutory requirements:

i. Grid disturbances
ii. System isolation
iii. Partial black out in a state
iv. Any other event in the system that may have an adverse impact on the system security by the proposed outage

Pakistan

In Pakistan, any operational changes can be made only under the instructions of system operator. Pakistan grid code specifies that all thermal and reservoir based generators of capacity above 100 MW shall provide free governor control action within the frequency sensitive band of 49.8-50.2 Hz.

Adequate operating reserves (Spinning/Contingency/Stand-by) shall be made available for use during contingency conditions and large demand variation conditions. Reserves are also included in the day-ahead despatch schedule. While preparing generation schedules, the concerned entity should consider the ramping-up/ramping-down limits of the generators.

It is noted that,

- Operating frequency range is from - 49.8 Hz to 50.2 Hz
- All users, system operators, transmission licensees shall take all possible measures to ensure that the grid voltage always remains within +8% and -5% for 500 kV and 220 kV during normal conditions and within +/-10% for 500 kV and 220 kV during emergency conditions.
- All distribution licensees shall provide automatic under-frequency relays for load shedding.
- All users under the operation control of system operator shall send information/data including disturbance recorder/sequential event recorder output.

Transmission licensee is responsible for demand estimation (MW, MVAr and MWh) for daily/weekly/monthly/yearly basis. System Operator and Distribution licensees should make provisions to reduce their demand in the event of insufficient generating capacity or supply from external interconnections.

During frequency-level problems, the concerned entity shall give instructions to distribution licensees to decrease their drawl by a certain quantum. Further, when system frequency falls to 49.4 Hz or below, load shedding must be carried out to bring the frequency back to at least 49.8 Hz. It specifies that facility to disconnect demand during low frequencies is given at all transmission connection points and system operator shall provide automatic load shedding groups and the amount of load to be shed. The measures taken to reduce the drawl from the transmission system shall not be withdrawn as long as the frequency/voltage remains at a low level or congestion continues unless specifically permitted by the system operator.

In Pakistan, system operator shall finalise the outage plan for the following year based on the discussions with generation and distribution licensees and other transmission consumers. Pakistan grid code specifies that adjustments to outage schedule are allowed but there is no commitment on others to adjust their outage plan.

The system operator is authorised during the restoration process following a black out, to operate with reduced security standards for voltage and frequency as necessary in order to achieve the fastest possible recovery of the grid.

Sri Lanka

Sri Lanka grid code specifies that the Transmission Licensee shall ensure that switching operations are carried out only by authorised persons, under the direction of Systems Control Centre (SCC). In extreme emergencies where there is a threat to human life or to system equipment, switching operations may be carried out without being directed by SCC. Immediately after carrying out any switching operations, all related information shall be reported to the SCC by the relevant officers.

Droop settings in the range of 3% to 6% and governor dead band of ±0.05 Hz are specified. Adequate operating reserves (Spinning/Contingency/Stand-by) shall be made available for use during contingency conditions and large demand variation conditions. Reserves are also included in the day-ahead despatch schedule. While preparing generation schedules, the concerned entity should consider the ramping-up/ramping-down limits of the generators. All generating units shall have an automatic voltage regulator (AVR) in service.

It is noted that the operating frequency Range from - 49.5 Hz to 50.5 Hz and requires that all users, system operators, transmission licensees shall take all possible measures to ensure that the grid voltage always remains within +/- 5% for 132 KV, +/-10% for 220 kV during normal conditions and within +/- 10% for 132 KV, +/-10% for 220 kV during emergency conditions.

Transmission licensee is responsible for demand estimation (MW, MVAr and MWh) for daily/weekly/monthly/yearly basis. Transmission licensee should make provisions to reduce their demand in the event of insufficient generating capacity or supply from external interconnections. During frequency level problems, the concerned entity shall give instructions to distribution licensees to decrease their drawl by a certain quantum.

Sri Lanka grid code specifies that an automatic under-frequency load shedding program will be implemented by the Transmission Licensee to control the system demand. Distribution licensees shall provide details to transmission licensee identifying feeders at each grid sub-station as essential and non-essential loads with feeders having non-essential loads being further categorised in the order of priority.

In Sri Lanka, the transmission licensee shall establish a transmission outage program with a three-year window; Year 3 will be indicative with tentative dates, year 2 will be rolling over to the Year 3 program, and the Year 1 will be the committed outage plan.

The Transmission licensee is authorised during the restoration process following a black out, to operate with reduced security standards for voltage and frequency as necessary in order to achieve the fastest possible recovery of the grid.

INTERNATIONAL PRACTICE

Europe

For each element in its transmission system, the European grid code mandates each TSO define operational security limits. On the basis of these limits, the TSO must classify the current operating condition of its transmission system under one of the following five states in real time:

- Normal state
- Alert state
- Emergency state
- Black out state
- Restoration

The determination of the system operation state must be done at least every 15 minutes by performing contingency analysis in real time, monitoring the parameters against pre-set criteria, considering remedial actions and measures of system defense plan.

The European TSOs have the possibility of accessing Reserve Capacity connected to another LFC Area, LFC Block, or Synchronous Area to comply with the amount of required reserves resulting from their own reserve dimensioning process of Frequency Containment Reserve, Frequency Restoration Reserve or Replacement Reserves.

All TSOs should perform annual summer and winter generation adequacy assessments before May 21st and November 21st respectively, by forecasting the weekly peak demand for each period of study for both normal and severe conditions. This is used in generation adequacy assessment which deals with the ability of a power system to supply its demand in all the steady states that it may face. Due to the larger fluctuations in generation, demand, and cross-border flows, it becomes more and more important to accurately assess and forecast adequacy.

Frequency thresholds are defined for load shedding by each TSO. The UCTE recommends that the frequency threshold should not be set lower than 49 Hz. Load shedding should be established in stages to minimise the risk of further uncontrolled separation, loss of generation, or system shutdown.

Outage coordination process is an iterative process that starts in the second half of the preceding year and finishes on the day preceding actual operation (day-ahead). An outage coordination region is formed by grouping responsibility areas based on the extent of interconnection, for an efficient coordination. The set of power system assets which influence two or more TSOs while being out of operation are identified as relevant assets. Of these, which are considered to have a major influence on the operational management of the neighbouring systems are identified as critical assets. The outage coordination planning takes all relevant assets into account. Each outage coordinating TSO establishes and manages a coordination process to ensure the available or unavailable status of relevant assets in its responsibility area in case of forced outages and when operational security is endangered.

Each TSO has to prepare in advance and update regularly a restoration plan. TSOs have to know the status of components of their power system after a blackout before starting the restoration process. This process must be started only after the grid reaches a stabilised situation.

NERC

The NERC grid code doesn't mention any hard-set limits for the classification of the operating state of a system. However, Planning Authorities (PAs), Transmission Planners (TPs), and Reliability Authorities (RAs) identify System Operating Limits (SOLs) via various planning and operating studies and real-time experience. These SOLs define the boundary of reliable operations for the Bulk Electric System (BES). The NERC code further recognises that there is a subset of SOLs, called Interconnection Reliability

Operating Limits (IROLs) that, if violated, could lead to instability, uncontrolled separation, or could initiate Cascading Outages.

Each Balancing Authority and each Reserve Sharing Group shall maintain a minimum amount of Contingency Reserve. Each Balancing Authority and each Reserve Sharing Group shall maintain at least half of its minimum amount of Contingency Reserve, as Operating Spinning Reserve that can immediately and automatically respond to frequency deviations through the action of a governor or other control system and is capable of fully responding within ten minutes.

The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighbouring Transmission Operators shall utilise identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject to confidentiality requirements), and to its Reliability Coordinator.

Each Transmission Operator and Balancing Authority shall coordinate load shedding plans, excluding automatic under-frequency load shedding plans, among other interconnected Transmission Operators and Balancing Authorities. A Transmission Operator or Balancing Authority shall implement load shedding, excluding automatic under-frequency load shedding, in steps established to minimise the risk of further uncontrolled separation, loss of generation, or system shutdown. Each Transmission Operator or Balancing Authority shall have plans for operator controlled manual load shedding to respond to real-time emergencies. The Transmission Operator or Balancing Authority shall be capable of implementing the load shedding in a timeframe adequate for responding to the emergency.

Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of system voltage regulating equipment, such as automatic voltage regulators on generators, supplementary excitation control, synchronous condensers, shunt and series capacitors, reactors, etc., among affected Balancing Authorities and Transmission Operators as required.

Each Transmission Operator shall have a restoration plan approved by its Reliability Coordinator, allowing for restoring the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Black start Resources is required to restore the shutdown area to service. Following a Disturbance in which one or more areas of the BES shuts down and the use of black-start resources is required to restore the shutdown area to service; the Transmission Operator shall re-synchronise area(s) with neighbouring Transmission Operator area(s) only with the authorisation of the Reliability Coordinator or in accordance with the established procedures of the Reliability Coordinator.

INFERENCES FOR SOUTH ASIA

It is recommended to have the 5 classifications of the operating states, i.e. Normal, Alert, Emergency, Blackout and Restoration. The operating limits must be maintained at all interconnections and interconnecting sub-stations.

Incorporation of contingency studies during operational time horizons will ensure increased preparedness of the system operator. For this, scope of contingencies needs to be defined and automated simulations must be implemented to the extent possible.

In the initial development process, it is recommended to plan for Special Protection System (SPS) to prevent cascading with the outage of cross-border links. The SPS can be planned with hard-wired control either to demand facility or generation facility to limit the unintended power flow.

Transient stability is considered only during planning in South Asian countries. It is recommended to include high probable stability issues in the automated contingency simulation and be prepared with appropriate remedial actions for the same.

As regards to the frequency, the European countries and North America is maintaining the frequency without deviation and working with time error control. This is made possible with defined ancillary services in maintaining and dispatching reserves with the help of governor/primary response, secondary response/tertiary reserves, contingency reserves and load shedding contract. With synchronised interconnection, it may be required to adopt the same principles and enforce time error control in the respective control area.

The cross-border links shall facilitate in the primary reserve process. However, it is desirable that the adequate control be established to restore the power flow to the scheduled level within a block period (15 minutes).

Short-term demand forecast must be made mandatory for all countries participating in the power transfer through interconnection to the extent to specify the scheduled power transfer through the cross-border links. The forecast must consider the daily variations, seasonal variations and other external parameters for an acceptably accurate assessment of demand. This demand must be managed by the respective authority without affecting the grid security.

The frequency thresholds of 49.5 Hz can be defined for automatic shedding of loads for the synchronous cross-border links. The loads should be classified as recommended in the Indian Grid Code and similar shedding rules may be adopted. All manual load shedding must be coordinated between operators and demand facilities. This load shedding must be maintained by the respective country authorities without affecting the grid security.

The coordination of outages and unavailability of network elements is an important aspect that is covered in the grid codes of South Asia. However the process of selection of those important cross-border assets which have a considerable impact on the security of cross-border power flow is not included. European grid code discusses the identification of relevant assets and critical assets. The same selection process could be adopted and the outage plans of these assets needs to be made transparent to all the regions that have this element in their list of relevant or critical assets.

Most of the South Asian countries plan their coordinated outage schedules for the next following year and review and update it periodically. A similar practice is followed in the European Grid Code. The review/updating period may be fixed for quarterly and monthly scheduled review. Weekly and/or day-ahead review may be taken up if found necessary.

A Restoration Plan must be prepared and fixed by each region well in advance and during a black-out condition, this plan must be followed till the grid reaches a stable state. This plan must be reviewed on an annual basis. As followed by the European Grid Code, the process of re-energising customers should be taken up stepwise in block loads of maximum size defined by the TSO.

5. SCHEDULING & DISPATCH

CURRENT PRACTICE IN SOUTH ASIA

Bangladesh

The Scheduling and Dispatch code is applicable to the NLDC, Generator and Distribution Licensee. Generators are responsible to provide their capability for the day-ahead schedules. The generation is scheduled for 60-minute time blocks. The system operator shall be responsible for scheduling and dispatch of electricity over inter-regional links in accordance with the grid code and for coordination for trans-national exchange of power.

By 12 PM every day, the station-wise ex-power plant MW and MWh capabilities foreseen for the next day (from 00:00 hrs to 24:00 hrs of the following day) shall be estimated. The day-ahead generation schedules will be informed to the respective generators not less than seven hours before the beginning of each day in Bangladesh.

Bhutan

The Scheduling and Dispatch code is applicable to the system operator, generation licensees, distribution licensees and large consumers. Generators are responsible to provide their capability for the day-ahead schedules. The generation is scheduled for 60-minute time blocks.

When the frequency is higher than 50.5 Hz, and spilling of water is not envisaged, the system operator shall reschedule the dispatch schedule of hydro-generating stations. Similarly, in the event of frequency falling below 49.5 Hz the system operator may consider revision in dispatch schedule after examining the overall inflow position and scheduled dispatch of other generating stations. The system operator shall be responsible for scheduling and despatch of electricity over inter-regional links in accordance with the grid code and for coordination for trans-national exchange of power.

In Bhutan, by 9 AM every day, the station-wise ex-power plant MW and MWh capabilities foreseen for the next day (from 00:00 hrs to 24:00 hrs of the following day) shall be estimated. In the event of bottleneck in evacuation of power due to any constraint, outage, failure or limitation in the transmission system, associated switchyard and sub-stations owned by the transmission licensee, sudden demand change by the distribution licensees or large consumers, the system operator shall revise the schedules and advise the NLDC in Bhutan.

Revision of declared capability by the generating stations (exporting power to Indian Transmission System) for sudden increase or decrease in inflows for the remaining period of the day shall be allowed with advance notice. The concerned generator may advise the system operator in Bhutan of such revision who shall then forward the information to NLDC in Bhutan. The day-ahead generation schedules will be informed to the respective generators by 6 PM (1800 hrs) in Bhutan.

In general, the Distribution Licensees shall endeavour to minimise the reactive power drawl at an interchange point when the voltage at that point is below 95% of rated, and shall not return reactive power when the voltage is above 105%. ICT taps at the respective drawl points may be changed to control the reactive power interchange as per Distribution Licensee's request but only at reasonable intervals. In Pakistan, system operator can instruct generators to provide reactive power support for voltage control. The Bus and Line Reactors at all voltage levels and tap changing of all ICTs up to 66/33 kV level shall be done as per instructions of system operator.

India

The Scheduling and Dispatch code is applicable to the NLDC, RLDC/SLDCs, ISGS, Distribution licensees/SEBs/STUs/regional entities, power exchanges, wind and solar generating stations and other concerned persons in the national and regional grid.

In India, the regional grids shall be operated as loose power pools with decentralised scheduling and despatch, in which the states shall have operational autonomy. In other countries, it is centralised scheduling and dispatch. If regional entities deviate from the drawl schedule, within the limit specified by the CERC in Deviation Settlement Regulations as long as such deviations do not cause system parameters to deteriorate beyond permissible limits and/or do not lead to unacceptable line loading, however, such deviations from net drawl schedule shall be priced through the DSM (Deviation Settlement Mechanism). DSM rates are also applicable for generator when deviations occur with respect to scheduled values. India has progressively moved to a stricter regime in respect of deviations from schedules and penalties have also been increased. Even under-drawl is considered a deviation.

Generators are responsible to provide their capability for the day-ahead schedules. The current day revisions are also allowed. IEGC specifies that generation be scheduled for 15-minute time blocks. For generators which work with different fuels, availability shall be declared with respect to each fuel type. Indian grid code specifies that generators can deviate from the schedules within the limits specified in CERC DSM regulations.

According to Indian grid code, any bilateral agreements between buyer and seller for scheduled interchanges on long-term, medium-term basis shall also specify the interchange schedule, which shall be duly filed with CTU and they shall inform RLDC and SLDC, as the case may be about these agreements in accordance with CERC Regulations, 2009. All other regional entities should abide by the concept of frequency-linked load despatch and pricing of deviations from schedule.

The hydro-generating stations shall be free to deviate from the given schedule without causing grid constraint and a compensation for difference between the actual net energy supply by the hydro-generating station and the scheduled energy (ex-bus) over day shall be made by the concerned Regional Load Despatch Centre in the day-ahead schedule for the 4th day (day plus 3). NLDC shall be responsible for scheduling and despatch of electricity over inter-regional links in accordance with the grid code and for coordination for trans-national exchange of power.

In India, by 8 AM every day, the ISGS shall advise the concerned RLDC, the station-wise ex-power plant MW and MWh capabilities foreseen for the next day, i.e., from 00:00 hrs to 24:00 hrs of the following day. According to Indian grid code, all renewable energy power plants, except for biomass power plants, and non-fossil fuel based co-generation plants whose tariff is determined by the CERC shall be treated as 'MUST RUN' power plants and shall not be subjected to 'merit order despatch' principles. In the event of bottleneck in evacuation of power due to any constraint, outage, failure or limitation in the Transmission System, associated switchyard and sub-stations owned by the Transmission Licensee, sudden demand change by the Distribution Licensees or Large Consumers, RLDC shall revise the schedules which shall become effective from the 4th time block.

According to Indian grid code, revision of declared capability by the ISGS(s) having two part tariff with capacity charge and energy charge (except hydro stations) and requisition by beneficiary(ies) for the remaining period of the day shall also be permitted with advance notice. In case of forced outage of a unit for a short-term bilateral transaction, where a generator of capacity of 100 MW and above is seller, the generator shall immediately intimate the same along with the requisition for revision of schedule and estimated time of restoration of the unit, to SLDC/RLDC as the case may be. When for the reason of transmission constraints, e.g. congestion or in the interest of grid security, it becomes necessary to curtail power flow on a transmission corridor, the transactions already scheduled may be curtailed by the RLDC. The short-term customer shall be curtailed first followed by the medium-term customers, which shall be followed by the long-term customers and amongst the customers of a particular category, curtailment shall be carried out on pro rata basis. The day-ahead generation schedules will be informed to the respective generators by 6 PM (1800 hrs) in India.

Scheduling of Collective Transactions: Provisions for buyers and sellers of power to participate in power trade through a power exchange has been made only in the grid code of India. Regional entities in India can participate by availing of short-term open access to inter-control area transmission facilities. Other state utilities/intra-state entities shall obtain "Standing Clearance/ No Objection Certificate" from their respective SLDCs for participating through power exchange. NLDC shall, by 11:00 hrs on the previous day, provide the power exchange a list interfaces/ control areas/regional transmission systems on which unconstrained flows are required and the power exchange shall furnish the same by 13:00 hrs along with the information of total drawl and injection in each of the regions. On the basis of this information, NLDC shall check for congestion and inform the same along with available limit for scheduling collective transactions to the power exchange by 14:00 hrs. After ensuring that the scheduled collective transactions are within the limits, power exchange shall submit the same to NLDC by 15:00 hrs. NLDC shall send the details to different RLDCs for final checking and accommodating in their schedules. RLDCs shall confirm on the same by 17:00 hrs and NLDC shall inform the power exchanges about the acceptance by 17:30 hrs. RLDCs shall schedule the collective transaction at the respective periphery of the regional entities and individual transactions for State Utilities/intra-State Entities shall be scheduled by the respective SLDCs based on the elaborate breakup of each point of injection and each point of drawl within the state provided by the power exchanges.

The power exchange shall ensure that the necessary infrastructure for data exchange/communication with NLDC/RLDCs and SLDCs is put in place prior to commencement of the operation and shall be responsible for the day-to-day maintenance of the same. Power exchange shall be responsible for Settlement of Energy Charges, Price Discovery and Settlement arising due to congestion with its participants.

Sharing of Transmission Losses: Regulation for sharing of transmission losses amongst the designated transmission customers has been laid down only in India. Central Electricity Regulatory Commission (Sharing of Inter-State Transmission Charges and Losses) Regulations, 2010 and its amendments contain the procedures and mechanism to be followed. An Implementing Agency (IA), approved by CERC, shall compute loss allocation factors using the Hybrid method and losses shall be apportioned to the DICs (Designated ISTS Customers) by suitably adjusting their scheduled MWs. The Intra-State transmission system losses shall be taken care of in the schedules by respective SLDCs.

In Indian grid code, reactive energy drawl at the rate of 10 paise/kVArh (with an increase of 0.5 paise/kVArh per year) is mentioned. In general, the regional entities except generating stations shall endeavour to minimise the reactive power drawl at an interchange point when the voltage at that point is below 95% of rated, and shall not return reactive power when the voltage is above 105%. ICT taps at the respective drawl points may be changed to control the reactive power interchange as per regional entities except generating station's request but only at reasonable intervals. In Pakistan, system operator can instruct generators to provide reactive power support for voltage control. Hydro-generating units of capacity 50 MW and above shall be capable of operation in synchronous condenser mode. The quantum of absorption/injection of reactive power shall be instructed by the appropriate load dispatch centre. Switching in/out of all 400 kV Bus and Line Reactors throughout the grid and tap changing on all 400/220 kV ICTs shall also be done as per RLDCs instructions.

Nepal

The Scheduling and Dispatch code is applicable to the System Operator; Grid Owner; Generators; Distributors; and any other non-NEA entity with a User System connected to the Grid. Generators are responsible for providing their capability for the day-ahead schedules. The generation is scheduled for 60-minute time blocks. The system operator shall be responsible for scheduling and despatch of electricity over inter-regional links in accordance with the grid code and for coordination for trans-national exchange of power.

By 12 PM every day, the station-wise ex-power plant MW and MWh capabilities foreseen for the next day (from 00:00 hrs to 24:00 hrs of the following day) shall be estimated. The day-ahead generation schedules will be informed to the respective generators by 4 PM (1600 hrs) in Nepal.

Pakistan

The Scheduling and Dispatch code is applicable to centrally dispatching generation units, system operator, transmission consumers and other NTDC code participants. Generators are responsible for providing their capability for the day-ahead schedules. The current day revisions are also allowed. The generation is scheduled for 30-minute time blocks. For generators which work with different fuels, availability shall be declared with respect to each fuel type. The system operator may give notice to generators to increase their output during a settlement period.

The system operator shall be responsible for scheduling and despatch of electricity over inter-regional links in accordance with the grid code and for coordination for trans-national exchange of power.

In Pakistan, by 10 AM every day, the station-wise ex-power plant MW and MWh capabilities foreseen for the next day (from 00:00 hrs to 24:00 hrs of the following day) shall be estimated. The day-ahead generation schedules will be informed to the respective generators by 5 PM (1700 hrs) in Pakistan.

Sri Lanka

The Scheduling and Dispatch code is applicable to the Transmission Licensee, Generation Licensees, Distribution Licensees, Transmission Customers and Embedded generators.

Generators are responsible for providing their capability for the day-ahead schedules. The current day revisions are also allowed. The generation is scheduled for 60-minute time blocks. The transmission licensee shall be responsible for scheduling and despatch of electricity over inter-regional links in accordance with the grid code and for coordination for trans-national exchange of power.

By 12 PM every day, the station-wise ex-power plant MW and MWh capabilities foreseen for the next day (from 00:00 hrs to 24:00 hrs of the following day) shall be estimated. The day-ahead generation schedules will be informed to the respective generators by 3 PM (1500 hrs) in Sri Lanka.

INTERNATIONAL PRACTICE

Europe

Each market participant and market coupling operator, to which requirements for scheduling apply, shall appoint a scheduling agent. For regions with central dispatching of generation, the operator responsible for the central dispatching of generation shall appoint or act as a scheduling agent and establish the provisions necessary to produce schedules.The agents are responsible for the transmission of their cross-border schedule nominations to the responsible control area operator.

Data exchanged for matching purposes between control areas, termed as Control Area Schedule (CAS), documents the cross-border exchange per registered market party nominating schedules for a defined process (Day-Ahead, Intra-Day etc.) and border. The Control Area Exchange (CAX) data, transmitted from the Control Area (CA) to its Control Block (CB), enables the matching between control blocks. The CAX is made up of the matched values of the CAS but must contain only the aggregated and netted values of all nominations per control area border, thereby containing only the total bilateral exchange per border and includes the compensation program for unintentional deviations of the control area.

On a bilateral basis, the control block schedule (CBSb) is exchanged and used for the matching between control blocks. It is assembled out of the aggregated CAX values for every time interval for the common control block border. On a multilateral basis, the control block schedule (CBSm) is transmitted from the control block to the co-ordination centre (CC) and enables the matching between the co-ordination centres. In this case it is assembled out of the matched CAX values at all control block borders and includes the compensation program for unintentional deviations of the control block.

The data exchanged between co-ordination centers for matching purposes is termed as the co-ordination centre total exchange (CCT). It is assembled out of the values of the related CBSm and contains the exchange programs between control areas located at the coordination centre border and the compensation program for unintentional deviations of the co-ordination centre.

The responsibility for the process of capacity determination and allocation of transmission rights is carried by the TSO. TSOs implement countertrade primarily as a preventive measure, normally at a day-ahead time horizon. During the day of operation, TSOs initiate re-dispatch primarily as a curative measure. Countertrade means TSO-initiated trade between two adjacent price areas relieving the congestion caused by trade between these two areas with an amount equal to the countertraded quantity. Re-dispatch is a countermeasure where the TSOs change the generation and/or load pattern to redistribute the physical flows in the grid. The TSOs choose the participants on the basis of their physical location in the grid to achieve the maximal relieve of the actual congestion. The relief in congestion can exceed the re-dispatched amount, with an increase of the actual cross-border electricity exchange.

Regulation (EC) No. 1228/2003 of 26 June 2003 on conditions for access to the network for cross-border exchanges in electricity states that transaction curtailment procedures shall only be used in emergency situations where the transmission system operator must act in an expeditious manner and re-dispatching or countertrading is not possible. Except in cases of "force majeure", market participants who have been allocated capacity shall be compensated for any curtailment.

The existing cross-border re-dispatch agreements are mostly based on 'requester pays' principle. Here, the TSO(s) calling for action bear(s) all costs, without being compensated by other TSOs. In some exceptional cases the costs of remedial actions concerning cross-border lines are shared 50:50.

ENTSO-E operates the Inter-Transmission System Operator Compensation (ITC) mechanism, through the ITC Agreement, and the Agency for the Co-operation of Energy Regulators (ACER) oversees and reports on the implementation. The Regulation established an ITC fund to compensate TSOs for the costs incurred in hosting cross-border flows. The fund aims to cover the cost of transmission losses and making infrastructure available for cross-border flows. TSOs participating in the mechanism either contribute to the fund, or are compensated, according to their net imports/exports.

NERC

Each Purchasing-Selling Entity that secures energy to serve load via a dynamic schedule must submit a Request for Interchange (RFI) as a non-time arranged interchange to the Sink Balancing Authority for that Dynamic Schedule.

The Purchasing-Selling Entity that submits a Request for Interchange (RFI) shall update the Confirmed Interchange associated with that Dynamic Schedule for future hours in order to support congestion management procedures in any of these conditions:

- For confirmed interchange greater than 250 MW for the last hour, if the actual hourly integrated energy deviates from the confirmed interchange by more than 10% for that hour and that deviation is expected to persist.
- For confirmed interchange less than or equal to 250 MW for the last hour, if the actual hourly integrated energy deviates from the confirmed interchange by more than 25 MW for that hour and that deviation is expected to persist.
- If requested to update by the Reliability Coordinator or Transmission Operator.

The Balancing Authority (BA) must ensure that,

- If it is experiencing loss of resource, the RFI is submitted within 60 minutes of loss of the resource (RFI may not be required if the use of energy sharing agreement is under 60 minutes from the time of resource loss).
- If a Reliability Coordinator directs the modification of a Confirmed Interchange or Implemented Interchange for reliability reasons, a Reliability Adjustment Arranged Interchange reflecting a modification is submitted within 60 minutes of the start of the modification and its updated RFI is submitted within 60 minutes of the start of the scheduled interchange.

Once this on-time Arranged Interchange is approved and transitioned to on-time Confirmed Interchange, the Sink Balancing Authority must notify the following entities:

- Source Balancing Authority
- Each intermediate balancing authority and their respective reliability coordinators involved in the interchange
- Each Transmission Service Provider (TSP) involved in the interchange
- Each Purchasing Selling Entity involved in the interchange

The Balancing Authority may approve or deny each on-time Arranged Interchange or emergency Arranged Interchange that it receives, within a fixed time period if it does not expect the system to be capable of handling the interchange throughout the duration of interchange or if the scheduling path is invalid.

The Transmission Service Provider (TSP) may approve or deny each on-time Arranged Interchange or emergency Arranged Interchange that it receives, within a fixed time period if the transmission path is invalid.

The Reliability Coordinator uses local transmission loading relief or congestion management procedures, provided the Transmission Operator experiencing the potential or actual SOL or IROL violation is a party to those procedures. Congestion management procedures include:

- Inter-area re-dispatch of generation
- Intra-area re-dispatch of generation
- Reconfiguration of the transmission system
- Voluntary load reductions (e.g., Demand-side Management)
- Controlled load reductions (e.g., load shedding)

Settlement of losses shall be either handled as financial or as payment in-kind in accordance with the Transmission Service Provider tariff.

INFERENCES FOR SOUTH ASIA

Day-ahead scheduling procedure is recommended for the cross-border links. A common time of Indian Standard Time (IST) can be adopted for uniformity. Till the development of secure cross-border scheduling mechanism, it is recommended to follow the Indian scheduling and Dispatch procedure.

Till development of a matured marked in the South Asian region, the TTC and ATC calculations carried out by India can be adopted for other cross-border flows also. In the long term, it would be necessary to adopt a sound principles based on European/North American practice to optimise the cross-border power flows.

In order to facilitate and streamline the cross-border transactions, it may be necessary to develop commercial principles for congestion management wherein the responsibility lies with the transmission agencies. Till the development of congestion reliving mechanism based on the market is established, the principle of honouring long-term commitment on cross-border power flow shall be followed by re-dispatching of generators or permitting counter flow. In case of medium-term or short-term transactions, curtailment of cross-border power flow can be accommodated as a last resort after exhausting all other available measures.

In order to encourage and streamline the cross-border energy exchange, it may be necessary to follow the mechanism similar to European practice wherein a scheduled fund can be created and the losses are compensated through this fund. The transmission agencies need to procure additional energy to compensate for the losses. This may be necessary as there would be multiple transactions in the cross-border trade with varying energy cost. This will also provide in standardising the transmission loss.

Annexure 2: Function of Proposed Regional Technical Institution/Body

i.e. South Asia Forum of Transmission System Utilities

For a structured institutionalised approach, different coordination groups/committees for planning, implementation and operation & maintenance will be required to be constituted under South Asian Forum of Transmission Utility (SAFTU). The following coordination groups are required.

1. **Design Coordination Group:** The Design Coordination Group would prepare the Detailed Project Report on the basis of various activities like detailed survey of the routes of transmission lines, assessment of size and location of sub-station land, finalisation of the details of design parameters of the sub-stations and transmission lines etc. On the basis of above results, the design coordination group would prepare the detailed cost estimate which could be utilised for the tendering purpose.
2. **Project Monitoring Group:** The project monitoring group would monitor different milestones of the project after completion of DPR. The detailed activities need to be monitored which include tendering activities, forest and environmental clearances, acquisition of land for sub-station, construction of the project, commissioning of the project etc.
3. **Operation and Maintenance Coordination Group:** The Operation and Maintenance Coordination Group needs to be constituted for smooth operation and maintenance of the interconnecting project after commissioning. The scope would also include maintenance of associated communication facilities, coordination of protective devices, maintenance coordination etc.
4. **Operation and Protection Coordination Group:** The Operation and Protection Coordination Group would have members from the system operators of both the countries to look into various aspects associated with the operation of the cross-border links, including any protection coordination issues. The group would meet once every calendar quarter.
5. **Commercial Coordination Group:** The Commercial Coordination Group would have members from the system operators of both the countries to look into all commercial aspects related to the operation of the cross-border links. The group would meet once every calendar quarter.

POWER SYSTEM PLANNING COMMITTEE

Apart from the above groups, it is essential for the planning process to have a co-ordinating agency for planning the cross-border links and over a period of time formulate itself into an authority overseeing all the activities of cross-boundary transactions. However, in the interim, as in the SAPP, each country/utility authorised as a designated agency by the country shall prepare their transmission system development plan and then same can be integrated with the South Asian transmission system development plan. For the same it is recommended to create a **Power System Planning Committee** under SAFTU. The South Asian transmission development plan can be prepared by the **Power System Planning Committee** (bilateral/trilateral/mutual agreement) which is to be formed by the member countries involving entities of all interconnected regions as per Article 7 of SAARC Framework Agreement for Energy Cooperation (Electricity). This committee shall be responsible for all the planning activities of their domain.

The participating SAAR Member States shall ensure that the respective System Operators (Control Centres) and the Sub-station Control Rooms at either ends of the cross-border interconnection shall be manned/staffed by adequate and trained manpower at all times to facilitate round the clock operation of the cross-border interconnections. If necessary, in abnormal times, additional trained manpower would also be made available by the participating countries at their respective ends.

Further, it would be necessary to prepare the Master Plan, which shall formulate the plan for next 10 years, considering necessary system upgradations, both proposed and commissioned. It must be reviewed annually and must ensure adequacy for all scenarios that could be possible in the next 10 years, by forecasting both demand and generation considering necessary factors. **Power System Planning Committee will take the lead in preparation of Regional Master Plan.**

Given the above background and rationale, the following is proposed:

Functions of SAFTU

SAFTU would have the following key objectives or guiding principles as part of its strategic plan to promote CBET in South Asia:

- Facilitate regional system planning and coordinated operation of the interconnected transmission network etc., and lead the work towards development of regional master plan.
- Facilitate and lead the work towards the adoption and implementation of framework guidelines and draft cross border grid codes by the national regulatory agencies and provide technical support and assistance to SAFER on the framework guidelines and draft codes.
- Act as a Secretariat to the various technical Groups/Committees formed under SAFTU.
- Come up with various white papers, discussion papers on various technical issues related regional power system planning, operation, maintenance etc.
- To act as a platform for cross-cutting deliberations on technical, standard, system operation, planning related issues for advancing CBET in South Asia and for development of an integrated and regional power system.
- To facilitate technical capacity building among members at both national and regional levels through information sharing and skills training.
- To act as a clearing house of information and data bank on south Asia regional power system including dissemination of global and regional best practices.

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ABOUT SARI/EI

Over the past decade, USAID's South Asia Regional Initiative/Energy (SARI/E) has been advocating energy cooperation in South Asia via regional energy integration and cross border electricity trade in eight South Asian countries (Afghanistan, Bangladesh, Bhutan, India, Pakistan, Nepal, Sri Lanka and the Maldives). This fourth and the final phase, titled South Asia Regional Initiative for Energy Integration (SARI/EI), was launched in 2012 and is implemented in partnership with Integrated Research and Action for Development (IRADe) through a cooperative agreement with USAID. SARI/EI addresses policy, legal and regulatory issues related to cross border electricity trade in the region, promote transmission interconnections and works toward establishing a regional market exchange for electricity.

ABOUT USAID

The United States Agency for International Development (USAID) is an independent government agency that provides economic, development, and humanitarian assistance around the world in support of the foreign policy goals of the United States. USAID's mission is to advance broad-based economic growth, democracy, and human progress in developing countries and emerging economies. To do so, it is partnering with governments and other actors, making innovative use of science, technology, and human capital to bring the most profound results to a greatest number of people.

ABOUT IRADe

IRADe is a fully autonomous advanced research institute, which aims to conduct research and policy analysis and connect various stakeholders including government, non-governmental organizations (NGOs), corporations, and academic and financial institutions. Its research covers many areas such as energy and power systems, urban development, climate change and environment, poverty alleviation and gender, food security and agriculture, as well as the policies that affect these areas.

For more information on the South Asia Regional Initiative for Energy Integration (SARI/EI) program, please visit the project website:

www.sari-energy.org