

REPORT OF THE EXPERT GROUP:
REVIEW OF INDIAN ELECTRICITY
GRID CODE

NEW DELHI
JANUARY, 2020

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MEMBERS OF THE EXPERT GROUP

1.	Shri Rakesh Nath, Ex-Chairperson, CEA	Chairman
2.	Shri A.S.Bakshi, Ex-Member, CERC	Member
3.	Shri Ravinder, Ex-Chairperson, CEA	Member
4.	Shri S R Narasimhan, Director (S.O), POSOCO	Member
5.	Shri Hemant Jain, Chief (Engg.), CEA	Member
6.	Shri S.C. Shrivastava, Chief (Engg.), CERC	Member, Convenor

FOREWORD

The Commission vide office order dated 28.5.2019 constituted an Expert Group to review “Indian Electricity Grid Code and other related issues” under the Chairmanship of Shri Rakesh Nath, Ex-Chairperson, CEA & Ex-Member (Tech) of APTEL with Shri A.S.Bakshi, Ex-Chairperson, CEA & Ex-Member, CERC, Shri Ravinder, Ex-Chairperson, CEA & Ex-Chief (Engg.), CERC as Members and Shri S.C.Shrivastava, Chief (Engg.), CERC as Member, Convenor. The group co-opted Shri S.R.Narasimhan, Director (S.O), POSOCO and Shri Hemant Jain, Chief Engineer (G.M), CEA as Members of the Expert Group. The Terms of Reference (TOR) are as follows:

- a) To review the provisions of Central Electricity Regulatory Commission (Indian Electricity Grid Code) Regulations, 2010 based on past experience, recent developments in the power system of India, changes in market structure and the future challenges which includes high level of renewable penetration in the grid, introduction of new products in market.*
- b) Suggest appropriate regulatory intervention and prepare draft IEGC making recommendation for proposed amendment or changes in the existing Grid Code.*

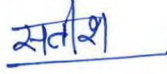
The Expert Group held twenty-six meetings between June 2019 - December 2019. Consultations were held with broad spectrum of stakeholders including thermal, hydro and renewable generators, RPCs, RLDCs, SLDCs, CTU, Discoms, international experts, Shri S.K.Soonee, Ex-CEO (POSOCO), Dr. Pukhraj Singh, Head of R&D, Suzlon, Germany, Solvina International, forecasting and scheduling agencies, Association of Power Producers (APP), SECI and OEM Manufactures for Wind turbines generators and PV inverters and Energy Storage Solutions.

The Expert Group has finalized its recommendation in the form of draft Indian Electricity Grid Code (IEGC), 2020. The Report provides rationale and explanation for the changes and addition carried out while drafting the new Grid Code with a view to improving grid security, stability and flexibility in the operation of generating resources in the context of national targets for high renewable energy penetration. Further, a few suggestions which cannot be included in the Grid Code, but are, nevertheless relevant in a larger context, have been listed in the Report for perusal of the Commission.

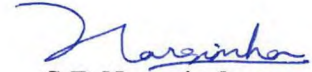
The draft IEGC 2020, the Report of the Expert Group and summary of suggestions received from stakeholders is submitted herewith for the perusal of the Commission.



Hemant Jain
Chief Engineer (GM), CEA –
Member



S.C. Shrivastava
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*Signed at New Delhi
on 09 January 2020*

ACKNOWLEDGEMENT

The Expert Group would like to place on record its appreciation for the valuable inputs and suggestions provided by NLDC, CERC staff, CEA, RPCs, RLDCs, SECI, CTU, SLDCs, Discoms and other stakeholders who made presentation before the Expert Group and gave their written comments and suggestions. The Expert Group would like to convey special thanks to Shri S.K.Soonee, Shri Rajiv Porwal, Smt. Shilpa Agarwal, Shri M.M.Chaudhari, Shri Ravi Shankar, Shri Abhishek Rohilla, Shri Nitin Agarwal, Shri Gaurav Kumar, Shri Samir Saxena, Shri N Nallarasan and Shri Rahul Shukla for their valuable contribution. The Expert Group also acknowledges the hard work contribution of consultants Shri Devesh Khattar and Ms. Sayali. The Expert Group is thankful to the administration of CERC for providing logistics.



(Rakesh Nath)

Chairman of the Expert Group

LIST OF ACRONYMS

ACE	: Area Control Error
AEC	: Auxiliary Energy Consumption
AG	: Actual Generation
AGC	: Automatic Generation Control
AMR	: Automatic Meter Reading
ATC	: Available Transfer Capability
ATRS	: Automatic Turbine Run-Up Scheme
AVR	: Automatic Voltage Regulator
BBMB	: Bhakra Beas Management Board
BUL	: Block Unit Loading
CEA	: Central Electricity Authority
CERC	: Central Electricity Regulatory Commission
CVT	: Capacitive Voltage Transformer
CII	: Critical Information Infrastructure
CISO	: Chief Information Security Officer
COD	: Date of Commercial Operation
CT	: Current Transformer
CTU	: Central Transmission Utility
DAS	: Data Acquisition System
DC	: Declared Capacity
DOP	: Detailed Operating Procedure
DR	: Disturbance Recorder
DSM	: Deviation Settlement Mechanism
DVC	: Damodar Valley Corporation
EL	: Event Logger
EMS	: Energy Management System
ESS	: Energy Storage System

FACTS	: Flexible Alternating Current Transmission System
FGMO	: Free Governor Mode of Operation
FL	: Fault Locator
FRAS	: Fast Response Ancillary Services
FRC	: Frequency Response Characteristics
FRL	: Full Reservoir Level
FRO	: Frequency Response Obligation
FRP	: Frequency Response Performance
FRS	: Frequency Response Service
FOLD	: Forum of Load Despatchers
GD	: Grid Disturbance
GI	: Grid Incident
HVDC	: High Voltage Direct Current
HP	: High Pressure
HVRT	: High Voltage Ride Through
IEEE	: Institute of Electrical and Electronics Engineers
IEGC	: Indian Electricity Grid Code
IEM	: Interface Energy Meters
IMD	: Indian Meteorological Department
ISC	: Information Security Committee
ISGS	: Inter State Generating Station
ISTS	: Inter State Transmission System
LGBR	: Load Generation Balance Report
LP	: Low Pressure
LTA	: Long Term Access
LVRT	: Low Voltage Ride Through
MCR	: Maximum Continuous Rating
MDDL	: Minimum Drawdown Level
MSC	: Mechanically Switched Capacitor Banks
MSR	: Mechanically Switched Reactor Banks
MTOA	: Medium Term Open Access

NER	: North Eastern Region
NCIIPC	: National Critical Information Infrastructure Protection Centre
NLDC	: National Load Despatch Center
NPC	: National Power Committee
OCC	: Operation Coordination Sub-Committee
PAF	: Plant Availability Factor
PLCC	: Power Line Carrier Communication
PMU	: Phasor Measurement Unit
PPA	: Power Purchase Agreement
POD	: Power Oscillation Damping
PSS	: Power System Stabilizers
PT	: Potential Transformer
QCA	: Qualified Co-ordinating Agency
RAS	: Reserves Ancillary Service
RE	: Renewable Energy
REA	: Regional Energy Account
RGMO	: Restricted Governor Mode of Operation
RLDC	: Regional Load Despatch Center
RPC	: Regional Power Committee
RRAS	: Reserves Regulation Ancillary Services
RSD	: Reserve Shutdown
RTA	: Regional Transmission Account
RTM	: Real Time Market
SCADA	: Supervisory Control and Data Acquisition
SCED	: Security Constrained Economic Despatch
SCUC	: Security Constrained Unit Commitment
SERC	: State Electricity Regulatory Commission
SG	: Scheduled Generation
SHR	: Station Heat Rate
SLD	: Single Line Diagram
SLDC	: State Load Despatch Center

SNA	: State Nodal Agency
SPS	: System Protection Scheme
SSP	: Sardar Sarovar Project
STOA	: Short Term Open Access
STU	: State Transmission Utility
SVC	: Static Var Compensators
TCC	: Technical Co-ordination Committee
TCSC	: Thyristor Controlled Series Capacitor
TRM	: Transmission Reliability Margin
TTC	: Total Transfer Capability
UFLS	: Under Frequency Load Shedding
UFR	: Under Frequency Relays
UVLS	: Under Voltage Load Shedding
VSC	: Voltage Source Convertor
VDCOL	: Voltage Dependent Current Order Limiter
VWO	: Valve Wide Open

EXECUTIVE SUMMARY

When the first Grid Code was prepared in 1999, Indian electricity grid was divided and operating at four independent frequencies. Since then the grid has expanded and grown rapidly and has been strongly integrated in to one synchronous grid operating at a common frequency. It has increased the grid stability and its capacity to accommodate the variability of renewable generation. The nominal operating frequency band has been progressively narrowed and deviations from the schedules have been checked, significantly controlling frequency excursions. Operating an integrated national grid with cross-border interconnections makes the task of grid operation, one of immense responsibility.

2. The Expert Group received several responses from various stakeholders. The same have been uploaded on the Commission's website. A gist of the comments is enclosed as Annexure-III. The Expert Group also undertook an extensive literature survey to understand the practices prevalent in large power systems of the world such as Continental Europe, North America and other continents. The important international references in this regard are given at the end of this report. The two decades of rich history and journey of Indian Electricity Grid Code evolution was also traversed. The List of these references from India are also given at the end of this report.
3. The Expert Group feels that each Power system is unique in terms of its evolution and development and the practices followed. The grid code is a dynamic document evolving over time recognising the current operating environment, future mix of energy-resources, technological advancements and the maturity of the system.
4. The draft IEGC 2020 proposes further measures to strengthen grid security and resilience with emphasis on flexibility of resources and ensuring automatic response to frequency excursions. Various measures proposed to be enforced for grid security, reliability and renewable integration are technically feasible, in compliance with CEA standards and established in renewable rich countries.
5. The planning code has been thoroughly overhauled covering all facets of power system planning including demand forecasting, generation resource planning (flexibility,

ramping, minimum turndown level), requirements of energy storage system, system reserves, system inertia for grid stability, inter-state system planning (including re-optimization system study, adequacy, enhancement of total transfer capability (TTC) across inter-regional boundaries as well as ISTS interfaced with STU network).

6. The Connection Code has been reviewed and made applicable to the generators as well as the transmission licensees. This code specifies the requirements to be fulfilled by the connectivity grantees prior to obtaining the permission of the RLDC/NLDC/SLDC for first time energizing of a new or modified power system element. In addition to above, this code specifies the technical requirements to be complied by a transmission licensee including deemed transmission licensees or cross-border entity prior to being allowed by RLDC/NLDC/SLDC to energize a new or modified power system element. The code also specifies the tests required before trial run.
7. A new code namely, protection and commissioning code has been added. A centralized data base containing details of relay setting for grid elements shall be maintained by RPC and system wide study twice a year for validating the protection setting shall be carried out by RPC secretariat. The new protection code provides for annual self-audit and third party once in five years. In the commissioning code procedure for trial run and declaration of CoD for renewable generators has been included. Further, to confirm the flexibility of generators for grid security, some necessary tests prior to trial run have been prescribed for different type of conventional and renewable generators.
8. The draft IEGC 2020 has suggested frequency response measures to correct the load-generation imbalances in an automated manner with the help of primary, secondary and tertiary reserves coupled with demand response as a last resort. In view of the comfortable power supply position, it is now possible to have reserve generating capacity on bar for a quick response. NLDC has already done the preparatory work with regard to automatic generation control or AGC. We are getting initial or primary response at the rate of about 12–14 GW/Hz to contain frequency excursions. In place of restricted governor mode of operation (RGMO), the new Grid Code has proposed free governor mode of operation (FGMO) for all generating units in the country in order to arrest steady fall in the frequency in the event of a major grid disturbances. The primary response shall be provided by the generating machines immediately up to five minutes by which time

the secondary response shall take over through automatic generation control to recover the frequency.

9. The quantum of reserve capacity required to be maintained for grid security is related to credible contingency including net error in the forecasts of demand and renewable generation. In the draft IEGC 2020, demand forecasting activity has been properly organized and there is a monitoring mechanism for errors in demand forecasting. The operating code provides for ensuring and monitoring of availability of reserve capacity.
10. In order to minimize forecasting errors of renewable generators, aggregation of renewable energy has been allowed at one or more pooling stations for the purpose of deviation settlement. An institutional mechanism (QCA) for the composite scheduling and common deviation settlement of renewable generating stations at one or more pooling stations has been provided. The role and functions of QCA has been specified in the Grid Code.
11. The nominal frequency band has been narrowed from 49.90- 50.05 Hz to 49.95-50.05 Hz band. The power system condition has been categorized in to normal, alert, emergency, extreme emergency and restoration state. The role of users has been defined for each state. Structured demand estimation for operational planning studies has been described on daily, monthly and yearly basis.
12. In order to accurately forecast grid behavior in different eventualities it is necessary to validate the performance characteristics of power system elements particularly, generating units. Therefore, field testing of machines for validation of their mathematical models to be used in power system studies has been mandated once in five year.
13. The draft IEGC 2020 mandates adequacy of generation resources for round the clock supply to all consumer categories. It proposes load shedding through demand response contracts or through special protection schemes in the event of an emergency situation.
14. There is emphasis on continuous re-optimisation of interstate transmission system with a view to achieving economy and efficiency in operation. In addition to inter-regional power transfer capability, both CTU and NLDC shall be required to declare import/export transfer capability at the electrical periphery of a state in coordination with the STU.

15. Wind, solar, wind-solar hybrid and hydro plants (in case of excess water leading to spillage) shall be treated as MUST RUN power plants and shall not be subjected to curtailment on account of merit order despatch or any other commercial consideration.
16. In the event of transmission or system security constraint, the renewable generation may be curtailed after harnessing available flexible resources including energy storage systems.
17. In the event of extreme circumstances when any MUST RUN plant has to be curtailed, the details shall be published on the RLDC/SLDC website the following day, as the case may be, giving the date, name of RE generation plant, installed capacity, curtailment quantum in MWh, duration of curtailment and detailed reasons thereof.
18. Flexibility has been granted to the distribution utilities/ buyers having long-term transmission access for scheduling power out of their basket of power purchase agreements, including short-term contracts, up to the approved quantum of LTA. This will facilitate the distribution utilities to optimize their power procurement cost.
19. Distribution utilities/ buyers having short-term bilateral access shall be able to revise their schedule as per the same timelines provided for the long-term or medium-term schedule.
20. With a view to enhancing the flexibility of coal, lignite and gas based thermal generating stations for the emerging scenarios of high renewable energy penetration the compensatory mechanism for below the normative plant load factor has been reviewed and rationalized. The compensation for degradation in performance parameters resulting in higher cost of energy shall be calculated for each time block and settled on monthly basis. However, the extant mechanism has been retained for sharing of efficiency gain for power plants.
21. A new Code namely, Cyber Security has been added. The code provides for identification of Critical Information Infrastructure, appointment of Information Security Officer as per the Information Technology Rules 2018 and take necessary measures in accordance with guidelines by National Critical Information Infrastructure Protection Centre.

22. In line with the above considerations, the various chapters on operating code and scheduling and despatch code have been thoroughly overhauled. The draft IEGC 2020 has been organized into the following chapters:

- Chapter 1: Preliminary
- Chapter 2: Structure of Grid Code
- Chapter 3: Role of Various Organizations and their Linkages
- Chapter 4: Planning Code
- Chapter 5: Connection Code
- Chapter 6: Protection, Testing and Commissioning Code (NEW)
- Chapter 7: Operating Code
- Chapter 8: Unit Commitment, Scheduling and Despatch Code
- Chapter 9: Cyber Security (NEW)
- Chapter 10: Monitoring and Compliance Oversight (NEW)
- Chapter 11: Miscellaneous

CONTEXT, RATIONALE AND JUSTIFICATION FOR CHANGES AND ADDITIONS PROPOSED IN THE NEW IEGC 2020

1. Evolution of Grid Code

After the formation of the Commission in 1998, a draft Grid Code was prepared by POWERGRID in 1999 and the same was approved by the Commission in Dec 1999. The Grid Code was re-notified on 14th March 2006 and again on 28th April, 2010. The Grid Code 2010 was amended from time to time to address requirements of the sector. The Commission notified six amendments in the Grid Code 2010. The major amendments were related to inclusion of forecasting, scheduling framework for renewable generation, compensation for part load operation of thermal stations for absorbing renewable energy and procedure for declaration of commercial operation date.

2. Background

When the first Grid Code was prepared by POWERGRID in 1999, the all India installed generation capacity was 89 GW which, in Dec 2019 has crossed 360 GW, out of which renewable capacity alone is 82 GW. Since then, the annual all India electricity generation has trebled to 1250 billion units. The average renewable energy penetration is presently in the order of 9% but is expected to cross 20% in the few next years. Even now, the renewable rich states are finding it difficult to manage renewable generation during high renewable generation season. So far, grid operators have been trying to manage the variability and intermittency of solar and wind generation with minor innovations such as asking the solar and wind generators to forecast their output and backing down thermal units during high renewable season. We have reached an inflection point of renewable energy growth curve beyond which it is becoming necessary to adopt structured and organised approach for larger absorption of variable renewable energy in order to respect its must-run status as an environmentally benign resource.

3. Preamble

The preamble has been redrafted to reflect focus on reliable Grid operation and integration of renewable energy as follows:

.... The IEGC lays down regulations to be followed by various persons and participants to plan, develop, maintain and operate power system in the country in a secure, economic, reliable, resilient and efficient manner. The regulations provide for integration of renewable energy resources in the grid, flexible operation of energy resources, optimum scheduling & despatch, open access, promoting competition in the generation sector and various measures including reserves necessary for grid stability. It seeks to create a robust framework for maintaining demand-supply balance under credible contingencies and an enabling framework for transition to clean energy sources. According to clause (h) of sub-section (1) of Section 86, the State Commission shall specify its state grid code consistent with the IEGC.

4. Definitions

Definition has been updated according to the terminology used in the Grid Code.

5. CHAPTER 2: STRUCTURE OF GRID CODE

The new structure of the Grid Code is listed below:

Chapter 1: Preliminary

Chapter 2: Structure of Grid Code

Chapter 3: Role of Various Organizations and their Linkages

Chapter 4: Planning Code

Chapter 5: Connection Code

Chapter 6: Protection, Testing and Commissioning Code (NEW)

Chapter 7: Operating Code

Chapter 8: Unit Commitment, Scheduling and Despatch Code

Chapter 9: Cyber Security (NEW)

Chapter 10: Monitoring and Compliance Oversight (NEW)

Chapter 11: Miscellaneous

6. CHAPTER 3: ROLE OF VARIOUS ORGANIZATIONS

(1) Activities of CTU has been redrafted as follows:

(1) *The Central Transmission Utility (CTU) shall carry out the functions in accordance with the section 38 of Act.*

(2) *CTU shall also perform following activities:*

- (a) *Be responsible for consultation with stakeholders such as generators, STU, RLDC, SLDC and distribution licensees and maintain transparency at all stages of planning of augmentation or strengthening of ISTS.*
- (b) *Planning activities as specified under Central Electricity Regulatory Commission (Planning, Coordination and Development of Economic and Efficient Inter-State Transmission System by Central Transmission Utility and other related matters) Regulations, 2018.*
- (c) *Nodal agency for the connectivity, long-term access and medium-term open access in accordance with the Central Electricity Regulatory Commission (Grant of Connectivity, Long-term Access and Medium-term Open Access in Inter-State Transmission and related matters) Regulations, 2009, as amended from time to time.*
- (d) *Activities assigned under these regulations or any other CERC regulations.*

(2) Role of National Power Committee (NPC) has been included as follows:

The functions of NPC shall be in accordance with Order no A-60016/24/2012-Adm-I dated 25th March 2013 as follows:

- a) *Discuss and resolve issues referred to NPC requiring consultation among one or more RPCs, concerning inter-alia inter-regional implication or any other issue affecting more than one region or all regions.*
- b) *To resolve issues amongst RPCs.*

(3) Role of QCA has been included as follows:

As pointed out during interaction with stakeholders the cost of forecasting infrastructure and error in forecasting can be reduced by doing a forecast over a large geographical area. This is a practice followed in Europe and this was recommended in a study sponsored by MNRE through GIZ, Germany for India. This has been successfully demonstrated for intra-state renewable generators in Karnataka, Andhra Pradesh and Rajasthan. Therefore, renewable energy has been allowed at one or more pooling stations for the purpose of deviation settlement. An institutional mechanism through Qualified Coordinating Agency (QCA) for scheduling and common deviation settlement of renewable generating stations at one or more pooling stations has been provided. The name QCA has been adopted as the same is already in vogue at intra-state level. The role and functions of QCA has been specified in the Grid Code.

- (1) *The roles and functions of QCA shall be as follows:*
- (a) *To act as the nodal agency on behalf of the wind, solar and hybrid generators including energy storage system connected to one or more pooling stations represented by it for the purpose of Grid Code in general and operational and scheduling liaison in particular.*
 - (b) *To undertake generation forecasting, declaration of combined capability on behalf of generators, energy storage system at one or more pooling stations to the concerned load despatch centre for the purpose of scheduling.*
 - (c) *To undertake scheduling, metering and accounting of energy. QCA shall be responsible for pooling of declared availability, de-pooling of despatch schedule and DSM account as necessary.*
 - (d) *To operate and maintain a co-ordination centre manned by qualified and competent personnel for round the clock operational co-ordination and information exchange with the concerned Load Despatch Centre and generating stations.*
 - (e) *To settle all payments as per DSM Regulations arising out of deviations from its aggregated schedule given by relevant LDC.*
- (2) *Any instruction or direction given by the LDC to QCA shall be deemed to have been given to the renewable generator represented by it.*

7. CHAPTER 4: PLANNING CODE

In the earlier Grid Code, the scope in the planning Code was limited to transmission planning only and it basically reiterated salient aspects of CEA Transmission Planning Criteria. It was pointed out during the stakeholders consultation that apart from adequacy of transmission resources, adequacy of generation resources, flexibility of conventional generation, system inertia, adequacy of primary reserve to prevent frequency fall during grid emergency, adequacy of secondary and tertiary reserve to restore the grid frequency, planning of energy storage devices for energy shift to absorb excess renewable energy such as stand-alone pump storage plants and battery energy storage system, an institutional mechanism for long-term and short-term demand forecasting by each control area are equally important for secure, reliable and resilient grid operation and the same should be the part of the Planning Code. Accordingly, the new planning code covers the system planning in the holistic manner and the Code has been re-drafted as highlighted below:

(1) Planning Dimensions

- (1) *The integrated power system planning shall include:*
- (a) *Probabilistic assessment by the designated agency of a State of its future demand pattern under different scenarios.*

- (b) *Adequacy of generation resources taking into account loss of load probability and energy not served as specified by CEA.*
- (c) *Adequate generation reserves and demand response for maintaining grid stability.*
- (d) *Validation of adequacy of transmission resources through system studies considering economic despatch under various demand and generation scenarios including must run generation.*
- (e) *Validation of adequate power transfer capability to be carried out for the entire grid in a comprehensive manner by CTU:*
 - *adequate power transfer capability across each flow-gate*
 - *import and export capability for each control area*
 - *import and export capability between regions*
 - *cross-border import and export capability*
- (f) *Validation of adequate power transfer capability to be carried out by STU:*
 - *Adequate power transfer capability across each flow-gate*
 - *Import and export capability across ISTS and STU interface*

(2) The following aspect of system planning have been described in the new Planning Code:

(a) Demand forecasting by State

- i. Each distribution licensee of the state shall estimate the demand in its control area including the demand of open access consumers for next five years starting from 1st April of the next year and submit to STU by 30th September every year.*
- ii. STU, in co-ordination with all distribution licensees, shall estimate the demand by 31st October of every year for the entire state duly considering the diversity, for the next five (5) years starting 1st April of the next year using trend method, time series, econometric methods or any state of the art methods and submit the same to CEA and CTU.*
- iii. CTU, in consultation with STUs, shall estimate by 31st December every year, the demand for each region as well as the entire country taking into account the diversity for the next five (5) years starting 1st April of the next year based on the inputs from STU.*
- iv. The demand estimation shall include daily load curve (hourly basis) for a typical day for each month.*

(b) Generation resource planning

- i. Each distribution licensee shall ensure demonstrable resource adequacy as specified by the respective SERC for the next five (5) years starting 1st April of the next year. Adequacy statement containing a list of such resources along with associated capacities shall be submitted to the respective STU and SERC. STU shall submit the same to CTU.*

- ii. *The National Electricity Plan may consider the following from grid operation perspective:*
 - (a) *Generation flexibility, ramping and minimum turndown level and start-stops*
 - (b) *Requirement of energy storage systems and demand response measures*
 - (c) *Generation reserve requirement*
 - (d) *System inertia for grid stability*
 - (e) *Cross-border electricity exchange*
 - (f) *Fuel security*
- iii. *While finalizing transmission plan for implementation, CTU shall simulate the economic despatch considering grid security under various scenarios based on adequacy statement furnished by STU and provide feedback to CEA.*

(c) Inter-State Transmission Planning

- i. *The inputs for inter-state transmission planning shall be collated by CTU based on the National Electricity Plan of CEA and conventional and renewable generation capacity addition assessment of various agencies, estimates of renewable energy potential in different areas as assessed by MNRE and demand forecast of Electric Power Survey. The CTU shall interact with various stakeholders such as CEA, MNRE, state renewable development agencies, STUs, distribution licensee, SLDC, RLDC, NLDC and generation developers to make a comprehensive assessment of inter-state transmission plan covering power evacuation schemes, pooling stations, enhancement of power transfer capability between regions and enhancement of power transfer capability for each STU system.*
- ii. *Based on the inputs compiled and collated by CTU for preparation of transmission planning, load generation balance scenarios shall be prepared by CTU and disseminated in public domain for comments. The finalized load generation balance for transmission planning shall be shared with stakeholders.*
- iii. *The CTU shall carry out the planning of inter-state transmission system based on the following:*
 - (a) *Manual on Transmission Planning Criteria issued by CEA*
 - (b) *Central Electricity Authority (Technical Standards for Connectivity to the Grid) 2007*
 - (c) *Central Electricity Regulatory Commission (Planning, Coordination and Development of Economic and Efficient Inter-State Transmission System by Central Transmission Utility and other related matters) Regulations, 2018*
 - (d) *Central Electricity Regulatory Commission (Grant of Connectivity, Long-Term Access and Medium-Term Open Access in interstate transmission and related matters) Regulations 2009*
- iv. *While planning the ISTS transmission system, the following shall be duly considered by CTU:*

(a) *CTU shall analyze N-2 contingencies which could lead to cascade tripping. Special Protection Schemes (SPS) with adequate redundancies may be designed wherever necessary.*

(b) *While planning the transmission system, CTU shall consider resilience in terms of nearby black start resources and building up of the cranking path to load centres and thermal generating stations.*

v. *The transmission planning alternatives shall be shared with stakeholders for consultation through a national level workshop before finalization.*

vi. *CTU shall carry out periodic all India transmission review and re-optimization study in collaboration with STUs on yearly basis and its report shall be submitted to CEA for remedial measures under intimation to CERC by 1st April every year. In the summary of the report, immediate priorities shall be highlighted for the purpose of improving reliability, adequacy and opportunities increasing TTC across inter regional boundaries as well as well as ISTS interface with state control areas. Emerging pattern of power flows based on economic despatch shall be captured by the CTU in its re-optimization studies.*

vii. *In order to achieve economy, before planning new transmission corridors, CTU shall endeavor to maximize the utilization of existing transmission corridors by considering reconfiguration, re-conductoring, use of flexible AC technologies, series and shunt compensation and dynamic line rating options.*

8. CHAPTER 5: CONNECTION CODE

- (1) This code has been redrafted and it now clearly specifies the requirements to be fulfilled by the connectivity grantees prior to obtaining the permission of the RLDC/NLDC/SLDC for first time energizing of a new or modified power system element. In addition to above, this code specifies the technical requirements to be complied by a transmission licensee including deemed transmission licensees or cross-border entity prior to being allowed by RLDC/NLDC/SLDC to energize a new or modified power system element. The connectivity must ensure the security of the grid as well as element getting connected to the grid as provided in the CEA (Technical Standards for connectivity to the Grid) Regulations. Physical connection of the element to the grid is transition from construction phase to operation phase.
- (2) Therefore, NLDC/RLDC in consultation with CTU shall carry out a joint system study six (6) months before expected date of first energization of a new power system element to identify operational constraints, if any. For this purpose, the

connectivity grantee, transmission licensee and SLDC/STU shall furnish all technical data including that of its embedded generators and other elements to the CTU/NLDC for necessary technical studies.

- (3) It includes for the first-time tests to be performed after connectivity and prior to Trial Run for Declaration of Commercial Operation.
- (4) The Connection Code covers the following aspects:
 - i. Procedure for Connection
 - ii. Technical Requirements
 - iii. Data and Communication Facilities
 - iv. Tests prior to Trial Run for Declaration of Commercial Operation

9. CHAPTER 6: PROTECTION AND COMMISSIONING CODE

(1) Protection Code

- (a) This code has been newly added to have a common protection philosophy amongst users of the grid, to provide proper co-ordination of protection system in order to isolate the faulty equipment and avoid unintended operation of protection system, to have a repository of protection system and settings at regional level, to have a repository of events, timelines for submission of data and ensure healthiness of recording equipment's along with time synchronization, to provide for periodic audit of protection system.
- (b) It is observed that in absence of a coordinated procedure and specific guidelines of protection systems the desired outcomes are not being witnessed. It is therefore recommended that a coordinated protection setting are adopted by all users of regional grid. The provision of protection philosophy to be adopted at regional level has been added to achieve a uniformity in the procedure for adopting protection settings. The guideline and recommendation provided under various committee Report as constituted under the various orders (Report of the Task Force on Power System Analysis under Contingencies (2013), TASK II PHASE I AND PHASE II – FINAL REPORT (2017), CBIP Manual on Power System Protection (Publication No. 328), Protection philosophy of different RPC (Regional Power Committee)/ NPC (National Power Committee) and any other as prescribed by commission) may form the basis for finalising the protection philosophy by all RPCs uniformly.

(c) The Protection Code covers the following aspects:

- i. Protection philosophy
- ii. Protection Settings
- iii. Protection Audit Plan
- iv. System Protection Schemes (SPS)
- v. Recording Instruments

(2) Commissioning Code

(a) The Commissioning Code covers the Notice of Trial Run and declaration of Date of Commercial Operation (COD) of generating stations, ESS and transmission elements. The declaration of Date of Commercial Operation (COD) of generating stations including wind, solar, hybrid, ESS has been added for the first time.

(b) The criteria for date of commercial operation and successful trial run were earlier a part of the scheduling code. However, the expert group found it necessary to create a separate code in order to provide clarity on the same.

(c) In its current state, the grid code incorporates the criteria for trial run and data of commercial operation for conventional generators, transmission elements and communication systems.

(d) Stakeholders have submitted the necessity to include the same for renewable energy generating stations. It has been observed that the conditions regarding date of commercial operation has been dealt in the PPA which varies from PPA to PPA. Further, the PPAs may not include provision of successful trial operation of renewable energy generating stations. MNRE bidding guidelines allow part commissioning upto 50 MW for both wind and solar generation in ISTS system. Further, any unit partly commissioned becomes eligible for tariff. MNRE in its bidding guidelines provides as follows:

- i. Guidelines for Tariff Based Competitive Bidding Process for Procurement of Power from Grid Connected Wind Power Projects (Resolution dated: 8th December 2017)

“Part Commissioning: Part Commissioning of the project shall be accepted by procurer subject to the condition that the minimum capacity

for acceptance of first part commissioning shall be 50% of project cost or 50 MW, whichever is lower, without prejudice to the penalty, in terms of the PPA on the part which is not commissioned. However, in case of interstate project, minimum capacity for acceptance of first part commissioning shall be atleast 50 MW. A project of capacity 100 MW or less can be commissioned in maximum two parts. The projects with capacity more than 100 MW can be commissioned in parts of atleast 50 MW each, with last part could be the balance capacity, However, the SCD shall not get altered due to part commissioning. Irrespective of dates of part commissioning, the PPA will remain in full force of 25 years from the SCD or from the date of full commissioning, whichever is earlier.

Early Commissioning: The Wind Power Generator shall be eligible for full commissioning as well as part commissioning even prior to the SCD subject to the availability of transmission Connectivity and Long-Term Access (LTA). In cases of part commissioning, till the achievement of full commissioning or SCD, whichever is earlier, the Procurer may purchase the generation at 75% (seventy-five percent) of the PPA tariff.

Commercial Operation Date (COD): The commercial operation date shall be considered as the actual date of commissioning of the project as declared by the Commissioning Committee constituted by SNA. In case of part commissioning, COD will be declared only for that part of the project capacity.”

- ii. Guidelines for Tariff Based Competitive Bidding Process for Procurement of Power from Grid Connected Solar PV Power Projects (Resolution dated: 3rd August 2017)

Part Commissioning:

Part commissioning of the Project shall be accepted by Procurer subject to the condition that the Minimum Capacity for acceptance of first and subsequent part(s) commissioning shall be 50 MW, without prejudice to the imposition of penalty, in terms of the PPA on the part which is not commissioned. However, the SCD will not get altered due to part-commissioning. Irrespective of dates of part commissioning or full commissioning, the PPA will remain in force for a period of 25 (twenty-five) years from the SCD.

Early Commissioning:

The Solar Power Generator shall be permitted for full commissioning as well as part commissioning of the Project even prior to the SCD. In cases

of early part-commissioning, till SCD, the Procurer may purchase the generation till SCD, at 75% (seventy-five per cent) of the PPA tariff. However, in case the entire capacity is commissioned prior to SCD, the Procurer may purchase the generation at PPA Tariff.

Commercial Operation Date (COD):

Commercial Operation Date (COD) shall be the date on which the commissioning certificate is issued upon successful commissioning of the full capacity of the Project or the last part capacity of the Project as the case may be.

(3) Rationale for proposed amendment:

- (a) It is necessary to harmonize the criteria for commercial operation date declaration across all generators to maintain consistency and clarity. It is proposed to allow part commissioning for a capacity of 50 MW for both wind and solar generators. This may also benefit the consumers since it will help meet the adequacy targets and RPO obligations.
- (b) Provisions for trial run have been included where corroboration of test results with plant parameters have been mandated so that any variability of solar irradiance and wind generation is taken into account.
- (c) The date of declaration of commercial operation has been mandated as within fifteen days from date of achieving trial operation. It is observed that there should not be inordinate delays in declaration of COD post declaration of successful trial run.
- (d) Stakeholders had requested to specify COD criteria of rooftop solar and off-shore wind. As rooftop solar will have connectivity to the state grid, the SERC regulations shall apply. The connectivity of off-shore wind shall be governed in accordance with connectivity to ISTS or state. Hence, no separate provisions have been introduced.

10. CHAPTER 7: OPERATING CODE

The following aspects of grid operation have been added in this chapter:

- i. Under frequency Relay Load Shedding settings

- ii. Primary, Secondary and Tertiary Reserves and its activation for frequency control
- iii. Operational Planning Studies
- iv. Post-Despatch Analysis
- v. Field testing for model validation

(1) Under Frequency Relay (UFR) Settings:

- (a) Considering the All India electricity grid operating as a synchronous grid and being one of the largest grids in the world, the defence plans now need to be looked at from a national level rather than regional level. The same needs to be mandated in the IEGC itself rather than any discussion at the RPC level. As indicated in the section on primary response, for the reference contingency of 4500 MW generating station outage, the frequency would dip to 49.50 Hz and quickly recover to 49.70 Hz. So, the chances of the frequency falling below 49.50 Hz in an integrated large power system like India would be rare. The frequency would fall below this value only in case of part separation of systems leading to a generation deficit in one system.
- (b) At present, there are four stages of Under-Frequency Load-Shedding (UFLS) relays which are set at 49.2 Hz, 49.0 Hz, 48.8 Hz, and 48.6 Hz in NR, WR, ER, SR, and NER. These settings were last raised in end 2013 before synchronization of Southern region with rest of the grid. In addition to UFLS relays, df/dt relays are also installed in NR, WR, and SR grids. In NR and WR df/dt relays are set to get armed at 49.9 Hz to shed load automatically if the rate of fall of frequency is faster than 0.1, 0.2, or 0.3 Hz/s (i.e., three stages). In SR, however, the frequency at which UFLS is armed and the rate thresholds are 49.5 Hz & 0.2 Hz/s, 49.3 Hz & 0.2 Hz/s, and 49.3 Hz & 0.3 Hz/s for the three stages, respectively.
- (c) During any contingency, the grid frequency will start to drop and UFLS along with df/dt relays (if required) may be activated to arrest its fall. Governor response will play a key role in this regard, as well as in settling at the final frequency. Another important consideration is possible islanding, consequential load shedding and over voltages which might occur due to lightly loaded lines. Thus, excitation systems are equally important, as well as timely switching of

shunt reactor/capacitor banks. This aspect is particularly important in the case of Southern Region and North Eastern Region as they are importing regions and there is a stray chance of islanding.

- (d) AUFLS is an important feature of emergency control in system operation. It is recommended to raise the set point for first stage of under frequency operation to 49.4 Hz. The quantum of load shedding at each stage of underfrequency may be set in terms of percentage of total load at regional as well as national level. The similar practice is being followed in Continental Europe as brought out in “*Commission Regulation on establishing a network code on emergency and restoration.*” The table used as reference for automatic low frequency demand disconnection scheme is given below:

Automatic low frequency demand disconnection scheme characteristics:					
Parameter	Values SA Continental Europe	Values SA Nordic	Values SA Great Britain	Values SA Ireland	Measuring Unit
Demand disconnection starting mandatory level: Frequency	49	48,7 – 48,8	48,8	48,85	Hz
Demand disconnection starting mandatory level: Demand to be disconnected	5	5	5	6	% of the Total Load at national level
Demand disconnection final mandatory level: Frequency	48	48	48	48,5	Hz
Demand disconnection final mandatory level: Cumulative Demand to be disconnected	45	30	50	60	% of the Total Load at national level
Implementation range	± 7	± 10	± 10	± 7	% of the Total Load at national level, for a given Frequency
Minimum number of steps to reach the final mandatory level	6	2	4	6	Number of steps
Maximum Demand disconnection for each step	10	15	10	12	% of the Total Load at national level, for a given step

- (e) The number of steps and quantum of load shedding at each step is decided based on recommendations of consultant as well as the NERC standard. The strength has been derived from the following documents:

(i) *North American Electric Reliability Corporation (NERC) standard PRC-006-2* — Automatic Underfrequency Load Shedding mentions that “Each Planning Coordinator shall develop a UFLS program, including notification of and a schedule for implementation by UFLS entities within its area, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load — actual generation output) / (load)], of up to 25 percent within the identified island(s).” On the similar lines, in Indian power system, 25% load may be identified for disconnection during low frequency.

(ii) This is also available in recommendation of consultant appointed by “Taskforce on Power System Analysis under Contingencies” in December 2012 as a follow up of the recommendations of Enquiry Committee under Chairperson, Central Electricity Authority (CEA) on Grid Disturbances of 2012 in Indian Grid.

(f) At the implementation stage, it is very important that status of wired loads envisaged for shedding during under frequency are monitored at SLDC/RLDC. The SLDC/RLDC may be provided with real time power flow display for the feeders identified for AUFLS. The periodic mock testing to verify the status of UFR and df/dt relays at RPC level is recommended. The periodic testing of relays comprising of site inspection of random location to ensure the relay is working (properly wired), monitoring of active power (MW) trend etc. It is suggested that SLDCs shall furnish the status of UFR and df/dt relays to respective RPC on monthly basis which shall be uploaded on RPC website. Similarly, any modification/update made to the UFR & df/dt relays may also be reviewed at RPC level.

(2) Highlights of the new provisions added:

All distribution licensees/STUs/bulk consumers shall provide automatic under-frequency and df/dt relays for load shedding in their respective systems to arrest frequency decline that could result in a collapse/disintegration of the grid, as per the plan given in Table-1 given below. The following common points need to be factored for design and implementation of the scheme:

Table 1: UFR Settings

<i>S. No.</i>	<i>Stage of UFR Operation</i>	<i>Frequency (Hz)</i>	<i>Load Shedding (% of All India demand)</i>
<i>1</i>	<i>Stage-1</i>	<i>49.40</i>	<i>6%</i>
<i>2</i>	<i>Stage-2</i>	<i>49.20</i>	<i>6%</i>
<i>3</i>	<i>Stage-3</i>	<i>49.00</i>	<i>6%</i>
<i>4</i>	<i>Stage-4</i>	<i>48.80</i>	<i>7%</i>
<i>Total (Cumulative)</i>			<i>25%</i>
<i>Note 1: All states shall plan further UFR settings for frequency below 48.8 Hz and df/dt load shedding schemes depending on their local load generation balance. The same shall be coordinated and agreed by the concerned RPC.</i>			
<i>Note 2: Pumped storage hydro plants or ESS operating in pumping or charging mode shall be automatically disconnected before the first stage of UFR.</i>			

(3) Generation Reserve Estimation and Frequency Control

- (a) The Commission has through periodic amendments in the Indian Electricity Grid Code (IEGC) tightened the allowable frequency band from a range of 49.0-50.5 Hz in Feb 2000 to the range 49.90-50.05 Hz since February 2014. Maintaining frequency profile within the allowable band was mainly through the frequency linked Unscheduled Interchange (UI) or Deviation Settlement Mechanism (DSM) Regulations (Passive Balancing).
- (b) The primary control has been emphasised by Commission in various amendments of IEGC and orders from time to time, similarly the secondary control has now been mandated by the Commission in its order recently. Slow tertiary control through Ancillary Services has been implemented pan India since April 2016. Though all these efforts have resulted in improved frequency profile but a lot need to be done in this regard. The Indian system is growing at large pace and with expected integration of large quantum of renewable generation in near future, it would be desirable to manage system operation with stringent frequency controls. A list of frequency control required to be implemented in Indian power system have been mentioned in this grid code.
- (c) The frequency band has been tightened further and made 49.95 Hz to 50.05 Hz in line with practices adopted in large power systems of the world. No further tightening of this band would be required. Rather, all efforts by way of primary,

secondary and tertiary control should be exercised to bring the frequency back to within band in 15 minutes or less in case it goes outside the band due to any contingency.

- (d) It would be worthwhile to discuss the frequency controls available in major systems like North America and Continental Europe for implementation in Indian context.

North America

- (i) In respect of primary response, the NERC Reliability Standards (BAL-003-1) define the Interconnection Frequency Response Obligation (IFRO) which usually considers the largest generation loss possible and the Under-Frequency Load Shedding (UFLS) setting. In case of Eastern Interconnection (the largest system in US), this is 4500 MW and 59.5 Hz giving an IFRO of 1002 MW/0.1 Hz. The actual Frequency Response Characteristics (FRC) observed for the Eastern Interconnection as well as Western Interconnection is much above the IFRO, at least 2.5 to 3 times the IFRO. This IFRO is apportioned amongst all entities depending on their load and generation.
- (ii) In respect of secondary control through AGC, termed as regulation services, standards exist for setting the frequency bias (BAL-003-1.1) as well as Control Performance Standard 1 or CPS1. CPS1 is calculated on monthly basis and has to remain above 100 for a Control Area to ensure compliance. CPS1 is mainly calculated from the Area Control Error (ACE). Apart from CPS1, a balancing area must also ensure that its ACE does not exceed the Balancing Authority ACE Limit or BAAL for more than 30 minutes. Violations of CPS1 and BAAL would make the Balancing Authority liable for penalties. The third category of reserves deployed as part of any contingency is termed as contingency reserve or supplemental reserve.

Continental Europe

- (i) For the Continental Europe (CE), the frequency is expected to be within the 49.95-50.05 Hz band. Following a reference contingency of 3000 MW generation outage, the instantaneous frequency could dip to 49.20 Hz and recover to 49.8 Hz through primary response.

(ii) The frequency, once outside the range, has to be restored to within the 49.95-50.05 Hz band within fifteen (15) minutes. As per Article 127 of the EU Regulation, the frequency can be outside the defined range for a maximum of 15000 minutes per year. Thus, frequency has to be within the band for 49.95-50.05 Hz for 97.15% of the time in a year. The frequency is maintained within the range with the combined efforts of all the TSOs and obligation to have reserves. Reserves are of the following types:

- Frequency Containment Reserve (FCR) similar to primary control
- Frequency restoration Reserves (FRR) similar to secondary control through AGC
- Restoration Reserves (RR) to replace FRR similar to tertiary control.

Primary Control

(e) Wind/Solar generating units need a different treatment from conventional generating units as far as primary response is concerned. The Central Electricity Authority (Technical Standards for Connectivity to the Grid) (Amendment) Regulations, 2019 (effective for units commissioned on or after 6th Aug 2019) have specified the requirement of primary response from wind/solar/hybrid generating units and ESS. The same has been adopted upto 31 March 2022. It is plausible that during certain hours of the day the spare capacity may be available with wind/solar generators. The IEGC facilitates the absorption of such energy by way of primary response without binding them to restrict output upto the installed capacity.

(f) The present installed capacity of RE based generation is 85 GW and with the target of Government of India to integrate 175 GW of RE based generation into the grid. It is imperative that in future primary response is also contributed by renewable generators. Accordingly, it has been provided in the IEGC that *Wind/Solar/Hybrid plant commissioned after 31st March 2022 shall have the option to provide primary response individually through BESS or through a common BESS installed at its pooling station.*

Secondary Control

- (g) The quantum of reserves which need to be earmarked for secondary control need to be assigned equitably between all the control areas. In Continental Europe, ENTSOE System Operation Guidelines, mention the procedure to dimension the secondary reserve as 99 percentile value of previous years Frequency Restoration Control Error (FRCE) (similar quantity as ACE), both in positive and negative direction. The quantum of reserves will be taking care of exceptional high values due to weather related phenomenon or any other exceptional circumstances. It is also recommended that s, the obligated entities may provide secondary control through ESS. SLDC/RLDC shall calculate the desired secondary reserve to be kept in their control areas at the beginning of each financial year and submit to NLDC.
- (h) The AGC need to act as early as possible after the event, a time of 30 seconds has been provided for activation of secondary reserves considering the delays in the scheme. The secondary control thus activated will be deployed fully within 15 minutes and continue at this level for next 30 minutes.
- (i) AGC has been implemented as a pilot project at five power plants (one in each region) in line with the Commission order dated 6th Dec 2016 and with the order of Commission dated 28th August 2019 in Petition No. 319/RC/2018, it is expected that AGC will be operationalised shortly in all regional entity generating units whose Tariff is regulated/adopted by Commission. The Unrequisitioned Surplus available in these power plants would be utilised for secondary control as per the orders of Commission. Security Constrained Unit Commitment (SCUC) and Security Constrained Economic Despatch (SCED) would ensure availability of suitable margins for AGC. Presently, the payments for Ancillary Services (Regulation Services) are being met through the pool account, this mechanism may be further modified by the Commission from time to time covering other resources such as Demand Response, Energy Storage etc.
- (j) The various cut-off dates for implementing AGC on generating units/Resources capable of providing secondary control under RLDC as well as SLDC jurisdiction has been brought out.

- (k) It is desirable that reserves should be provided locally by the control area. The responsibility to provide reserve response should be shared by all Control Areas in a distributed manner in the interest of grid security and in a participative manner so that there is no tendency to pass on the responsibility to other entities. Only in exceptional cases where a control area doesn't have generation resources within the Control Area, the responsibility of frequency control response may be taken over by the RLDC/NLDC. However, it may be added that with the advent of new technologies such as BESS, it may be possible to provide frequency response even without physical generation assets in its control area.

Tertiary Control:

- (l) Tertiary reserves may be arranged from the generating stations, ESS and/or through demand response. Tertiary reserve shall be greater or equal to secondary reserves to take care of contingencies, and shall be maintained at both regional entity level as well as state control area. Tertiary reserves are to be activated in response to various contingencies as defined in grid code. Tertiary reserves will act as replenishment for secondary reserves as secondary reserves are to be restored back to their original level for preparation towards next contingency. Tertiary reserves activation would restore the secondary reserves to the desired level. The tertiary reserve shall be fully activated within fifteen (15) minutes of operator's instructions from appropriate load despatch centre and shall be capable of delivering until next 60 minutes.

(4) Operational Planning Studies:

(a) Operational Planning Studies & Definition of System States

- (i) The draft IEGC 2020 provides for Operational Planning Studies to be carried out in different time horizons viz Yearly, Monthly, Weekly, Day-ahead and intra-day. The yearly and monthly studies shall be done by study committee at the RPC level while other studies shall be done at each LDC level. Such studies would cover:
- i. Inter-regional, intra-regional, inter-state, intra-state total transfer capability/available transfer capability assessment
 - ii. Planned outage assessment

- iii. Special scenario assessment
- iv. System protection scheme assessment
- v. Natural disaster assessment
- vi. Any other study relevant in operational scenario

(ii) Emphasis has been placed on real-time network applications available in the EMS SCADA systems at LDCs.

(iii) The annual load-generation balance review (LGBR) at the national level shall be a comprehensive document considering overall overall economy, absorption of renewable energy, anticipated cross-border energy exchange, requirement of reserves and overall grid security. All India LGBR shall assess likely flow on inter-regional, HVDC and major transmission corridors and moderate the LGBR such that transmission constraint are honored.

(iv) The system states pertaining to the real time operation have been introduced such as Normal, Alert, Emergency, Extreme Emergency and Restorative State.

(5) Post Despatch Analysis

(a) In a large power system such as India with a large transmission network, events in the generation and transmission system have increased manifold. Equipment failures, incorrect operation of protective systems, human error, extreme weather conditions etc. lead to multiple tripping of transmission elements and/or generating units. Loss of generation or load at local level is generally the consequence but it could also lead to cascading failures and widespread interruption of loads. Hence post despatch analysis or event analysis is an important step in enhancing reliability of the system as till the root cause is identified, analysed and remedial measures taken across all utilities, the system remains vulnerable.

(b) The Draft IEGC accordingly provides a timeline for event analysis, responsibilities of the different agencies in event analysis and disseminating the lessons learnt. The CEA Grid Standards classify Grid Disturbances on a scale of 1

to 5 depending on the percentage load or generation lost in any region. However, the Standards don't cover 'near misses' which are also important and needs a thorough analysis. The Draft IEGC defines as to what constitutes a 'near-miss'.

(6) Field Testing for Model Validation

- (a) This section specifies the periodicity and tests to be carried out on power system elements for ascertaining correctness of mathematical models used for simulation studies as well as ensuring desired performance during an event in the system.

International Practices on Model Validation:

- (i) NERC in USA through MOD -025-2, MOD-026-1, MOD-027-1 and MOD-033-1 standards have mandated the verified and validated data submission by generation owner, transmission owner and other power system instrument owner which are provided to Planners and System operators for simulation activity for planning as well as operation on the regular basis.
- (ii) ENTSOE Network Code provides that the relevant Network Operator in coordination with the Relevant TSO shall have the right to obtain the simulation models, that shall properly reflect the behaviour of the Power Generating Module in both steady-state and dynamic simulations (50 Hz component) and, where appropriate and justified, in electromagnetic transient simulations. The models shall be verified against the results of compliance tests as given in the code. They shall then be used for the purpose of verifying the requirements of Network Code and for use in studies for continuous evaluation in system planning and operation.
- (iii) EIRGRID provides for Dynamic Model Specifications for Users in their Code. It states that users applying for connection to the Transmission System must provide the TSO with relevant dynamic models and supporting documentation. The model documentation should clarify the range of short circuit levels for which the model is expected to perform to expected equipment behaviour.

- (b) The following tests shall be carried out on respective power system elements:

<i>Power System Elements</i>	<i>Tests</i>	<i>Applicability</i>
<i>Synchronous Generator</i>	<i>(1) Real and Reactive Power Capability assessment. (2) Reactive Power Control Capability (As per CEA Technical Standards for Connectivity to the Grid) Regulations, 2007) assessment.</i>	<i>Individual Unit of rating 100MW and above for</i>

Power System Elements	Tests	Applicability
	(3) <i>Model Validation and verification test for the complete Generator and Excitation System model including PSS.</i> (4) <i>Model Validation and verification of Turbine/Governor and Load Control or Active Power/ Frequency Control Functions.</i> (5) <i>Testing of Governor performance and Automatic Generation Control.</i>	<i>Coal/lignite, 50MW and above gas turbine and 25 MW and above for Hydro.</i>
<i>Non synchronous Generator (Solar/Wind)</i>	(1) <i>Real and Reactive Power Capability for Generator</i> (2) <i>Power Plant Controller Function Test</i> (3) <i>Frequency Response Test</i> (4) <i>Fault Ride through Test (sample testing of a unit in the generating stations).</i>	<i>Applicable as per CEA (Technical Standards for Connectivity to the Grid) Regulations, 2007</i>
<i>HVDC/FACTS Devices</i>	(1) <i>Damping capability of HVDC/FACTS Controller</i> (2) <i>Frequency Controller Capability of HVDC Controller</i> (3) <i>Reactive Power Controller (RPC) Capability for HVDC/FACTS</i> (4) <i>Validation of voltage dependent current order limiter (VDCOL) characteristic for ensuring proper validation of HVDC performance</i> (5) <i>Filter bank adequacy assessment based on present grid condition.</i> (6) <i>Validation of response by FACTS devices as per settings.</i>	<i>To all ISTS HVDC as well as Intra-State HVDC/FACTS</i>

11. CHAPTER 8: UNIT COMMITMENT, SCHEDULING AND DESPATCH CODE FOR PHYSICAL DELIVERY OF ELECTRICAL ENERGY

The existing scheduling and despatch Code has been reviewed thoroughly and redrafted to the extent necessary in line with the new features such as real time market, combined scheduling for QCA, Security Constrained Unit Commitment. The scheduling and curtailment of must run plants has been prescribed in detail.

(1) Role of QCA

The role of QCA for scheduling and coordination has been prescribed as follows:

- (1) Scheduling of wind and solar generation by QCA:
 - (i) *The wind, solar or hybrid generator including energy storage systems shall, on their behalf, appoint the QCA by mutual consent to undertake scheduling for a particular ISTS pooling station or combined scheduling for more than one pooling station. Provided that:*
 - a) *where there is no consensus among wind, solar or hybrid generator, the QCA may be appointed by majority vote (51% of installed capacity) by the concerned generators. The voting rights allocated to*

- each generator shall be based on the capacity connected to the concerned ISTS pooling station(s);*
- b) Till the QCA has not been appointed, the lead generator or the individual generator, as the case may be, shall undertake the responsibilities of QCA.*
 - c) NLDC shall notify a procedure for aggregation of pooling stations for the purpose of combined scheduling and deviation settlement for multiple pooling stations wind/solar/hybrid generating stations within six (6) month.*
 - d) RLDC shall recognise QCA as user, on submission of authorisations from the concerned generating station and after registration with the concerned RLDC (as user) and RPC.*
- (ii) For the purpose of scheduling clause (i) above, the QCA shall undertake the activities to the extent of authorisation by wind, solar or hybrid generators which shall include:*
- (a) facilitate the concerned RLDC in the scheduling of power including periodic revisions and settlement of energy accounts in accordance with grid code;*
 - (b) responsible for metering, data collection and submission, coordination with SLDC, RLDC and NLDC;*
 - (c) undertake commercial settlement of deviation pool account with RLDC in accordance with grid code and applicable regulations.*
- (iii) the concerned wind, solar or hybrid generators including energy storage system shall indemnify RLDC for all act or conduct of QCA including compliance with the Grid Code and settlement of its financial liability in the pooled account.*
- (iv) The scheduling, energy accounting and settlement among the concerned wind, solar or hybrid generators, the terms and the extant of authorization of the QCA will be governed as per their mutually agreed terms:*
- Provided that any dispute arising between the generators and QCA shall be resolved in accordance with the contract. During the period of dispute, the generators and QCA shall not suspend any activities with regard to compliance of the Grid Code.*

(2) Minimum turndown level:

The technical minimum operating level has been reworded as minimum turn down level. Minimum turndown level has been defined as minimum station loading corresponding to the units on bar upto which a regional entity generating stations is required to be on bar on account of less schedule by its buyers or as per the direction of RLDC. The thermal generating stations shall be compensated for generation below the normative level as per the mechanism given in Annexure – 5 of the Grid Code.

(3) Scheduling of Inter-Regional and Cross-Border Transactions:

NLDC shall be responsible for scheduling and despatch of electricity over inter-regional links and cross-border links in accordance with the grid code specified by Central Commission in coordination with Regional Load Despatch Centres. The schedules prepared by NLDC for inter-regional and cross-border exchange of power shall be on net of the regions and net of the country basis respectively.

(4) Security Constrained Unit Commitment (SCUC)

(1) *The SCUC exercise shall be carried out to facilitate reliability of supply to the regional entities/beneficiaries taking into account optimal cost, adequate reserves, ramping requirements factoring security constraints:*

Provided that, the payment of carrying cost for the generation reserves committed through SCUC shall be as specified by the commission.

(2) *In order to ensure availability of adequate secondary and tertiary reserves with sufficient ramping capability, NLDC shall identify the generating unit for purpose of unit commitment at the national level three (3) days in advance of actual day of scheduling for regional entity generating stations on a rolling basis. NLDC, through RLDC shall advise the regional entity generators to commit or de-commit the unit. (Refer ANNEXURE – 7: Detailed Operating Procedure for Backing Down of Coal/Lignite/Gas unit(s) of the Central Generating Stations, Inter-State Generating Stations and other Generating Stations and for taking such units under Reserve Shut Down on scheduling below Minimum Turndown Schedule.)*

Provided that as and when enabling framework is in place, reserves may be procured through the market.

(3) *Based on the SCUC instructions from RLDC, the generating station shall revise the on-bar DC (with due consideration to ramp up/down capability), off-bar DC and ramp up/down rate.*

(4) *SLDC shall perform similar SCUC exercise at the intra-state level.*

(5) Must Run Plants:

Wind, solar, wind-solar hybrid and hydro plants (in case of excess water leading to spillage) shall be treated as MUST RUN power plants and shall not be subjected to curtailment on account of merit order despatch or any other commercial consideration.

(1) Must Run Plants:

(a) *Wind, solar, wind-solar hybrid and hydro plants (in case of excess water leading to spillage) shall be treated as MUST RUN power plants and shall not be subjected to curtailment on account of merit order despatch or any other commercial consideration.*

- (b) *In the event of transmission or system security constraint, the renewable generation may be curtailed after harnessing available flexible resources including energy storage systems.*
- (c) *In the event of extreme circumstances when any MUST RUN plant has to be curtailed, the details shall be published on the RLDC/SLDC website the following day, as the case may be, giving the date, name of RE generation plant, installed capacity, curtailment quantum in MWh, duration of curtailment and detailed reasons thereof.*

Explanation:

- (i) In the event of constraints in the transmission system, the renewable generation may be curtailed if it is the only source which relieves the constraint. Curtailment could also be required in case all the flexible resources are harnessed by the Appropriate LDC but frequency remains above 50.05 Hz and the Area Control Error (ACE) remains high (high level of underdrawal) and any further reduction in conventional generation would necessitate de-commitment of units leading to shortage conditions and possible load shedding during the peak hours.
- (ii) Accommodating a larger percentage share of renewable energy in the system can lead to a few hours of over-supply in a year necessitating curtailment of renewable energy as an economic option.

(6) Flexibility in Scheduling from various contracts upto approved LTA/ MTOA

- (a) It is observed that a distribution utility may enter into long term PPA and obtain long term access towards such PPA. Such utility may enter into short term contract as per its estimate of demand forecasting and as per relative economics of cost of power. Hence while placing requisition on day ahead basis, it may not need the entire quantum of power under long-term PPA and short-term contract entered into by such Utility. For scheduling such short-term contract, the Utility obtains short term open access which is granted upto 3 months in advance. Under current Regulations, short term open access is granted with firm power contract only and once granted the schedules under such short-term open access cannot be changed on day ahead basis. The same can be changed only with a notice of 2 days.

(b) It is observed that distribution utility who obtains advance STOA, may not require entire power under such STOA if merit Order is followed, however since schedule under STOA cannot be changed with a notice of 2 days, such STOA is scheduled fully. The same is illustrated with an example. A distribution company say “DISCOM 1” enters into long term PPA with generating station namely “GEN A” for 1000 MW @ Rs 2/unit variable cost. DISCOM 1 also enters into short term contract with generating station namely “GEN B” for 200 MW @ Rs. 4/unit and obtains STOA for same, 3 months in advance considering its demand forecasting and uncertainty of availability of capacity GEN A. Suppose on day ahead basis DISCOM1 needs 900 MW power, it has to schedule full 200 MW under STOA and will requisition 700 MW under long term PPA despite such power being cheaper @2/unit.

(c) A distribution utility enters into PPAs as per its estimate of demand forecasting which gets accurate in nearer term time frame. However, distribution utility should be provided flexibility to finalise its day ahead schedule based on merit order as per its demand forecasting for the next day.

(d) The draft IEGC 2020 provides such flexibility to buyer/distribution utility to place requisition on day ahead basis from its long term or medium term or short-term contract once it has obtained access under such contracts.

(e) For example, DISCOM1 situated in Northern Region has following PPAs with indicated generating stations:

Type of PPA	Quantum	Generating Station	Price	Location of Generating Station	Access granted
Long term	1000 MW	GEN A	Rs 2 / unit VC	Western region	LTA
Medium term	500 MW	GEN B	Rs.3 / unit VC	Southern Region	MTOA
Short term	500 MW	GEN C	Rs 4 / unit	Eastern Region	STOA

(f) Suppose Short term PPA is for month of March 2020. Day ahead schedule for 2 march 2020 shall be finalised on 1 March 2020. On 1 March 2020,

DISCOM1 estimates a requirement of 1500 MW. GEN A, GEN B provides full Availability towards such PPA. DISCOM1 shall have to provide requisition among Declared capacity provided by GEN A and GEN B since they are under LTA and MTOA. DISCOM1 shall also be provided flexibility to requisition from GEN C as per its short-term contract while placing day ahead requisition. For example, in the instant example, DISCOM1 may place requisition of 1000 MW from GEN A and 500 MW from GEN B and doesn't requisition anything from GEN C.

- (g) Suppose in the above example GEN A declares its availability as 500 MW for 2.3.2020, DISCOM1 may place requisition as 500 MW from GEN A, 500 MW from GEN B and 500 MW from GEN C. DISCOM1 may decide to place requisition as 500 MW from GEN A, 500 MW from GEN B, 200 MW from GEN C and decides to procure 300 MW from day ahead power exchange. The same shall be scheduled as requested by DISCOM subject to availability of transmission system.
- (h) In the above example, LTA has been granted on WR-NR corridor, MTOA on SR-NR corridor and STOA on ER-NR corridor. It is proposed that if DISCOM1 does-not requisition full 500 MW under STOA, the balance quantum which is 300 MW in ER-NR corridor in the above example shall be released under day ahead power exchange and real time power exchange. DISCOM1 shall not be provided flexibility to reschedule the power not requisitioned under STOA from 7th/8th block which is allowed for long term or medium-term open access. This has been proposed to ensure that DISCOM1 does-not block the corridor under STOA, at the same time it is allowed flexibility to ensure economy in scheduling on day ahead scheduling. The left-over corridors shall be released for market.
- (i) The flexibility of scheduling on day ahead basis under STOA shall only be available with DISCOM/buyer and not with generating station or seller to avoid any gaming by generator.
- (j) There may be short term contracts where even if DISCOM schedules less power on day ahead basis, it has to pay full like "Take or Pay". On

introduction of such flexibility in Grid Code, it is expected that contracts will be entered into keeping in view such flexibility.

- (k) The flexibility to revise schedule under STOA on day ahead basis shall only be provided for upto LTA or MTOA quantum only. For example, DISCOM1 in above example will have flexibility to requisition power under STOA on day ahead basis only upto 1500 MW since it has LTA +MTOA for 1500 MW. In case DISCOM1 needs 1600 MW for 2.3.2020, on 1.3.2020 if it schedules 1000 MW under Long term PPA and 500 MW under medium term PPA it won't be provided flexibility to revise its STOA of 500 MW on day ahead basis, since it has already exhausted its LTA+MTOA.

Accordingly, following has been specified in the draft IEGC 2020:

“A Distribution utility/ buyer shall have the flexibility to requisition/schedule such quantum of power as per its preference from its portfolio of power contracts (long/medium/short-term agreements) upto the approved quantum of long-term access and/or medium-term open access to such User.

Provided that:

- (a) for scheduling power under short-term bilateral contract, the user shall be required to obtain STOA as per CERC (Open Access in Interstate Transmission) Regulations 2008.*
- (b) If the user does not fully requisition its short-term access before the opening of day-ahead bidding in power exchanges, the unused corridor(s) against such access shall be forfeited, and released in the day ahead and real time markets.*

NLDC shall include the modalities of implementation in the Detailed Procedure and Timelines for Scheduling and Despatch of Regional Entities.”

12. CHAPTER 9: CYBER SECURITY

A new Code namely, Cyber Security has been added. The code provides for identification of Critical Information Infrastructure, appointment of Information Security Officer as per the Information Technology Rules 2018 and take necessary measures in accordance with guidelines by National Critical Information Infrastructure Protection Centre.

13. CHAPTER 10: MONITORING AND COMPLIANCE CODE

A separate chapter on monitoring and compliance code has been added which provides for self-audit as well as third party audit for the performance of all users,

CTU, STU, NLDC, RLDC, SLDC and RPC with respect to grid code compliance shall be assessed periodically. All users, CTU, STU, NLDC, RLDC, RPC and SLDC shall conduct annual self-audits to review compliance of the regulations and submit by 31st July of every year. CERC may order independent third-party compliance audit for any user, CTU, NLDC, RLDC and RPC as deemed necessary.

14. List of Annexure

The following annexures comprise integral part of the Grid Code. All the annexure has been reviewed and redrafted to the extant required to align the new Grid Code.

	Contents
ANNEXURE – 1	Generation Reserve Estimation and Frequency Control
ANNEXURE – 2	Third Party Protection System checking & validation template for a substation
ANNEXURE – 3	Reporting Requirements
ANNEXURE – 4	Reactive Power Compensation
ANNEXURE – 5	Minimum Turndown Level for Operation of Regional Entity Generating Stations
ANNEXURE – 6	Mechanism for Compensation for Degradation of Heat Rate, Aux Consumption and Secondary Fuel Oil Consumption, due to Part Load Operation and Multiple Start/Stop of Units
ANNEXURE – 7	Detailed Operating Procedure for Backing Down of Coal/Lignite/Gas unit(s) of the Central Generating Stations, Inter-State Generating Stations and other Generating Stations and for taking such units under Reserve Shut Down on scheduling below Minimum Turndown Schedule
ANNEXURE – 8	Procedure for implementation of the Framework on Forecasting, Scheduling and Imbalance handling of Renewable Energy Generating Stations including power parks based on Wind and Solar at inter-state level
ANNEXURE -9	Accounting and Pool settlement system

15. Issues for consideration of Commission which have not been included in Grid Code

(1) Compensation to seller/buyer due to outage of ISTS/STU systems

At present there is no direct accountability of the transmission licensee if power supply to users is disrupted due to poor maintenance and faulty operation or design of the transmission line and substation equipment. The same is only partly accounted for by recovery based on availability. On the other hand, the transmission licensees get incentive on the average availability of their system aggregated on a regional basis. This is not sending the right signal to the transmission licensees. It may happen that due to inadequate supervision, poor preventive maintenance or faulty design outages of transmission lines due to tower failure, insulator tracking faults, touching of tree branches etc. or maloperation of relays or any other reason, generating station or buyer may not be able to schedule the power under long term access or medium-term open access. The incidents of tower failures including on relatively new lines during the last few years compiled by POSOCO are given below as an illustration to emphasise the need for regulatory oversight over the performance of transmission licensees. There are daily mal-tripping's due to faulty protection operation, but there is no penalty.

Transmission Line Outage due to Tower Collapse (400 kV and above voltage level)						
Year	No. of trippings involving tower collapse(HVDC)	No. of trippings involving tower collapse(765 kV)	No. of trippings involving tower collapse(400 kV)	Total no. of trippings involving tower collapse	Average Down Time (hh:mm:ss) (Sum of outage duration/no. of incidents)	Maximun Down Time for an incident(hh:mm:ss)
2015	0	9	13	22	560:00:00	2304:00:00
2016	0	6	14	20	2740:48:00	12288:00:00
2017	2	6	14	22	2388:00:00	7608:00:00
2018	4	12	20	36	2949:00:00	14328:00:00
2019 (upto 16th Dec 2019)	0	2	24	26	1901:32:00	5280:00:00
Total	6	35	85	126	2107:52:00	14328:00:00

It is suggested that cases of transmission system outage due to poor performance of the transmission licensee leading to interruption of supply to consumers, penalty should be levied on the transmission licensee for paying compensation to affected LTA holders. In Norway, the state transmission licensee has to arrange power from alternate sources in the event of congestion. The commission may review the conditions of transmission licence and create more accountability for deemed and other transmission licensees. This will go a long way in improving reliability of Grid operation.

(2) Virtual Power Plant (VPP)

Stakeholders have requested that Virtual power plant may be defined in the Grid Code as “A Virtual Power Plant (VPP) is an aggregated power plant, which is spatially distributed, connected to the grid at multiple points and remotely controllable from a common control centre. Acting as a single despatchable power plant, a VPP aggregates the capacities of heterogeneous energy resources, and Energy Storage(s) for the purposes of providing renewable energy on demand.”. The matter was discussed in the Expert group and it was a general view that transmission adequacy has to be ensured before allowing a spatially distributed generation complex, flexibility of delivering power to different points in the grid. As a matter of fact, nobody has approached the Commission with a formal request to recognise VPP as a single dispatchable unit. The Commission may take appropriate view at appropriate time.

(3) Fuel availability with generating stations

Unencumbered fuel/coal availability free from conditionalities is ideal for a free and intense competition in the electricity market to drive prices down and give impetus to efficiency and innovation. In the future, a situation could arise leading to deficient or negative generation reserves during peak hours although spare installed capacity of conventional generation plants is available yet are inoperative due to paucity of coal. Since CERC is responsible for market development under the Act, it may like to take up the issue of liberalisation of coal market to synergize with the liberalisation of the electricity market which has enabled the country to get rid of chronic power shortages.

- 16. Office Order dated 28.5.2019 is attached at Annexure I.**
- 17. Draft IEGC 2020 is attached at Annexure II.**
- 18. Gist of comments received is attached at Annexure- III.**

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केन्द्रीय विद्युत विनियामक आयोग
CENTRAL ELECTRICITY REGULATORY COMMISSION



Sanoj Kumar Jha, IAS
Secretary

No. ENGG/2012/1/2019-CERC

Dated :- 28th May, 2019

NOTIFICATION

Subject: Constitution of Expert Group to review "Indian Electricity Grid Code and other related issues"

Central Electricity Regulatory Commission (CERC) has decided to constitute an Expert Group to review "Indian Electricity Grid Code and other related issues".

2. The Expert Group has been constituted having following members:-

- Shri Rakesh Nath, Ex-Chairperson, CEA & Ex-Member (Tech) of APTEL - Chairman
- Shri A.S.Bakshi, Ex-Chairperson, CEA & Ex-Member, CERC - Member
- Shri Ravinder, Ex-Chairperson & Member (PS), CEA, Ex-Chief (E), CERC - Member
- Shri Satish Shrivastava, Chief (Engg), CERC - Member, Convenor

3. The scope of work of the Group is as follows:-

- To review the provisions of Central Electricity Regulatory Commission (Indian Electricity Grid Code) Regulations, 2010 based on past experience, recent developments in the power system of India, changes in market structure and the future challenges which includes high level of renewable penetration in the grid, introduction of new products in market etc.; and
- Suggest appropriate regulatory intervention and prepare draft IEGC making recommendation for proposed amendment or changes in the existing Grid Code.

4. While carrying out the task, the group may co-opt or invite any person / expert / institution / organization for advise or opinion in the subject matter. POSOCO is requested to provide necessary assistance to the group for any data and study. Secretarial assistance to the group will be provided by the Engg. Division of CERC.

5. The Group shall submit revised draft IEGC to the Commission within six months of issue of the notification.

Yours faithfully,


28/05/19
(Sanoj Kumar Jha)

To,

Shri Satish Shrivastava,
Chief (Engg), CERC - Member, Convenor
Email ID : sechandra@hotmail.com

*Based on recommendations of Expert Group
constituted by the Central Electricity Regulatory
Commission*

DRAFT
INDIAN ELECTRICITY
GRID CODE 2020

New Delhi, January 2020

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**CENTRAL ELECTRICITY REGULATORY COMMISSION
NEW DELHI**

No.

Dated:....., 2020

PREAMBLE

No. -The Indian Electricity Grid Code (IEGC) is a regulation made by the Central Commission in exercise of powers under clause (h) of sub-section (1) of Section 79 read with clause (g) of sub-section (2) of Section 178 of the Act. The IEGC lays down regulations to be followed by various persons and participants to plan, develop, maintain and operate power system in the country in a secure, economic, reliable, resilient and efficient manner. The regulations provide for integration of renewable energy resources in the grid, flexible operation of energy resources, optimum scheduling & despatch, open access, promoting competition in the generation sector and various measures including reserves necessary for grid stability. It seeks to create a robust framework for maintaining demand-supply balance under credible contingencies and an enabling framework for transition to clean energy sources. According to clause (h) of sub-section (1) of Section 86, the State Commission shall specify its state grid code consistent with the IEGC.

NOTIFICATION (DRAFT)

In exercise of powers conferred under clause (h) of sub-section (1) of Section 79 read with clause (g) of sub-section (2) of Section 178 of the Electricity Act, 2003 (36 of 2003), and all other powers enabling it in this behalf, the Central Electricity Regulatory Commission hereby makes the following regulations.

CHAPTER 1: PRELIMINARY

1. SHORT TITLE, EXTENT AND COMMENCEMENT

- i. These regulations may be called the Central Electricity Regulatory Commission (Indian Electricity Grid Code) Regulations, 2020.
- ii. These regulations shall come into force from the date notified by the Commission.
- iii. These regulations shall supersede the Indian Electricity Grid Code, 2010 read with amendments thereof.

2. SCOPE AND EXTENT OF APPLICATION

These regulations shall apply to:

- i. All users, State Load Despatch Centres, Regional Load Despatch Centres, National Load Despatch Centre, Central Transmission Utility, State Transmission Utilities, licensees, National Power Committee, Regional Power Committees, and Power Exchanges are required to abide by the principles and procedures defined in the IEGC to the extent applicable.
- ii. For the purpose of the IEGC, the Damodar Valley Corporation (DVC) shall be treated as regional entity and a separate control area. The DVC Load Despatch Centre shall perform functions of a SLDC for the control area of DVC.
- iii. The generating stations of the Bhakra Beas Management Board (BBMB) and Sardar Sarovar Project (SSP) shall be treated as regional entities and their generating units shall be scheduled and despatched in coordination with BBMB or Narmada Control Authority, as the case may be, with regard to the irrigation requirements.
- iv. A neighboring country inter-connected with the National/Regional Grid shall be treated as a separate control area.

- v. The State Grid Code specified by the State Commission shall be consistent with the IEGC.

3. DEFINITIONS

(1) In these regulations unless the context otherwise requires:

S. No.	Particulars	Definition
1.	'Act'	means the Electricity Act, 2003;
2.	'Alert State'	means the state in which the system is within the operational parameters as defined in the code but a contingency has occurred;
3.	'Ancillary Services'	means 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 and includes secondary response, tertiary response, active power support for load following, reactive power support and black start;
4.	'Area Control Error' or 'ACE'	means the instantaneous difference between a control area's net actual and scheduled interchange, taking into account the effects of Frequency Bias and correction of meter error. Mathematically, it is equivalent to: $ACE = \text{Deviation } (\Delta P) + (\text{Frequency Bias}) (K) * (\text{Deviation from nominal frequency}) (\Delta f) + \text{meter error};$
5.	'Automatic Generation Control' or 'AGC'	means a mechanism that automatically adjusts the generation of a control area to maintain its Interchange Schedule Plus its share of frequency response;

S. No.	Particulars	Definition
6.	'Automatic Voltage Regulator' or 'AVR'	means a continuously acting automatic excitation control system to control the voltage of a generating unit measured at the generator terminals;
7.	'Available Transfer Capability' or 'ATC'	means power transfer capability of the inter-control area transmission system or across electrical regions or between ISTS and state network or between cross-border interconnections available for scheduling transactions in a specific direction, taking into account the network security declared by the concerned load despatch centre. Mathematically, ATC is the Total Transfer Capability less Transmission Reliability Margin;
8.	'Beneficiary'	means a person who has a share or entitlement in an ISGS
9.	'Bilateral Transaction'	means a transaction for exchange of energy (MWh) between a specified buyer and a specified seller, directly or through a trading licensee or discovered at Term Ahead Market at power exchange through anonymous bidding, from a specified point of injection to a specified point of drawal for a fixed or varying quantum of power (MW) for any time period during a month;
10.	'Blackout State'	means a part or all the operations of power system have got suspended;
11.	'Black Start Procedure'	means the procedure necessary to recover from a partial or a total blackout in the region;

S. No.	Particulars	Definition
12.	'Bulk Consumer'	shall have the same meaning as defined in Central Electricity Regulatory Commission (Grant of Connectivity, Long-term Access and Medium-term Open Access in inter-State Transmission and related matters) Regulations,2009 including its amendments and subsequent re-enactment;
13.	'Captive Generating Plant'	means a power plant set up by any person to generate electricity primarily for his own use and includes a power plant set up by any co-operative society or association of persons for generating electricity primarily for use of members of such cooperative society or association;
14.	'Central Generating Station'	means the generating station owned by a company owned or controlled by the Central Government;
15.	'Central Transmission Utility' or 'CTU'	means any government company, which the Central Government may notify under sub-section (1) of Section 38 of the Act;
16.	'Cogeneration'	means a process which simultaneously produces two or more forms of useful energy (including electricity);
17.	'Cold Start'	in relation to steam turbine means start up after a shutdown period exceeding 72 hours (turbine metal temperatures below approximately 40% of their full load values);
18.	'Collective Transaction'	means a set of transactions discovered in power exchange through anonymous, simultaneous competitive bidding by buyers and sellers;

S. No.	Particulars	Definition
19.	'Communication System'	means a collection of individual communication networks, communication media, relaying stations, tributary stations, terminal equipment usually capable of inter-connection and inter-operation to form an integrated communication backbone for power sector;
20.	'Congestion'	means a situation where the demand for transmission capacity or power flow on any corridor exceeds its Available Transfer Capability;
21.	'Connection Agreement'	means an agreement between CTU, inter-state transmission licensee and any person setting out the terms relating to a connection to and/or use of the Inter State Transmission System;
22.	'Connectivity'	means the state of getting connected to the inter-State transmission system by a generating station, including a captive generating plant, a bulk consumer or a person or an Inter-State Transmission licensee;
23.	'Control Area'	means 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 and contributes to regulation of frequency as specified;
24.	'Control Centre'	means NLDC or RLDC or REMC or SLDC or Area LDC or Sub-LDC or DISCOM LDC including main and backup as applicable;

S. No.	Particulars	Definition
25.	'Critical Information Infrastructure'	means the computer resource, the incapacitation or destruction of which, shall have debilitating impact on national security, economy, public health or safety;
26.	'Date of Commercial Operation' or 'COD'	shall have the same meaning as provided in Regulation 32 of these regulations;
27.	'Declared Capacity' or 'DC'	in relation to a generating station means, the capability to deliver ex-bus electricity in MW declared by such generating station in relation to any time-block of the day as defined in the Grid Code or whole of the day, duly taking into account the availability of fuel or water, and subject to further qualification in the relevant regulations;
28.	'Demand'	means the demand of active power in MW;
29.	'Demand Response'	means variation in electricity usage by end customers/control area manually or automatically, as per system requirement identified by concerned load despatch centre;
30.	'Despatch Schedule'	means the ex-power plant net MW and MWh output of a generating station, scheduled to be exported to the Grid from time to time;
31.	'Deviation Settlement Mechanism (DSM) Regulations'	means Central Electricity Regulatory Commission (Deviation Settlement Mechanism and related matters) Regulations, 2014 including any subsequent amendments thereof;
32.	'Disturbance Recorder' or 'DR'	means a device provided to record the behavior of the pre-selected digital and analog values of the system parameters during an event;

S. No.	Particulars	Definition
33.	'Data Acquisition System' or 'DAS'	means a system provided to record the sequence of operation in time, of the relays/equipment as well as the measurement of pre-selected system parameters;
34.	'Drawal Schedule'	means the summation of the station-wise ex-power plant drawal schedules from all ISGS and drawal from/injection to regional grid consequent to other long-term access, medium term and short-term open access transactions;
35.	'DVC'	means the Damodar Valley Corporation established under sub-section (1) of Section 3 of the Damodar Valley Corporation Act, 1948;
36.	'Emergency State'	means the state in which one or more variables are outside their operating limit or many of the equipment are above their operational limit;
37.	'Energy Storage System' or 'ESS'	means any system or device capable of storing electrical energy in any form using any technology and delivering it back in the form of electrical energy;
38.	'Event'	means an unscheduled or unplanned occurrence on a grid including faults, incidents and breakdowns;
39.	'Event Logging Facilities'	means a device provided to record the chronological sequence of operations, of the relays and other equipment;
40.	'Ex-Power Plant'	means net MW/MWh output of a generating station, after deducting auxiliary consumption and transformation losses;

S. No.	Particulars	Definition
41.	'Fault Locator' or 'FL'	means a device provided at the end of a transmission line to measure/ indicate the distance at which a line fault may have occurred;
42.	'Flexible Alternating Current Transmission System' or 'FACTS'	means 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;
43.	'Flow-gate'	Means a group of parallel transmission line (s), outage of which may lead to cascade tripping or separation of systems or loss of generation complex or load centre;
44.	'Forced Outage'	means an outage of a generating unit or a transmission facility due to a fault or other reasons which has not been planned;
45.	'Frequency Response Characteristics' or 'FRC'	means automatic, sustained change in the power consumption by load or output of the generators that occurs immediately after a change in the control area's load-generation balance and which is in a direction to oppose a change in interconnection's frequency. Mathematically it is equivalent to $\text{FRC} = \text{Change in Power } (\Delta P) / \text{Change in Frequency } (\Delta f)$
46.	'Frequency Response Obligation' or 'FRO'	is defined as the minimum frequency response a control area has to provide in the event of any frequency deviation;
47.	'Frequency Response Performance' or 'FRP'	means the ratio of actual frequency response with frequency response obligation;

S. No.	Particulars	Definition
48.	'Frequency Stability'	means the ability of the transmission system to maintain frequency stable in the normal state and after being subjected to a disturbance;
49.	'Gate Closure'	means the time after which the bids submitted to the Power Exchange cannot be modified for a specified delivery period;
50.	'Generating Unit'	means a) For all generating stations except solar photo voltaic, wind and hybrid stations: an electrical generator coupled to a prime mover within a power station together with all plant and apparatus at the power station which relate exclusively to operation of that turbo-generator; b) For solar photo voltaic generating stations including hybrid, each inverter along with associated modules will be reckoned as a separate generating unit; c) For wind generating stations including hybrid: each wind turbine generator with associated equipment shall be reckoned as a separate generating unit;
51.	'Governor Droop'	in relation to the operation of the governor of a generating unit means the percentage drop in system frequency which would cause the generating unit under governor action to change its output from zero to full load;
52.	'Grid Security'	means the power system's capability to retain a normal state or to return to a normal state as soon

S. No.	Particulars	Definition
		as possible, and which is characterized by operational security limits;
53.	'Grid Standards'	means the standards specified by the Authority under clause (d) of the Section 73 of the Act;
54.	'Hot Start'	in relation to steam turbine, means start up after a shutdown period of less than 10 hours (turbine metal temperatures below approximately 80% of their full load values);
55.	'Inertia'	means the contribution to the capability of the power system to resist changes in frequency by means of an inertial response from a generating unit, network element or other equipment that is coupled with the power system and synchronized to the frequency of the power system;
56.	'Infirm Power'	means electricity injected into the grid prior to the date of commercial operation of a unit of the generating station;
57.	'Inter-State Generating Station' or 'ISGS'	means a central generating station or other generating station having a scheme of generation and sale of electricity in more than one state;
58.	'Inter-State Transmission System' or 'ISTS'	shall have the same meaning as defined in the Act;
59.	'Licensee'	means a person who has been granted a license under Section 14 of the Act;
60.	'Load'	means the active, reactive or apparent power consumed by a utility/installation of consumer;
61.	'Long-Term Access'	shall have the same meaning as specified by the Commission in Central Electricity Regulatory

S. No.	Particulars	Definition
		Commission (Grant of Connectivity, Long term Access and Medium-term Open Access in inter-State Transmission and related matters) Regulations, 2009;
62.	'Long-Term Customer'	shall have the same meaning as specified by the Commission in Central Electricity Regulatory Commission (Grant of Connectivity, Long term Access and Medium-term Open Access in inter-State Transmission and related matters) Regulations, 2009;
63.	'Maximum Continuous Rating' or 'MCR'	means the maximum continuous output in MW at the generator terminals guaranteed by the manufacturer at rated parameters;
64.	'Medium-Term Open Access'	shall have the same meaning as specified by the Commission in Central Electricity Regulatory Commission (Grant of Connectivity, Long term Access and Medium-term Open Access in inter-State Transmission and related matters) Regulations, 2009;
65.	'Medium-Term Customer'	means a person who has been granted medium-term open access;
66.	'Merit Order'	means the order of ranking of available electricity generation in ascending order from least energy charge to highest energy charge to be used for deciding despatch instruction to minimize the overall cost of generation.
67.	'Merit Order Despatch'	means despatch of generating stations to supply electricity variable in accordance with the merit order

S. No.	Particulars	Definition
		taking into account any technical and operational limits of generation and transmission facilities;
68.	'Minimum Turndown Level'	means minimum station loading corresponding to the units on bar upto which a regional entity generating stations is required to be on bar on account of less schedule by its buyers or as per the direction of RLDC as detailed in Chapter 8;
69.	'Nadir Frequency'	means minimum frequency after a contingency in case of generation loss and maximum frequency after a contingency in case of load loss;
70.	'National Grid'	means the entire inter-connected electric power network of the country;
71.	'Net Drawal Schedule'	means the drawal schedule of a regional entity after deducting the apportioned transmission losses (estimated);
72.	'National Load Despatch Centre' or 'NLDC'	means the centre established under sub-section (1) of Section 26 of the Act;
73.	'National Power Committee' or 'NPC'	means a committee established by Ministry of Power, Government of India to deliberate and resolve the issues requiring consultation on issues affecting more than one region or all regions;
74.	'Normal State'	means the state in which the system is within the operational parameters as defined in this Grid Code;
75.	'On-Bar Declared Capacity'	in relation to a generating station means the capability to deliver ex-bus electricity in MW from the units on-bar declared by such generating station in relation to any time block of the day as

S. No.	Particulars	Definition
		defined in the Grid Code or whole of the day, duly taking into account the availability of fuel and water and subject to further qualification in the relevant regulations;
76.	'On-Bar Installed Capacity'	means the summation of name plate capacities or the capacities as approved by the Commission from time to time, of all units of the generating station in MW which are on- bar. In case of a combined cycle module of a gas/liquid fuel-based stations, the installed capacity of steam turbine shall be in proportion to the on-bar capacity of gas turbines of the module;
77.	'Off-Bar Declared Capability'	shall be considered as the difference between Declared Capacity and On-Bar Declared Capacity in MW;
78.	'Operation Co-ordination Sub-Committee' or 'OCC'	means a sub-committee of RPC which deliberates the operational aspects of the regional grid;
79.	'Primary Reserve'	means the maximum quantum of power which will immediately come into service through governor action of the generator in the event of sudden change in frequency. This reserve response shall start instantaneously and attain its peak in less than 30 seconds, and shall sustain upto 5 minutes;
80.	'Pool Account'	means regional account for i. Payments regarding deviation settlement/ancillary services or

S. No.	Particulars	Definition
		ii. reactive energy exchanges (Reactive Energy Account) or iii. congestion charge, as the case may be;
81.	'Pooling Station'	means the ISTS grid sub-station where pooling of generation of individual generators is done for interfacing with the next higher voltage level;
82.	'Power Exchange'	means an exchange registered under CERC (Power Market), Regulations 2010;
83.	'Power System'	means all aspects of generation, transmission, distribution and supply of electricity and includes one or more of the following, namely: <ul style="list-style-type: none"> i. generating stations; ii. transmission or main transmission lines; iii. sub-stations; iv. tie-lines; v. load despatch activities; vi. mains or distribution mains; vii. electric supply lines; viii. overhead lines; ix. service lines; x. works;
84.	'Protection Co-ordination Sub-Committee'	means a sub-committee of RPC with members from all the regional entities which decides on the protection aspects of the regional grid;
85.	'Qualified Coordinating Agency' or 'QCA'	means the lead generator or any authorized agency on behalf of wind, solar and hybrid generators including Energy Storage Systems connected to one or more pooling station(s) for

S. No.	Particulars	Definition
		coordinating with concerned load despatch centre for scheduling, operational coordination and deviation settlement;
86.	'Ramp Rate'	means rate of change of a generating station output expressed in %MW per minute;
87.	'Rate of Change of Frequency' or ' <i>df/dt</i> '	means the time derivative of the power system frequency which negates short term transients and therefore reflects the actual change in synchronous network frequency;
88.	'Reference contingency'	means the maximum positive power deviation occurring instantaneously between generation and demand and considered for dimensioning of reserves;
89.	'Regional Entity'	means such persons who are in the RLDC control area and whose metering and energy accounting is done at the regional level;
90.	'Regional Power Committee' or 'RPC'	means a Committee established through a resolution by the Central Government for a specific region for facilitating the integrated operation of the power systems in that region;
91.	'Restorative State'	means a condition in which control action is being taken to reconnect the system elements and to restore system load;
92.	'RPC Secretariat'	means the Secretariat of the RPC;
93.	'Regional Energy Account' or 'REA'	means regional accounts of energy and other parameters issued by the RPC Secretariat for the purpose of billing and settlement of charges of ISGS and other users;

S. No.	Particulars	Definition
94.	'Regional Transmission Account' or 'RTA'	means regional accounts of transmission issued by the RPC Secretariat for the purpose of billing and settlement of transmission charges of ISTS;
95.	'Regional Grid'	means the entire inter-connected electric power network of the concerned region;
96.	'Regional Load Despatch Centre' or 'RLDC'	means the Centre established under sub-section (1) of Section 27 of the Act;
97.	'Secondary Reserve'	means the maximum quantum of power which can be activated through Automatic Generation Control (AGC) to free the capacity engaged by the primary control. This reserve response shall come into service starting from 30 seconds and shall sustain up to 15 minutes;
98.	'Security Constrained Economic Despatch' or 'SCED'	means operation of generation facilities to produce energy at lowest cost to reliably serve consumers, recognizing any operational and technical limits of generation and transmission facilities;
99.	'Security Constrained Unit Commitment' or 'SCUC'	means committing/de-committing generating units while respecting limitations of the transmission system and unit operating characteristics;
100.	'SERC'	means State Electricity Regulatory Commission;
101.	'Settlement Nodal Agency' or 'SNA'	means the nodal agency as notified by Ministry of Power, Government of India for each neighboring country for settlement of grid operation related charges in terms of CERC (Cross Border Trade of Electricity) Regulations, 2019;

S. No.	Particulars	Definition
102.	'Share'	means percentage or MW entitlement of a beneficiary in an ISGS either notified by Government of India or agreed through contracts and implemented through long-term access and medium-term open access;
103.	'Short-Term Open Access'	means open access for a period as specified by the Commission;
104.	'State Load Despatch Centre' or 'SLDC'	means the Centre established under subsection (1) of Section 31 of the Act;
105.	'State Transmission Utility' or 'STU'	means the board or the government company specified as such by the state government under sub-section (1) of section 39 of the Act;
106.	'System Constraint'	means a situation in which there is a need to prepare and activate a remedial action in order to respect operational security limits;
107.	'System State'	means the operational state of the power system in relation to the operational security limits which can be normal state, alert state, emergency state, extreme emergency state and restoration state;
108.	'Technical Co-ordination Committee' or 'TCC'	means the sub-committee set up by RPC to coordinate the technical and commercial aspects of the operation of the regional grid;
109.	'Tertiary Reserve'	means the quantum of power which can be activated, in order to restore an adequate secondary reserve. Fast Tertiary Reserve Response shall come into service starting from five (5) minutes and shall sustain upto thirty (30) minutes. Slow Tertiary Reserve Response shall

S. No.	Particulars	Definition
		come into service starting from fifteen (15) minutes and shall sustain upto sixty (60) minutes;
110.	'Time Block'	means block of duration as specified by the Commission for which energy meters record values of specified electrical parameters with first time block starting at 00.00 Hours, presently fifteen (15) minutes;
111.	'Total Transfer Capability' or 'TTC'	means the amount of electric power that can be transferred reliably over the inter-control area transmission system under a given set of operating conditions considering the effect of occurrence of the worst credible contingency;
112.	'Transmission Planning Criteria'	means the manual issued by CEA for transmission system planning;
113.	'Transmission Reliability Margin' or 'TRM'	means the amount of margin kept in the total transfer capability to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions;
114.	'Trial Operation' or 'Trial Run'	shall have the same meaning as provided in Regulation 29 of these regulations;
115.	'User'	means a generating company, captive generating plant, energy storage system, transmission licensee including deemed transmission licensee, distribution licensee, solar park developer, wind park developer, wind-solar photo voltaic hybrid system, or bulk consumer whose electrical plant is connected to the Grid at voltage level 33 kV and above;

S. No.	Particulars	Definition
116.	'Voltage Stability'	means the ability of a transmission system to maintain steady acceptable voltages at all nodes in the transmission system in the normal situation and after being subjected to a disturbance;
117.	'Warm Start'	means in relation to steam turbine means start up after a shutdown period between 10 hours and 72 hours (turbine metal temperatures between approximately 40% to 80% of their full load values);

(2) Words and expressions used in these regulations and not defined herein but defined in the Act or other relevant regulations of the Commission shall have the meaning as assigned to them under the Act or relevant regulations of the Commission.

CHAPTER 2: STRUCTURE OF GRID CODE

4. STRUCTURE OF THE GRID CODE

(1) Chapter 3: Role of Various Organizations and their Linkages

This chapter defines the functions and activities of various organizations and entities relevant to the Grid Code.

(2) Chapter 4: Planning Code

This chapter covers the following aspects:

- i. Integrated planning and development of adequate resources including demand estimation, active and reactive power resources, reserves and energy storage resources required for secure grid operation.
- ii. Planning of transmission system for safe, reliable, economic and resilient power system.
- iii. Exchange of information amongst the stakeholders and planning agencies.

(3) Chapter 5: Connection Code

This chapter covers the technical and design criteria for connectivity, procedure and requirements for physical connection and integration of new grid elements. It includes tests to be performed after connectivity and prior to Trial Run for Declaration of Commercial Operation.

(4) Chapter 6: Protection and Commissioning Code

This chapter covers the protection requirement and protection settings of electrical systems, performance monitoring of protection system, protection audit and procedure

and requirements for declaration of commercial operation of a generating unit or a generating station or a transmission element of an interstate transmission system.

(5) Chapter 7: Operating Code

This chapter describes the operational philosophy, operational requirements, technical capabilities and procedures or methodologies to maintain secure and reliable grid operation including aspects related to real time operation, outage planning and system restoration. As maintenance of load-generation balance is a vital aspect of reliable system operation and significant challenges are associated with increasing penetration of renewables (both wind and solar) in the country, the chapter, thus, also deals with generation reserves estimation and frequency control.

(6) Chapter 8: Unit Commitment, Scheduling and Despatch Code for Physical Delivery of Electricity

This chapter deals with the procedure to be adopted for forecasting of demand and generation resources in a control area, scheduling and despatch of generation of the Inter-State Generating Stations (ISGS) and scheduling for other transactions through long-term access, medium-term and short-term open access, on a day-ahead and intra-day basis along with scheduling and despatch of ancillary services and reserves. This chapter shall also deal with the process of the flow of information between the ISGS, National Load Despatch Centre (NLDC), Regional Load Despatch Centre (RLDC), Power Exchanges and State Load Despatch Centre (SLDC) and other concerned persons for the secure and reliable operation of the grid.

(7) Chapter 9: Cyber Security

This chapter deals with measures to be taken to safeguard the national grid from spyware, malware, cyber-attacks, network hacking, procedure for security audit from time to time,

upgradation of system requirements and keeping abreast of latest developments in the area of cyber-attacks and cyber security requirements.

(8) Chapter 10: Monitoring and Compliance Oversight

This chapter deals with monitoring of compliance of Grid Code by various entities in the Grid by RLDC and RPC or any other person and manner of reporting the instances of violations of Grid Code and taking remedial steps or initiating appropriate action. This chapter also covers compliance audit.

(9) Chapter 11: Miscellaneous

CHAPTER 3: ROLE OF VARIOUS ORGANIZATIONS

5. OBJECTIVE

This chapter specifies the roles and functions of the various organizations involved in the grid operation and management and their organizational linkages so as to facilitate development and smooth operation of the grid at large.

6. ROLE OF NLDC

- (1) According to notification dated 2nd March 2005 by Ministry of Power, Government of India issued under Section 26(2) of the Act, NLDC shall be the apex body to ensure integrated operation of the national power system and shall discharge the following functions:
 - (a) Supervision over the Regional Load Despatch Centers.
 - (b) Scheduling and despatch of electricity over inter-regional links in accordance with Grid Standards specified by the Authority and Grid Code specified by Central Commission in coordination with Regional Load Despatch Centers.
 - (c) Coordination with Regional Load Despatch Centers for achieving maximum economy and efficiency in the operation of National Grid.
 - (d) Monitoring of operations and grid security of the National Grid.
 - (e) Supervision and control over the inter-regional links as shall be required for ensuring stability of the power system under its control.
 - (f) Coordination with Regional Power Committees for regional outage schedule in the national perspective to ensure optimal utilization of power resources.
 - (g) Coordination with Regional Load Despatch Centers for the energy accounting of inter-regional exchange of power.
 - (h) Coordination for restoration of synchronous operation of national grid with Regional Load Despatch Centers.

- (i) Coordination for trans-national exchange of power.
- (j) Providing operational feedback for national grid planning to the Authority and the Central Transmission Utility.
- (k) Levy and collection of such fee and charges from the generating companies or licensees involved in the power system, as shall be specified by the Central Commission.
- (l) Dissemination of information relating to operations of transmission system including inter-regional ATC and ISTS–STU ATC in accordance with directions or regulations issued by Central Electricity Regulatory Commission and the Central Government from time to time.

(2) NLDC shall also carry out the following activities:

- (a) NLDC shall be the nodal agency for power exchanges, collective transactions and ancillary services.
- (b) NLDC would act as the central control room in case of natural & man-made emergency/disaster where it affects the power system operation.
- (c) Scheduling and despatch of electricity over transnational links.
- (d) Operation of Security Constrained Unit Commitment / Economic Despatch (SCUC/SCED).
- (e) NLDC shall perform the roles as defined under Central Electricity Regulatory Commission (Cross Border Trade of Electricity) Regulations, 2019.
- (f) NLDC shall perform the roles as defined under Central Electricity Regulatory Commission (Measures to relieve congestion in real time operation) Regulations, 2009.
- (g) Activities assigned to NLDC under these regulations.
- (h) Any other activities as maybe assigned by the Central Government or Central Commission.

7. ROLE OF RLDC

- (1) The functions of RLDC shall be in accordance with section 28 of the Act.
- (2) In accordance with sub-section (1) of section 29 of the Act, the RLDC may give such directions and exercise such supervision and control as may be required for ensuring the integrated grid operations and for achieving the maximum economy and efficiency in the operation of power system in that region. Every licensee, generating company, generating station, sub-station and any other person connected with the operation of the power system shall comply with the directions issued by the State Load Despatch Centre under sub-section (1) of Section 29 of the Act.
- (3) RLDC shall also be responsible for following activities:
 - (a) System operation and control including inter-state transfer of power, covering contingency analysis and operational planning on real time basis;
 - (b) Scheduling / re-scheduling of generation;
 - (c) System restoration following grid disturbances;
 - (d) Meter data processing;
 - (e) Compiling and furnishing data pertaining to system operation;
 - (f) Operation of regional DSM pool account, regional reactive energy account and congestion charge account, provided that such functions shall be undertaken by any entity other than RLDC, if the Commission so directs.
 - (g) Operation of ancillary services as required.
 - (h) Regional renewable energy forecasting week ahead, day ahead and intra day
 - (i) Monitoring the absorption of renewable energy by the constituents from contracted sources and adherence to must run status of regional entity renewable plants.
 - (j) Activities assigned to RLDC under CERC regulations.

8. ROLE OF RPC

- (1) The RPC in the Region may, from time to time, agree on matters concerning the stability and smooth operation of the integrated grid and economy and efficiency in the operation of the power system in that region.
- (2) The functions of RPC in accordance with Ministry of Power Resolution dated 25th May 2005 shall be to:
 - (a) Undertake Regional Level operation analysis for improving grid performance.
 - (b) Facilitate inter-state/inter-regional transfer of power.
 - (c) Facilitate all functions of planning relating to inter-state/intra- state transmission system with CTU/STU.
 - (d) Coordinate planning of maintenance of generating machines of various generating companies of the region including those of interstate generating companies supplying electricity to the Region on annual basis and also to undertake review of maintenance programmed on monthly basis.
 - (e) Undertake planning of outage of transmission system on annual / monthly basis.
 - (f) Undertake operational planning studies including protection studies for stable operation of the grid.
 - (g) Undertake planning for maintaining proper voltages through review of reactive compensation requirement through system study committee and monitoring of installed capacitors.
 - (h) Evolve consensus on all issues relating to economy and efficiency in the operation of power system in the region.
- (3) RPC shall also be responsible for the following activities:
 - (a) To perform the functions as mandated under the Central Electricity Regulatory Commission (Ancillary Services Operation) Regulations, 2015.

- (b) A database of protection settings in this regard shall be maintained by RPC and updated time to time.
 - (c) Activities assigned under these regulations.
- (4) RPC Secretariat shall perform following activities:
- (a) Member Secretary, RPC shall certify transmission system availability factor for regional AC and HVDC transmission systems separately for the purpose of payment of transmission charges and publish the details thereof on the RPC website.
 - (b) RPC Secretariat shall prepare monthly Regional Energy Account (REA), Regional Transmission Account (RTA), Compensation account for Part Load Operations as per **Annexure- 5**, weekly deviation settlement account, RRAS account, SCED account, FRAS account, reactive energy account, and congestion charge account, based on data provided by RLDC, and any other charges specified by the Commission for the purpose of billing and payments of various charges.
 - (c) Carry out intra-regional optimization studies with a view to enhancing ISTS-STU ATC of the constituent states and take further necessary action in the matter.
 - (d) Activities assigned under CERC regulations from time to time.
- (5) The decisions of RPC with regard to functions assigned by the Grid Code shall be followed by the concerned RLDC, SLDC, CTU, STU and users, subject to directions/regulations of the Commission, if any.

9. ROLE OF CTU

- (1) The Central Transmission Utility (CTU) shall carry out the functions in accordance with the section 38 of Act.
- (2) CTU shall also perform following activities:

- (a) Be responsible for consultation with stakeholders such as generators, STU, RLDC, SLDC and distribution licensees and maintain transparency at all stages of planning of augmentation or strengthening of ISTS.
- (b) Planning activities as specified under Central Electricity Regulatory Commission (Planning, Coordination and Development of Economic and Efficient Inter-State Transmission System by Central Transmission Utility and other related matters) Regulations, 2018.
- (c) Nodal agency for the connectivity, long-term access and medium- term open access in accordance with the Central Electricity Regulatory Commission (Grant of Connectivity, Long-term Access and Medium-term Open Access in Inter-State Transmission and related matters) Regulations, 2009, as amended from time to time.
- (d) Activities assigned under these regulations or any other CERC regulations.

10. ROLE OF SLDC

- (1) The functions of State Load Despatch Centre (SLDC) shall be in accordance with section 32 of the Act. Every licensee, generating company, generating station, sub-station and any other person connected with operation of power system shall comply with the directions issued by SLDC under sub-section (1) of Section 33 of the Act. The SLDC shall comply with the directions of the RLDC.
- (2) State Load Despatch Centre shall also be responsible for following activities:
 - (a) Ensuring adequate primary, secondary and tertiary reserves.
 - (b) Ensuring must-run status of renewable sources of energy contracted by the state.
 - (c) In case of inter-state bilateral and collective short-term open access transactions having a state utility or an intra-state entity as a buyer or a seller, SLDC shall accord concurrence or no objection or a prior standing clearance, as the case may be, in

accordance with the Central Electricity Regulatory Commission (Open Access in Inter-State transmission) Regulations,2008.

- (d) Activities assigned under these regulations.

11. ROLE OF STU

- (1) STU shall perform its functions in accordance with Section 39 of the Act.
- (2) STU shall perform activities as assigned under these regulations.

12. ROLE OF QCA

- (1) The roles and functions of QCA shall be as follows:
 - (a) To act as the nodal agency on behalf of the wind, solar and hybrid generators including energy storage system connected to one or more pooling stations represented by it for the purpose of Grid Code in general and operational and scheduling liaison in particular.
 - (b) To undertake generation forecasting, declaration of combined capability on behalf of generators, energy storage system at one or more pooling stations to the concerned load despatch centre for the purpose of scheduling.
 - (c) To undertake scheduling, metering and accounting of energy. QCA shall be responsible for pooling of declared availability, de-pooling of despatch schedule and DSM account as necessary.
 - (d) To operate and maintain a co-ordination centre manned by qualified and competent personnel for round the clock operational co-ordination and information exchange with the concerned Load Despatch Centre and generating stations.
 - (e) To settle all payments as per DSM Regulations arising out of deviations from its aggregated schedule given by relevant LDC.

- (2) Any instruction or direction given by the LDC to QCA shall be deemed to have been given to the renewable generator represented by it.

13. ROLE OF NATIONAL POWER COMMITTEE (NPC)

The functions of NPC shall be in accordance with Order no A-60016/24/2012-Adm-I dated 25th March 2013 as follows:

- a) Discuss and resolve issues referred to NPC requiring consultation among one or more RPCs, concerning inter-alia inter-regional implication or any other issue affecting more than one region or all regions.
- b) To resolve issues amongst RPCs.

CHAPTER 4: PLANNING CODE

14. OBJECTIVE

The objective of the Planning Code is to set out principles for planning of generation and transmission resources for reliably meeting the projected demand in compliance with specified reliability standards for serving the load with optimum generation mix, and to create framework for integration of environmentally benign technologies for electricity generation. It factors large scale absorption of renewable energy in accordance with national policy taking into account measures, including flexible resources, storage systems for energy shift and demand response measures for managing the intermittency and variability of renewable energy sources.

15. PLANNING DIMENSIONS

(1) The integrated power system planning shall include:

- (a) Probabilistic assessment by the designated agency of a State of its future demand pattern under different scenarios.
- (b) Adequacy of generation resources taking into account loss of load probability and energy not served as specified by CEA.
- (c) Adequate generation reserves and demand response for maintaining grid stability.
- (d) Validation of adequacy of transmission resources through system studies considering economic despatch under various demand and generation scenarios including must run generation.
- (e) Validation of adequate power transfer capability to be carried out for the entire grid in a comprehensive manner by CTU:

- adequate power transfer capability across each flow-gate
 - import and export capability for each control area
 - import and export capability between regions
 - cross-border import and export capability
- (f) Validation of adequate power transfer capability to be carried out by STU:
- Adequate power transfer capability across each flow-gate
 - Import and export capability across ISTS and STU interface

(2) The following approach would be adopted to ensure the same:

(a) Demand forecasting by state

- i. Each distribution licensee of the state shall estimate the demand in its control area including the demand of open access consumers for next five years starting from 1st April of the next year and submit to STU by 30th September every year.
- ii. STU, in co-ordination with all distribution licensees, shall estimate the demand by 31st October of every year for the entire state duly considering the diversity, for the next five (5) years starting 1st April of the next year using trend method, time series, econometric methods or any state of the art methods and submit the same to CEA and CTU.
- iii. CTU, in consultation with STUs, shall estimate by 31st December every year, the demand for each region as well as the entire country taking into account the diversity for the next five (5) years starting 1st April of the next year based on the inputs from STU.

- iv. The demand estimation shall include daily load curve (hourly basis) for a typical day for each month.

(b) Generation resource planning

- i. Each distribution licensee shall ensure demonstrable resource adequacy as specified by the respective SERC for the next five (5) years starting 1st April of the next year. Adequacy statement containing a list of such resources along with associated capacities shall be submitted to the respective STU and SERC. STU shall submit the same to CTU.
- ii. The National Electricity Plan may consider the following from grid operation perspective:
 - (a) Generation flexibility, ramping and minimum turndown level and start-stops
 - (b) Requirement of energy storage systems and demand response measures
 - (c) Generation reserve requirement
 - (d) System inertia for grid stability
 - (e) Cross-border electricity exchange
 - (f) Fuel security
- iii. While finalizing transmission plan for implementation, CTU shall simulate the economic dispatch considering grid security under various scenarios based on adequacy statement furnished by STU and provide feedback to CEA.

(c) Inter-State Transmission Planning

- i. The inputs for inter-state transmission planning shall be collated by CTU based on the National Electricity Plan of CEA and conventional and renewable generation capacity addition assessment of various agencies, estimates of renewable energy potential in different areas as assessed by MNRE, demand forecast of Electric Power Survey and demand estimates by CTU as per clause 15(2)(a)(iii). The CTU shall interact with various stakeholders such as CEA, MNRE, state renewable development agencies, STUs, distribution licensee, SLDC, RLDC, NLDC and generation developers to make a comprehensive assessment of inter-state transmission plan covering power evacuation schemes, pooling stations, enhancement of power transfer capability between regions and enhancement of power transfer capability for each STU system.
- ii. Based on the inputs compiled and collated by CTU for preparation of transmission planning, load generation balance scenarios for each month [as specified in clause 15(2)(a)(iv)] shall be prepared by CTU and disseminated in public domain. The finalized load generation balance for transmission planning shall be shared with stakeholders.
- iii. The CTU shall carry out the planning of inter-state transmission system based on the following:
 - (a) Manual on Transmission Planning Criteria issued by CEA
 - (b) Central Electricity Authority (Technical Standards for Connectivity to the Grid) 2007
 - (c) Central Electricity Regulatory Commission (Planning, Coordination and Development of Economic and Efficient Inter-State Transmission System

by Central Transmission Utility and other related matters) Regulations, 2018

(d) Central Electricity Regulatory Commission (Grant of Connectivity, Long-Term Access and Medium-Term Open Access in interstate transmission and related matters) Regulations 2009

iv. While planning the ISTS transmission system, the following shall be duly considered by CTU:

(a) CTU shall analyze N-2 contingencies which could lead to cascade tripping. Special Protection Schemes (SPS) with adequate redundancies may be designed wherever necessary.

(b) While planning the transmission system, CTU shall consider resilience in terms of nearby black start resources and building up of the cranking path to load centres and thermal generating stations.

v. The transmission planning alternatives shall be shared with stakeholders for consultation through a national level workshop before finalization.

vi. CTU shall carry out periodic all India transmission review and re-optimization study in collaboration with STUs on yearly basis and its report shall be submitted to CEA for remedial measures under intimation to CERC by 1st April every year. In the summary of the report, immediate priorities shall be highlighted for the purpose of improving reliability, adequacy and opportunities for increasing TTC across inter regional boundaries as well as well as ISTS interface with state control areas. Emerging pattern of power flows based on economic despatch shall be captured by the CTU in its re-optimization studies.

- vii. In order to achieve economy, before planning new transmission corridors, CTU shall endeavor to maximize the utilization of existing transmission corridors by considering reconfiguration, re-conductoring, use of flexible AC technologies, series and shunt compensation and dynamic line rating options.

16. TECHNICAL DETAILS AND CO-ORDINATION

- (1) All STUs, RLDCs, SLDCs and Users shall furnish the data as desired by CEA and CTU from time to time to enable them to formulate and finalize the National Electricity Plan and planning of ISTS.
- (2) STU shall put in place systems at the intra state level for getting timely updates from the distribution companies in respect of developments related to distributed energy resources and electric vehicles charging stations.
- (3) All study models related to transmission planning shall be periodically updated by CTU and STU. A similar system shall be developed for cross border transmission planning studies.
- (4) CTU may organize periodic capacity building workshops so that all stakeholders have a shared vision in respect of generation and transmission resource planning.
- (5) CTU shall publish on its website the planned inter-regional and ISTS-STU power transfer capability for the next 3-5 years in coordination with the respective STU.

CHAPTER 5: CONNECTION CODE

17. OBJECTIVE

- (1) The connectivity to ISTS shall be granted by CTU as per the regulations laid down by CERC and the detailed procedure specified therein. The connectivity to intra-state transmission system shall be granted by STU as per the regulations laid down by respective SERC and the detailed procedure specified therein.
- (2) This code specifies the requirements to be fulfilled by the connectivity grantees prior to obtaining the permission of the RLDC/NLDC/SLDC for first time energizing of a new or modified power system element. In addition to above, this code specifies the technical requirements to be complied by a transmission licensee including deemed transmission licensees or cross-border entity prior to being allowed by RLDC/NLDC/SLDC to energize a new or modified power system element.
- (3) It includes tests to be performed after connectivity and prior to Trial Run for Declaration of Commercial Operation

18. COMPLIANCE WITH EXISTING RULES AND REGULATIONS

All users connected to or seeking connection to grid shall comply with applicable regulations as under:

- i. Central Electricity Authority (Technical Standards for Connectivity to the Grid) Regulations, 2007
- ii. Central Electricity Authority (Technical Standards for Construction of Electrical Plants and Electric Lines) Regulations, 2010
- iii. Central Electricity Authority (Measures Relating to Safety & Electric Supply) Regulations, 2010

- iv. Central Electricity Regulatory Commission (Communication System for Inter-State Transmission of Electricity) Regulations,2017
- v. Central Electricity Authority (Installation and Operation of Meters) Regulations, 2006
- vi. Central Electricity Regulatory Commission (Grant of Connectivity, Long-term Access and Medium-term Open Access in Inter-State Transmission and related matters) Regulations,2009
- vii. Central Electricity Regulatory Commission (Planning, Coordination and Development of Economic and Efficient Inter-State Transmission System by Central Transmission Utility and other related matters) Regulations, 2018
- viii. Central Electricity Regulatory Commission (Fees and Charges for Regional Load Despatch Centres) Regulations, 2019
- ix. Any other regulations and standards specified from time to time

19. PROCEDURE FOR CONNECTION

- (1) The grant of connectivity by CTU to ISTS shall be governed by Central Electricity Regulatory Commission (Grant of Connectivity, Long-term Access and Medium-term Open Access in Inter-State Transmission and related matters) Regulations, 2009.
- (2) Post completion of all physical arrangements of connectivity and completing the necessary site tests, the connectivity grantee and/or licensee shall request the RLDC for permission of first energization in the specified format as per the procedure for first time energization of power system elements.
- (3) NLDC shall publish a detailed procedure covering modalities for first time energization and integration of new or modified power system elements. The procedure shall specify requirements for integration with the grid such as protection, telemetry and

communication systems, metering, statutory clearances and modelling data requirements for system studies.

- (4) SLDC shall prepare procedure for first time energization of new or modified elements power system elements to intra-State transmission system in line with the procedure developed by NLDC. In the absence of such procedure of SLDC, the NLDC procedure shall apply.

20. TECHNICAL REQUIREMENTS

NLDC/RLDC in consultation with CTU shall carry out a joint system study six (6) months before expected date of first energization of a new power system element to identify operational constraints, if any. The connectivity grantee, transmission licensee and SLDC/STU shall furnish all technical data including that of its embedded generators and other elements to the CTU/NLDC for necessary technical studies. Similar exercise shall be done by STU and SLDC for the intra-state system.

21. DATA AND COMMUNICATION FACILITIES

- (1) Reliable speech and data communication systems on path diversified data links shall be provided to facilitate necessary communication and data exchange and supervision/control of the grid by the NLDC, RLDC and SLDC in accordance with CERC (Communication System for Inter-State Transmission of Electricity) Regulations, 2017 and CEA standards.
- (2) The associated communication system to facilitate data flow up to appropriate data collection point on CTU/STU system including inter-operability requirements shall also be established by the concerned user or STU as specified by CTU in the connection agreement. All users/STU/participating entities in case of cross-border trade, in coordination with CTU, shall provide the required facilities at their respective ends as

specified in the connection agreement. The communication system along with data links provided for speech and real time data communication shall be monitored in real time by all users, CTU, STU and RLDC shall ensure high reliability of the communication links.

22. TESTS PRIOR TO TRIAL RUN FOR DECLARATION OF COMMERCIAL OPERATION

Notwithstanding the requirements in other standards, codes and contracts, the following tests shall be scheduled and carried out in coordination with NLDC/RLDC by the generating company and transmission licensee, as the case may be, before being allowed to proceed for the trial run for declaration of commercial operation. These tests shall be performed for ensuring grid security and relevant reports shall be submitted to NLDC/RLDC.

(1) Tests required for thermal (coal/lignite) generating stations

- (a) Operation of control load of fifty (50) percent of MCR as per CEA standards for a sustained period of four (4) hours.
- (b) Ramp-up from fifty (50) percent MCR to rated capacity at a ramp rate of at least three (3) percent of MCR per minute. Sustained operation at MCR for one (1) hour.
- (c) To demonstrate overload capability with valve wide open as per Central Electricity Authority (Technical Standards for Construction of Electrical Plants and Electric Lines) Regulations, 2010. Sustained operation at this level for at least five (5) minutes.
- (d) Ramp-down from MCR to fifty (50) percent of MCR at a ramp rate of at least three (3) percent of MCR per minute.
- (e) Testing primary response through injecting a frequency test signal with a step change of ± 0.1 Hz at 60%, 75% and 100% load.
- (f) Reactive power capability test as per the generator capability curve considering over-excitation and under-excitation limiter settings.

(2) Tests/Documents required for hydro stations

Documents

(a) The generating company shall submit the document for turbine characteristics curve indicating the operating zone(s) and prohibited zone(s). In order to demonstrate operating flexibility of generating unit, it shall be operated below and above the prohibited zone(s).

Tests

(b) Testing primary response through injecting a frequency test signal with a step change of ± 0.1 Hz for various loadings within the operating zone.

(c) Reactive power capability test as per the generator capability curve considering over-excitation and under-excitation limiter settings.

(d) Black start capability.

(e) Operation in synchronous condenser mode wherever designed.

The tests will be performed considering the water availability and head.

(3) Tests/Documents required for gas turbine based generating stations

Documents

(a) Submit documents having information about starting time of gas turbine from cold and warm conditions and ramping up from no load to full load at design ramp rate.

Tests

(b) Testing primary response through injecting a frequency test signal with a step change of ± 0.1 Hz for various loadings within the operating zone.

- (c) Reactive power capability test as per the generator capability curve considering over-excitation and under-excitation limiter settings.
- (d) Test to validate Black start capability upto 100 MW capacity wherever designed.
- (e) Test to validate Operation in synchronous condenser mode wherever designed.

(4) Tests/Documents required for wind/solar generating stations

Documents

- (a) Submission of certificate confirming compliance to CEA (Technical Standards for Connectivity to the Grid) Regulations, 2007

Tests

- (b) To demonstrate the frequency response of machines as per CEA (Technical Standards for Connectivity to the Grid) Regulations, 2007 Reactive power capability test as per OEM rating at the available irradiance or the wind energy, as the case may be.
- (c) To demonstrate the Grid forming capability, wherever provided.

(5) Tests/Documents required for Energy Storage Systems

Documents

- (a) Submission of certificate confirming compliance to CEA connectivity standards.

Tests

- (b) To demonstrate the frequency response of ESS.
- (c) To demonstrate the ramping capability as per design.

- (d) To demonstrate rated power output capability in MW and energy output capacity in MWh.

(6) Tests/Documents required for HVDC transmission elements

Documents

- (a) Submission of technical particulars including operating guidelines such as filter bank requirements at various operating loads and monopolar/bipolar configuration, reactive power controller, power demand overrides, run-back features, frequency controller, reduced voltage mode of operation, power oscillation damping.

Tests

- (b) Minimum load operation.
- (c) Ramp rate
- (d) Overload capability
- (e) Black start capability in case of Voltage source convertor (VSC) HVDC.

(7) Tests /Documents required for SVC/STATCOM

Documents

- (a) Submission of technical particulars including operating guidelines such as number of blocks and rating of each block, single line diagram, V/I characteristics, rating of coupling transformer, MSR/MSC design parameters, different operating modes, IEEE standard Model, Power Oscillation Damping (POD) enabled and tuned (if not then reasons for same). The results for Offline simulation-based study to validate the performance of POD

Tests

(b) Tests to validate full reactive power capability of SVC/STATCOM in both the directions i.e. absorption as well as injection mode, POD performance, dynamic performance testing

CHAPTER 6: PROTECTION AND COMMISSIONING CODE

A. PROTECTION CODE

23. OBJECTIVE

- (1) To have a common protection philosophy amongst users of the grid.
- (2) To provide proper co-ordination of protection system in order to isolate the faulty equipment and avoid unintended operation of protection system.
- (3) To have a repository of protection system and settings at regional level.
- (4) To have a repository of events, timelines for submission of data and ensure healthiness of recording equipment's along with time synchronization.
- (5) To provide for periodic audit of protection system.

24. BASIC FEATURES

- (1) All users connected to the integrated grid shall provide and maintain effective protection system having reliability, selectivity, speed and sensitivity to isolate faulty section and protect element(s) as per CEA (Grid Standards) Regulations, 2010, CEA (Technical Standards for Connectivity to the Grid) Regulations, 2007 and CEA (Technical Standards for Construction of Electrical Plants and Electric Lines), Regulations 2010.
- (2) Back-up protection system shall be provided to protect an element in the event of failure of the primary protection system.

25. PROTECTION PHILOSOPHY AND SETTINGS

- (1) Protection philosophy

- (a) RPC shall develop the protection philosophy, and review and revise from time to time, in consultation with stakeholders in the concerned region, and in doing so shall be guided by minimum electrical protection functions for equipment connected with the grid shall be provided as per CEA (Technical Standards for Construction of Electrical Plants and Electric Lines) Regulations 2010, CEA (Technical standards for Connectivity to the Grid) Regulations 2007, CEA (Measures relating to Safety and Electric Supply) Regulations 2010 and any other CEA standards specified time to time.
- (b) The protection philosophy in a particular system may vary depending upon operational experience in the broad contours of above protection design guidelines. However, such changes shall be carried out after deliberation and approval at RPC level.

(2) Protection Settings

- (a) RPC shall undertake review of the protection settings, assess the requirement of revisions in protection setting and develop revised protection settings in consultation with stakeholders in the concerned region. The necessary studies in this regard shall be carried out by RPC.
- (b) All users connected to the grid shall:
- i. ensure correct and appropriate settings of protection as per RPC approved protection philosophy.
 - ii. cooperate for proper coordinated protection settings.
 - iii. report any changes in network to other users for changes required in protection settings.

- iv. furnish the implemented protection settings of each element to respective RPC in a format as prescribed by RPC. Any implemented changes in protection system or protection setting shall also be intimated to RPC Secretariat.
- v. obtain approval of RPC for any revision in settings and inform RPC on its successful implementation.

(c) RPC Secretariat shall:

- i. maintain a centralized database containing details of relay settings for grid elements connected to 220kV and above (132 kV and above in NER).
- ii. provide the database access to all users, NLDC, RLDC, SLDC, CTU and STU. The database may have different access rights for different users.
- iii. carry out system wide studies, twice a year, for protection settings and advise modifications/ changes, if any, to all users, CTU and STU.

26. PROTECTION AUDIT PLAN

- (1) All users shall conduct internal audit of their protection system annually and any shortcomings identified shall be rectified and informed to RPC.
- (2) All users shall also conduct third party protection audit of each sub-station (132 kV and above in NER and 220 kV and above for rest of the grid) once in five years or earlier as advised by RPC.
- (3) After analysis of an event, RPC shall identify a list of substations/generating stations where third-party protection audit is required and accordingly advise the respective users to complete third party audit within three months.

- (4) The third-party protection audit report shall inter-alia contain points given in format enclosed as **Annexure – 2**. The audit reports, along with action plan for rectification of deficiencies found, if any, shall be submitted to RPC or RLDC within a month of submission of report by auditor.
- (5) Annual audit plan shall be submitted by users to RPC Secretariat by 31st October for the next financial year. Users shall adhere to the submitted plan and report the compliance to RPC.
- (6) Users shall submit the following protection performance indices to RPC Secretariat on monthly basis. The performance indices shall also be reviewed by respective RPC Secretariat during monthly Protection Sub-Committee meeting of RPC:

(a) The Dependability Index defined as $D = \frac{N_c}{N_c + N_f}$

Where,

N_c is the number of correct operations during the given time interval and

N_f is the number of failures to operate at internal power system faults.

(b) The Security Index defined as $S = \frac{N_c}{N_c + N_u}$

Where,

N_u is the number of unwanted operations.

(c) The Reliability Index defined as $R = \frac{N_c}{N_c + N_i}$

Where

N_i is the number of incorrect operations and is the sum of N_f and N_u

- (7) Each user shall also submit the reasons behind the fall in performance indices of individual element wise protection system to RPC secretariat and Action plan along with

deadline for corrective measures. The action plan will be followed up regularly in the monthly protection sub-committee meeting of RPC.

- (8) The RPC Secretariat shall report to the Commission if the above indices are less than one in a year and if any user has failed to undertake any remedial action identified by RPC.

27. SYSTEM PROTECTION SCHEMES (SPS)

- (1) SPS design shall duly factor redundancies in measurement of inputs, logic as well as communication paths involved upto the last mile to ensure security and dependability.
- (2) For the operational SPS, RPC Secretariat shall perform regular dynamic studies and mock testing for reviewing SPS parameters & functions, at least once in a year. The respective users and SLDC shall report the SPS operation in the format specified by RPC within 3 days of operation to RPC and RLDC.

28. RECORDING INSTRUMENTS

- (1) All users shall ensure the healthiness of recording instruments (disturbance recorder and event logger) in the station.
- (2) The disturbance recorder should have a standard format for analogue and digital signals, time synchronization and capture time as per guideline given by RPC.

B. COMMERCIAL OPERATION DECLARATION CODE

29. NOTICE OF TRIAL RUN

- (1) The generating company offering its unit for trial run or repeat of trial run shall give a notice of not less than three days to the concerned RLDC or SLDC, as the case may be, and the beneficiaries/long-term customers of the generating station wherever identified. The trial run shall commence from the time and date to be informed by the RLDC or

SLDC. The SLDC/RLDC shall endeavor to commence the trial run from the requested date or in case of any system constraints not later than seven (7) days from the proposed date of trial run.

- (2) In case the repeat trial run is to take place within twenty-four (24) hours of the failed trial run, fresh notice shall not be required.
- (3) The transmission licensee shall give a notice of not less than seven days to the concerned RLDC or SLDC, as the case may be, including long term transmission customers.

30. TRIAL RUN OF GENERATING UNIT/STATION

(1) Trial run for thermal generating unit

- (a) Continuous operation at MCR for seventy-two (72) hours on designated fuel provided that short interruption or load reduction shall be permissible with corresponding increase in duration of test:

Provided that:

- (i) interruption or partial loading maybe allowed with the condition that the average load during the duration of trial run shall not be less than MCR excluding period of interruption but including the corresponding extended period.
 - (ii) cumulative interruption of more than four (4) hours shall call for a repeat of trial run.
- (b) Where on the basis of the trial run, a unit of the generating station fails to demonstrate the unit capacity corresponding to MCR, the generating company has the option to de-rate the capacity or to go for repeat trial run. Where the generating company decides

to de-rate the unit capacity, the demonstrated capacity in such cases shall be more or equal to 105% of de-rated capacity.

(2) Trial run for hydro station

(a) Continuous operation at MCR for twelve (12) hours provided that any interruption shall call for a repeat of trial run:

Provided that:

(i) the partial loading maybe allowed with the condition that the average load during the duration of trial run shall not be less than MCR excluding period of interruption but including the corresponding extended period.

(ii) If it is not possible to demonstrate the MCR due to insufficient reservoir or pond level or insufficient inflow, the same shall be demonstrated immediately when sufficient water is available after the date of declaration of COD.

(iii) In case the generation is reduced on the directions of the RLDC due to system constraints, the RLDC shall permit corresponding increase in duration of test.

(b) Where on the basis of the trial run, a unit of the generating station fails to demonstrate the unit capacity corresponding to MCR, the generating company shall have the option to either de-rate the capacity or to go for repeat trial run. If the generating company decides to de-rate the unit capacity, the demonstrated capacity in such cases shall be more or equal to 110% of de-rated capacity.

(3) Trial run for wind/solar/storage/hybrid/ generating unit

(a) Successful trial run of a solar inverter unit(s) aggregating to 50 MW and above shall mean flow of power and communication signal for not less than the period between sunrise to sunset in a single day with the requisite metering system telemetry and protection system in service. The generating company shall record the output of the

station during the trial run and corroborate its performance with the solar irradiation during the day and plant design parameters. Further, a declaration would be given that no unit tripped during period of the trial operation:

Provided that:

- (i) The output below the corroborated performance level with the solar irradiation of the day shall call for repeat of the trial run.
- (ii) If it is not possible to demonstrate the rated capacity of the plant due to insufficient solar irradiation, the same shall be demonstrated immediately when sufficient solar irradiation is available after the date of declaration of COD.

(b) Successful trial run of a wind turbine(s) aggregating to 50 MW and above shall mean flow of power and communication signal for a period of not less than four (4) hours during periods of wind availability with the requisite metering system telemetry and protection system in service. The generating company shall record the output of the station during the trial run and corroborate its performance with the wind speed during the day and plant design parameters. Further, a declaration would be given that no unit tripped during period of the trial operation:

Provided that:

- (i) the output below the corroborated performance level with the wind speed of the day shall call for repeat of the trial run.
- (ii) If it is not possible to demonstrate the rated capacity of the plant due to insufficient wind velocity, the same shall be demonstrated immediately when sufficient wind velocity is available after declaration of date of COD.

(c) Successful trial run of standalone energy storage device shall mean one (1) cycle of charging and discharging of energy as per the design capability with the requisite metering system telemetry and protection system in service.

(d) Successful trial run of hybrid systems shall mean individual compliance as per above definitions with the requisite metering system telemetry and protection system in service.

31. TRIAL RUN OF INTER-STATE TRANSMISSION SYSTEM

Trial run in relation to a transmission system or an element thereof shall mean successful energisation of the transmission system or an element thereof at rated nominal voltage through interconnection with the grid with continuous twenty-four (24) hours flow of power, and communication signal from the sending end to the receiving end and with requisite metering system, telemetry and protection system.

Provided that under exceptional circumstances and with the prior approval of CEA, a transmission element can be energized at next lower nominal voltage as per CEA planning criteria for the purpose of trial run.

32. DECLARATION OF DATE OF COMMERCIAL OPERATION (COD)

(1) Thermal generating station

(a) Date of commercial operation in case of a unit of thermal generation stations shall mean the date declared by the generating company after a successful trial run at MCR or de-rated capacity, as the case may be, and after getting clearance from the respective RLDC or SLDC, as the case may be, and in case of the generating station as a whole, the date of commercial operation of the last unit of the generating station.

(b) The generating company shall certify that:

- i. The generating station meets the relevant requirements and provisions of the technical standards of Central Electricity Authority (Technical Standards for Construction of Electrical Plants and Electric Lines) Regulations, 2010, CEA (Technical Standards for Connectivity to the Grid) Regulations, 2007 and Indian Electricity Grid Code, as applicable.
 - ii. The main plant equipment and auxiliary systems including balance of plant, such as fuel oil system, coal handling plant, DM plant, pre-treatment plant, fire-fighting system, ash disposal system and any other site specific system have been commissioned and are capable of full load operation of the units of the generating station on sustained basis.
 - iii. Permanent electric supply system including emergency supplies and all necessary instrumentation, control and protection systems and auto loops for full load operation of unit have been put in service.
- (c) Above mentioned certificates shall be signed by the CMD/CEO/MD of the generating company and a copy of the certificate shall be submitted to the Member Secretary of the concerned Regional Power Committee and the concerned RLDC/SLDC before declaration of COD. The generating company shall submit approval of Board of Directors to the certificates as required within a period of 3 months of the COD.

(2) Hydro generating unit/station

- (a) Date of commercial operation (COD) in relation to a generating unit of hydro generating station including pumped storage hydro generating station shall mean the date declared by the generating company after demonstrating peaking capability corresponding to the installed capacity of the generating station through a successful trial run, and after getting clearance from the respective RLDC or SLDC, as the case

may be, and in relation to the generating station as a whole, the date of commercial operation of the last generating unit of the generating station.

(b) The generating company shall certify that:

- i. The generating station or unit thereof meets the requirement and relevant provisions of the technical standards of Central Electricity Authority (Technical Standards for Construction of Electrical Plants and Electric Lines) Regulations, 2010, CEA (Technical Standards for Connectivity to the Grid) Regulations, 2007 and Indian Electricity Grid Code, as applicable.
- ii. The main plant equipment and auxiliary systems including drainage de-watering system, primary and secondary cooling system, LP and HP air compressor and firefighting system have been commissioned and are capable for full load operation of units on sustained basis.
- iii. Permanent electric supply system including emergency supplies and all necessary Instrumentations Control and Protection Systems and auto loops for full load operation of the unit are put into service.

(c) The certificates as required above shall be signed by the CMD/CEO/MD of the generating company and a copy of the certificate shall be submitted to the Member Secretary of the concerned Regional Power Committee and concerned RLDC or SLDC, as the case may be, before declaration of COD. The generating company shall submit approval of Board of Directors to the certificates within a period of 3 months of COD.

(3) Transmission system

(a) Date of commercial operation in relation to an Inter-State Transmission System or an element thereof shall mean the date declared by the transmission licensee from 0000

hours of which an element of the transmission system is in regular service after successful trial operation for transmitting electricity and communication signal from the sending end to the receiving end.

- (b) In case a transmission system or an element thereof is prevented from regular service on or after the scheduled COD for reasons not attributable to the transmission licensee or its supplier or its contractors but is on account of the delay in commissioning of the concerned generating station or in commissioning of the upstream or downstream transmission system of other transmission licensee, the transmission licensee shall approach the Commission through an appropriate application for approval of the date of commercial operation of such transmission system or an element thereof.

Provided that in case of inter-State Transmission System executed through Tariff Based Competitive Bidding, the transmission licensee shall declare deemed COD of the ISTS in accordance with the provisions of the Transmission Service Agreement.

- (c) An element shall be declared to have achieved COD only after all the elements which are pre-required to achieve COD as per the Transmission Services Agreement are commissioned. In case any element is required to be commissioned prior to the commissioning of pre-required element, the same can be done if CEA confirms that such commissioning is in the interest of the power system.
- (d) The transmission licensee shall submit a certificate from the CMD/CEO/MD of the company that the transmission line, sub-station and communication system conform to the relevant Grid Standard and Grid Code and are capable of operation to their full capacity.

(4) Wind/Solar/Storage/Hybrid generating station

- (a) Date of commercial operation in case of units of a renewable generating station aggregating to 50 MW and above shall mean the date declared by the generating company after undergoing successful trial run and after getting clearance from the respective SLDC/RLDC.
- (b) The generating company shall certify that the generating station including main plant equipment such as wind turbines/solar inverters, auxiliary systems, as the case may be, has complied with all relevant provisions of CEA (Technical Standards for Connectivity to the Grid) Regulations, 2007 and CERC approved '*Procedure for implementation of the Framework on Forecasting, Scheduling and Imbalance handling of Renewable Energy Generating Stations including power parks based on Wind and Solar at inter-state level*'. (Refer **Annexure - 8**). The certificates as mentioned above shall be duly signed by the MD/CEO/CMD of the generating company.
- (5) All generating companies shall declare the Date of Commercial Operation of unit or plant thereof within fifteen (15) days from the date of clearance by RLDC/SLDC.
- (6) Scheduling of generating unit/station shall start from 0000 hours of the date of declaration of Commercial Operation.

CHAPTER 7: OPERATING CODE

33. OPERATING PHILOSOPHY

- (1) The primary objective of operation of the integrated grid is to enhance the overall reliability and economy of the power system. All users including CTU, STU, licensee, power exchange, generating station, QCA, SNA, NLDC, RLDC, SLDC, RPC and others shall cooperate at all times to ensure reliable, resilient, economic and efficient grid operation.
- (2) Overall operation of the integrated grid shall be supervised by NLDC. Operation of the regional grid shall be supervised by RLDC and operation of the state grid shall be supervised by SLDC.
- (3) A set of detailed operating procedures for the integrated grid shall be developed and maintained by NLDC in consultation with RLDCs. The NLDC operating procedure shall be updated each year and uploaded on website.
- (4) A set of detailed operating procedure for each regional grid shall be developed and maintained by RLDC in consultation with the regional entities. It shall enable compliance with the requirement of this grid code. The RLDC operating procedure shall be updated each year and uploaded on website.
- (5) A set of detailed operating procedure for each state grid shall be developed and maintained by SLDC in consultation with sub-load despatch centres in its control area. The SLDC operating procedure shall be updated each year and uploaded on website.
- (6) NLDC, RLDC, SLDC shall have competent, certified operating personnel manning the control room round the clock.

- (7) Every generating station connected at 33 kV and above, transmission substation or pooling substation connected at 132 kV and above shall have a control room manned by qualified and competent operating personnel round the clock. Alternatively, the same may be operated from a remotely located control centre ensuring physical security of the infrastructure and its cyber security. Remote operation of any generating station or substation shall not adversely delay the execution of any switching instruction and/or information flow:

Provided that a transmission licensee not having its own substation terminating with the line, shall also be required to have a coordination centre .QCA, representing renewable generators shall have a coordination centre manned by qualified and competent personnel round the clock, wherever required, for operational coordination and information exchange with the concerned load despatch centre and generators.

- (8) SNA shall have a coordination centre manned by qualified and competent personnel round the clock for operational coordination and information exchange with the concerned load despatch centre and generators.

34. SYSTEM SECURITY ASPECTS

- (1) All generating stations, transmission licensees and other entities connected to the power system shall endeavor to operate their respective infrastructure in an integrated manner at all times in coordination with the appropriate load despatch centres.
- (2) No part of the grid shall be deliberately isolated from the rest of the National/Regional grid, except (i) under an emergency, and conditions in which such isolation would prevent a total grid collapse and/or would enable early restoration of power supply, (ii) for safety of human life (iii) when serious damage to a costly equipment is imminent and such isolation would prevent it, (iv) when such isolation is specifically instructed by RLDC.

Complete synchronization of grid shall be restored as soon as the conditions again permit it. The restoration process shall be supervised by RLDC, in co-ordination with NLDC /SLDC in accordance with system restoration procedures separately formulated by NLDC/RLDC.

- (3) No important element of the National/Regional grid shall be deliberately switched into service or taken out of service at any time, except when specifically instructed by RLDC or with specific and prior clearance of RLDC. The list of such important grid elements on which the above stipulations apply shall be prepared by the RLDC in consultation with the concerned Users, CTU and STUs, and be available at the websites of NLDC/RLDC/SLDCs. In case of switching of any important element of the grid under an emergency situation, the same shall be communicated to RLDC at the earliest possible time after the event. RLDC shall inform the opening/removal of the important elements of the regional grid, to NLDC, and to the concerned Regional Entities (whose grid would be affected by it) as specified in the detailed operating procedure by NLDC.
- (4) Any tripping, whether manual or automatic, of any of the above elements of Regional grid shall be precisely intimated by the concerned SLDC/CTU/User to RLDC as soon as possible, say within ten minutes of the event. 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. RLDC shall inform the tripping of the important elements of the regional grid, to NLDC, and to the concerned Regional Entities (whose grid would be affected by it) as specified in the detailed operating procedure by NLDC.
- (5) Any prolonged outage of power system elements of any User/CTU/STU/Licensee which is causing or likely to cause danger to the grid or sub-optimal operation of the grid shall be

regularly monitored by RLDC. RLDC shall report such outage to RPC for necessary action.

(6) Except under an emergency, or to prevent an imminent damage to a costly equipment, no user shall suddenly reduce his generating unit output by more than one hundred (100) MW (20 MW in case of NER) without prior intimation to and consent of the RLDC. Similarly, no user shall cause a sudden variation in its load by more than one hundred (100) MW without prior intimation to and consent of the RLDC.

(7) All generating units shall have their automatic voltage regulators (AVRs) in operation and tuned. In particular, if a generating unit of over fifty (50) MW size is required to be operated without its AVR in service, the RLDC shall be immediately intimated about the reason and duration, and its permission obtained. AVR, Power System Stabilizers (PSS) of synchronous generating units, voltage or reactive power controller of wind, solar generating unit or ESS shall be properly tuned by the respective owner. The above tuning, including for low and high voltage ride through capability of wind and solar generators shall be carried out -

- at least once every five (5) years,
- based on operational feedback provided by the RLDC after analysis of a grid event or disturbance and
- in case of a major change in excitation system or major network changes/fault level changes near to generating plant as reported by NLDC, RLDC.

(8) In order to provide basic requirement of PSS tuning for system security, the PSS tuning procedure shall be prepared by NLDC. The generating stations shall submit the detailed list of proposed tuning of AVR/PSS or reactive power controllers to RPC prior to 31st December for the next financial year. RPC shall compile a list before 31st March and share

with all users and RLDC. After completing the PSS tuning, the report shall be submitted by the generating station. The report shall comprise of requisite power system mapping, simulation study and field testing, and report shall be submitted to RPC. RPC may carry out field checking of AVR, Power System Stabilizers (PSS) or voltage or reactive power controller of wind, solar generating unit or ESS, whenever considered necessary. Behavior of the generating station during actual system event would also be recorded and retuning advised by RPC, if necessary.

(9) Provision of protections and relay settings shall be coordinated periodically throughout the regional grid, as per plan to be separately finalized by the Protection Sub-Committee of the RPC in accordance with chapter on Protection, Testing and Commissioning Code.

(10) RPC shall prepare and review islanding schemes in accordance with Central Electricity Authority (Grid Standards) Regulations, 2010 wherever deemed necessary. RPC shall ensure implementation of planned islanding schemes. Mock drill of the islanding scheme shall be carried out once in a year in coordination with RLDC, SLDC and other users involved with the islanding scheme. The islanding schemes shall be reviewed and augmented depending on assessment of critical loads once in three (3) years.

(11) All distribution licensees/STUs/bulk consumers shall provide automatic under-frequency and df/dt relays for load shedding in their respective systems to arrest frequency decline that could result in a collapse/disintegration of the grid, as per the plan given in Table-1 given below.

Table 1: UFR Settings

S. No.	Stage of UFR Operation	Frequency (Hz)	Load Shedding (% of demand)
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1	Stage-1	49.40	6%
2	Stage-2	49.20	6%
3	Stage-3	49.00	6%
4	Stage-4	48.80	7%
Total (Cumulative)			25%
<p>Note 1: All states shall plan further UFR settings for frequency below 48.8 Hz and df/dt load shedding schemes depending on their local load generation balance. The same shall be coordinated and agreed by the concerned RPC.</p> <p>Note 2: Pumped storage hydro plants or ESS operating in pumping or charging mode shall be automatically disconnected before the first stage of UFR.</p>			

The following common points need to be factored for design and implementation of the scheme:

- (a) All distribution licensees, transmission licensees, CTU, STU and SLDC shall ensure that the above under-frequency and df/dt load shedding schemes are always functional.
- (b) Demand disconnection shall not be set with any intentional time delay in addition to the operating time of the relays and circuit breakers.
- (c) RPC shall ensure the implementation of the UFR defence scheme and df/dt load shedding schemes, and ensure uniform spatial spread of affected feeders selected for UFR/ df/dt disconnection.
- (d) SLDC shall ensure telemetered data of feeders (MW power flow in real time and circuit breaker status) on which UFR and df/dt relay are installed is available at its control centre. The combined load in MW of these feeders shall be monitored all the time. SLDC shall share the above data with RLDC in real time and submit monthly

exception report to RPC. RLDC shall inform SLDC as well as RPC secretariat on quarterly basis, duration during the quarter when combined load in MW of these feeders for UFR and df/dt scheme was below the desired value. SLDC shall take corrective measures and inform to RLDC/RPC within reasonable period.

- (e) RPC Secretariat shall carry out random inspection of the implementation of under-frequency relays and maintain proper records of the inspection. The details of scheme shall be monthly reviewed and displayed on website by respective RPC and exception report may be given to the commission.

(12) All users, STU, SLDC, CTU, RLDC and NLDC shall also facilitate identification, installation and commissioning of System Protection Schemes (SPS) (including inter-tripping and run-back) in the power system to operate the transmission system within limits and to protect against situations such as voltage collapse and cascade tripping and tripping of important corridors/flow-gates. Such schemes shall be finalized and reviewed from time to time by the NPC at inter-regional level and cross-border level and by the concerned RPC at the intra-regional level. The SPS shall be always kept in service. If any SPS is to be taken out of service for inter-regional and cross-border schemes, permission of NLDC shall be taken. If any SPS is to be taken out of service at intra-regional level, permission of RLDC shall be taken.

(13) All Users, RLDC, SLDC STUs, CTU and NLDC shall take all possible measures to ensure that the steady state grid voltage as per Central Electricity Authority (Grid Standards) Regulations, 2010 remains within the following operating range:

Voltage – (kV rms)		
Nominal	Maximum	Minimum
765	800	728
400	420	380

Voltage – (kV rms)		
Nominal	Maximum	Minimum
220	245	198
132	145	122
110	121	99
66	72	60
33	36	30

Appropriate LDC will take suitable measures to control the voltage as per its operating procedure.

- (14) All users, transmission licensee shall provide adequate defence mechanism through under-voltage load shedding scheme (UVLS) as finalized by RPC, to prevent voltage collapse and shall ensure its effective application to prevent voltage collapse/ cascade tripping.

35. GENERATION RESERVE ESTIMATION AND FREQUENCY CONTROL

- (1) The National Reference Frequency is 50.000 Hz. All Users, SLDCs, RLDCs and NLDC shall measure the grid frequency with a resolution of +/-0.001 Hz. The frequency data shall be archived at the rate of one sample every second.
- (2) All Users, SLDCs, RLDCs, and NLDC shall take all possible measures to ensure that the grid frequency remains within the 49.95-50.05 Hz band.
- (3) All possible endeavor shall be made by NLDC, RLDCs and SLDCs to bring the frequency back within the above band within fifteen (15) minutes of the start of excursion beyond the band through despatch of secondary and tertiary reserves.

(4) There shall be different levels of reserves such as primary, secondary and tertiary for the purpose of frequency control and regulating area control error. The reserves shall be deployed by each control area connected with the grid.

- Provision for primary reserve (governor droop response) shall be mandatory as per this code. The primary response of machines shall be verified by the load despatch centres during grid events.
- Secondary reserves (automatic generation control) shall be deployed by a control area as per this code.
- Tertiary reserves shall be deployed by control area as per this code.
- Any other type of reserves required to be deployed in the interest of grid security as per the direction of the SLDC, RLDC or NLDC.
- ESS reserves may be deployed by SLDC, RLDC or NLDC if required depending on the impact of variability of renewable generation and the need for frequency control.

(5) Primary Control

(a) Primary control is local automatic control in a generating unit for the purpose of adjusting its active power output in response to frequency excursion. Primary control is immediate automatic control implemented through turbine speed governors or frequency controllers. The generating units shall have their governors in operation at all times with droop settings of 3-6 % as per the requirements mentioned separately for each category in Table-2.

TABLE 2: PRIMARY RESPONSE RANGE OF VARIOUS TYPES OF GENERATING UNITS

Fuel/ Source	Min. Capacity /Requirement to fall in Primary Response purview	Upper ceiling limit (% of MCR)
Coal/Lignite Based	200 MW and above	105
Hydro	25 MW and above & non-canal based	110
Gas based	Gas Turbine above 50 MW	105 (corrected for ambience temperature)
Wind/ Solar (commissioned between 6th Aug 2019 -31st March 2022)	Capacity of Generating station more than 10 MW and connected at 33 kV and above	110 (subject to availability of capacity and commensurate wind speed in case of wind generating stations and solar insolation in case of solar generating stations)
Wind/ Solar/Hybrid (commissioned after 31st March 2022) [^]	Capacity of Generating station more than 10 MW and connected at 33 kV and above	105

[^]*Wind/ Solar/Hybrid plant commissioned after 31st March 2022 shall have the option to provide primary response individually through BESS or through a common BESS installed at its pooling station.*

- (b) The normal governor action shall not be suppressed in any manner through load limiter, Automatic Turbine Run-up System (ATRS), turbine supervisory control, coordinated control system and no time delays shall be deliberately introduced. In case of renewable energy generating unit, reactive power limiter or power factor controller or voltage limiter shall not suppress the primary frequency response within

its capability. The inherent dead band of a generating unit/frequency controller shall not exceed +/- 0.03 Hz.

Provided that for solar and wind generator (commissioned between 6th Aug 2019 to 31st March 2022) the dead band of frequency controller shall not exceed +0.05 Hz/-0.03 Hz.

- (c) All generating stations mentioned in Table-2 above shall provide primary response shall have the capability of (and shall not in any way be prevented from) instantaneously picking up to minimum 105% of their operating level or 105% or 110% of their MCR, as the case maybe, when the frequency falls suddenly. After an increase in generation as above, a generating unit may ramp back to the original level at a rate of about one percent (1%) per minute, in case continued operation at the increased level is not sustainable. Any generating unit not complying with the above requirements shall be kept in operation (synchronized with the regional grid) only after obtaining the permission of RLDC.
- (d) The thermal/hydro generating unit shall not resort to Valve Wide Open (VWO) operation of units whether running on full load or part load, and shall ensure that there is margin available for providing governor action as primary response.
- (e) The minimum primary reserve required for reference contingency shall be declared by NLDC at the start of each financial year.
- (f) The primary reserves shall be activated immediately (within few seconds) when the frequency deviates from 50 Hz and the maximum steady state frequency deviation should not cross 0.30 Hz for the reference contingency.
- (g) The power system must be operated at all the times with a minimum inertia to be specified by NLDC so that minimum nadir frequency post reference contingency

stays above threshold set for UFLS. NLDC shall do the study in this regard and reschedule the generation (including curtailment of wind, solar and wind-solar hybrid generation) in coordination with RLDC/SLDC to maintain the minimum inertia.

- (h) The primary reserve response shall start immediately and attain its peak in less than thirty (30) seconds, and shall sustain up to five (5) minutes.
- (i) The minimum All India target frequency response characteristics and frequency response obligation of each control area shall be assessed by NLDC giving due consideration to generation and load within each control area and factors in Table 2 above. The same shall be informed to all control areas by 15th of March every year for the next financial year.
- (j) The procedures at **Annexure-1** provides the methodology for the following:
 - assessment of reference contingency,
 - All India minimum target frequency response characteristics,
 - calculation of frequency response obligation of each control area,
 - criteria for reportable event and
 - calculation of actual frequency response characteristics of control area
 - calculation of frequency response performance
- (k) NLDC in consultation with RLDC shall calculate actual frequency response characteristic of all the control areas. The performance of each control area in providing frequency response characteristic shall be calculated for each reportable event. Each control area shall separately assess their frequency response characteristic and share with RLDC along with high resolution data of at least one

(1) second for regional entity generating stations and ten (10) second for state control area.

- (l) Each control area shall be graded based on median Frequency Response Performance annually (considering at least 10 events) as per following criteria:

TABLE 3: FREQUENCY RESPONSE CRITERIA

	Performance	Grading
i.	FRP \geq 1	Excellent
ii.	$0.85 \leq$ FRP $<$ 1	Good
iii.	$0.75 \leq$ FRP $<$ 0.85	Average
iv.	$0.5 \leq$ FRP $<$ 0.75	Below Average
v.	FRP $<$ 0.5	Poor

(6) Secondary and Tertiary Control

- (a) Secondary control is area-wise automatic generation control which regulates reserve power to bring area control error close to zero (0), consequentially restoring the frequency.
- (b) Secondary control signals are generated at control centre (NLDC, RLDC, SLDC) as the Area Control Error (ACE) deviates from zero (0) and transmitted to generating stations/units within the control area jurisdictions for responding with desired change in generation.
- (c) ACE of each control area/region shall be calculated as per following formula:

$$\text{ACE} = (I_a - I_s) - 10 * B_f * (F_a - F_s) + \text{Offset}$$

Where,

I_a = Actual net interchange in MW (positive value for export)

I_s = Scheduled net interchange in MW (positive value for export)

B_f = Frequency Bias Coefficient in MW/0.1 Hz (negative value)

F_a = Actual system frequency in Hz

F_s = Schedule system frequency in Hz

Offset = means provision for compensating measurement error

Tie-line bias mode means AGC is correcting ACE according to the above equation, factoring deviation in area interchange ($I_a - I_s$) as well as frequency deviation ($F_a - F_s$).

- i. Frequency Bias shall normally be equal to median FRC during previous financial year of each control area and refined from time to time.
 - ii. Offset shall be used to account for metering errors and shall be decided by SLDC/RLDC for its respective control area.
 - iii. Schedule system frequency (F_s) would normally be reference frequency of 50.000 Hz unless otherwise specified by NLDC for time correction.
 - iv. If AGC is operating in frequency sensitive mode only ignoring difference in area interchange i.e. ($I_a - I_s$), it would mean *flat frequency control*.
 - v. If AGC is operating in area interchange sensitive mode only ignoring difference in frequency i.e. ($F_a - F_s$), it would mean *flat tie-line control*.
- (d) SLDC/RLDC/NLDC shall compute the ACE of respective control area in real time based on telemetered data. ACE data should be archived at the interval of 10 seconds

or better if adequate measurement is available through synchro-phasor measurement.

- (e) The secondary reserves through automatic generation control shall start responding within thirty (30) seconds of ACE of a particular control area going beyond the minimum threshold limit of +/- 10 MW.
- (f) The required secondary reserves through automatic generation control shall be fully delivered within fifteen (15) minutes and shall be capable of sustaining for the next thirty (30) minutes thereafter.
- (g) The secondary reserve capacity shall be computed by NLDC, RLDC, SLDC as per any of the following methodologies:

The positive and negative secondary reserve capacity for any control area for a financial year shall be equal to 99 percentile of positive and negative ACE respectively of that control area during the previous financial year,

OR

The secondary reserves capacity for any control area shall be equal to the 110 % of largest unit size in that control area plus load forecast error plus wind forecast error plus solar forecast error.

Provided that the All India secondary reserves capacity shall be equal to the reference contingency.

- (h) This reserve capacity as per above regulation shall be calculated by respective control area by 15th February every year for next financial year and submitted to NLDC. NLDC would work out the minimum quantum of secondary reserves to be maintained at inter-state level (region-wise at regional entity generating station) and

intra-state level for each control area. NLDC will publish the information on its website by 1st March every year which will be implemented for next financial year from 1st April onwards by control areas.

- (i) The secondary reserves shall be maintained in regional entity generating stations for activation by RLDC/NLDC and Intra-state generating stations for activation by respective SLDC. Energy Storage Systems (ESS) and/or demand response may also be deployed for providing adequate secondary response,
- (j) Secondary control through automatic generation control shall be provided by generating stations/ ESS as per the following Table:

S. No.	Generating unit/ ESS category	Control Centre for supervision	Start Date for Application
1	Regional entity generating stations with CERC regulated or adopted Tariff (Thermal with rated capacity more than 200 MW and Hydro with rated capacity more than 25 MW)	NLDC	On or before 1 st Apr 2020
2	Other Regional entity generating stations not covered under SI.No.1(Thermal with rated capacity more than 200 MW and Hydro with rated capacity more than 25 MW) and ESS for providing secondary response	NLDC	To be notified by Commission
3	State (having annual Peak demand more than 10 GW or renewable energy rich states) generating stations (Thermal with rated capacity more than 200 MW and Hydro with rated capacity more than 25 MW) and ESS for providing secondary response	SLDC	On or before 1 st Apr 2021
4	State (not covered under SI. No. 3) generating stations (Thermal with rated capacity more than 200 MW and Hydro with rated capacity more than 25 MW) and ESS for providing secondary response	SLDC	To be notified by the Commission or earlier if agreed by State. However secondary reserves within the state shall be activated manually till the implementation of AGC.

- (k) Similar mechanism shall be implemented at state level for intra-state generating station. NLDC, RLDC or SLDC would indicate the short fall in secondary reserves and announce emergency alerts for such periods.
- (l) Normal mode of operation of AGC would be tie-line bias control. NLDC may also operate select region/country automatic generation control on flat frequency control mode during anticipated congestion free period or flat tie-line mode.
- (m) Tertiary reserves maybe arranged from the generating stations, ESS and/or demand response. Tertiary reserve shall be greater or equal to secondary reserves to take care of contingencies, and shall be maintained at both regional entity level as well as state control area. Tertiary reserves activation would restore the secondary reserves to the desired level.
- (n) The tertiary reserve shall be fully activated within fifteen (15) minutes of operator's instructions from appropriate load despatch centre and shall be capable of delivering until next 60 minutes. Instruction for tertiary reserve activation shall be given by appropriate load despatch centre based on the following:
 - i. When area control error (more than 100 MW) persists for more than fifteen (15) minutes in one direction;
 - ii. In the event of loss of generation or loss of load of more than 100 MW in the control area;
 - iii. In case the secondary reserve has been deployed continuously in one direction for fifteen (15) minutes for more than 100 MW, then tertiary reserves shall be triggered in order to replenish the secondary reserve;

- iv. Any other condition such as mitigating local congestion due to transmission lines.
- (o) Each state control area shall keep reserve capacity one day in advance and inform RLDC as outlined in the scheduling code.
- (p) The secondary and tertiary reserves shall be arranged by the RLDC and SLDC according to the mechanism decided by the appropriate commission.
- (q) The control area wise performance of secondary and tertiary control shall be evaluated in accordance with the detailed procedure prepared by NLDC.

36. OPERATIONAL PLANNING

(1) Introduction

- (a) Operational planning for ensuring reliable and secure operation in real time shall be carried out in advance by the concerned agency as per the following time table:

Time Horizon	Agency
Monthly/Yearly	RPC/CTU/STU/NLDC/RLDC/SLDC
Weekly	NLDC/RLDC/SLDC
Day Ahead	NLDC/RLDC/SLDC
Intra-day	NLDC/RLDC/SLDC

- (b) NLDC and RLDC shall issue a procedure for all users, CTU and STU for:

- i. Operational planning analysis,
- ii. Real-time monitoring,
- iii. Real-time assessments and
- iv. Format for data submission and updating

(2) Demand Estimation for Operational Planning

- (a) This section describes the procedures/responsibilities of the SLDCs for demand estimation for both active power and reactive power incident on the transmission system based on the details collected from respective distribution licensees, distributed generation resources, captive power plants and other bulk consumer embedded within the states.
- (b) The demand estimation by SLDC is to be done on day ahead basis for the daily operation and scheduling activity. The granularity of load forecast should be either the time block or lower. Based on SLDC demand estimate, RLDC will prepare the regional demand estimate and submit to NLDC. NLDC, based on regional demand estimate, shall prepare national demand estimate. In case, SLDC observes major change in demand in real time for the day then it shall immediately submit the revised demand estimate to RLDC for demand estimate correction.
- (c) SLDC shall also estimate demand (active as well as reactive power) on weekly/monthly/yearly basis for current year for load - generation balance planning as well as for operational analysis and shall be part of operational planning data. The demand estimates mentioned above shall have granularity of a time block. It shall cover the load incident on the grid. It shall also cover net load incident on the transmission system taking into account embedded generation in the form of roof-top solar/other distributed generation.
- (d) Timeline for submission of demand estimation data by SLDC to RLDC/RPC is as follows:

TABLE 4: TIMELINE FOR DEMAND ESTIMATION

Daily demand estimation	10:00 hours of previous day
Weekly demand estimation	First working day of previous week
Monthly demand estimation	Fifth day of previous month
Yearly demand estimation	31 st Oct of the previous year.

- (e) Each SLDC shall develop methodology for daily/weekly/monthly/yearly demand estimation in MW and MWh for operational analysis purposes as well resource adequacy. All distribution licensees shall also maintain historical database for demand.
- (f) Each SLDC shall utilize state of the art tools, weather data, historical data and any other data for getting effective demand estimate for operational use. Each SLDC, RLDC and NLDC shall compare the actual demand with forecast demand and compare the forecasting error for improvement. The forecast error for daily/day-ahead/weekly/monthly and yearly basis by SLDC, RLDC and NLDC shall also be made available on their website.
- (g) Each SLDC shall submit node-wise morning peak, evening peak, day shoulder and night off-peak estimated demand in MW and MVA_r on monthly and quarterly basis at all nodes including and above 132 kV for preparation of scenarios for computation of ATC/TTC by RLDC and NLDC.
- (h) Each distribution company of state shall furnish expected off take from each thermal generating station with whom they have long-term or medium-term power purchase agreement, on weekly and monthly basis to respective thermal generating station for planning procurement of fuel.

37. OUTAGE PLANNING

(1) Introduction

- (a) This section provides the procedure for preparation of outage schedules for the grid elements in a coordinated and optimal manner keeping in view the system operating conditions and grid security.
- (b) Annual outage plan of grid elements shall be prepared in advance for the financial year by the RPC secretariat in consultation with users, NLDC and RLDC and reviewed during the year before every quarter and every month. All users, CTU, STU, licensee shall follow the annual outage plans. If any deviation is required, the same shall be with prior permission of concerned RPC, RLDC and NLDC. The outage planning of hydro plant, wind and solar power plant and its associated evacuation network shall be planned to extract maximum power from these renewable sources of energy. Outage of wind generator should be planned during lean wind season, outage of solar, if required, during the rainy season and outage of hydro power plant in the lean water season. Wherever multiple agencies are involved in outage of any grid element, the outage shall be planned by RPC secretariat with a view to minimizing overall downtime.
- (c) Protection relay related works, auto – re-closure outages and SPS testing shall be planned on monthly basis with prior permission of RPC, RLDC & NLDC as per outage planning procedure.

(2) Objective

- (a) To produce a coordinated generation and transmission outage programme for the national/regional grid, considering all the available resources and taking into account demand, transmission constraints, as well as, irrigational requirements.

(b) To optimize the transmission outages of the elements of the National/Regional grid without adversely affecting the grid operation but taking into account the generation outage schedule, outages of user/STU/CTU systems and maintaining system security standards.

(3) Outage Planning Process

(a) A list of important elements of the grid to be coordinated at regional and national level by RLDC/NLDC shall be prepared by RLDC/NLDC and shall be available with RLDC, NLDC and SLDC.

(b) The RPC Secretariat shall be primarily responsible for finalization of the annual outage plan for the following financial year.

(c) Timeline for Outage Planning Process is as follows:

TABLE 5: TIMELINE FOR OUTAGE PLANNING PROCESS

Activity	Agency	Cut-off date
Submission of proposed outage plan of element(s) for next financial year to RPC with the earliest start date and latest finishing date	STUs, transmission licensees, CTU, all generating stations	31 st October
Submission of LGBR of the control area to RPC for both peak and off-peak scenarios	SLDC	31 st October
Publishing draft LGBR and draft outage plan of regional grid for next financial year in website	RPC	30 th November
Publishing final LGBR and final outage plan of regional grid for next financial year in website	RPC	31 st December

(d) Basis of preparation of LGBR by SLDC in consultation with concerned state entities:

The LGBR shall be prepared for the entire year with time block wise granularity, as follows:

- i. Considering the actual load curve for last three (3) years and projecting the load growth for the next year. Further, projected load curve shall be moderated taking into account anticipated change in load pattern and magnitude for reasons such as introduction of energy efficiency devices, rooftop solar, solar pumps, electric vehicles and energy shift due to deployment of ESS.
 - ii. The intra-state generation pattern of last three (3) years, hydro generation forecast for next year, expected addition of new generation for the state, must run power contracted through renewable energy sources, availability of contracted conventional power through ISTS shall be part of the LGBR. While preparing the LGBR, the SLDC shall also factor overall economy in operation considering renewable sources of energy as must run. In addition to above, while preparing the LGBR, reserves, transmission losses and auxiliary consumption shall be factored and shown.
- (e) RPC Secretariat shall compile LGBR and also prepare annual outage plan for generating units and transmission elements in the respective region. This shall be done after carrying out necessary system studies and, if necessary, the outage plan shall be rescheduled and LGBR shall be modified in order to ensure system security and resource adequacy.
- (f) NPC, in consultation with NLDC, shall compile the regional LGBR and prepare an All India LGBR considering overall economy, absorption of renewable energy, anticipated cross-border energy exchange, requirement of reserves and overall grid security. NPC, while preparing the All India LGBR shall assess likely flow on inter-

regional, HVDC and major transmission corridors and moderate the LGBR such that transmission constraint are honored.

- (g) At the end of each year, the projected load curve shall be compared with the actual load of the control area. In case of incidents of variation exceeding $\pm 5\%$, analysis shall be carried out by the SLDC indicating reasons. The analysis shall be submitted to the RPC and RLDC.
- (h) The outage plan shall be finalized in consultation with NLDC and RLDCs. The final outage plan and the final LGBR shall be intimated to NLDC, Users, STUs, CTU, other generating stations connected to the ISTS and the RLDC. The final outage plan and the final LGBR shall be made available on the websites of the respective utilities and on the websites of RPCs, RLDCs and NLDC.
- (i) The above annual outage plan shall be reviewed by RPC Secretariat on quarterly and monthly basis in coordination with all parties concerned, and adjustments made wherever found to be necessary.
- (j) To facilitate planned outages of grid elements a common outage planning procedure shall be formulated by RPC in consultation with NLDC and RLDC.
- (k) In case of emergency in the system, viz., loss of generation, breakdown of grid element affecting the system, grid disturbances, system isolation, SLDC/RLDC/NLDC may conduct studies again before clearance/denial of the planned outage.
- (l) NLDC/RLDC are authorized 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.

(m) Each user shall obtain the final approval from NLDC or RLDC in accordance with outage planning procedure, prior to availing planned outage of grid element.

38. OPERATIONAL PLANNING STUDY

(1) Based on the operational planning analysis data, operational planning study shall be carried out by various agencies as defined for the various time horizons.

TABLE 6: TIME HORIZON FOR OPERATIONAL PLANNING STUDY

Time horizon of operational planning study	Agency	Means for carrying out study
Real time/Intra-day	NLDC/RLDC/ SLDC	At least fifteen (15) minutes interval using online/offline SCADA/EMS system
Day-ahead	NLDC/RLDC/ SLDC	For various operating condition using offline tool
Weekly	NLDC/RLDC/ SLDC	For various operating condition using offline tool
Monthly/Yearly	Study committee formed by RPC secretariat/ NLDC/ RLDC/SLDC	For various operating condition using offline tool

(2) SLDC, RLDC and NLDC shall utilize network estimation tool integrated in their EMS/SCADA system for the real time operational planning study. All users shall ensure that real time operational data for successful execution of network analysis using EMS/SCADA is made available in healthy condition throughout. Any prolonged outage

of data shall be immediately reported to SLDC, RLDC or NLDC along with firm timeline for its restoration. The performance of online network estimation tools at SLDC and RLDC shall be discussed in the monthly operational meeting organized by RPC secretariat. Telemetry related issues impacting the online network estimation tool shall be monitored by RPC Secretariat for early resolution.

- (3) SLDC, RLDC and NLDC shall also perform day-ahead/ weekly/ monthly/ yearly operational study for:
 - i. Inter-regional, intra-regional, inter-state, intra-state total transfer capability/available transfer capability assessment
 - ii. Planned outage assessment
 - iii. Special scenario assessment
 - iv. System protection scheme assessment
 - v. Natural disaster assessment
 - vi. Any other study relevant in operational scenario

- (4) Each SLDC shall also carry out total transfer capability/available transfer capability on three months ahead basis and any changes required during real time/day ahead operation due to change in operating scenario considered and declare it on their website for each time block. The process shall be in line with the CERC (Measures to Relieve Congestion in Real Time Operation) Regulation 2010. The SLDC shall also furnish the constraints considered and assumption made during the declaration of TTC/ATC.

- (5) Operational planning analysis shall be done to assess whether the planned operations will not exceed any of the operational limits defined under this regulation, CEA Grid

Standard 2010 and any other CERC/CEA regulations and CEA Manual on Transmission Planning Criteria.

- (6) SLDC, RLDC, NLDC, STU, CTU and RPC shall have evidence of a completed operational planning study. These evidences shall include dated power flow study results, operational plan and minutes of meeting on operational study.
- (7) SLDC, RLDC, NLDC, STU, CTU and RPC shall have evidence that it has an operating plan to address potential violation of system operational limit identified as a result of the operational planning study as above. These plans shall be intimated to users in advance to take corrective measures. In case any user is unable to adhere with the operational plan submitted, they shall intimate the respective SLDC, RLDC or NLDC in advance with appropriate explanation. These explanations shall also be discussed in the monthly operation sub-committee of respective region and RPC secretariat will submit a quarterly feedback report to CERC/CEA for long-term measures.
- (8) SLDC shall perform study for new element to be commissioned in intra-state system in the next six (6) months for its impact on the intra-state system.
- (9) RLDC shall perform study for new element to be commissioned in the next six (6) months in (a) ISTS system of the region and (b) intra-state system having impact on inter-state system.
- (10) NLDC shall perform study for new element to be commissioned in the next six (6) months in (a) inter-regional system, (b) cross-border link, (c) intra-regional system having impact on inter-regional system and (d) HVDC link.
- (11) NLDC, RLDC and SLDC shall assess its impact on the system and transfer capability addition. Any significant variation vis-a-vis interconnection and planning studies by

CTU/STU shall be communicated to CTU/STU for immediate and long-term mitigation measures.

- (12) Defense mechanisms like system protection scheme, load-rejection scheme, generation run-back or any other scheme for system security shall be proposed by concerned user or SLDC or RLDC or NLDC and shall be deployed as finalized by RPC.

39. SYSTEM RESTORATION

- (1) Based on the template issued by NLDC, SLDC of each state and RLDC of each region shall prepare restoration procedure for the grid for their respective control area and update the same every year taking into account changes in the configuration of their power system.
- (2) Detailed plans and procedures for restoration of the regional grid under partial/total blackout shall be developed by RLDC in consultation with NLDC, all users, STU, SLDC, CTU and RPC Secretariat and shall be reviewed/updated annually.
- (3) Detailed plans and procedures for restoration post partial/total blackout of each user system within a region, shall be developed by the concerned user in coordination with SLDC, RLDC or NLDC. The procedure shall be reviewed and revised once every year. Mock trial runs of the procedure for different sub-systems including black-start of generating units along with VSC based HVDC black-start support shall be carried out by the user at least once a year under intimation to the SLDC or RLDC. Diesel generator sets or other standalone auxiliary supply source used for black start shall be tested on weekly basis and test report shall be sent to SLDC, RLDC or NLDC on quarterly basis.
- (4) Simulation studies shall be carried out for preparing restoration procedures considering the following factors:

- (a) Black start capability of generator;
 - (b) Ability of black start generator to build cranking path and sustain island;
 - (c) Impact of block load switching in or out;
 - (d) Line/transformer charging;
 - (e) Reduced fault levels;
 - (f) Protection settings under restoration condition;
- (5) The thermal and nuclear generating station shall ensure preparedness for house load operation as per design. User/SLDC shall report the performance of house load operation of a generating station in the event where such operation was required.
- (a) List of generating stations with black start, house load facility, inter-state/inter-regional ties, synchronizing points, essential loads to be restored on priority shall be prepared and shall be available with NLDC, RLDC and SLDC.
 - (b) During restoration process following a black out, SLDC, RLDC and NLDC is authorized to operate with reduced security standards for voltage and frequency and may direct upon such operational measures viz. suspension of secondary or tertiary frequency control, power market activities, defense schemes, reduced governor droop setting as necessary, in order to achieve the fastest possible recovery of the grid.
 - (c) All communication channels required for restoration process shall be used for operational communication only, till grid normalcy is restored.

40. REAL TIME OPERATION

- (1) Principles for real time operation
 - (a) Classification of system state:

- i. Power system condition shall be categorized under various stages depending on the type of contingencies and states of power system variables/parameters. These shall be broadly classified as normal, alert, emergency, extreme emergency and restoration state.

(a) Normal:

Power system is operating within the operational limits and equipment are within their loading limits. The system is secure and capable of maintaining stability under contingencies defined in the CEA Transmission Planning Criteria.

(b) Alert:

Operational parameters are within operational limit but single contingency would lead to violation of security criteria. In this state, system operator shall take corrective measures to bring back the system to normal state. The power system remains intact under such operational state.

(c) Emergency:

Under this state of operation, many of the power system variables are outside their operating limit or many of the equipment are above their operational limit. The system can be brought to alert/ normal state by taking:

- extreme measures such as load shedding, generation unit tripping, line tripping/closing,
- emergency control action such as HVDC Control, Excitation Control, HP-LP Bypass, tie line flow rescheduling on critical lines, and

- automated action such as system protection scheme, load curtailment scheme and generation run-back scheme.

Such operation can arise out of multiple contingencies or any major grid disturbance in the system. The power system remains intact under such operational state.

(d) Extreme Emergency:

System reaches extreme emergency state if the control actions taken during Emergency state are not able to bring the system to Alert or Normal state. In this state of system, system parameters are beyond operation limits and equipment are critically loaded. System may or may not remain intact (splitting may occur) and extreme events like Generation plant tripping, bulk load shedding, under frequency load shedding (UFLS) and under voltage load shedding (UVLS) operation may occur. Such situation may also arise due to high impact low frequency events like natural disasters.

(e) Restorative State: It represents a condition in which control action is being taken to reconnect the system elements and to restore system load. The system transits from this state to either the alert state or the normal state, depending on the system conditions.

(b) NLDC/RLDC/SLDC shall endeavor to maintain the grid in a normal state by taking suitable measures. In case system is drifting away from normal state, appropriate measures shall be taken to bring the system back to normal operating state. In case system has moved to Extreme Emergency state, appropriate LDCs shall take emergency action and initiate restorative measures of system immediately.

(c) Procedure to be followed during an event:

- i. Immediately following an event on intra-state system which may significantly impact the inter-state system, the concerned SLDC shall inform the RLDC; in case of event on the ISTS system or regional entity, the concerned agency shall inform RLDC.
- ii. Following an event on regional grid, the RLDC shall inform each user and/or SLDC for necessary action.
- iii. Any warning in respect of system security issued by NLDC/ RLDC/ SLDC shall be taken note of immediately by user who shall take the necessary steps to withstand the said disturbance or to minimize the effect.

(d) Operational coordination:

- i. Each inter-state transmission licensee shall have a coordination centre in the region(s) in which its assets are located for round the clock operational coordination.
- ii. Each conventional generating station shall have a coordination centre in the region in which it is located for round the clock operational coordination.
- iii. Each QCA, representing the renewable generator shall have a coordination centre within the region in which it is located for round the clock operational coordination.

Provided that where a QCA is not appointed by the renewable generator, the respective generating station shall undertake operational coordination.

- iv. Each SNA shall have a coordination centre in the country for round the clock operational coordination.

- v. Any planned operation activity in ISTS system (transmission element opening or closing (including breakers), protection system outage, SPS outage and testing etc.) should be done by taking operational code from RLDC or NLDC as per the jurisdiction. The operational code shall have validity of thirty (30) minutes from the time of issue. In case such operation does not take place within validity period, the entity shall obtain the operational code again.

41. DEMAND MANAGEMENT

- (1) The demand management under this clause covers the management to the extent of ensuring grid security which affects integrated grid operation.
 - (a) STU shall ensure transmission adequacy of intra-state system for secure grid operation.
 - (b) SLDC shall ensure reserves adequacy for secure grid operation.
 - (c) Each Distribution licensee shall ensure resource and network adequacy to meet demand of consumption centres and all category of consumers all the time.
 - (d) Each state shall endeavor to contract automated demand response schemes with willing consumers.
 - (e) In case the system is in alert or emergency state as assessed by SLDC or advised by RLDC, the respective distribution licensee shall abide by directions of SLDC to secure the system, and extreme measures like load shedding may be carried out as a last resort.
 - (f) SLDC or RLDC (through SLDC) may direct distribution licensee to restrict drawal from grid or curtail load for ensuring the stability of grid:

Provided that load shedding shall be resorted to after the demand response schemes have been exhausted.

- (g) The disconnected load, if any, shall be restored as soon as possible on clearance from SLDC, in coordination with RLDC if required, after the system has been normalized.

42. POST DESPATCH ANALYSIS

(1) Operational analysis:

(a) SLDC, RLDC, NLDC shall also analyse and report the following:

- i. Pattern of demand met, frequency profile, voltage and tie-line flows, angular spread, area control error, reserve margin, ancillary services despatch transmission congestion and n-1 violations,
- ii. Generation mix: source and station wise generation,
- iii. Irregular pattern in any of the above system parameters and reasons thereof and
- iv. Extreme weather events, special events

(b) Data archiving: For the above purpose, telemetered data shall be archived with granularity of not more than five (5) minutes and higher granularity for special events. Such data shall be stored by SLDC, RLDC and NLDC for at least fifteen (15) years and reports shall be stored for twenty-five (25) years for operational analysis only.

(2) Disturbance monitoring and reporting

Disturbance monitoring and reporting is required to ensure that adequate data is available to facilitate event analysis.

- (a) Immediately following an event (GD/GI) in the system, the concerned user/SLDC shall inform the RLDC through voice message.
- (b) Following the above, written flash report shall be submitted to RLDC and SLDC by concerned users within time line specified in the table below.
- (c) Disturbance Recorder (DR), station Event Logger (EL), Data Acquisition System (DAS) shall be submitted within time line specified in the table below.
- (d) RLDC shall report the GD/GI event to CEA, RPC Secretariat and all regional entities within twenty-four (24) hours of receipt of the flash report.
- (e) After complete analysis of the event, user shall submit a detailed report in case of grid disturbance or grid incident within one (1) week of occurrence of event to RLDC and RPC Secretariat.
- (f) RLDC/NLDC (for events involving more than one region) shall prepare a draft report of each grid disturbance/grid including simulation results and analysis which shall be discussed and finalized at Protection sub-committee of RPC as per timeline given below:

TABLE 7: REPORT SUBMISSION TIMELINE

S. N	Grid Event^ (Classification)	Flash report submission deadline (users/ SLDC)	Disturbance record and station event log submission deadline (users/ SLDC)	Detailed report and data submission deadline (users/ SLDC)	Draft report submission deadline (RLDC/ NLDC)	Discussion in protection committee meeting and final report submission deadline (RPC)
1	GI-1/GI-2	8 hours	24 hours	+7 days	+14 days	+30 days
2	Near miss*	8 hours	24 hours	+7 days	+30 days	+30 days

S. N	Grid Event [^] (Classification)	Flash report submission deadline (users/ SLDC)	Disturbance record and station event log submission deadline (users/ SLDC)	Detailed report and data submission deadline (users/ SLDC)	Draft report submission deadline (RLDC/ NLDC)	Discussion in protection committee meeting and final report submission deadline (RPC)
3	GD-1	8 hours	24 hours	+7 days	+14 days	+30 days
4	GD-2/GD-3	8 hours	24 hours	+7 days	+21 days	+30 days
5	GD-4/GD-5	8 hours	24 hours	+7 days	+30 days	+30 days

[^]The classification of Grid Disturbance (GD)/Grid Incident (GI) shall be as per CEA (Grid Standards) Regulations, 2010.

*Near miss event means an incident of multiple failures that had the potential to cause a grid disturbance, power failure or partial collapse but did not result in a grid disturbance.

- (g) The implementation of the recommendations of final report shall be monitored in the protection sub-group meeting of RPC. NPC shall disseminate the lessons learnt from each event to all the RPCs for necessary action in each region.
- (h) Any additional data such as single line diagram (SLD) of station, protection relay settings, HVDC transient fault record, switchyard equipment and any other relevant station data required for carrying out analysis of an event by RPC, NLDC, RLDC or SLDC shall be furnished by the users or SLDC within forty- eight (48) hours of the request. All users shall also furnish high-resolution analog data from various instruments including power electronic devices like HVDC, FACTS, renewable generation on the request of RPC, NLDC, RLDC or SLDC.
- (i) Triggering of STATCOM, TCSC, HVDC run-back, HVDC power oscillation damping, generating station power system stabilizer and any other controller system during

any event in the grid shall be reported to RLDC and RPC if connected to ISTS and to SLDC if connected to intra-state system. The transient fault records and event logger data shall be submitted to RLDC or SLDC within 24 hours of occurrence of the incident.

- (j) A monthly report mentioning the events of unintended operation or non-operation of protection system shall be prepared and submitted by each utility to RPC and RLDC within the first week of the subsequent month.

43. PERIODIC REPORTS

- (1) Daily and monthly report covering performance of the integrated grid shall be prepared by NLDC.
- (2) Daily and monthly report covering the performance of the regional grid shall be prepared by each RLDC based on the inputs received from SLDCs/users.
- (3) The reports shall inter-alia contain the following:
 - i. Frequency profile
 - ii. Source wise generation for each control area
 - iii. Drawal from the grid and area control error
 - iv. Demand met (peak, off-peak and average)
 - v. Demand/Energy unserved in MW and MWh
 - vi. Instances and quantum of curtailment of renewable energy
 - vii. Voltage profile of important substations and sub-stations normally having low /high voltage.
 - viii. Major generation and transmission outages

- ix. Constraints and instances of congestion in transmission system
 - x. Instances of persistent/significant non-compliance of Grid Code
 - xi. Status of reservoirs
- (4) The NLDC shall prepare a quarterly report providing operational feedback for grid planning and re-optimization.

44. REACTIVE POWER MANAGEMENT

- (1) All users shall endeavour to maintain the voltage at interconnection point in the range specified in the Grid Code.
- (2) NLDC, RLDC or SLDC may direct the users about reactive power set-points, voltage set-points and power factor control to maintain the voltage at interconnection point.
- (3) NLDC, RLDC and SLDC shall assess the dynamic reactive power reserve available at various substations or generating stations under any credible contingency on a regular basis based on technical details and data provided by the users.
- (4) NLDC, RLDC and SLDC shall take appropriate measures to maintain the voltage within limits inter-alia using following facilities and facility owner shall abide by the instructions of SLDC, RLDC and NLDC:
- i) shunt reactors
 - ii) shunt capacitors
 - iii) TCSC
 - iv) VSC based HVDC
 - v) synchronous/non-synchronous generator voltage control
 - vi) synchronous condenser;

- vii) static VAR compensators (SVC), STATCOM and other FACTS devices
 - viii) transformer tap change: generator transformer and inter-connecting transformer
 - ix) HVDC power order or HVDC controller selection to optimise filter bank
- (5) Reactive power facility shall be in operation at all times and shall not be taken out without the permission of concerned RLDC or SLDC.
- (6) Periodic/seasonal tap changing of inter-connecting transformers and generator transformers shall be carried out to optimize the voltages and if required other options such as tap staggering may be carried out in the network.
- (7) All generating stations connected to grid shall generate/absorb reactive power as per instructions of RLDC or SLDC, within capability limits of the respective generating units. Such instructions shall ensure that active power generation is not sacrificed under normal conditions.
- (8) Hydro and gas generating units having capability shall operate in synchronous condenser mode operation as per instructions of RLDC or SLDC. Standalone synchronous condenser units shall operate as per instructions of RLDC or SLDC.
- (9) Any commercial settlement for reactive power shall be governed as per regulatory framework specified as per **Annexure – 4** until the same is separately notified as part of CERC Ancillary Services Regulations.
- (10) If voltages are outside acceptable limits and the means of voltage control set out in the above clause are exhausted, SLDC, RLDC or NLDC shall take all reasonable actions necessary to restore the voltages to within the relevant limits including dropping of lines considering security of system.

45. FIELD TESTING FOR MODEL VALIDATION

(1) Objective

This section specifies the periodicity and tests to be carried out on power system elements for ascertaining correctness of mathematical models used for simulation studies as well as ensuring desired performance during an event in the system.

(2) General provisions regarding testing

- (a) The owner of the power system element shall be responsible to carry out test as described in respective sections and submission of report to NLDC/ RLDC/ CEA/ CTU for all elements and STU/SLDC for intra-state elements.
- (b) All equipment owner shall submit a testing plan for the next year to RPC secretariat for information to all by 31st October for ensuring proper coordination during testing as per the schedule. In case of any change in schedule, the owner shall inform RPC Secretariat in advance.
- (c) The tests shall be performed once every five (5) years or whenever major retrofitting is done or if necessitated earlier due to any adverse performance observed during any grid event.
- (d) The owner of the power system elements shall implement recommendations if any suggested in the test reports in consultation with NLDC/ RLDC/ CEA/ CTU or any changes suggested by the latter.

(3) Testing requirements:

The following tests shall be carried out on respective power system elements:

TABLE 8: TESTS REQUIRED FOR POWER SYSTEM ELEMENTS

Power System Elements	Tests	Applicability
Synchronous Generator	(1) Real and Reactive Power Capability assessment. (2) Reactive Power Control Capability (As per CEA (Technical Standards for Connectivity to the Grid) Regulations, 2007) assessment. (3) Model Validation and verification test for the complete Generator and Excitation System model including PSS. (4) Model Validation and verification of Turbine/Governor and Load Control or Active Power/ Frequency Control Functions. (5) Testing of Governor performance and Automatic Generation Control.	Individual Unit of rating 100MW and above for Coal/lignite, 50MW and above gas turbine and 25 MW and above for Hydro.
Non synchronous Generator (Solar/Wind)	(1) Real and Reactive Power Capability for Generator (2) Power Plant Controller Function Test (3) Frequency Response Test (4) Fault Ride through Test (sample testing of a unit in the generating stations).	Applicable as per CEA (Technical Standards for Connectivity to the Grid) Regulations, 2007
HVDC/FACTS Devices	(1) Damping capability of HVDC/FACTS Controller (2) Frequency Controller Capability of HVDC Controller (3) Reactive Power Controller (RPC) Capability for HVDC/FACTS (4) Validation of voltage dependent current order limiter (VDCOL) characteristic for ensuring proper validation of HVDC performance	To all ISTS HVDC as well as Intra-State HVDC/FACTS

Power System Elements	Tests	Applicability
	(5) Filter bank adequacy assessment based on present grid condition. (6) Validation of response by FACTS devices as per settings.	

46. CAPACITY BUILDING AND CERTIFICATION

(1) Certification of System Operators

- (a) Capacity building, skill upgradation and certification of the personnel deployed in load despatch centres shall be done periodically under an institutional framework.
- (b) The certification shall be done by certifying agency(ies) as designated and accredited by CEA/Central Government from time to time.
- (c) A governing board shall be formed by certifying agency(ies), comprising of members from CEA, CERC/SERC, NLDC, CTU and academia for administering the entire certification process.
- (d) The governing board may create sub-groups for finalizing the details of the course content, examination procedure and other related issues.
- (e) A detailed procedure shall be issued by the governing board, in consultation with Forum of Load Despatchers (FOLD), for periodic capacity building, certification and recertification for system operators at NLDC, RLDC, SLDC and sub-LDC.
- (f) The grid operators at NLDC, RLDC, SLDC and sub-LDC shall undergo periodic re-certification once in every three (3) years to ensure continuous skill upgradation.

(2) Certification of Transmission System Planners

- (a) Capacity building, skill upgradation and certification of the personnel involved in transmission planning in CEA, CTU, STU and distribution licensees shall be done periodically under an institutional framework.
- (b) The certification shall be done by certifying agency(ies) as designated and accredited by CEA/Central Government from time to time.
- (c) An independent governing board shall be formed by certifying agency(ies), comprising of members from CEA, CERC/SERC, CTU, NLDC and academia for administering the entire certification process.
- (d) The governing board may create sub-groups for finalizing the details of the course content, examination procedure and other related issues.
- (e) A detailed procedure shall be issued by the governing board for periodic capacity building, certification and recertification for transmission planners at CEA, CTU, STU and distribution licensees.
- (f) The transmission planners at CEA, CTU, STU and distribution licensees shall undergo periodic re-certification once in every five (5) years to ensure continuous skill upgradation.

CHAPTER 8: UNIT COMMITMENT, SCHEDULING AND DESPATCH CODE FOR PHYSICAL DELIVERY OF ELECTRICAL ENERGY

47. INTRODUCTION

This chapter covers a) control area jurisdiction b) procedure for scheduling and despatch in a decentralized manner c) mechanism for unit commitment d) framework for Security Constrained Economic Despatch (SCED) of regional entity generators and e) compensatory mechanism for part load operation of generating stations.

48. OBJECTIVE

This chapter deals with the procedure to be adopted for scheduling of the net injection/drawal of regional entities and the modalities for information exchange including scheduling for intra-state and cross-border entities transacting power through Inter-State Transmission System.

49. CONTROL AREA JURISDICTION

(1) The national grid is demarcated into different control areas where the appropriate load despatch centre controls its generation and load to maintain interchange with the grid as per schedule, and contributes to frequency regulation. The load despatch centre shall be responsible for real-time monitoring and control of the grid operation within its control area including management of the generation reserves and demand response. It shall also be responsible for processing of interface energy meter data and coordinating the accounting and settlement of pool accounts.

(2) Jurisdiction of RLDC and SLDC

(a) Jurisdiction of RLDC:

- i. Generating station connected only to the ISTS including deemed ISTS except where full share is allocated to home state
- ii. Generating station connected to both ISTS and state network unless more than 50% of installed capacity is tied up with the home state through long-term PPAs.

(b) Jurisdiction of SLDC:

- i. Generating station connected only to the state transmission network.
- ii. Generating station connected only to the ISTS where full share is allocated to home state
- iii. Generating station connected to both ISTS and state network with more than 50% of installed capacity tied up with the home state through long term PPAs:

Provided that in case of ISGS, the role of RLDC shall be to schedule inter-state exchange of power on account of the ISGS while determining the net drawal schedule of the home state.

(3) Notwithstanding above, there may be exceptions to above provisions, for reasons of operational expediency subject to approval of CERC.

(4) In case a generating station is connected to both ISTS and state transmission network, the load despatch centres involved shall coordinate with each other while scheduling with a view to ensuring grid security. In case of any difference of view on scheduling, the directions of the RLDC/NLDC shall be binding.

(5) The scheduling of ISGS under the jurisdiction of SLDC shall be done according to the provisions of IEGC.

50. FUNCTIONS OF CONTROL AREA

- (1) Entities such as SLDC, DVC, cross-border control centre shall be responsible for the following in its control area:
 - (a) Forecasting demand and internal renewable generation for each time block on a day ahead and intraday basis.
 - (b) Scheduling/despatch of internal generation.
 - (c) Requisitioning drawal from the regional entity generating stations/cross-border generating stations with whom its embedded entities have PPA.
 - (d) Scheduling long-term, medium-term and short-term open access and power exchange transactions for embedded entities in accordance with the contracts.
 - (e) Balancing demand and supply to minimize Area Control Error (ACE).
 - (f) Facilitating absorption of energy from renewable energy sources
 - (g) Maintaining and despatching of reserves of various kinds as envisaged in these regulations. Deployment of secondary reserves (Automatic Generation Control) and tertiary reserves.
 - (h) Declaration of Import/Export TTC/ATC of respective control area with respect to ISTS in coordination with RLDC/NLDC on three (3) months in advance and day-ahead basis, which shall be revised from time to time based on grid conditions.
 - (i) Declaration of intra-state TTC/ATC of each distribution licensee in coordination with state grid entities and STU. TTC/ATC along with all the assumptions and limiting constraints would be published on the SLDC website.
- (2) RLDC, NLDC shall be responsible for the following in its control area:

- (a) Forecasting demand and ISTS connected renewable generation for each time block on a day-ahead and intraday basis.
- (b) Running a Security Constraint Unit Commitment (SCUC) on regional and All India basis.
- (c) Scheduling of regional entity generating stations/cross-border generating stations with whom its regional entities have PPA.
- (d) Scheduling long-term, medium-term and short-term open access and power exchange transactions for regional entities in accordance with the contracts.
- (e) Running Security Constrained Economic Despatch (SCED) on All India basis.
- (f) Balancing demand and supply to minimize Area Control Error (ACE).
- (g) Facilitating absorption of energy from renewable energy sources.
- (h) Maintaining and despatching reserves of various kinds as envisaged in these regulations. Deployment of secondary reserves (Automatic Generation Control) and tertiary reserves.
- (i) Declaration of simultaneous Import/Export TTC/ATC across regions and for cross-border interconnections in three (3) months in advance, which shall be revised from time to time based on grid conditions. TTC/ATC along with all the assumptions and limiting constraints would be published on the NLDC website.
- (j) Declaration of Import/Export TTC/ATC of each state in coordination with respective SLDC. TTC/ATC along with all the assumptions and limiting constraints would be published on the NLDC website.

51. GENERAL PROVISIONS

(1) Net Drawal Schedule:

The drawal schedule of any regional drawee entity would be the algebraic sum of all its transactions through the inter-state transmission system. This would be reflected at the periphery of the regional drawee entity after applicable transmission losses to arrive at net drawal schedule.

(2) Net Injection Schedule:

The injection schedule of any regional entity generating station would be the algebraic sum of all its transactions through the inter-state transmission system. This would be reflected at the periphery of the regional generating entity after applicable transmission losses.

(3) Adherence to Schedule:

Each regional entity shall regulate its generation and/or demand so as to adhere to the net injection or drawal schedule from the inter-state transmission system.

(4) Area Control Error:

(a) The concerned SLDC/bulk consumer connected to ISTS shall ensure that their automatic demand management scheme is kept in service. The generation, storage and demand response reserves shall be efficiently deployed to minimize the ACE. In order to sustain ACE close to zero (0), the algebraic sign of ACE shall traverse the zero (0) error line at least once in six (6) time-blocks.

(b) With regard to regional entity generating station, the algebraic sign of ACE shall traverse the zero (0) error line at least once in six (6) time-blocks in order to sustain ACE close to zero (0):

Provided that the requirement of algebraic sign of ACE shall not be applicable to wind, solar, hybrid of wind and solar, run of the river hydro generation without pondage:

Provided further that the requirement of algebraic sign of ACE shall not be applicable to injection of infirm power and drawal for start-up power by a generating station, inter-regional deviations and post forced outage of a generating station transacting through collective day ahead or real time transactions on a power exchange.

(5) Short-term Demand Estimation and Resource Management:

- (a) SLDC, in coordination with distribution licensees, shall carry out short-term demand estimation taking into account embedded renewable generation for its Control Area on monthly, weekly and daily basis for each time block of the day.
- (b) SLDC shall estimate and ensure resource adequacy, identification of generation reserves and demand response capacity and generation flexibility requirement.

(6) Power to Revise Schedules:

- (a) Irrespective of finalized injection/drawal schedules, in case of contingencies such as overloading of lines, transformers, abnormal voltages, threat to system security, RLDC may direct the SLDCs/regional entities to increase/decrease their drawal/injection. Such directions shall be immediately acted upon.
- (b) In case of overloading of lines, transformers, abnormal voltages or threat to system security, the following steps may be taken by RLDC or SLDC as the case may be:
 - (i) Issue directions to adhere to the schedules and ensure deviations are stopped.
 - (ii) Despatching ancillary services.

- (iii) Take appropriate measures like tripping of pump storage plants operating in pumping mode.
 - (iv) Despatching emergency demand response measures.
- (c) In case it becomes necessary to curtail scheduled transactions - short-term, medium-term or long-term - then the transaction which is likely to relieve the threat to grid security shall be identified and curtailed first. This is, notwithstanding the identified priority of curtailment, that is short-term followed by medium-term followed by long-term transactions. RLDC or SLDC, as the case may be, shall publish a report of such incidents on the website.
- (d) Notwithstanding above, RLDC may revise the drawal and/or injection schedule of a regional entity in the interest of reliable system operation.
- (e) RLDCs would curtail a transaction at the periphery of the regional entities. SLDC(s) shall further incorporate the inter-se curtailment of intra-state entities to implement the curtailment.
- (f) Whenever RLDC/SLDC revises final schedules due to reasons of grid security or contingency, the short reason shall be informed immediately to the concerned followed by a detailed explanation to be posted on the website within 24 hours.

(7) Third Party Sale Out of Long-term PPA:

- (a) The regional entity generating station shall be allowed to sell the power of any long-term PPA holder in the market with express consent of the PPA holder. The PPA holder shall communicate its consent for a day or standing consent for longer duration to the regional energy generating station about the quantum and duration for which power shall not be requisitioned. Where the consent has been given by the PPA holder to the regional entity generating station, the PPA holder shall not be allowed to recall

such power. The regional entity generating station shall submit the details to the respective RLDC regarding such power sold in the market along with details of PPA holder who had surrendered its power.

(b) Without prejudice to above, scheduling for third party sale may also be carried out in accordance with CERC (Regulation of Power Supply) Regulations 2010.

(8) Requirement for Commencement of Scheduling:

(a) The following documents shall be submitted to RLDC before commencement of the scheduling of transactions under long-term and medium-term access:

- i. Grant of long-term or medium-term open access by the CTU;
- ii. Power Purchase/Supply Agreement between generator or seller and the beneficiary or buyer by either of the parties;
- iii. Letter of operationalization of long-term or medium-term open access by the CTU;

(b) The scheduling of short-term open access and collective power exchange transactions shall be based on approval accorded under CERC (Open Access in Inter-State Transmission) Regulations, 2008

(9) Declaration of Capability for Scheduling:

(a) The regional entity generating stations shall make an advance declaration of ex-power plant maximum and minimum MW and MWh capabilities on a daily basis, ramping up/down capability foreseen for the next seven (7) days on a rolling basis:

Provided that:

- i. In case of a hydro generating stations, the generating station shall declare MWh capabilities foreseen for the next day along with maximum generation capacity in MW for continuous three hours.
 - ii. In case of a gas turbine generating station or a combined cycle generating station, the generating station shall declare fuel-wise MWh energy capability on differently priced fuels separately along with the combined maximum capacity in MW for units/modules.
 - iii. The regional entity renewable generating stations generators (including hybrid systems) shall make an advance declaration of forecast and available capacity foreseen for the next day, i.e., from 00:00 hrs. to 24:00 hrs.
- (b) While making or revising its declaration of capability, except in case of run-off-river (with up to three-hour pondage) hydro stations and canal fed hydro, the regional entity generating station shall ensure that the declared capability during peak hours is not less than that during other hours. However, exception to this rule shall be allowed in case of tripping/re-synchronization of units as a result of forced outage of units.
- (c) It shall be incumbent upon the regional entity generators to declare the plant capabilities and available capacity, faithfully. The regional entity generators may be required to demonstrate the declared capability of its generating station as and when asked by the RLDC of the region. For this purpose, RLDC, in coordination with SLDC and the beneficiaries, shall schedule upto the declared capability of the generator. RLDC shall ask each regional entity generating station to demonstrate the declared capacity at least once in a year and report mis-declaration if any to the Commission.

(d) The schedule decided by the RLDC shall be binding on the beneficiaries for such testing of declared capacity. In case the regional entity generator fails to demonstrate the declared capability, this shall be treated as mis-declaration which shall be dealt in terms of these regulations as under:

The quantum of penalty for the first mis-declaration for any duration/block in a day shall be the charges corresponding to two days fixed charges. For the second mis-declaration the penalty shall be equivalent to fixed charges for four days and for subsequent mis-declarations, the penalty shall be multiplied in the geometrical progression over a period of a month.

(10) Declaration of Peak Hours:

Seasonal and diurnal peak/off peak periods may be declared by NLDC as directed by CERC in Terms and Conditions of Tariff Regulation 2019-24-. RLDCs, based on demand pattern analysis / forecast and after duly considering the comments of the concerned stakeholders, shall declare peak hours and high demand season for respective region. For the generators whose tariff is determined by CERC but falling under the control area of SLDC as per these regulations, the hours of peak and off-peak periods during a day shall be declared by the concerned SLDC at least a week in advance in line to above procedure for RLDCs.

(11) Optimum Utilization of Hydro Energy:

(a) Run-of-river power station with pondage and storage type power stations are designed to operate during peak hours to meet system peak demand. Maximum capacity of the station declared for the day shall be equal to the installed capacity including overload capability (during water spillage condition only), if any, minus auxiliary consumption, corrected for the reservoir level. RLDC shall ensure that

generation schedules of such type of stations are prepared and the stations despatched for optimum utilization of available hydro energy except in the event of specific system constraints.

- (b) During high inflow period and spillage condition, subject to availability of margins in transmission system, RLDCs shall allow scheduling of power from hydro generating stations (irrespective of ownership) corresponding to overload capacity upto 10% of existing LTA even without obtaining additional LTA/ MTOA/ STOA for the overload capacity:

Provided that RLDCs shall allow the Declared Capacity declared by the generator for the purpose of PAF calculation of the generating station.

Provided that in case of beneficiaries with PPAs for fixed quantum of power, the beneficiary shall have the first right of refusal in such overload capacity.

In the scenario of the beneficiary deciding not to avail such power under overload capacity, the generating station shall be free to sell the same to any other entity or in power exchanges and shall be liable to pay the applicable STOA charges, instead of additional LTA charges, for the scheduled overload capacity.

- (c) The schedule finalized by the concerned load despatch centre for hydro generating station, shall normally be such that the scheduled energy for a day shall be close to the total energy (ex-bus) declared by the generating station.

(12) Flexibility in Scheduling from various contracts upto approved LTA/ MTOA

A Distribution utility/ buyer shall have the flexibility to requisition/schedule such quantum of power as per its preference from its portfolio of power contracts (long/medium/short-term agreements) upto the approved quantum of long-term access and/or medium-term open access to such User.

Provided that:

- (a) for scheduling power under short-term bilateral contract, the user shall be required to obtain STOA as per CERC (Open Access in Interstate Transmission) Regulations 2008.
- (b) If the user does not fully requisition its short-term access before the opening of day-ahead bidding in power exchanges, the unused corridor(s) against such access shall be forfeited, and released in the day ahead and real time markets.

NLDC shall include the modalities of implementation in the *Detailed Procedure and Timelines for Scheduling and Despatch of Regional Entities*.

(13) Ramping Rate to be Declared for Scheduling:

- (a) The generating plants shall declare the ramping rate along with the declaration of day-ahead availability in the following manner. The same shall be accounted_for in the preparation of generation schedules.
 - i. Coal/lignite fired plants shall declare a ramp up/down rate of not less than 1% of MCR on bar per minute.
 - ii. Gas power plants shall declare a ramp up/down rate of not less than 3% of MCR on bar per minute.
 - iii. Hydro power plants shall declare a ramp up/down rate of not less than 10% of MCR on bar per minute.
 - iv. Wind, solar and wind-solar hybrid power plants shall declare a ramp up/down rate as per CEA Connectivity Standards.
- (b) The drawee regional entities shall ensure that the ramp rate in the drawal/ injection schedule is not more than 10% of previous time block schedule.

- (c) All the trade transactions, bilateral as well as collective shall ensure that ramp rate in the drawal/injection schedule is not more than 10% of previous time block schedule.

(14) Scheduling of wind and solar generation by QCA:

- (i) The wind, solar or hybrid generator including energy storage systems shall, on their behalf, appoint the QCA by mutual consent to undertake scheduling for a particular ISTS pooling station or combined scheduling for more than one pooling station. Provided that:
- a) where there is no consensus among wind, solar or hybrid generator, the QCA may be appointed by majority vote (51% of installed capacity) by the concerned generators. The voting rights allocated to each generator shall be based on the capacity connected to the concerned ISTS pooling station(s);
 - b) Till the QCA has not been appointed, the lead generator or the individual generator, as the case may be, shall undertake the responsibilities of QCA.
 - c) NLDC shall notify a procedure for aggregation of pooling stations for the purpose of combined scheduling and deviation settlement for multiple pooling stations wind/solar/hybrid generating stations within six (6) month.
 - d) RLDC shall recognise QCA as user, on submission of authorisations from the concerned generating station and after registration with the concerned RLDC (as user) and RPC.

- (ii) For the purpose of scheduling clause (i) above, the QCA shall undertake the activities to the extent of authorisation by wind, solar or hybrid generators which shall include:
- (a) facilitate the concerned RLDC in the scheduling of power including periodic revisions and settlement of energy accounts in accordance with grid code;
 - (b) responsible for metering, data collection and submission, coordination with SLDC, RLDC and NLDC;
 - (c) undertake commercial settlement of deviation pool account with RLDC in accordance with grid code and applicable regulations.
- (iii) the concerned wind, solar or hybrid generators including energy storage system shall indemnify RLDC for all act or conduct of QCA including compliance with the Grid Code and settlement of its financial liability in the pooled account.
- (iv) The scheduling, energy accounting and settlement among the concerned wind, solar or hybrid generators, the terms and the extant of authorization of the QCA will be governed as per their mutually agreed terms:
- Provided that any dispute arising between the generators and QCA shall be resolved in accordance with the contract. During the period of dispute, the generators and QCA shall not suspend any activities with regard to compliance of the Grid Code.

(15) Minimum turndown level for thermal generating stations:

- (i) The minimum turndown level for operation in respect of a unit (s) of a regional entity generating station shall be 55% of MCR loading or installed capacity of the unit of a generating station. The regional entity generating station may be directed by concerned RLDC to operate its unit(s) at or above the minimum turndown level

on account of grid security or due to the lesser schedules given by the beneficiaries.

Provided that:

- i) the generating station on its own option may declare suitability for operation at minimum turndown level below the aforesaid 55% limit.
- (ii) The thermal generating stations shall be compensated for generation below the normative level as per the mechanism given in **Annexure – 5**.

(16) Energy Metering and Accounting:

- (a) The CTU shall install Interface Energy Meters (IEMs) on all inter-connections between the regional entities, cross border entities and other identified points for recording of actual net active and reactive energy interchange in each time-block.
 - i. The installation, operation and maintenance of Interface Energy Meters (IEMs) shall be in accordance with CEA (Installation and Operation of Meters) Regulations, 2006.
 - ii. All concerned entities (in whose premises the IEMs are installed) shall take weekly meter readings and transmit them to the RLDC by Tuesday noon.
 - iii. All concerned entities shall be responsible for monitoring the healthiness of the CT/PT inputs and shall ensure that the time drift of IEM within the limits as specified in CEA Metering Regulations 2006.
 - iv. Utilities shall promptly intimate the changes in CT and PT ratio to RLDC.
- (b) SLDC must ensure that the meter data from all installations within their control area are transmitted to RLDC within the specified time schedule.

(c) RLDC shall be responsible for computation of actual net injection/drawal of concerned regional entities and cross border entities, time block wise, based on the IEM readings.

- i. This data along with the processed data of meters and the implemented schedule shall be forwarded by the RLDC to the RPC Secretariat on a weekly basis by each Friday for the seven day period ending on the previous Sunday mid-night, to enable the latter to prepare and issue the various accounts such as Deviation Settlement Mechanism (DSM), reactive charges, congestion, ancillary services, SCED, heat rate compensation charges and regional transmission deviation account in accordance with the regulations.
- ii. All computations carried out by NPC/RPCs/RLDCs shall be open to all regional entities and cross border entities for checking/verifications for a period of fifteen (15) days.
- iii. In case any error/omission is detected, the RLDC/RPC/NPC/NLDC shall forthwith make a complete check and rectify the same.

(17) Inspection of Records:

The operational logs/records of the regional entity generating stations and inter-state transmission licensees shall be available for inspection and review by the RLDC and RPC.

(18) Oversight of Injection and Drawal:

NLDC/RLDC shall periodically review the persistent over drawal and under injection. In case any such practice is detected, the matter shall be reported to the Member Secretary, RPC and Market Monitoring Cell, CERC for further investigation/action.

(19) Scheduling of Inter-Regional and Cross-Border Transactions:

NLDC shall be responsible for scheduling and despatch of electricity over inter-regional links and cross-border links in accordance with the grid code specified by Central Commission in coordination with Regional Load Despatch Centres. The schedules prepared by NLDC for inter-regional and cross-border exchange of power shall be on net of the regions and net of the country basis respectively.

(20) NLDC shall undertake Security Constrained Economic Despatch as per CERC regulations/orders.

(21) NLDC, RLDC or SLDC, as the case may be, shall be responsible for operation of secondary and tertiary reserves in its control area in accordance with these regulations.

(22) NLDC shall be responsible for coordinating the set-points of all HVDCs within the country and cross-border HVDC interconnections.

52. SECURITY CONSTRAINED UNIT COMMITMENT (SCUC)

(1) The SCUC exercise shall be carried out to facilitate reliability of supply to the regional entities/beneficiaries taking into account optimal cost, adequate reserves, ramping requirements factoring security constraints:

Provided that, the payment of carrying cost for the generation reserves committed through SCUC shall be as specified by the commission.

(2) In order to ensure availability of adequate secondary and tertiary reserves with sufficient ramping capability, NLDC shall identify the generating unit for purpose of unit commitment at the national level three (3) days in advance of actual day of scheduling for regional entity generating stations on a rolling basis. NLDC, through RLDC shall advise the regional entity generators to commit or de-commit the unit. (Refer **ANNEXURE – 7: Detailed**

Operating Procedure for Backing Down of Coal/Lignite/Gas unit(s) of the Central Generating Stations, Inter-State Generating Stations and other Generating Stations and for taking such units under Reserve Shut Down on scheduling below Minimum Turndown Schedule.)

Provided that as and when enabling framework is in place, reserves may be procured through the market.

(3) Based on the SCUC instructions from RLDC, the generating station shall revise the on-bar DC (with due consideration to ramp up/down capability), off-bar DC and ramp up/down rate.

(4) SLDC shall perform similar SCUC exercise at the intra-state level.

53. PROCEDURE FOR SCHEDULING AND DESPATCH FOR INTER-STATE TRANSACTIONS

(1) Listing of regional entity generating stations:

(a) All regional entity generating stations shall be duly listed and updated quarterly on the respective RLDC website along with station capacity, allocated share of beneficiaries and/or contracted quantum of buyers under long-term, medium-term PPAs and balance capacity.

(b) The following details, as applicable, shall be furnished by each generating stations including coal, lignite, gas, Hydro, Wind, Solar, Hybrid, ESS/ Pumped Storage Plant.

TABLE 9: DETAILS NEEDED FOR REGIONAL ENTITY GENERATING STATIONS

Description	Units
Installed Capacity of station	MW
Installed Capacity of station	MWh

Description	Units
Number x unit size	No x MW
Time required for cold start	Minute
Time required for warm start	minute
Time required for hot start	Minute
Time required for combined cycle operation under cold conditions	Minute
Time required for combined cycle operation under warm conditions	Minute
Ramping up capability	% per minute
Ramping down capability	% per minute
Minimum turndown level	% of ex-bus capacity
Inverter Loading Ratio (DC/AC capacity)	
Name of QCA	
Full reservoir level (FRL)	Metre
Design Head	Metre
Minimum draw down level (MDDL)	Metre
Water released at Design Head	M ³ / MW

Notes:

- i. *The minimum up-time for coal fired units shall be eight (8) hours while for combined cycle shall be three (3) hours.*
- ii. *The minimum down-time for coal fired units shall be eight (8) hours while for combined cycle shall be three (3) hours. After tripping of any unit, the same maybe revived in lesser time also.*
- iii. *The regional entity generating stations must be capable of receiving the load set point signals from the RLDC/NLDC as per CEA Technical Standards for Connectivity.*

(2) Listing of Regional Drawing Entities:

All drawee regional entities shall be duly listed and updated quarterly on the respective RLDC website along with allocated and/or contracted quantum from regional entity

generating stations and other sources outside the state under long-term and medium-term PPAs.

(3) Entitlement of a Beneficiary/ long-term PPA Holder:

Each beneficiary/state shall be entitled to a proportionate MW/MWh despatch corresponding to declared capability of regional entity generating station and its share/contracted capacity.

(4) The following scheduling related activities shall be carried out on daily basis as per the timelines specified in the “***Detailed Procedure and Timelines for Scheduling and Despatch of Regional Entities***” to be issued by NLDC within three (3) months:

(a) Declaration of capability by regional entity generating stations:

i. Regional entities *thermal generating stations* (including stations without any access) shall submit the following information of every day for 0000 hours to 2400 hours of the following day:

(a) On-bar Declared Capability (MW) and on-bar units

(b) Off-bar Declared Capability (MW) and off-bar units

(c) Ramp up/down rate (MW/min) for on-bar capability

(d) Minimum turndown level (MW) and in percentage (%) of ex-bus capacity on-bar

ii. Regional entity *hydro generating station (including merchant power plant)* shall submit the following information, for 0000 hours to 2400 hours of the following day:

(a) Ex-bus peaking capability in MW and MWh

(b) Ramp up/down rate (MW/min) for on-bar capability

- (c) Ex-bus declared capability
- (d) Unit-wise forbidden zones in MW and percentage (%) of ex-bus installed capacity
- (e) Minimum MW and duration corresponding to requirement of water release for irrigation, drinking water and other considerations.

Based on the above information of availability and respective share of beneficiaries, RLDC shall schedule the station in an optimal manner subject to technical limitations, if any. The hydro station shall adhere to the flexible scheduling and ramping requirement decided by the RLDCs.

iii. Regional entity *gas based generating station* shall submit the following information, for 0000 hours to 2400 hours of the following day:

- a) Capability (DC) for the station in MW.
- b) Capability to deliver energy in MWh separately for each fuel such as domestic gas, RLNG and/or liquid fuel for the following day.
- c) Ramp up/down rate (MW/min) for on-bar capability
- d) Minimum turndown level (MW) and in percentage (%) of ex-bus capacity on-bar

Based on the above information of availability and respective requisition of beneficiaries, RLDC shall schedule the gas-based generation in an optimal manner subject to technical limitations, if any. The gas-based generation stations shall adhere to the flexible scheduling and ramping requirement decided by the RLDCs.

iv. Wind, solar, hybrid, storage plants, ESS including pumped storage plant, individually or represented by lead generator or QCA on their behalf, shall submit

aggregate available capacity of the pooled generation and aggregate schedule for each time block along with PPA-wise breakup for the same.

(b) Entitlement of each beneficiary:

Based on above declared capabilities of regional entity generating stations, the RLDC shall advise the corresponding MW and MWh entitlements of each state/beneficiary.

(c) Embedded Long-term, medium-term and short-term quantum for scheduling:

Notwithstanding scheduling of long-term, medium-term open access transactions from the embedded entities within the state system and short-term transactions shall be carried out as under:

- i) The buyers and the sellers shall submit mutually agreed schedule through the authorized person
- ii) The settlement nodal agency (SNA) shall submit the cross-border schedule along with its breakup from various sources

(d) Transmission clearance and scheduling of day-ahead collective transactions:

- i) The power exchange shall submit the day-ahead provisional trade schedules along with net power interchange of each bid area and region as per the timeline specified by NLDC, and any other information, if required.
- ii) NLDC shall validate the same from system security angle and inform the power exchange with revisions required if any due to transmission congestion or any other system constraint.
- iii) The power exchange shall accordingly submit the final trade schedules to NLDC for regional entities and to SLDC for intra-state entities.

(e) Scheduling of Real-time collective transaction:

NLDC shall indicate to Power Exchange(s), margin available in each of the transmission corridors before the gate closure, i.e. before the window for trade closes for a specified duration. Power Exchange(s) shall clear the buy and sell bids for the said duration under consideration on various interfaces or control areas or regional transmission systems as intimated by NLDC. The limit for scheduling of collective transaction during real time for respective Power Exchanges shall be worked out in accordance with the directives of the Commission. NLDC shall furnish the available transmission corridors to the Power Exchange(s) before the trading for real time market closes for a specified duration. Based on the information furnished by NLDC, Power Exchange shall clear the RTM bids and announce the Market Clearing price and volume. Based on the volume cleared by the Power Exchanges, NLDC shall communicate the schedules to the respective RLDCs. After getting confirmation from RLDCs, NLDC shall convey the acceptance of scheduling of collective transaction to Power Exchange(s). RLDCs shall schedule the Collective Transactions at the respective periphery of the Regional Entities.

(f) Submission of information by SLDC:

SLDC shall furnish time block-wise information for all intra-state entities for the following day to concerned RLDC for the purpose of validating resource adequacy and scheduling of its inter-state transactions:

- i) Demand forecast aggregated for the control area
- ii) Renewable energy forecast for generation in its control area;
- iii) Requisition from regional entity generating stations in which it has share/contracted capacity

- iv) Power contracted at inter-state level through other long-term, and medium-term and short-term contracts
- v) Power contracted at inter-state level through power exchange
- vi) Conventional generation in its control area Secondary and tertiary reserves at its disposal for regulating its ACE

(f) Issue of day-ahead schedule:

RLDC shall convey the following for the next day to all regional and other entities involved in inter-state transactions:

- i) The regional entity generating unit(s) that has to be committed or de-committed based on result of Security Constrained Unit Commitment (SCUC) performed by NLDC.
- ii) The ex-power plant schedule to each of the regional entity generating station, in MW for different time block, for the next day. The breakup of such schedules for respective beneficiary, long term access, medium term and short-term open access transactions shall also be indicated.
- iii) The “net drawal schedule” to each regional entity, in MW for different time block, for the next day. The summation of the station-wise ex-power plant drawal schedules from all regional entity generating station and drawal from /injection to regional grid consequent to other long-term access, medium term and short-term open access transactions, after deducting the transmission losses (estimated), shall constitute the regional entity-wise drawal schedule. In case the net ex-power plant injection schedule for a generating station is less than the minimum turndown level, RLDC shall request NLDC to accommodate the requisitions for such generating stations through SCUC and SCED. NLDC shall endeavour to accommodate through SCUC and SCED at national level.

(5) Power to revise schedules:

RLDC may *suo-motu* revise the schedule of any regional entity generating station to operate at or above minimum turndown in the interest of reliable system operation. While doing so, it is possible that the requisition of some beneficiaries may go up to ensure technical minimum. In this case, SLDCs may surrender power from some other inter-state generating station(s) or intra-state generating station(s) out of merit order. The concerned RLDC shall issue revised schedule accordingly and this shall be intimated to the concerned generating station, through the scheduling process.

(6) Issue of schedules by SLDC:

SLDC shall take into account the schedule released by concerned RLDC for its embedded entities and issue the corresponding intra-state schedules. The individual transactions for State Utilities/intra-State Entities shall be scheduled by the respective SLDCs. Power Exchange(s) shall send the detailed break up of each point of injection and each point of drawal within the state to respective SLDCs after receipt of acceptance from NLDC. Power Exchange(s) shall ensure necessary coordination with SLDCs for scheduling of the transactions.

(7) Must Run Plants:

- (a) Wind, solar, wind-solar hybrid and hydro plants (in case of excess water leading to spillage) shall be treated as MUST RUN power plants and shall not be subjected to curtailment on account of merit order despatch or any other commercial consideration.
- (b) In the event of transmission or system security constraint, the renewable generation may be curtailed after harnessing available flexible resources including energy storage systems.

(c) In the event of extreme circumstances when any MUST RUN plant has to be curtailed, the details shall be published on the RLDC/SLDC website the following day, as the case may be, giving the date, name of RE generation plant, installed capacity, curtailment quantum in MWh, duration of curtailment and detailed reasons thereof.

(8) Margins for primary response:

For the purpose of ensuring primary response, RLDCs/SLDCs shall not schedule the generating station or unit(s) thereof beyond ex-bus generation corresponding to 100% of the Installed capacity of the generating station or unit(s) thereof. The generating station shall not resort to Valve Wide Open (VWO) operation of units whether running on full load or part load, and shall ensure that there is margin available for providing Governor action as primary response. In case of gas/liquid fuel-based units, suitable adjustment in Installed Capacity should be made by RLDCs/SLDCs for scheduling in due consideration of prevailing ambient conditions of temperature and pressure vis-à-vis site ambient conditions on which installed capacity of the generating station or unit(s) thereof have been specified:

Provided that the hydro stations shall be permitted to schedule ex-bus generation corresponding to 110% of the installed capacity during high inflow period to avoid spillage:

Provided further that the VWO margin shall not be used by RLDC to schedule Ancillary Services.

(9) Revision of schedules:

1) SLDC or regional entity generating station or beneficiaries or cross-border entity may revise its schedules for long-term and medium-term transactions.

- 2) Any revision in schedule made in odd time blocks shall become effective from 7th time block and any revision in schedule made in even time blocks shall become effective from 8th time block, counting the time block in which the request for revision has been received by the RLDCs to be the first one.

Note: Odd Time blocks referred in this clause, are the Time blocks 00:00 to 00:15, 00:30 to 00:45, 01:00 to 01:15 and so on. Even Time blocks referred in this clause, are the Time blocks 00:15 to 00:30, 00:45: 01:00, and 01:15 to 01:30 and so on.

Illustration:

If a request for revision in schedule or declared capability has been made in Time block 17:00 to 17:15 (odd Time block) of a day D, it shall be effective from Time block 18:30 to 18:45 of the day D (7th Time block from the Time block in which the request for revision was made). Similarly, if a request for revision in schedule or declared capability has been made in Time block 17:15 to 17:30 (even Time block) of a day D, it shall be effective from Time block 19:00 to 19:15 of the day (D) (8th Time block from the Time block in which request of revision was made).

- (10) While finalizing the drawal and despatch schedules as above, the RLDC shall also check that the resulting power flows do not give rise to any transmission constraints. In case any constraints are foreseen, the RLDC shall moderate the schedules to the required extent, under intimation to the concerned regional entities. Any changes in the scheduled quantum of power which are too fast or involve unacceptably large steps, may be converted into suitable ramps by the RLDC.
- (11) In the event of bottleneck in evacuation of power due to any constraint, outage, failure or limitation in the transmission system, associated switchyard and substations owned by the Central Transmission Utility or any other transmission

licensee involved in inter-state transmission (as certified by the RLDC) necessitating reduction in generation, the RLDC shall revise the schedules.

- (12) In case of any grid disturbance of category GD-5:
- (a) scheduled generation of all the affected regional entity generating stations supplying power under long term / medium term/ short term transactions shall be deemed to have been revised to be equal to their actual generation and scheduled drawals of the beneficiaries/buyers shall be deemed to have been revised to corresponding actual generation schedule of regional entity generating stations for all the time blocks affected by the grid disturbance. Certification of grid disturbance and its duration shall be done by the RLDC.
 - (b) The scheduled generation of all the affected regional entity generating stations supplying power under collective transactions shall be deemed to have been revised to be equal to their actual generation. Such regional entity generating stations shall refund the charges received towards such scheduled energy to the DSM pool.
 - (c) The declaration of disturbance shall be done by the concerned RLDC at the earliest. A notice to this effect shall be posted at its website by the RLDC of the region in which the disturbance occurred. Issue of the notice at RLDC web site shall be considered as declaration of the disturbance by RLDC. All regional entities shall take note of the disturbance and take appropriate action at their end.
- (13) Energy and deviation settlement for the period of any grid disturbance causing disruption in injection and/or drawal of power shall be done by the RPC in consultation with RLDC and their decision shall be final.

- (14) Generation schedules and drawal schedules issued/revised by the Regional Load Despatch Centre shall become effective from 7th block or 8th block depending on block in which schedule has been revised as first block. The generation schedules and drawal schedules are only accessible to the regional entities through proper user credentials. All concerned utilities shall make efforts for seamless schedule data transfer between generators, SLDC, regional entities and RLDC.

After the operating day is over at 2400 hours, the schedule finally implemented during the day (taking into account all before-the-fact changes in despatch schedule of generating stations and drawal schedule of the States) shall be issued by RLDC. These schedules shall be the basis for commercial accounting.

- (15) In case of forced outage of a unit of a generating station (having generating capacity of 100 MW or more) and selling power under Short Term bilateral transaction (excluding collective transactions in day ahead market and real time market through power exchange), the generator or electricity trader or any other agency selling power from the unit of the generating station shall immediately intimate the outage of the unit along with the requisition for revision of schedule and estimated time of restoration of the unit, to SLDC/RLDC, as the case may be. The schedule of beneficiaries, sellers and buyers of power from this generating unit shall be revised accordingly. The revised schedules shall become effective from the time block and in the manner as specified in Clause (14) of this Regulation.

Provided that:

- (a) the generator or trading licensee or any other agency selling power from a generating station or unit(s) thereof may revise its estimated restoration time once in a day and the revised schedule shall become effective from the 7th

block or 8th time block as per Clause (14) of this Regulation, counting the time block in which the revision is informed by the generator to be the first one.

- (b) SLDC/RLDC as the case may be, shall inform the revised schedule to the seller and the buyer. The original schedule shall become effective from the estimated time of restoration of the unit.
- (c) transmission charges as per original schedule shall continue to be paid for two days.
- (d) the schedule of the buyers and sellers shall be revised after forced outage of a unit, only if the source of power for a particular transaction has clearly been indicated during short-term open access application and the said unit of that generating station goes under forced outage.

(16) A generating station availing short term open access, which has to take one or more of units under reserve shutdown due to scheduling less than Minimum turndown level under long term or medium term PPA shall be allowed to revise its schedule from 7th /8th time block, as applicable, for such short-term open access.

(17) Scheduling information for renewable energy generators:

The figures in respect of schedules as forwarded by the renewable energy generators and that finalized by SLDCs/RLDCs used for final accounting shall be made available to the respective SLDC/RLDC

(18) All regional entities, open access customers, injecting entities/ drawee consumers shall closely check their transaction Schedule and point out errors if any to the concerned LDC (during real time) well in advance. Any (request for revision of schedule) errors pointed out later (after issuance of scheduling data for preparation

of commercial account shall not be entertained), would be corrected at the sole discretion of the RLDC.

- (19) The procedure for scheduling and the final schedules issued by RLDC shall be open to all regional entities and other regional open access entities for any checking/verification, for a period of 5 days. In case any mistake/omission is detected, the RLDC shall forthwith make a complete check and rectify the same.
- (20) The share allocation of regional entity generating station shall be rounded off up to two (2) decimal points for the purpose of scheduling and accounting. While availability declaration by regional entity generating station shall have a resolution of two decimal (0.01) MW and three decimal (0.001) MWh, all entitlements, requisitions and schedules shall be rounded off to the nearest two decimals at each control area boundary for each of the transaction, and shall have a resolution of 0.01 MW.
- (21) RLDC shall start scheduling of new transactions or revise existing transactions through regional entity generating station share allocation/LTA/MTOA from 00:00 hrs of D+2 day considering D as the day of receipt of change of share allocation from RPC/operationalization of LTA/MTOA from the CTU and based on the availability and requisitions by the generator/ procurer.
- (22) With the implementation of net-injection/net-drawal based scheduling for each region, a 'National Deviation Settlement (DSM) Pool' which would be maintained and operated by NLDC as a Regulatory Pool Account. The respective Regional DSM pools would then interact with the National DSM Pool only. The National Pool Account shall also be maintained and operated by NLDC for the purpose of settlement of energy schedule under SCED.

(23) The accounting and pool settlement system at the regional and national level shall be maintained as per **Annexure-9**.

CHAPTER 9: CYBER SECURITY

54. IDENTIFICATION OF CRITICAL INFORMATION INFRASTRUCTURE

All users, CEA, NLDC, RLDC, SLDC, CTU and STU shall undertake the due process for identification of Critical Information Infrastructure (CII) immediately on notification of these regulations.

55. APPOINTMENT AND RESPONSIBILITIES OF INFORMATION SECURITY COMMITTEE AND CHIEF INFORMATION SECURITY OFFICER

(1) All users, CEA, NLDC, RLDC, SLDC, CTU and STU shall, within six (6) months of enforcement of the regulations, appoint an Information Security Committee (ISC) and Chief Information Security Officer (CISO) in accordance with the Information Technology (Information Security Practices and Procedures for Protected System) Rules, 2018

(2) The ISC, under the chairmanship of Chief Executive Officer/Managing Director/Secretary of the organization shall comprise of IT Head or equivalent, Financial Advisor or equivalent, CISO, Representative of National Critical Information Infrastructure Protection Centre (NCIIPC) and any other expert(s) to be nominated by the organization. The ISC shall carry out the responsibilities in accordance with Information Technology (Information Security Practices and Procedures for Protected System) Rules, 2018

(3) The CISO shall carry out the responsibilities as per latest “Guidelines for Protection of Critical Information Infrastructure” and “Roles and Responsibilities of Chief Information Security Officers (CISOs) of Critical Sectors in India” released by NCIIPC

56. MEASURES TO BE UNDERTAKEN FOR ENSURING CYBER SECURITY:

All users, CEA, NLDC, RLDC, SLDC, CTU and STU shall take necessary measures in accordance with Guidelines for the Protection of National Critical Information Infrastructure by NCIIPC. These shall, amongst others, necessarily include the following:

(1) Planning related measures:

- (a) All entities shall have an information security policy to prevent unauthorized access, use, disclosure, disruption, modification, recording or destruction, including incident management. All entities shall ensure that CII is governed by necessary access control policies
- (b) All entities shall have necessary protection mechanisms such as firewalls for all systems interfacing with the network
- (c) All entities shall develop a vulnerability, risk and threat (VRT) assessment process which shall be reviewed regularly. The VRT shall comprise of the following:
 - i. Vulnerabilities are defined as gaps/weaknesses in the system that allow an attacker to reduce the systems information assurance.
 - ii. Threats are defined as actors / actions targeting the vulnerabilities in a system.
 - iii. Risks are the possibilities that a particular threat will successfully exploit vulnerability and the resultant impact of that exploitation on the information assurance of the system.
- (d) All entities shall ensure necessary security measures are undertaken by the supply chain. Security precautions including Non-Disclosure Agreements, confidentiality clauses must be ensured wherever required.

(e) All entities shall take all steps to achieve the necessary security certifications that are required for CII.

(2) Operational control:

(a) All entities shall take necessary back-up and protection measures for classified and sensitive data.

(b) All entities shall develop necessary training, awareness and skill development program to ensure compliance.

57. CONTINGENCY MEASURES

(1) All users shall plan adequate redundancies for CII which are capable of taking over in case of malfunction or failure

(2) All entities shall develop Cyber Crisis Management Plan case of any major cyber-attack. This may include continuity plans, recovery plans, communication plans, cyber incident response plan, disaster recovery plan and priority resource and manpower allocation plan.

58. MECHANISM OF REPORTING

(1) All entities shall immediately report to the appropriate government agencies under IT Act 2000 in case of any cyber-attack.

(2) NLDC, RPC Secretariat and the Commission shall also be informed in case of any instance of cyber-attack.

CHAPTER 10: MONITORING AND COMPLIANCE CODE

59. ASSESSMENT OF COMPLIANCE:

The performance of all users, CTU, STU, NLDC, RLDC, SLDC and RPC with respect to grid code compliance shall be assessed periodically.

60. MONITORING OF COMPLIANCE

(1) In order to ensure compliance, two methodologies shall be followed:

- (a) Self-Audit
- (b) Compliance Audit

(2) Self –Audit:

- (a) All users, CTU, STU, NLDC, RLDC, RPC and SLDC shall conduct annual self-audits to review compliance of the regulations and submit by 31st July of every year.
- (b) The self-audit report, amongst other aspects shall necessary contain the following information:
 - i. Sufficient information to understand how and why the non-compliance occurred
 - ii. Extent of damage caused by non-compliance
 - iii. Steps and timeline planned to rectify the same
 - iv. Steps taken to mitigate any future recurrence
- (c) The self-audit reports by users shall be submitted to the concerned RLDC/SLDC. The self-audit reports of NLDC, RLDC, CTU, and RPC Secretariat shall be submitted to CERC. The self-audit report of SLDC and STU shall be submitted to SERC.

- (d) The deficiencies shall be rectified in a time bound manner within a reasonable time.
- (e) The monitoring agency for user shall be concerned RLDC or SLDC as the case may be. The monitoring agency shall track the progress of compliances of users and exceptional reporting for non-compliance shall be submitted to the Commission.
- (f) The monitoring agency for RLDC, NLDC, CTU and RPC shall be CERC and that for STU, SLDC shall be concerned SERC.

(3) Independent Third-Party Compliance Audit:

CERC may order independent third-party compliance audit for any user, CTU, NLDC, RLDC and RPC as deemed necessary.

CHAPTER 11: MISCELLANEOUS

61. POWER TO RELAX

The Commission, for reasons to be recorded in writing, may relax any of the provisions of these regulations on its own motion or on an application made before it by an affected person to remove the hardship arising out of the operation of Regulation, applicable to a class of persons.

62. POWER TO REMOVE DIFFICULTY

If any difficulty arises in giving effect to the provisions of these regulations, the Commission may, on its own motion or on an application made before it by the nodal agency, by order, make such provision not inconsistent with the provisions of the Act or provisions of other regulations specified by the Commission, as may appear to be necessary for removing the difficulty in giving effect to the objectives of these regulations.

ANNEXURE - 1

GENERATION RESERVE ESTIMATION AND FREQUENCY CONTROL

This procedure is in line with the clause 34(5)(j) of IEGC which requires methodology for the following:

- Assessment of reference contingency,
- All India minimum target frequency response characteristics,
- Calculation of frequency response obligation of each control area,
- Criteria for reportable event,
- Calculation of actual frequency response characteristics of control area and
- Calculation of frequency response performance

The requirements are detailed in the points given below:

1. Assessment of Reference Contingency

The reference contingency is the quantum of sudden generation or demand outage in an event. The reference contingency shall consider quantum of generation outage based on outage of largest power plant, group of power plants, a generation complex, or a generation pooling station, or the actual generation outage occurred in an event during last two years, or a credible outage scenario. Similarly reference contingency shall also consider outage of single largest load center or actual outage of load occurred in an event during last two years. To start with reference contingency shall be considered as outage of 4500 MW which shall be revised by NLDC from time to time. The primary reserve at All India level shall be more than the reference contingency quantum. Therefore, minimum quantum of primary reserve shall be currently 4500 MW.

2. All India minimum target frequency response characteristics

The all India minimum target frequency response characteristic (MW/Hz) shall be reference contingency quantum (MW) divided by maximum steady frequency deviation (Hz) allowable for the reference contingency event.

The primary reserves would be activated immediately (within few seconds) when the frequency deviates from 50 Hz. The safe, secure and reliable operation of grid requires that the nadir frequency should be at least 0.1 Hz above the first stage of under frequency load shedding scheme. This implies that the nadir frequency shall be above or 49.5 Hz (considering first stage of under frequency loading shedding setting as 49.4 Hz) for the reference contingency event and the maximum steady state frequency deviation should not cross 0.30 Hz for the reference contingency event.

Therefore, the minimum All India target Frequency Response Characteristic currently would be quantum of load/generation loss in reference contingency (as defined in Section (1) above divided by frequency deviation value of 0.3 Hz i.e. 15000 MW/Hz (4500 MW/0.3 Hz).

3. Calculation of Frequency Response Obligation (FRO) of each control area:

The minimum Frequency Response Obligation (FRO) of each control area in MW/Hz shall be calculated as:

$$(a) \text{ FRO} = (\text{Control Area average Demand} + \text{Control Area average Generation}) * \text{minimum all India Target Frequency Response Characteristic} / (\text{Sum of peak /average demand of all control areas} + \text{Sum of average generation of all control areas})$$

4. Criteria for reportable event

The frequency response characteristic (FRC) calculation shall be carried out by each control area for any load/generation loss incident involving net change of more than 1000 MW of load/generation or a frequency change involving 0.1 Hz or more. The event shall be notified by the NLDC.

5. Calculation of actual frequency response characteristics of control area

(a) Frequency Response Characteristics (FRC) computations:

Frequency Response Characteristics (FRC) will be computed for all events involving a sudden 1000 MW or more load/generation loss or a step change in frequency by 0.10 Hz i.e. for all reportable events as notified by NLDC. The FRC shall be worked out by NLDC, RLDCs and SLDCs to for each interconnection/region/control area (including for each generating station). Each generating station shall also compute it's FRC. The following steps would be followed for computation of FRC

- i) After every event involving a sudden 1000 MW or more load/generation loss or a step change in frequency by 0.1 Hz, NLDC would get the PMUs frequency data. NLDC would also get the exact quantum of load/generation lost from the RLDC of the affected region.
- ii) NLDC would plot the frequency graph and determine the initial frequency, minimum/maximum frequency, settling frequency and time points (points A, C and B of the Figure-1). Accordingly, frequency difference points & corresponding time to be used for FRC calculations would be informed to all RLDCs.
- iii) NLDC would also work out region wise and neighboring countries (Bhutan and Nepal) FRC (Format as per Table-1) based on 10 second Historical Data Recording (HDR) data available at NLDC and inform all RLDCs within three (3) working days. RLDCs would inform the SLDCs/regional entities in their region.
- iv) RLDCs shall also work out each control area wise FRC (Format as per Table-1) based on HDR data available at RLDCs within six (6) working days.
- v) All the SLDCs shall work out FRC for all the intrastate entities (for events indicated by the Regional Load Despatch Centres) based on the HDR available at their respective SLDCs and submit the same to respective RLDC within six (6) working days. (Format as per Table-1).
- vi) All regional entity generating stations shall also assess the FRC for their respective stations and submit the same to respective RLDC within six (6) working days.

(Format as per Table-1). The high resolution data (1 second or better resolution) of active power generation and frequency shall also be shared with RLDC.

(b) Input data for FRC:

- i) The data for frequency response characteristic Calculations may be taken from the real time telemetered data recorded by the SCADA systems installed at Control Areas / Regional Load Despatch Centres / National Load Despatch Centre.
- ii) Bad quality of data could be flagged / mentioned by the control centre (s) and reasonable assumptions made for FRC computation. Details of these may be mentioned.

(c) Instructions for computation of FRC:

A Sample frequency chart given at Figure-1 with points A, B, and C labeled, depicts a typical frequency excursion caused by a loss of a large generator in Indian power system. Point A denotes the interconnection frequency immediately before the disturbance. Point B represents the Interconnection frequency at the point immediately after the frequency stabilizes due to governor action but before the contingent area takes any corrective actions, automatic or manual. Point C represents the interconnection frequency at its maximum deviation due to the loss of generation.

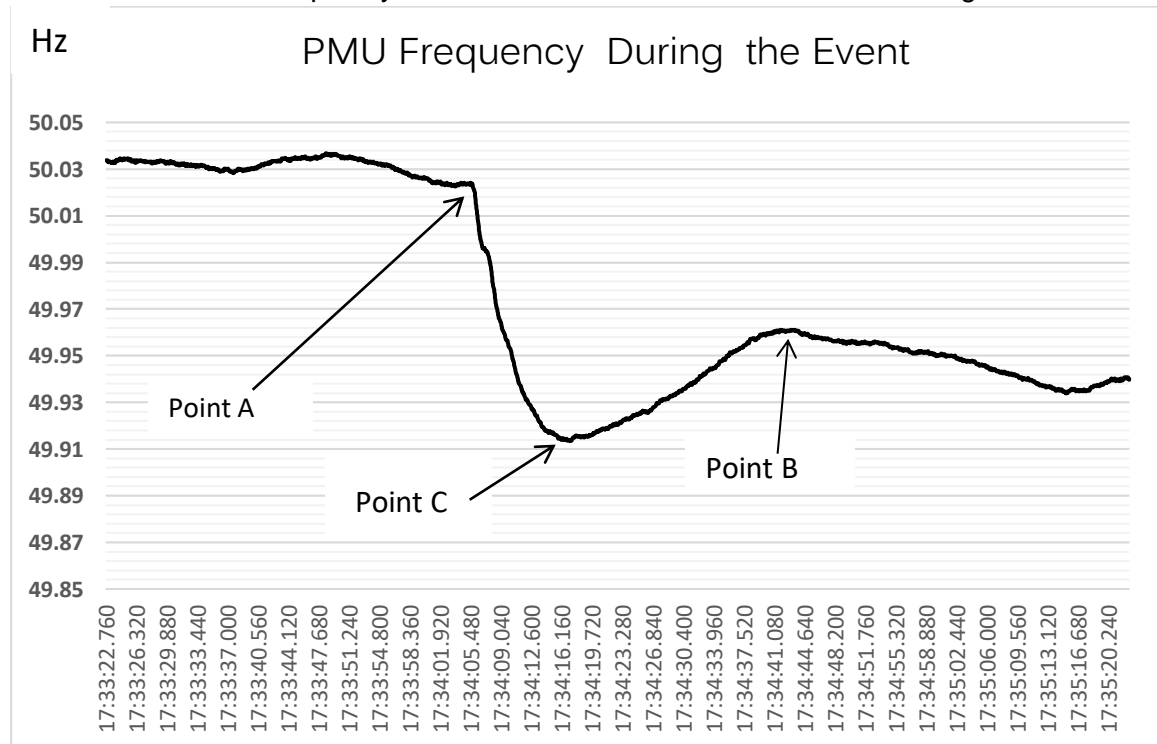


FIGURE 1: SAMPLE PMU FREQUENCY PLOT SHOWING RELEVANT POINTS FOR FRC CALCULATION

Steps to work out frequency response characteristics of control area are as follows: -

Step-1: Actual net interchange of the control area immediately before the disturbance (Point - A) = PA. Sign convention for net power imported into a CONTROL AREA is positive (+) and net power exported out of a control area is negative (-).

Step-2: Actual net interchange of the control area immediately after the disturbance (Point - B) = PB. Use the same sign convention as Step-1.

Step-3: The change in net interchange of the CONTROL AREA = (PB -PA). [For a disturbance that causes the frequency to decrease, this value should ideally be negative. The net interchange of a control area can positive within which drop in generation has occurred. Similarly, for load through off or frequency rise cases, the net interchange shall normally be positive except for the CONTROL AREA, wherein load throw off has taken place.]

Step-4: If the control area has suffered the loss, then Load or generation lost by the control area = PL. Otherwise, the loss (PL) is zero. Sign convention for Load Loss is negative (-) and Generation Loss positive (+).

Step-5: The Control Area Response $\Delta P = (PB-PA) - PL$

Step-6: The Frequency immediately before the disturbance = fA.

Step-7: The Frequency immediately after the disturbance = fB.

Step-8: Change in Interconnection Frequency from Point A to Point B = $\Delta f = (fB - fA)$

Step-9: Frequency Response Characteristic (FRC) of the Control Area = $\Delta P / \Delta f$

Step-10: Frequency Response Obligation (FRO) of each control area calculated in advance as per Clause 3 of this Annexure

Step 11: Frequency Response Performance (FRP) = Actual Frequency Response Characteristic (AFRC)/ Frequency Response Obligation (FRO)

TABLE 10: FRC CALCULATION SHEET TO BE USED BY ALL SLDC/RLDC/NLDC/CONTROL AREA

S. No	Particulars	Dimension	Control Area-1/Region
1	Actual Net Interchange before the Event (Time= hh:mm:ss)	MW	
2	Actual Net Interchange after the Event (Time= hh:mm:ss)	MW	
3	Change in Net Interchange (2 - 1)	MW	

S. No	Particulars	Dimension	Control Area-1/Region
4	Generation Loss (+) / Load Throw off (-) during the Event	MW	
5	Control Area Response (3-4)	MW	
6	Frequency before the Event	HZ	
7	Frequency after the Event	HZ	
8	Change in Frequency (7-6)	HZ	
9	Frequency Response Characteristic (5 / 8)	MW/HZ	
10	Frequency Response Obligation (FRO) of control area	MW/Hz	
11	Frequency Response Performance (FRP)(9/10)	Numeric value (upto two decimal places)	

6. Calculation of frequency response performance

(m) The performance of each control area in providing frequency response characteristic shall be calculated for each reportable event. Each control area shall separately assess their frequency response characteristic and share with RLDC along with high resolution data of at least one (1) second for regional entity generating stations and ten (10) second for state control area.

Frequency Response Performance (FRP) = Actual Frequency Response Characteristic (AFRC)/ Frequency Response Obligation (FRO)

Each control area shall be graded based on median Frequency Response Performance annually (at least 10 events) as per following criteria:

TABLE 11: FREQUENCY RESPONSE CRITERIA

S. N	Performance*	Grading
i.	$FRP \geq 1$	Excellent
ii.	$0.85 \leq FRP < 1$	Good
iii.	$0.75 \leq FRP < 0.85$	Average
iv.	$0.5 \leq FRP < 0.75$	Below Average
v.	$FRP < 0.5$	Poor

*Provided that for wind/solar generating stations and state control areas with internal generation less than 100 MW or annual peak demand less than 1000 MW, the FRP grading would be indicative only.

ANNEXURE - 2

THIRD PARTY PROTECTION SYSTEM CHECKING & VALIDATION TEMPLATE FOR A SUBSTATION

The audit reports, along with action plan for rectification of deficiencies found, if any, shall be submitted to RPC or RLDC within a month of submission of report by auditor.

The third-party protection system checking shall be carried at site by the designated agency. The agency shall furnish two reports:

- I. Preliminary Report: This report shall be prepared on the site and shall be signed by all the parties present.
- II. Detailed Report: This report shall be furnished by agency within one month after carrying out detailed analysis.

The protection system checklist shall contain information as discussed in subsequent paras.

- 1) General Information (to be provided prior to the checking as well as to be included in final report):
 - a) Substation name
 - b) Name of Owner Utility
 - c) Voltage Level (s) or highest voltage level?
 - d) Short circuit current rating of all equipment (for all voltage level)
 - e) Date of commissioning of the substation
 - f) Checking and validation date
 - g) Record of previous tripping's (in last one year) and details of protection operation
 - h) Previous Relay Test Reports
 - i) Overall single line diagram (SLD)
 - j) AC aux SLD
 - k) DC aux SLD
 - l) SAS architecture diagram
 - m) SPS scheme implemented (if any)
- 2) The preliminary report shall be drafted at site and shall be signed by all the parties present and shall contain information not less than following:

S. No.	Issues	Remarks
1	Recommendation of last protection checking and validation	Status of works and pending issues if any
2	Review of existing settings at substation	Recommended Action
3	Disturbance Recorder out available for last 6 tripping's (Y/N)	Recommended Action
4	Chronic reason of tripping, if any	Recommended Action
5	Major non-conformity/deficiency observed	Recommended Action

3) The relay configuration checklist for available power system elements at station:

- a) Transmission Line
- b) Bus Reactor/Line Reactor
- c) Inter-connecting Transformer
- d) Busbar Protection Relay
- e) AC auxiliary system
- f) DC auxiliary system
- g) Communication system
- h) Circuit Breaker Details
- i) Current Transformer Details
- j) Capacitive Voltage Transformers Details
- k) Any other equipment/system relevant for protection system operation

4) The minimum set of points on which checking and validation will be carried out is given below. The detailed list shall be prepared by checking and validation team in consultation with concerned entity, RLDC and RPC.

a) Transmission Line Distance Protection/Differential Protection

- Name and Length of Line
- Whether series compensated or not
- Mode of communication used (PLCC/OPGW)
- Relay Make and Model for Main-I and Main-II
- List of all active protections & settings
- Carrier aided scheme if any
- Status of Power Swing/Out of Step/SOTF/Breaker Failure/Broken Conductor/STUB/Fault Locator/DR/VT fuse fail/Ovoltage Protection/Trip Circuit supervision/Auto-reclose/Load encroachment etc.
- Relay connected to Trip Coil-1 or 2 or both
- CT ratio and PT ratio
- Feed from DC supply-1 or 2

- Connected to dedicated CT core (mention name)
 - Other requirements for protection checking and validation
- b) Shunt Reactor & Inter-connecting Transformer Protection
- Whether two groups of protections used (Group A and Group B)
 - Do the groups have separate DC sources
 - Relay Make and Model
 - List of all active protections along with settings
 - Status of Differential Protection/Restricted Earth Fault Protection/Back-up Directional Overcurrent/Backup Earth fault/ Breaker Failure
 - Status of Oil Temperature Indicator/Winding Temperature Indicator/Bucholz/Pressure Release Device etc.
 - Relay connected to Trip Coil-1 or 2 or both
 - CT ratio and PT ratio
 - Feed from DC supply-1 or 2
 - Connected to dedicated CT core (mention name)
 - Other requirements for protection checking and validation
- c) Busbar Protection Relay
- Busbar and redundant relay makes and models
 - Type of Busbar arrangement
 - Zones
 - Dedicated CT core for each busbar protection (Yes/No)
 - Breaker Failure relay included (Yes/No), if additional then furnish make and model
 - Trip issued to both Busbar protection in case of enabling
 - Isolator indication and check relays
 - Other requirements for protection checking and validation
- d) AC auxiliary system
- Source of AC auxiliary system
 - Supply changeover between sources (Auto/Manual)
 - Diesel generator (DG) details
 - Maintenance plan and supply changeover periodicity in DG
 - Single Line Diagram
 - Other requirements for protection checking and validation
- e) DC auxiliary system
- Type of Batteries (Make, vintage, model)
 - Status of battery Charger
 - Measured voltage (positive to earth and negative to earth)
 - Availability of ground fault detectors
 - Protection relays and trip circuits with independent DC sources
 - Other requirements for protection checking and validation

- f) Communication system
 - Mode of communication for Main-1 and Main-2 protection
 - Mode of communication for data and speech communication
 - Status of PLCC channels
 - Time synchronization equipment details
 - OPGW on geographically diversified paths for Main-1 and main-2 relay
 - Other requirements for protection checking and validation

- g) Circuit Breaker Details
 - Details and Status
 - Healthiness of Tripping Coil and Trip circuit supervision relay
 - Single Pole/Multi pole operation
 - Pole Discrepancy Relay available(Y/N)
 - Monitoring Devices for checking the dielectric medium
 - Other requirements for protection checking and validation

- h) Current Transformer (CT)/Capacitive Voltage Transformer (CVT) Details
 - CT/CVT ID name and voltage level
 - CT/CVT core connection details
 - Accuracy Class
 - Whether Protection/Metering
 - CT/CVT ratio available and ratio adopted
 - Details of last checking and validation of CT/CVT healthiness
 - Other requirements for protection checking and validation
 - Other protections: Direction earth fault, negative sequence, over current, over voltage, over frequency, under voltage, under frequency, forward power, reverse power, out of step/power swing, HVDC protection etc.

- 5) Summary of Checking: The summary shall specifically mention minimum following points:
 - The settings and scheme adopted are in line with agreed protection philosophy or any accepted guidelines (e.g. Ramakrishna guidelines or CBIP manual based).
 - The deviations from the RPC protection philosophy, if any and reasons for taking the deviations shall be recorded.
 - All the major general deficiency shall be listed in detail along with remedial recommendations.
 - The relay settings to be adopted shall be validated with simulation based or EMTP studies and details shall be enclosed in report.
 - The cases of protection maloperation shall be analysed from protection indices report furnished by concerned utility, the causes of failure along with corrective actions and recommendations based on the findings shall be noted in the report.

ANNEXURE- 3

A. REPORTING REQUIREMENTS

S. No.	Entity Responsible	Reporting Requirement and Frequency
1.	RPC Secretariat	<ul style="list-style-type: none"> • Exception report of UFR (<i>monthly</i>) • Annual LGBR (<i>annual</i>) • Annual Outage Plan(<i>annual</i>) • Feedback Report to address potential violation of system operational limit (<i>quarterly</i>)
2.	RPC	<ul style="list-style-type: none"> • Final report on grid disturbance (<i>post grid disturbance</i>)
3.	NPC	<ul style="list-style-type: none"> • All India LGBR (<i>annual</i>)
4.	CTU	<ul style="list-style-type: none"> • All India transmission review(<i>yearly</i>) • Planned inter-regional and ISTS-STU power transfer capability for the next 3-5 years(<i>yearly</i>)
5.	NLDC	<ul style="list-style-type: none"> • Forecast error (<i>daily/day-ahead / weekly / monthly and yearly</i>) • Operational study (<i>Day-ahead/ weekly/ monthly/ yearly</i>) • Operational analysis (<i>post despatch</i>) • Draft report of each grid disturbance/grid (<i>post grid disturbance</i>) • Daily and monthly report of integrated grid performance (<i>daily and monthly</i>)
6.	RLDC	<ul style="list-style-type: none"> • Forecast error (<i>daily/day-ahead / weekly / monthly and yearly</i>) • Operational study (<i>Day-ahead/ weekly/ monthly/ yearly</i>) • Operational analysis (<i>post despatch</i>) • Draft report of each grid disturbance (<i>post grid disturbance</i>) • Integrated grid performance (<i>daily and monthly</i>)
7.	SLDC	<ul style="list-style-type: none"> • Exception report of UFR (<i>monthly</i>) • Forecast error (<i>daily/day-ahead/weekly/monthly and yearly</i>) • Operational study (<i>Day-ahead/ weekly/ monthly/ yearly</i>) • Operational analysis (<i>post despatch</i>) • Flash report and detailed report on any grid disturbance (<i>post grid disturbance</i>) • Details of regional entity generating stations (<i>quarterly</i>)

S. No.	Entity Responsible	Reporting Requirement and Frequency
8.	User	<ul style="list-style-type: none"> Flash report and detailed report on any grid disturbance (<i>post grid disturbance</i>) PSS tuning report by generators (<i>based on tuning requirements</i>)

B. PROCEDURE DRAFTING REQUIREMENTS

S. No.	Entity Responsible	Drafting Responsibilities
1.	RPC	<ul style="list-style-type: none"> Common outage planning procedure
2.	CTU	<ul style="list-style-type: none"> All India transmission review Planned inter-regional and ISTS-STU power transfer capability for the next 3-5 years
3.	NLDC	<ul style="list-style-type: none"> Detailed procedure covering modalities for first time energization and integration of new or modified power system elements Operating procedure PSS tuning procedure Quantum of secondary/Tertiary reserves Assessment of Secondary/Tertiary control Procedure for operational planning analysis, real-time monitoring, real-time assessments and format for data submission and updating Restoration Procedure Timeline for scheduling activities
4.	RLDC	<ul style="list-style-type: none"> Operating procedure Procedure for operational planning analysis, real-time monitoring, real-time assessments and format for data submission and updating Restoration Procedure
5.	SLDC	<ul style="list-style-type: none"> Detailed procedure covering modalities for first time

S. No.	Entity Responsible	Drafting Responsibilities
		<p>energization and integration of new or modified power system elements</p> <ul style="list-style-type: none"> • Operating procedure • Restoration Procedure
6.	Governing board of certifying agency	<ul style="list-style-type: none"> • Periodic capacity building, certification and recertification for system operators at NLDC, RLDC, SLDC and sub-LDC

ANNEXURE - 4

A. REACTIVE POWER COMPENSATION

(1) Reactive power compensation should ideally be provided locally, by generating reactive power as close to the reactive power consumption as possible. The regional entities except generating stations are therefore expected to provide local VAR compensation/generation such that they do not draw VARs from the EHV grid, particularly under low-voltage condition. To discourage VAR drawls by regional entities except generating stations, VAR exchanges with ISTS shall be priced as follows:

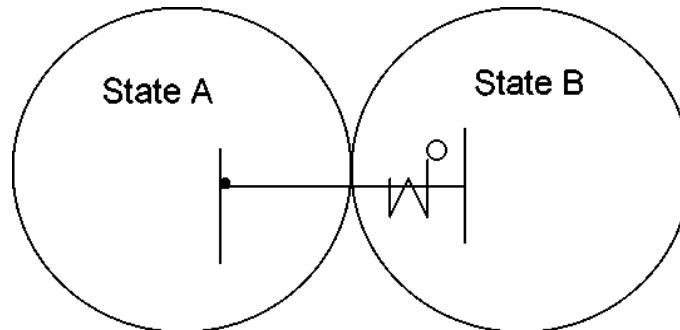
- The regional entity except generating stations pays for VAR drawal when voltage at the metering point is below 97%
- The regional entity except generating stations gets paid for VAR return when voltage is below 97%
- The regional entity except generating stations gets paid for VAR drawal when voltage is above 103%
- The regional entity except generating stations pays for VAR return when voltage is above 103%

Provided that there shall be no charge/payment for VAR drawal/return by a regional entity except generating stations on its own line emanating directly from an ISGS.

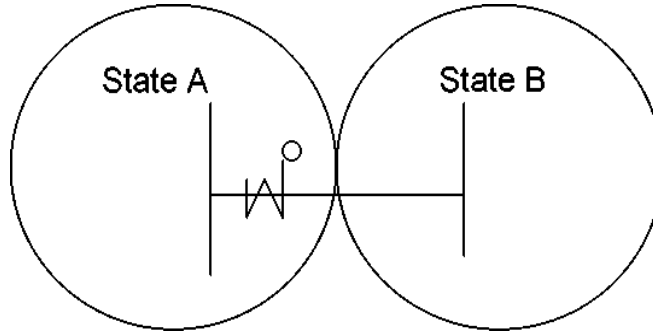
(2) The charge for VARh shall be at the rate of 12.61 paise/kVARh and this will be applicable between the regional entity, except generating stations, and the regional pool account for VAR interchanges. This rate shall be escalated at 0.6paise/kVARh per year thereafter, unless otherwise revised by the Commission.

B. PAYMENT FOR REACTIVE ENERGY EXCHANGES ON STATE-OWNED LINES

Case – 1: Interconnecting line owned by State-A Metering Point: Substation of State-B

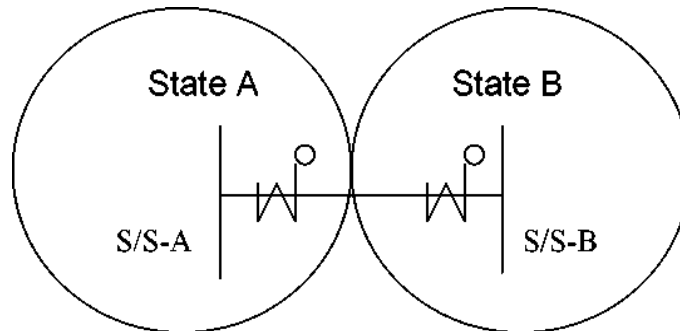


Case - 2: Interconnecting line owned by State-B Metering point: Substation of State-A



Note: Net VARh and net payment may be positive or negative

Case - 3: Interconnecting line is jointly owned by States-A and -B. Metering points: Substations of State-A and State-B



Net VARh exported from S/S-A, while voltage < 97% = X_1 Net VARh exported from S/S-A, while voltage > 103% = X_2 Net VARh imported at S/S-B, while voltage < 97% = X_3 Net VARh imported at S/S-B, while voltage > 103% = X_4

- (i) State-B pays to State-A for X_1 or X_3 , whichever is smaller in magnitude, and
- (ii) State-A pays to State-B for X_2 or X_4 , whichever is smaller in magnitude.

Note:

- I. Net VARh and net payment may be positive or negative.
- II. In case X_1 is positive and X_3 is negative, or vice-versa, there would be no payment under (i) above.
- III. In case X_2 is positive and X_4 is negative, or vice-versa, there would be no payment under (ii) above.

ANNEXURE – 5

MINIMUM TURNDOWN LEVEL FOR OPERATION OF REGIONAL ENTITY GENERATING STATIONS

(1) Where the regional entity generating station/ISGS, is directed by the concerned RLDC/SLDC to operate below normative plant availability factor, the regional entity generating station/ISGS may be compensated for increase in the unit heat rate and the auxiliary energy consumption depending on the unit loading in each time block duly taking into account the forced outages and planned outages of the units, generation at generator terminal, energy sent out ex-bus, and in due consideration of degraded and normative operating parameters of station heat rate, auxiliary energy consumption and secondary fuel oil consumption etc. on monthly basis duly supported by relevant data verified by RLDC or SLDC, as the case may be. The compensation shall be applicable to all regional entity generating stations/ISGS whose tariff is determined under section 62 or under section 63.

Provided that:

- (i) In case of coal / lignite based generating stations, following station heat rate degradation shall be considered for the purpose of compensation:

S. No.	Unit loading as a % of installed capacity of the unit	Increase in SHR (for supercritical units) (%)	Increase in SHR (for sub-critical units) (%)
1	85 and above	Nil	Nil
2	80	0.66	0.76
3	75	1.19	1.45
4	70	1.96	2.40
5	65	2.84	3.56

S. No.	Unit loading as a % of installed capacity of the unit	Increase in SHR (for supercritical units) (%)	Increase in SHR (for sub-critical units) (%)
6	60	3.67	4.79
7	55	4.92	6.59
8	50	6.15	8.60
9	45	7.40	10.21
10	40	8.81	12.14

- (ii) In case of coal / lignite based generating stations, the following auxiliary energy consumption (AEC) degradation shall be considered for the purpose of compensation:

Sl. No	Unit loading (% of MCR)	% degradation in AEC admissible
1	85 and above	Nil
2	80	0.10
3	75	0.25
4	70	0.40
5	65	0.55
6	60	0.75
7	55	0.95
8	50	1.20
9	45	1.55
10	40	2.10

- (iii) Where the scheduled generation falls below the minimum turndown level, the concerned regional entity generating station shall have the option to go for reserve shut down and in such cases, start-up fuel cost over and above seven (7) start / stop in a year shall be

considered as additional compensation based on following norms or actual, whichever is lower:

Unit Size (MW)	Oil Consumption per start-up(kl)		
	Hot	Warm	Cold
200/210/250 MW	20	30	50
500 MW	30	50	90
660 MW and above	40	60	110

(iv) In case of gas based regional entity generating station, following station heat rate degradation shall be considered for the purpose of compensation:

S. No.	Unit loading as a % of installed capacity of the unit	Increase in SHR (%)
1	85 and above	Nil
2	80	0.91
3	75	2.50
4	70	4.17
5	65	6.33
6	60	8.54
7	55	10.68
8	50	13.63

(v) In case of gas based regional entity generating station, the following auxiliary energy consumption (AEC) degradation shall be considered for the purpose of compensation:

S. No.	Unit loading as a % of installed capacity of the unit	% degradation in AEC admissible
1	85 and above	Nil
2	80	0.12
3	75	0.29
4	70	0.47
5	65	0.68
6	60	0.88
7	55	1.09
8	50	1.34

(vi) Compensation for the station heat rate and auxiliary energy consumption shall be worked out in terms of energy charges. The degradation in SHR and AEC on account of part load operation shall be carried on pro-rata basis up to second decimal place.

For instance, if SHR and AEC have to be calculated for a sub-critical plant unit operating at 77% loading factor, the methodology shall be as follows:

(a) Station Heat Rate:

Degradation in station heat rate at 80% + pro-rate degradation at 77% calculated between 80% and 75%

$$= [0.76 + (1.45-0.76)] * \frac{3}{5} = 1.17\%$$

(b) Auxiliary Energy Consumption:

Degradation in AEC at 80% + pro-rate degradation at 77% calculated between 80% and 75%

$$= [0.10 + (0.25-0.1)] * \frac{3}{5} = 0.19\%$$

- (vii) The compensation so computed shall be borne by the entity who has caused the plant to be operated at schedule lower than corresponding to normative plant availability factor based on the compensation mechanism as per Annexure – 6. In case of part untied capacity of a plant for which there is no long term or medium-term PPA, the compensation for backing down corresponding to the unutilized capacity shall be to the account of the generating company.
 - (viii) Compensation shall be calculated in each month as per the detailed procedure as in Annexure-6. In case the energy charges calculated based on actual SHR and AEC is less than the sum of energy charges calculated based on normative SHR and AEC or quoted energy charges/SHR as the case may be, and compensation payable for that month to the generating station, then such gains over the actual energy charges, restricted to compensation payable to generating station, shall be shared between generating station and beneficiaries in the ratio of 60:40.
 - (ix) The change in schedule of power under the provisions of Central Electricity Regulatory Commission (Ancillary Services Operations) Regulations, 2015 and Automatic Generation Control (AGC) as per order in Petition No. 319/RC/2018 dated 29th Aug, 2019 shall not be considered for compensation.
 - (x) The compensation on account of change in schedule under the provisions of Security Constrained Economic Despatch (SCED) shall be as per the detailed procedures.
- (2) Mechanism for compensation for station heat rate and auxiliary energy consumption for low unit loading on monthly basis in terms of energy charges and compensation for secondary fuel oil consumption for additional start-ups in excess of 7 start-ups, shall be as per Annexure – 6.

(3) The detailed operating procedure for taking units under reserve shut down containing the role of different agencies, data requirements, procedure for taking the units under reserve shut down and the methodology for identifying the generating stations or units thereof to be backed down up to the minimum turndown level in specific grid conditions such as low system demand, regulation of power supply and incidence of high renewables etc., based on merit order stacking is given at Annexure – 7.

ANNEXURE – 6

MECHANISM FOR COMPENSATION FOR DEGRADATION OF HEAT RATE, AUX CONSUMPTION AND SECONDARY FUEL OIL CONSUMPTION, DUE TO PART LOAD OPERATION AND MULTIPLE START/STOP OF UNITS

1. Introduction

The Grid Code inter-alia contains provisions relating to Technical Minimum Schedule for operation of Regional Entity Generating Stations / ISGS. The Grid Code further provides for compensation to Generating Stations for degradation of Heat Rate, Auxiliary Consumption and Secondary Fuel Oil consumption due to part load operation and multiple start-ups of units. This mechanism is for compensation for station heat rate and auxiliary energy consumption for low unit loading and for secondary fuel oil consumption for additional start-ups in excess of 7 start-ups (hereinafter referred to as “Compensation Mechanism”).

2. Applicability

This Compensation Mechanism is applicable to Coal/lignite/Gas based Regional Entity Generating Stations/ISGS, (hereinafter “designated generating stations”).

3. Definitions and abbreviations:

- 1) In this Compensation Mechanism, unless the context otherwise requires:
 - (i) “Block Unit Loading (BUL) of the Station” (in %) means loading of the station during a particular Time Block of Calculation Period determined as follows:

$$BUL(\%) = \left\{ \frac{\text{Higher of (AG or Basic SG)}}{\text{Effective Capacity in Block}} \times (1 - AEC) \right\} \times 100$$

Where

AG means Actual Generation (Ex Bus) of Station in MWhr for a Time Block

Basic SG (Scheduled Generation) means Only ISGS Part of Schedule given by RLDC i.e., Excluding Open Access (Bilateral), Collective (Exchanges), Any URS Sales, RRAS, AGC, SCED MW parts, expressed in MWhr for a Time Block

AEC means Normative Auxiliary Energy Consumption

- (ii) "Calculation Period" means the month for which compensation calculation shall be carried out.
- (iii) "Comp (F)" means reconciled final compensation in rupees to be received by a generator during the calculation period based on actual, normative parameters and degraded SHR and AEC based on block unit loading.
- (iv) "Comp (P)" means provisional compensation in rupees computed for the calculation period based on the normative parameters and degraded SHR and AEC based on block unit loading.
- (v) "EC (A)" means total energy charges in rupees computed for a designated generating station during the calculation period on actual furnished parameters of SHR and AEC and sum of basic scheduled energy for all blocks in that calculation period.
- (vi) "EC (N)" means total energy charges in rupees computed for a designated generating station during the calculation period on normative parameters and sum of basic scheduled energy for all blocks in that calculation period.

(vii) “Effective Capacity” in MWhr means maximum possible generation from a station during a time period and shall be calculated as:

Total Installed Capacity of the designated generating station (in MWhr) minus Installed Capacity (MW) of the Unit(s) of the said station under outage (planned or forced outage) and under reserve shut down during the time period X outage time.

(viii) “ECR (Comp)” means increase over normative Energy Charge Rate in Rupees/kWh considering degraded SHR and AEC based on block unit loading.

(ix) “ECR (DC)” means Energy Charge Rate in Rupees/kWh based on degraded SHR and AEC considering unit loading corresponding to Declared Capacity (DC) of the block

(x) “ECR (SE)” means Energy Charge Rate in Rupees/kWh based on degraded SHR and AEC considering block unit loading of generating station.

(xi) “Effective Generation” in MWhr means the actual generation ex-bus of the designated station or the Generation for Basic SG Schedule as in (i) during the calculation period, whichever is higher.

(xii) “RRAS Regulation” means Central Electricity Regulatory Commission (Ancillary Services Operations) Regulations, 2015.

(xiii) “Tariff Regulation” means Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2019 as amended from time to time or any subsequent enactment thereof.

2) Terms and abbreviations used in this Compensation Mechanism but not defined herein shall have the meaning as assigned to them in Electricity Act, 2003 or the Grid Code or other Regulations of the Commission as notified from time to time.

4. Mechanism for working out Compensation

1) Compensation for degradation of Heat Rate (SHR) and Auxiliary Energy Consumption (AEC)

- (i) The Compensation shall be worked out at the end of each month considering degradation in SHR and AEC based on Block Unit Loading (%).
- (ii) Energy scheduled under RRAS Regulations shall be taken as +ve for up-regulation and –ve for down regulation. Similarly, energy scheduled under AGC, SCED shall be taken as +ve for increase and –ve for decrease.
- (iii) The Normative Auxiliary Consumption of competitively bid projects shall be considered based on the normative AEC of similar units as per Tariff Regulation of the Commission or the difference between the Installed Capacity and the ex-bus Contracted Capacity as a percentage of Installed Capacity of the generating station, whichever is less. For projects where entire capacity is not tied up in long term or medium-term contracts, the Normative AEC shall be considered based on the normative AEC of similar units as per the Tariff Regulations of the Commission.
- (iv) Compensation for part load operation shall be calculated based on fifteen (15) minute block of unit loading %, to work out incremental SHR and AEC in accordance with the Annexure – 5.
- (v) Based on the values of increased SHR and AEC arrived above, Energy Charge Rate (ECR) for Block Unit Loading %, i.e. ECR (SE) for the station shall be calculated for a time block using the formula specified in Tariff Regulations of the Commission:

Provided that for generating stations whose tariff has been determined under Section 63 of the Act, the ECR(SE) shall be worked out as per the following formula:

(a) Where ECR is quoted without specifying SHR and AEC:

$$\text{ECR(SE)} = \text{quoted ECR or quoted Variable Charge} \times (1 + \% \text{ degradation in heat rate based on block unit loading corresponding to Effective Generation}/100) / (1 - \% \text{ degradation in Aux Consumption based on block unit loading corresponding to Effective Generation} /100)$$

(b) Where ECR is computed based on normative net Heat Rate and PPA already provides for energy charge payment corresponding to degradation in net station heat rate:

$$\text{ECR(SE)} = \text{ECR worked out based on net station heat rate (without \% degradation in heat rate based on block unit loading corresponding to Effective generation)} / (1 - \% \text{ degradation in Aux Consumption based on block unit loading corresponding to Effective generation}/100)$$

Note: Model PPA notified by GoI provides for energy charge payment corresponding to degradation in net station heat rate and hence as such no separate compensation is allowed under this procedure.

(c) Where ECR is computed based on normative net Heat Rate and PPA does not provide for energy charge payment corresponding to degradation in net station heat rate:

ECR(SE) = ECR worked out based on net station heat rate x (1+ % degradation in heat rate based on block unit loading corresponding to Effective generation /100) / (1- % degradation in Aux Consumption based on block unit loading corresponding to Effective generation /100)

- (viii) ECR corresponding to Declared Capacity (DC) i.e. ECR (DC) for the Time Block shall also be calculated using the formula specified in Tariff Regulations of the Commission and used as reference for calculating compensation. This is because, the effect of less declaration (with respect to normative ex-bus Installed capacity), if any, on the SHR and AEC should be to the account of regional entity generating station/ISGS:

Provided that for generating stations whose tariff has been adopted by Commission under Section 63 of the Act, the ECR(DC) shall be worked out as per following formula:

- (a) Where ECR is quoted without specifying Heat Rate or Aux Consumption:

ECR (DC)= ECR quoted or variable Charge quoted x (1+ % degradation in heat rate based on block unit loading corresponding to DC/100) / (1- % degradation in Aux Consumption based on block unit loading corresponding to DC /100)

- (b) Where ECR is computed based on net Heat Rate and PPA already provides for energy charge payment corresponding to degradation in net station heat rate:

ECR (DC) = ECR worked out based on net station heat rate (without % degradation in heat rate based on unit loading) corresponding to DC / (1- %degradation in Aux Consumption based on block unit loading corresponding to DC /100)

Note: Model PPA already provides for energy charge payment corresponding to degradation in net station heat rate as such no separate compensation under this procedure.

- (c) Where ECR is computed based on normative net Heat Rate and PPA does not provide for energy charge payment corresponding to degradation in net station heat rate:

$$\text{ECR(DC)} = \text{ECR worked out based on net station heat rate} \times (1 + \% \text{ degradation in heat rate based on block unit loading corresponding to DC /100}) / (1 - \% \text{ degradation in Aux Consumption based on block unit loading corresponding to DC/100})$$

The compensation to be paid to designated stations for each Time Block, ECR (Comp) shall be difference in the ECR (SE) and ECR (DC) for that Block.

$$\text{ECR}_n(\text{Comp}) = \text{ECR}_n(\text{SE}) - \text{ECR}_n(\text{DC})$$

Provided that the ECR (Comp) shall be worked out separately for each PPA of the station but annual reconciliation shall be on over all considerations of all PPAs after due prudence by RPC Secretariat.

- (x) The compensation $\text{Comp}_n(P)$ payable to ~~CGS~~/ISGS regional entity generating station/ISGS for a month shall be calculated as below:

$$\text{Comp}_n(P) = \sum_{\text{for all time blocks of month } n} \text{Basic SG in kWhr} \times \text{ECR}_n(\text{Comp})$$

- (xi) $\text{ECR}_n(A)$ for the calculation period at the end of month n shall be calculated using actual values of SHR and Aux Consumption furnished by regional entity generating station/ISGS at the end of the calculation period and normative secondary fuel oil

consumption as per CERC Tariff Regulation for which the requisite information shall be submitted by the generating station to the concerned RPCs Secretariat.

Similarly, $ECR_n(N)$ shall be calculated using normative values of SHR and Aux Consumption and normative secondary fuel oil consumption as per CERC Tariff Regulation furnished by regional entity generating station/ISGS.

Provided that in case of generating stations whose tariff has been adopted by Commission under Section 63 of the Act, $ECR_n(N)$ shall be calculated using normative net SHR or the ECR quoted for the relevant month as the case may be.

(xii) Now, following values shall be calculated:

(a) Total Energy Charges for the station computed on actual parameters

$$EC_n(A) = ECR_n(A) \times \sum_{\text{for all time blocks of month } n} \text{Basic SG in kWhr}$$

(b) Total Energy Charges payable to station based on Normative parameters

$$EC_n(N) = ECR_n(N) \times \sum_{\text{for all time blocks of month } n} \text{Basic SG in kWhr}$$

(xiii) Compensation payable for the calculation period to regional entity generating station/ISGS would be shared with beneficiaries as per following:

(a) If $EC_n(A) \leq \text{Sum of } \{EC_n(N) \text{ and } \text{Comp}_n(P)\}$, then such gain i.e., difference between the sum of $\{EC_n(N) \text{ and } \text{Comp}_n(P)\}$ and $EC_n(A)$ amount restricted to $\text{Comp}_n(P)$, shall be shared between generating station and beneficiaries in the ratio

of 60:40. In that case $Comp_n(F)$ for the month shall be $Comp_n(P)$ less the amount of gain to be shared with the beneficiary.

(b) If $EC_n(A)$ is more than the sum of $\{EC_n(N)$ and $Comp_n(P)\}$, there shall be no sharing of compensation between the generating station and the beneficiary and $Comp_n(P)$ shall be $Comp_n(F)$ for the month.

(xiv) Compensation payable for the calculation period to Final Compensation payable by k^{th} beneficiary for the calculation period:

(a) No compensation shall be payable by beneficiaries if it has requisitioned at least 85% of its entitlement during the calculation period.

(b) The compensation amongst other beneficiaries shall be shared in the ratio of un-requisitioned energy below 85% of their entitlement i.e. compensation payable by k^{th} beneficiary for the calculation period entitlement during the calculation period.

$$FCB_{kn} = Comp_n(F) \times \{UE_{kn} / \sum_k UE_{kn}\}$$

Where UE_{kn} is un-requisitioned energy of k^{th} beneficiary below 85% of its entitlement during the calculation period.

2) Calculation for Secondary Fuel Oil consumption:

(i) No compensation for degradation of Secondary Fuel oil consumption is payable for the year if total number of start-ups is equal to or less than 7 x no. of units in the generating station or the Actual Secondary Fuel Oil consumption is less than Normative Fuel Oil Consumption.

- (ii) Compensation (in terms of KL of Secondary Oil) shall be payable to CGS/ISGS/Regional Entity Generating Station for the year due to degradation of Secondary Fuel Oil Consumption shall be calculated by multiplying no. of start-ups exceeding 7 per unit and solely attributable to reserve shut-downs with the appropriate value of additional secondary oil consumption specified in Regulation.
- (iii) Compensation in terms of Rupees shall be calculated by multiplying compensation in terms of KL as calculated in step (b) and average landed price of Secondary fuel oil for the year.
- (iv) Any saving on account of oil, limited to amount received from the compensation, shall be shared with the beneficiaries in 60:40 ratio.
- (v) Each start-up due to reserve shutdown shall be attributed to the beneficiaries, who had requisitioned below 55% of their entitlement.
- (vi) Compensation (in terms of Rupees) shall be shared amongst the beneficiaries in the following manner:

$$\begin{aligned}
 & \textit{Compensation payable by beneficiary } i \\
 &= \left(N_i \times \frac{A_i}{\sum(N_i \times A_i)} \right) \times \text{Compensation payable to CGS/ISGS}
 \end{aligned}$$

Where

N_i = Number of start-ups attributable to the beneficiary i.

A_i = Weightage Average Percentage share of the beneficiary in the generating station

- (vi) The CGS/ISGS/ Regional Entity Generating Station is to take all due care to keep a check on secondary oil use during part operations and during start-ups to the extent

possible. The respective RPC Secretariat shall review the secondary oil consumptions of plants on quarterly basis along with concerned RLDC and CGS/ISGS to find out high consuming plants and reasons for high consumption and for suggesting measures to mitigate excess use of secondary oil to the extent possible.

- 3) In case generating station runs below technical minimum schedule it shall be entitled for compensation corresponding to technical minimum schedule.

5. Calculation of Compensation, Billing and Submission of Data by the Generator

- (i) Generating station shall calculate the compensation as specified in these procedures and bill the same to beneficiaries along with its monthly bill which shall be subject to adjustment based on compensation statement issued by RPC Secretariat subsequently.
- (ii) Generating station shall submit the requisite data along with compensation calculation to RPC secretariat as prescribed in Annexure-I to this procedure for a month by 15th day of the following month. For stations where the PPAs are not unit-wise, the information for the station shall be furnished. The data to be submitted is for the month and reconciled up to the month.

6. Issuance of compensation statement

- (i) RPC secretariat will issue the compensation statement along with final REA for the month.
- (ii) In case any anomaly or discrepancy is noticed by any Utility, the same may be brought to the notice of Member Secretary of the concerned RPC within 15 days of issuance of Compensation Statement.

Annexure-I

Information to be submitted by CGS and ISGS to the RPC Secretariat by 15th of each month (say in May) for the previous month (say of April)

Sr. No (a)	(b)	Unit No 1 (c)	Unit No 2 (d)	Unit No 3 (e)	Unit No 4 (f)	Total (g)
1	Installed capacity/MCR					
2	Planned outage/Tripped (Hrs)					
3	On bar hrs					
4	Normative SHR or Net SHR as the case may be					
5	Normative SFC					
6	CVSF					
7	LPPF					
8	LPSFI					
9	Normative LC					
10	LPL					
11	Normative Aux. Cons					
12	Actual GHR/SHR					
13	Actual SFC					
14	Actual LC					
15	Actual Aux. Cons					
16	RSD start /stop in the month					
17	RSD start/stop cumulative					
18	Total no. of Start /stop during year					
19	CVPF					

ANNEXURE – 7

DETAILED OPERATING PROCEDURE FOR COMMITTING AND DE-COMMITTING OF COAL/LIGNITE/GAS UNIT(S) OF THE REGIONAL ENTITY GENERATING STATIONS

OBJECTIVE

The objective of this Procedure is to lay down

- i. the methodology for identifying the generating stations or units thereof to be de-committed in specific grid conditions such as low system demand, during Regulation of Power Supply, incidence of high renewables etc.;
- ii. the procedure for committing or de-committing generating units;

1. Methodology for committing and de-committing generating station or unit(s)

- 1) The generating station shall submit the time block wise capability of generating station (DC) and other information, by 0600 hours of the day for next three (3) days on rolling basis in line with this Grid Code.
- 2) RLDCs shall compile the above information along with the entitlement for each regional entity beneficiary and advise the same to all SLDC/beneficiaries by 0800 hours for next three (3) days as per Grid Code and amendments thereafter. Entitlements shall be calculated based on the DC.
- 3) The beneficiaries shall furnish their requisition for the next three (3) day to respective RLDC by 1100 hours of the day based on the entitlements given by the concerned RLDC in accordance with the Grid Code, as amended from time to time.
- 4) Ex-Power Plant (Ex-PP) dispatch schedule of a generating station for each time block shall be computed by the respective RLDC by taking algebraic sum of requisitions of all beneficiaries of that generating station.
- 5) The RLDCs shall submit this information to NLDC. NLDC can also take into account the historical data of requisitions.
- 6) The NLDC shall carryout a security constrained unit commitment (SCUC) in order to fulfill the projected requisitions as well as for maintaining reserves at regional entity generating stations and also economizing the operations.
- 7) The SCUC mechanism by NLDC shall also factor following:
 - i. On bar and off bar requisitions by beneficiaries
 - ii. Extreme variation in Weather Conditions
 - iii. High Load Forecast
 - iv. To maintain reserves on regional or all India basis
 - v. Network Congestion
 - vi. Any other event which in the opinion of RLDC/NLDC shall affect the grid security.

- 8) The results of SCUC along with time to commit unit (s) on bar or de-commit unit (s) off bar shall be informed to RLDCs for onward information to generating stations. The generating stations shall bring or take out unit (s) accordingly.
- 9) The SCUC shall also be carried out by NLDC on daily and intraday basis as well and results shall be conveyed to generating stations accordingly with advance information for action by generating stations.
- 10) The generating stations/units committed through SCUC shall normally be provided the schedule above or upto minimum turn down level through security constrained economic dispatch (SCED) mechanism.
- 11) During the day of operation if net EX-PP injection schedule for a generating station is less than minimum turn down level, generating station can keep unit on bar and generate accordingly and would get compensation as given in this Grid Code.
- 12) If the requisition of some beneficiaries go up to ensure minimum turn down level as above, SLDCs/beneficiaries may surrender power from some other regional entity generating station(s) or intra-State generating station(s) out of merit order.
- 13) The eligibility conditions for the generating stations to participate in SCUC and SCED mechanism shall be separately announced by NLDC based on the orders of the Commission.
- 14) The generating stations not covered under the SCUC and SCED mechanism shall commit/de-commit units as per their respective Power Purchase Agreement (PPA) conditions. Before de-committing unit(s), the generating station shall revise the On Bar DC (with due consideration to ramp up/down capability), Off Bar DC, DC and Ramp UP/RAMP Down rate. The generator shall ensure that the Off Bar DC is not more than the MCR less Normative Auxiliary Consumption of the machines to be de-committed. The beneficiaries shall continue to bear the capacity charge corresponding to Total DC.
- 15) When the machine is being de-committed:
 - a. In case the total requisitioned power can be supplied through other units in the same generating station on bar, the generator shall be scheduled according to the requisitions received.
 - b. In case total requisitioned power cannot be supplied through other units in the same generating station on bar or through SCED mechanism, the requisition of the beneficiaries from off bar DC shall be reduced in the ratio of such requisitioned power.
- 16) In the special case of a generating station where the only running machine is de-committed, the beneficiaries who have requisitioned power may not get scheduled for few blocks. No maintenance activities on unit to be de-committed shall be undertaken by the generating station so that the de-committed unit is always readily available for revival/synchronization. If a generating station requires maintenance on any machine to be de-committed, then the same shall be done in due consultation with RLDC. The DC shall be reduced appropriately.
- 17) Regulation of Power Supply: When injection schedule of a regional entity generating station falls below technical minimum due to imposition of regulation of power supply by the generating company or transmission licensee under the Central Electricity

Regulatory Commission (Regulation of Power Supply) Regulations, 2010 and/or as per directions under the Commission order dated 2.9.2015 in Petition No. 142/MP/2012, the generator may endeavour to sell the surplus power through STOA or Power Exchange(s) before opting to de-commit.

2. Methodology for committing or de-committing generating station or unit(s) thereof (Real Time Schedule Revision)

- 1) A beneficiary can surrender its part or full entitlement during the day of operation in accordance with the relevant provisions of Grid Code.
- 2) In case, the schedule of a generating station goes below minimum turn down level, due to this surrender of power:
 - (a) RLDC may provide technical minimum schedule considering the system conditions in accordance with the Grid Code and SCED mechanism.
 - (b) In case the system condition does not require, RLDC shall direct the generating station to take any unit or the generating station to be de-committed. In such a scenario, RLDC shall display the station likely to go under RSD on its website. In case, the schedule is still less than the technical minimum and generating station decides to de-commit unit(s), it shall inform the same to concerned RLDC.
 - (c) In order to meet peak load and to maintain reserves, the generating station should endeavour to plan as far as possible the de-committing in such a manner that maximum number of units are kept on bar keeping in view economy and efficiency of the units of the generating station.

3. Methodology for committing of generating station or unit(s)

- 1) Once a unit is de-committed, the generating station shall notify the period for which the unit will remain off bar and the unit can be recalled any time after 8 hours. In case of system requirements, the generating unit can be revived before 8 hrs as well. The time to start a machine under different conditions such as HOT, WARM and COLD shall be as per the declaration given by the generating station under the Detailed Procedure for Ancillary Services Operations (Format AS-1 and AS-3 of the said Procedure).
- 2) One or more beneficiaries of the generating station as well as the generating station may decide for revival of unit(s) de-committed with commitment for technical minimum schedule with minimum run time of 8 hrs for Coal based generating stations and 3 hrs for Gas based generating stations post revival. In such situations, the generating station shall revise the On Bar and Off Bar DC (with due consideration to ramp up/down capability).
- 3) RLDC may also advise the generating stations to revive unit(s) which are de-committed for better system operation
- 4) In case the machine is not revived as per the revival time declared by the generating station under different types of start, the machine shall be treated under outage for the duration starting from the likely revival time and the actual revival time. RLDC shall ensure that intimation is sent to the generating station sufficiently in advance keeping in view its start-up time.

ANNEXURE – 8

Procedure for forecasting, scheduling and imbalance handling for renewable energy (re) generating stations at inter-state level

1. Introduction

The responsibility to coordinate with RLDC and provide forecast and the data required under the Procedure shall be that of Qualified Coordinating Agency on behalf of all generating stations it is representing.

Provided that where Qualified Coordinating Agency is not identified, individual renewable energy generating station with installed capacity of more than 50 MW or lead generator or Principal generator shall be responsible for the same.

2. Role of Entities

(1) QCA or Renewable Energy Generating Station

(a) The individual generating station or lead generator or principal generator shall submit one time details to concerned RLDC as per Annexure-I. Further, if there is any change in the information furnished, then the updated information shall be shared with the concerned RLDC not later than 7 working days of the change.

(b) QCA shall undertake the following activities:

- a) All the technical coordination amongst the generators connected at a pooling station shall be done by the QCA.
- b) Provide available capacity, Day ahead forecast (based on their own forecast or on the forecast done by RLDC) and Schedule as per Annexure-II through web-based application maintained by RLDCs.
- c) Provide real time availability (at turbine/inverter level) and generation data (at pooling station level) as per Annexure-III.
- d) Provide Monthly data transfer (as per Annexure – IV):
 - i. For wind plants, at the turbine level- average wind speed, average power generation at 15-min time block level
 - ii. For solar plants, for all inverters* ≥ 1 MW- average solar irradiation, average power generation at 15-min time block level

* if a solar plant uses only smaller string inverters, then data may be provided at the plant level

- e) Be Responsible for metering and data collection, transmission and co-ordination with RLDC, SLDC RPC, CTU and other agencies as per IEGC and extant CERC Regulations.
- f) Undertake commercial settlement of all deviation-settlement charges as per applicable CERC Regulations.
- g) Submit a copy of the agreement to concerned RLDC wherein it is mentioned that QCA shall undertake all operational and commercial responsibilities on behalf of generating stations as per the CERC Regulations. Further Connectivity grantee shall also submit the application for connectivity which was submitted to CTU to the respective RLDC in whose control area it is located.
- h) Use Automatic meter reading technologies for transfer, analysis and processing of interface meter data.
- i) Perform commercial settlement beyond the connection point (De-pooling arrangement) and technical coordination amongst the generators within the pooling station and upto the connection point as the case may be.
- j) Shall furnish the PPA rates on notarized affidavit for the purpose of Deviation charge account preparation to respective RPC supported by copy of the PPA.
- k) Keep each of the RLDCs indemnified at all times and shall undertake to indemnify, defend and save the SLDCs/RLDCs harmless from any and all damages, losses including commercial losses due to forecasting error, claims and actions including those relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the transactions undertaken by the Generators.

(2) RLDC

- (a) The concerned RLDC shall be responsible for scheduling, communication, coordination with QCA or generating station or Lead Generator or Principal Generator. Forecasting of the renewable energy generation shall be done by the RLDCs and the forecast will be available on the website of the concerned RLDC. The generation forecast shall be done on the basis of the weather data provided by IMD or on the basis of other methods used by the Forecasting Agency whose service may be availed by NLDC/RLDC. However, the forecast by the concerned RLDC shall be with the objective of ensuring secure grid operation.

- (b) The concerned RLDC will be responsible for processing the interface meter data and computing the net injections at pooling station represented by each QCA as specified in Annexure- V.
- (c) RLDC may, appoint additional manpower for carrying out the additional responsibility assigned in these Procedures, if required.

3. Forecasting

- (1) Regional forecasting shall be done by the concerned RLDC to facilitate secure grid operation. The concerned RLDC may engage a forecasting agency to undertake forecasting of renewable generation for each pooling station.
- (2) QCA shall provide the forecast to the concerned RLDC which may be based on their own forecast or RLDC's forecast as per Annexure-II. In case QCA is utilizing service of RLDC for its forecasting, necessary fees shall be paid by generator to RLDC as approved by CERC.
- (3) The concerned RLDC shall consolidate and forecast based on various parameters as mentioned in the enclosed Annexures and weather data obtained from IMD or from any other forecast service provider (which could be different from that provided by QCA)
- (4) QCA may prepare their schedule based on the forecast done by RLDC or their own forecast. Any commercial impact on account of deviation from schedule based on the forecast chosen by the QCA shall be borne by the respective QCA.

4. Scheduling and Despatch

- (1) Following alternatives exist for Scheduling and Despatch for Generators within Solar / Wind /Hybrid Power parks due to multiple generation developers within the Park injecting at various points with in the park and ultimately injecting at interface with ISTS:

Case-1 QCA shall be responsible for the scheduling, communication, coordination with generating stations connected at a pooling station which is under RLDC control area.

Case-2 Where QCA at a pooling station is not identified following situations may arise

Case-A: The concerned RLDC shall be responsible for the scheduling, communication, coordination with RE Generators of 50 MW and above and connected to Inter State Transmission System (ISTS).

Case-B: Lead generator or Principal generator shall be responsible for the coordination and communication with RLDC, SLDC, RPC and other agencies for scheduling of RE Generators individually having less than 50 MW, but collectively having an aggregate installed capacity of 50 MW and above and connected within the solar park.

- (2) For Case-1, QCA shall be responsible for doing de-pooling of DSM charges as per the mutual agreement between generators and QCA.
- (3) For Case- 2, where scheduling and accounting is to be coordinated by RLDC, a representative sketch showing the scheduling for Case-A and Case-B is attached as Annexure-IV.
- (4) The change of QCA would need a notice period of fifteen (15) days and the changeover shall take place with effect from 0000 hours of a Monday, the first day of weekly settlement cycle.
- (5) In case of any payment default by the QCA, the generators shall be liable to pay the DSM charges in proportion to their MW capacity.

5. Metering

- (1) Interface Energy Meters shall be installed by the Central Transmission Utility as per CEA Metering Regulations, 2006 and amendments thereof to facilitate boundary metering, accounting and settlement for RE Generators. Automated meter reading (AMR) system shall be used for communicating interface meter data at RLDCs. Internal Clock of the interface meter shall be time synchronized with GPS.
- (2) QCA shall ensure availability of data telemetry at the turbine/inverter level to the concerned RLDC and shall ensure the correctness of the real-time data and undertake the corrective actions, if required. Frequency of real-time data updation to be shared with concerned RLDC shall be 10 second or less as per prevailing practice followed by RLDCs. Further, turbine/inverter outage plan shall also be forwarded to the concerned RLDC. The suggested data telemetry requirement for RE Generators is enclosed at Annexure-III.

6. Treatment of RECs

- (1) Deviations by all RE Generators shall first be netted off by concerned RPC for the entire pool on a monthly basis and if Actual Generation is more than schedule generation, Notional RECs shall be credited to the respective Regional DSM Pool on Monthly Basis and carried forward

for settlement in future. If after netting off, including any carried forwarded notional RECs, the remaining shortfall in renewable energy generation shall be balanced through purchase of equivalent solar and non-solar Renewable Energy Certificates (RECs) through Power Exchanges by RLDC/ NLDC by utilising funds from the respective Pool Account at the end of the financial year within three months of finalization of accounts by concerned RPC.

7. RLDC Fees and Charges

- (1) The Solar Power Park Developer and Wind Power Park Developer and Generating stations with installed capacity of more than 50 MW or lead generator or principal generator shall be registered as User with the respective Regional/State Load Despatch Centre responsible for scheduling, metering and energy accounting.
- (2) Generating stations with installed capacity of more than 50 MW or lead generator or principal generator shall pay RLDC fees and charges as per CERC “Fees and charges of Regional Load Despatch Centre and other related matters”, Regulations 2019.

8. Removal of Difficulties

- (1) In case of any difficulty in implementation of this procedure, NLDC may approach the Commission for review or revision.
- (2) Notwithstanding anything contained in this Procedure, NLDC/RLDCs may take appropriate decisions in the interest of System Operation. Such decisions shall be taken under intimation to CERC and the procedure shall be modified /amended, as necessary.

Appendix-I

Details to be submitted by the Wind/Solar generating stations which are regional entities/ lead generator, principal generator	
Type: Wind/Solar Generator	
Individual / on Behalf of Group of generators	
If on Behalf of Group of generators group of then details of agreement to be attached	
Total Installed Capacity of Generating Station	
Total Number of Units with details	
Physical Address of the RE Generating Station	
Whether any PPA has been signed: (Y/N)	If yes ,then attach details
Connectivity Details	Location/Voltage Level
Metering Details	Meter No. 1. Main 2. Check
Connectivity Diagram	(Please Enclose)
Static data	As per attached sheet
Contact Details of the Nodal Person	Name : Designation : Number: Landline Number, Mobile Number, Fax Number
Contact Details of the Alternate Nodal Person	Name : Designation : Number: Landline Number, Mobile Number, Fax Number

Data to be submitted by the RE Generator / lead generator, principal generator for Wind turbine generating plants

S No	Particulars
1	Type
2	Manufacturer
3	Make /Model
4	
5	Capacity
6	COD
7	Hub height
8	Total height
9	RPM range
10	Rated wind speed
Performance Parameters	
11	Rated electrical power at rated wind speed
12	Cut in speed
13	Cut out speed
14	Survival speed (Max wind speed)
15	Ambient temperature for out of operation
16	Ambient temperature for in operation
17	Survival temperature
18	Low Voltage Ride Through (LVRT) setting
19	High Voltage Ride Through (HVRT) setting
20	Lightning strength (KA & in coulombs)
21	Noise power level (db)
22	Rotor

23	Hub type
24	Rotor diameter
25	Number of blades
26	Area swept by blades
27	Rated rotational speed
28	Rotational Direction
29	Coning angle
30	Tilting angle
31	Design tip speed ratio
Blade	
32	Length
33	Diameter
34	Material
35	Twist angle
Generator	
36	Generator Type
37	Generator no of poles
38	Generator speed
39	Winding type
40	Rated Gen.Voltage
41	Rated Gen. frequency
42	Generator current
43	Rated Temperature of generator
44	Generator cooling
45	Generator power factor
46	KW/MW @ Rated Wind speed
47	KW/MW @ peak continuous
48	Frequency Converter

49	Filter generator side
50	Filter grid side
Transformer	
51	Transformer capacity
52	Transformer cooling type
53	Voltage
54	Winding configuration
Weight	
55	Rotor weight
56	Nacelle weight
57	Tower weight
58	Over speed Protection
59	Design Life
60	Design Standard
61	Latitude
62	Longitude
63	COD Details
64	Past Generation History from the COD to the date on which DAS facility provided at RLDC, if applicable
65	Distance above mean sea level

For Solar generating Plants: Static data points:

1. Latitude
2. Longitude
3. Turbine Power Curve
4. Elevation and orientation angles of arrays or concentrators
5. The generation capacity of the Generating Facility
6. Distance above mean sea level etc.
7. COD details

8. Rated voltage
9. Details of Type of Mounting: (Tracking Technology If used, single axis or dual axis, auto or manual)
10. Manufacturer and Model (of Important Components, Such as Turbine, Concentrators, Inverter, Cable, PV Module, Transformer, Cables)
11. DC installed Capacity
12. Module Cell Technology
13. I-V Characteristic of the Module
14. Inverter Rating at different temperature
15. Inverter Efficiency Curve
16. Transformer Capacity & Rating, evacuation voltage, distance form injection point

Appendix-II

Forecast and Schedule Data to be submitted by QCA, generator-wise

FORMAT: A (to be submitted a day in advance)

15 Min time block (96 Block in a day)	TIME	Available Capacity (MW) - Day Ahead	Day Ahead Forecast (MW)	Day Ahead Schedule (MW)
1	00:00-00:15			
2	00:15-00:30			
3	00:30-00:45			
4	00:45-01:00			
.				
94				
95				
96				

Note: The forecast should ideally factor forecasting errors. As such schedule should ordinarily be same as forecast.

FORMAT: B (to be submitted on the day of actual generation, revision of availability and schedule, if any, shall be done as per CERC(IEGC) Regulations.

15 Min time block (96 Block in a day)	TIME	Day ahead schedule (MW)	Current Available Capacity (MW)	Revised Schedule (MW)
1	00:00-00:15			
2	00:15-00:30			
3	00:30-00:45			
4	00:45-01:00			
.				
94				
95				
96				

Appendix-III

Real-time Data Telemetry requirement (Suggested List)

Wind turbine generating plants

1. Turbine Generation (MW/MVAR)
2. Wind Speed(meter/second)
3. Generator Status (on/off-line)- this is required for calculation of availability of the WTG
4. Wind Direction (degrees from true north)
5. Voltage(Volt)
6. Ambient air temperature (° C)
7. Barometric pressure (Pascal)
8. Relative humidity(in percent)
9. Air Density (kg/m³)

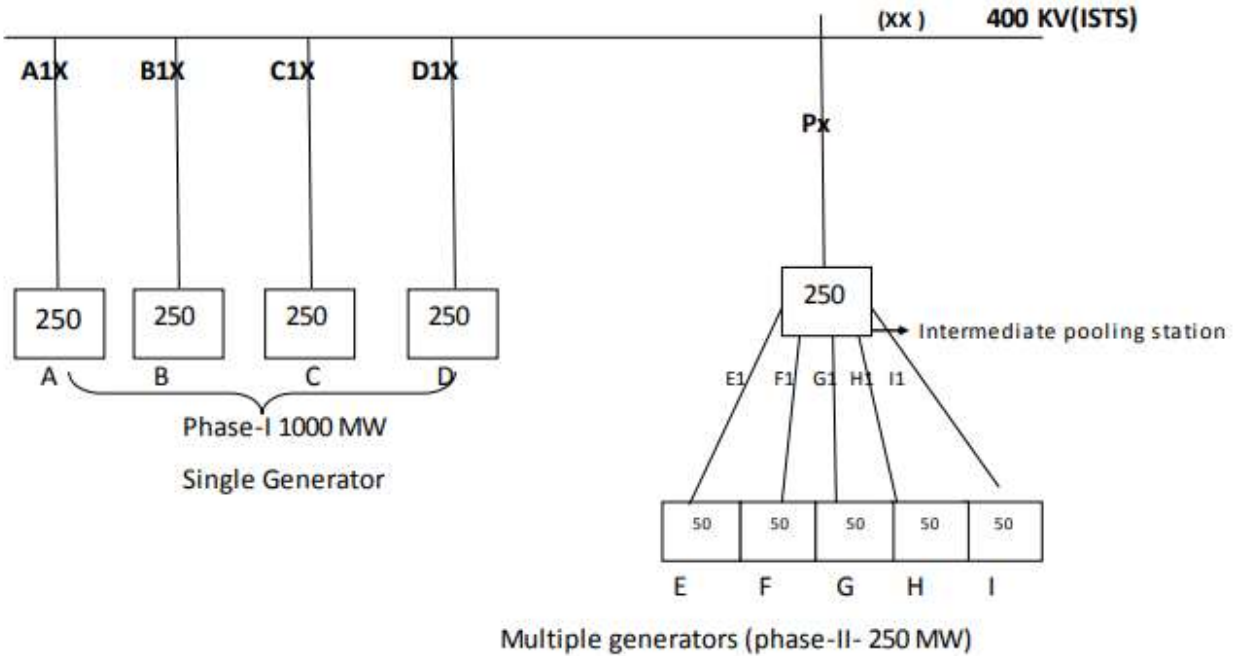
For Solar generating Plants

1. Solar Generation unit/ Inverter-wise (MW and MVAR)
2. Voltage at interconnection point (Volt)
3. Generator/Inverter Status (on/off-line)
4. Global horizontal irradiance (GHI)- Watt per meter square
5. Ambient temperature (° C)
6. Diffuse Irradiance- Watt per meter square
7. Direct Irradiance- Watt per meter square
8. Sun-rise and sunset timings
9. Cloud cover-(Okta)
10. Rainfall (mm)
11. Relative humidity (%)
12. Performance Ratio-

Appendix-IV

Block Diagram showing the case wise Scheduling and Forecasting considering a sample case

Case-I: 50 MW and above (Phase-I &II)



Phase-I – 1000 MW,

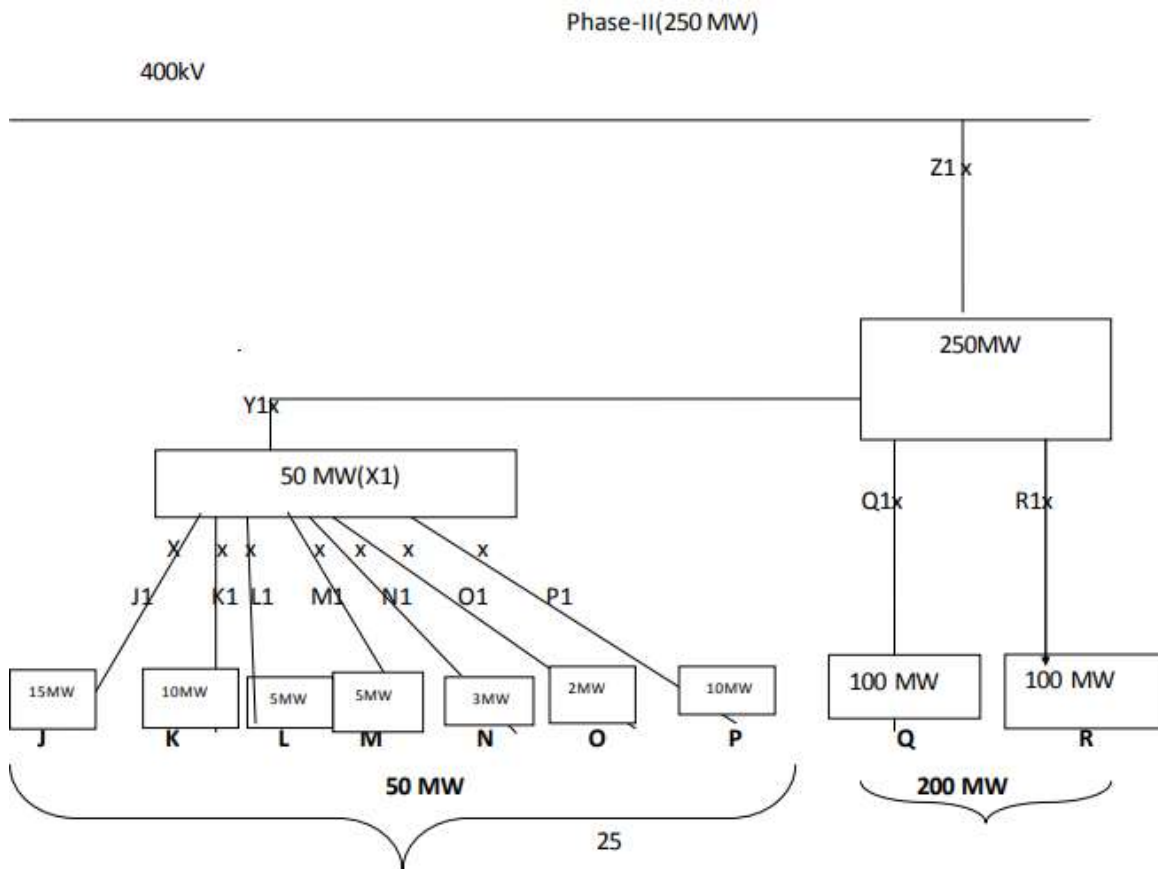
A single generator of 1000 MW capacity is developing the generating station in phase-1 in four blocks namely A,B,C & D of 250 MW capacity each and is directly connected to point A1,B1,C1& D1 respectively at ISTS. At the interface point scheduling and forecasting will be done by RLDC / SLDC (in case full share is allocated to host state as per IEGC).

Phase-II- 500 MW (Separate Generator/Entities)

- (1) Let multiple generators of 50 MW each aggregating to 250 MW (5 Nos. Multiple Generator of 50 Mw each (as separate entities), be connected to inter mediate pooling stations.
- (2) In this case Solar generating station may be developed by single or Multiple generators. Here we have considered as multiple generators namely E, F, G, H & I each having the capacity of 50 MW each ,the RE generators are connected to interface point E1, F1, G1, H1& I1 and thereby connected to ISTS at XX point.
- (3) In such a case scheduling, accounting, forecasting for these generators needs to be segregated at point E1, F1,G1, H1, I1. Scheduling shall be done at point P and shall be segregated at E1,F1,G1,H1,I1 by RLDC.

- (4) Further there may be case where multiple generators less than 50MW (<50MW) capacity are connected to the intermediate pooling station are stated as under:-

Case-II Below 50 MW



- (5) For remaining 250 MW of Phase-II, let us consider, multiple generators of 7 Nos (J,K,L,M,N,O&P) each having capacity less than 50 MW but collectively having an aggregate installed capacity of 50 MW or more. Further Generators Q & R each of 100 MW are connected at Q1 & R1. All these generators are connected to ISTS at point Z1.
- (6) Scheduling and forecasting for the generators J,K,L,M,N,O& P shall be done at Point Z1, but need to be segregated at Point J1, K1,L1, M1, N1,O1& P1 and for generators Q & R needs to be segregated at Q1 and R1. In this case, RLDC shall schedule at point Z1 and segregate at Y1,Q1& R1 . The lead generator shall provide aggregated schedule to RLDC at Y1. Further the lead generator shall do segregation of schedules and other operational & commercial activities for generators J,K,L,M,N,O,P at points J1, K1,L1, M1, N1,O1& P1.

ANNEXURE- 9

ACCOUNTING AND POOL SETTLEMENT SYSTEM

METERING, ACCOUNTING AND SETTLEMENT SYSTEM:

At the Inter State Transmission System (ISTS) level, the basic principle followed is that all settlements for the energy scheduled before the fact are done directly between the sellers and the buyers (with the Regional Power Committee issuing only the Accounts specifying the quantum of energy scheduled). All deviations from the schedule are settled through a regulatory pool account maintained by RLDCs; basically a net settlement where only the deviation payments are handled

The settlement system shall be transparent, robust, scale-able (multi buyer/seller, inter connection with lower and upper pool systems) and dispute-free with integrity & probity possible through double entry system and usage of state of the art techniques. The settlement computation details, applicable charges and operation of different regulatory pool accounts shall be known ex-ante and be in accordance with various regulations of the Commission.

However, the settlement system shall have following basic principles:

REGIONAL ENERGY ACCOUNTS:

- a. NPC, after consultations with the RPCs/NLDC/RLDCs, evolve and issue a detailed procedures for energy accounting and settlement by all the RPCs. Likewise, NLDC shall evolve and issue a detailed procedures for accounting and settlement by all the RLDCs. The SLDCs shall issue a detailed procedure which is aligned with the NLDC procedure for accounting and settlement by the SLDC and in case such a procedure has not been specified by the SLDC, the accounting and settlement shall be carried in line with the NLDC procedure.
- b. The Implemented Schedule (that incorporates all before-the-fact changes in schedule) be used as a reference for energy accounting.
- c. Energy Accounts inter-alia shall indicate Declared Capability of generating stations, Entitlements, Requisitions, Scheduled loss, Scheduled transactions through LTA/MTOA/STOA-bilateral/STOA-collective and actual Interchange.

- d. Assumptions, if any, in the accounts should be clearly stated in Notes to the Accounts.

DEVIATION ACCOUNTS:

- a. Deviation account shall be separate net settlement account for each region.
- b. Capacity and Energy charges shall be settled mutually between buyers and sellers.
- c. Each regional entity (whether generator, RE Generator, captive Power Plant, OA customer connected at ISTS) in a region shall be a member of the regional pool and separately accountable for deviations. For cross border transactions, the Settlement Nodal Agency (SNA) as appointed by the Government of India would be a member of the regional pool.
- d. Similar pool shall be at State level and national level and these state, regional and national pool (s) shall be delinked from each other in order that any change in one pool does not spill to all other pool through circular reference, recursive revisions and collection/disbursement.
- e. The Deviation accounts shall also have actual transmission losses computed for each time block of settlement. No post facto adjustment of transmission losses shall be done.
- f. The pool design shall be such that no deficit would normally arise in these pool accounts.
- g. Interface points (tie lines), Interchange computation formulae, CT/PT ratio, Interface Energy Meter data, and discrepancy statements shall be made available for reference and verification by the respective entities.
- h. CTU or STU as case may be shall coordinate the corrections, maintenance, calibration and testing of interface energy meters.

REACTIVE ENERGY ACCOUNTS:

As notified under the CERC Ancillary Services Regulations.

ANCILLARY SERVICES AND SCED POOL

It shall have gross settlement in the sense that these Pool Accounts are involved in payment/recovery of energy charges, fixed charges etc. However, these accounts shall also be regulatory in nature.

REAL TIME CONGESTION CHARGE ACCOUNT

It shall be maintained by RLDCs for collecting the amounts that would accrue in case of congestion in any corridor.

Any other Pool Account as directed by the Commission from time to time. The NPC, RPCs, NLDC, RLDCs and SLDCs shall carry out periodic reconciliation of all accounts as per the detailed procedures.

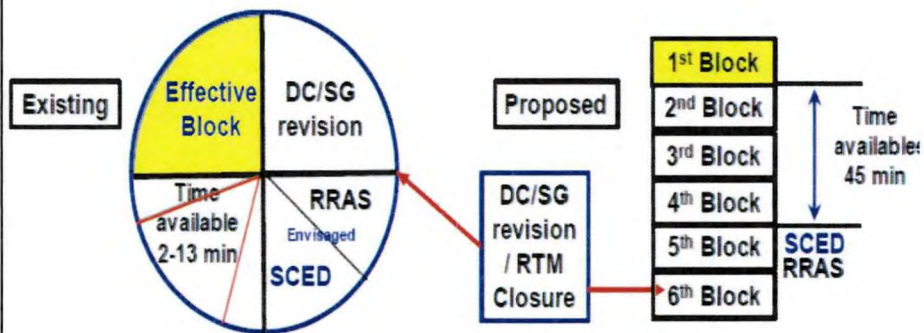
REVISION OF IEGC: SUMMARY OF COMMENTS			
S No	Point	Proposal	Entity
1)	Grid Security Definition	<i>'Changes in the basic pre-defined power system parameters (such as voltage, frequency, df/dt, dv/dt or thermal loading of equipment) beyond acceptable technical limits.'</i>	APP
2)	Definition of Control Area	Operation policy to be defined in operating code. It is suggested that frequency and inter regional exchange control to be implemented initially, considering each region as a control area. It is also reasonable to treat ER and NER as one control area. Without this definition AGC (including governor control) implementation can't proceed further.	NTPC
3)	New Definitions	1.0 Balancing Energy: it is quantum of energy and power in MW required by any grid while shifting from high renewable energy time period to peak hours when renewable generation is low. This need to be quantified both in energy and MW.	GREENKO
		2.0 Flexibility of Power system : Flexibility of power system refer to the extent to which generation or demand can be increased or reduced over a time scale ranging from few minutes to hours.	
		3.0 Ramp up rate: Ramp up rate of power system is rate in MW/ minute which a power system is required to increase its generation to match its demand at different time intervals.	
		4.0 Ramp down rate: It is rate in MW/minute which a power system is required to decrease it generation to match the grid demand at different time intervals.	
		Definition -Spinning Reserves- The definition of spinning reserve should include the Energy Storage System located at both the transmission line or at the generating stations.	APP
		ReNew suggestions <i>Generating units:</i> <i>"In case of Solar Photo voltaic generating station, each inverter along with associated modules will be reckoned as a separate generating unit"</i> <i>"In case of Wind Generating station, each wind turbine will be reckoned as a separate generating unit"</i> <i>Synchronisation:</i> <i>"The condition where an incoming Generating Unit or System is connected to another System so that the voltage, frequencies and phase relationships of that Generating Unit or System, as the case may be, and the System to which it is connected are identical and the terms "Synchronise" and "Synchronisation" shall be construed accordingly"</i>	ReNew

		<p>SECI suggestions</p> <p>The IEGC regulation defines a generating unit as "an electrical Generating unit coupled to a turbine within a Power Station together with all the Plant and Apparatus at that Power station which relates exclusively to the operation of that turbo-generator".</p> <p>With a view to make a more inclusive definition of Generating Unit, the definition may be amended as follows:</p> <p>"an electrical Generating unit coupled to a turbine within a Power Station together with all the Plant and Apparatus at that Power station which relates exclusively to the operation of that turbo-generator</p> <p>Or A power conversion system/electrical inverter coupled with a photovoltaic array or energy storage system that converts direct current into alternating current together with plant and apparatus for synchronisation with electrical grid"</p> <p>II. Optimal Operation of Grid:</p> <p>1. The Solar PV generators above 10 MW shall be obligated to utilise dynamic grid support capabilities of the inverter/PCU like active power regulation and reactive power control.</p> <p>2. To encourage adoption of capabilities as above, Solar PV Generators should be incentivised for supporting the grid, the mechanism of which could be worked out by a technical work group.</p>	SECI
4)	Definition of primary reserves	Please provide	IWPA
5)	Force Majeure	2.1.(ff) Force Majeure: Force majeure considered in IEGC are applicable for performance indices calculation, however the force majeure are not considered in power scheduling and dispatching activity. A suitable definition in line with the above may also be considered for the purposes of DSM regulations. The Discom/Buyer should not be held liable for under-drawl or over drawl in case of any Force Majeure Events and consequential DSM penalties. Tripping of transmission line, STU /CTU equipment should be considered as force majeure for Distribution companies.	TPDDL
6)	IEGC as Default Code	On the similar line of CERC Communication Regulation, if any State does . not have State Grid code in place, the IEGC regulation shall be made applicable for such ~ states.	MSEDCL
7)	Protection Code	Protection Code is missing in IEGC , needs to be included. The CBIP manual can be taken as the base document for the purpose.	NTPC
8)	Part 1, GENERAL	<p>i) Para 1.2:(i) In the last line of first para the following may be added :</p> <p>"Regional and state load dispatch centres and Renewable Energy Management centres".</p> <p>ii) In para 1.2 (in the end) the following para may be added as a new point:</p>	GREENKO

Facilitation different technologies to create flexibility in the grid to meet balancing power requirement through different storage options including pump hydro projects, battery storage etc..

9) Ripple Filter Additionally IEGC Regulation 5.2(f) (ii) b prescribe ripple filter of +/- 0.03 Hz to avoid frequent governor hunting. But considering International standards, it shall be revised to at least +/- 0.05 Hz in line with other developed countries. It will help in restricting primary control action more frequently in power system and frequency will remain in frequency band as prescribed above by 50 Hz committee most of the time.

10) RRAS and SCED scheduling mechanism RRAS and SCED scheduling mechanism shall also be prescribed in scheduling code of IEGC. Frequency of Schedule change due to SCED is very high ($\approx > 200$ per day) as optimization software of SCED is run every block. Generators shall get enough time to adjust to new schedule. Regulatory intervention required for introducing early gate closure. Final schedule should be available 3 clear blocks in advance as enumerated below:



11) Synchronous Condenser Definition of synchronous condenser proposed to be included as these may form part Ancillary services in near future. It is also proposed to include Reactive power exchange through synchronous condenser as Ancillary service. As voltage management plays an important role in inter-state transmission of energy, special attention shall be accorded, by CTU, for planning of capacitors, reactors, SVC and Flexible Alternating Current Transmission Systems (FACTS), Synchronous condenser etc. Similar exercise shall be done by STU for intra-State transmission system to optimize the utilization of the integrated transmission network.

NTPC

v. Also as indicated above, Machines with mechanical governors (MHG) like in VSTPS-I, Singrauli, Kahalgaon-I, may be exempted from complying RGMO stipulations, unless Governor Control in classical form is adopted. Retrofitting them with EHG would entail a huge financial burden on power sector as it will ultimately be passed on to the customers. Primary reserve margin need not be kept in all machines on bar as explained above.

12)	Part 2 – Role of Various Organizations	<ul style="list-style-type: none"> • Para 2.2 – Role of NLDC Keeping in view balancing requirement of RE generation in future, NLDC shall interact with RLDCs/ SLDCs to collate information about grid security and evacuation issues resulting large RE portfolios. • Para 2.3 , the role Renewable Energy Management centres at Regional and National level be included: <i>Forecasting of RE generation on different time scale, Real time tracking of generation from RE sources, interface with multiple parties forecasting service provider systems, prepare day ahead final schedule based on forecast information and proposed RE schedule by RE generators and communication and management of final RE schedule to RE generators and RLDC's main scheduling tools for integrated planning with conventional generation.</i> • Para 2.4, Role of RPC, following para may be added in the end <i>To undertake planning of adequate measures in the regional grid to to provide desired flexibility in the regional grid by planning different technology options</i> • Para 2.5, Role of CTU , a new para 2.5.6 may be added as follows : <i>To identify and formulate adequate measures to create flexibility in Indian grid while integrating large quantum of RE generation in different time periods including different energy storage options and development of flexible power sources.</i> <p>Role of SLDC para 2.7 ----- Following may be added in para 2.7.1 (2)</p> <ul style="list-style-type: none"> • <i>For secure and stable operation of regional grid, SLDC shall share the data with RLDC for its operation including RE generation in the state and its curtailment due to grid security issues along with reasons/ data of grid security issues resulting into RE curtailment so that RLDC can look into this aspect into comprehensive manner for planning of adequate measures to avoid such curtailments.</i> • <i>SLDC on its website shall furnish all data in regard to its generation both from conventional and RE generation in different time blocks and also power demand data at different time periods.</i> 	GREENKO
13)	RLDC role	2.3.1(6) add LC requirement a per MOP and MNRE. MNRE has given formulation for RE contracts	APP
14)	Role of SLDC – 2.7.1 (2) (a)	(a) Be responsible for optimum scheduling and dispatch of electricity within a State, in accordance with the contracts, including enforcement of such commercial terms as opening of LCs, entered into with the licensees or the generating companies operating in that State.'	APP

15)	Role of RPC	To develop and maintain MIS on such information like block-wise availability and transmission capability of regional grid, PLFs of conventional generators and backing down of RE plants so that backing down of RE on the pretext of grid security can be reduced and ultimately eliminated subject to grid security and contingency	APP
16)	Role of STU	Following addition is proposed in functions of STU: To consult state DISCOMs /understand their requirements and put up their issues in Regional standing committee meeting. Disseminate the decisions taken in their regional standing committee meeting to the DISCOMs and other state constituents.	TPDDL
17)	3.4 Transmission Planning	In addition to the exiting provisions of the grid code, the following may be included in the planning philosophy for ISTS lines: 1. An independent agency may be created /existing authority may be entrusted with the jobs of monitoring the performance/degree of utilization of the transmission system/assets vis a vis its technical and declared capacity. Any new transmission assets should be planned only after ensuring that the existing assets are being utilized up to its full capacity and subsequent to clearance from the above agency.” A certificate to this effect from the independent agency should be made a part of the tariff petition to be filed before CERC regarding any new transmission asset. 2. Additionally, Extensive planning of transmission capacity needs to be done considering the ongoing huge RE capacity addition. However, we propose that proper due diligence needs to be done for identifying the potential locations where these projects are coming considering the expected timelines for commissioning of the expected solar/ wind power generation. It should not happen in future that a huge transmission system is created on request of certain beneficiaries/project and in case of non-commissioning of such assets, their transmission charges are billed on the other beneficiaries. Connectivity and open access should be granted to these generators only after ascertaining the feasibility of these projects.	TPDDL
18)	Planning Criterion – General Philosophy 3.5 (a)	While planning of transmission network in Megacities, Metro cities, Urban area etc., planning may be based on N-1-1/ N-2 Criteria without load shedding	APP
19)	3.6 Planning Data –	Presently planning data / base case is not shared with all Transmission licensees, hence if any of the Transmission Licensee likes to undertake study of the network related to its Transmission assets or future development it is not possible to study or provide meaningful inputs in view of already planned / proposed network. Therefore, system base case/ network	APP

	Resource planning for grid stability	<p>simulation studies may be shared with all Transmission Licensees to facilitate system planning activities on need basis</p> <p>Each state utility shall quantify for different time period the requirement of balancing power and ramp up and ramp down requirement keeping in view there different generation sources available and variation in generation due to RE penetration and also variation in demand. <i>State utilities shall also inform the past date of RE curtailments due to grid security and other issues so that adequate measures are planned to avoid such curtailments in future.</i></p> <p>Based on this data CEA and CTU can look into the issue of balancing power, flexibility and also quantify the ancillary services requirements and addressing the same in more comprehensive manner at ISTS level.</p>	
20)	Resource planning for balancing power	<p>While planning power evacuation from renewable generation, measures to create flexibility in power system shall also be planned to address the variable and intermittent nature of renewable and also the balancing power requirement of different states. Accordingly, suitable technologies need to be planned for implementation in National grid like adoption of different storage options and also concept of hybrid of solar and wind with storage to provide round the clock power from renewable and also to provide flexible power on demand to address the variability in generation and demand.</p>	GREENKO
21)	PART 4 CONNECTION CODE	<p>In this code eligibility as included in CERC (Grant of Connectivity, Long term Access and Medium term open Access in inter- state transmission and related matters) (seventh Amendment) Regulations, 2019 including all type of RE generation, hybrid of RE with or without storage and also of RE parks may be incorporated.</p> <p>In the connection code, new para in regard to operation of Electric storage alone projects to be added as follows:</p> <p>Electric storage is a grid entity where electric energy is stored during the time when energy is surplus in the grid to utilise it during the time when energy is in demand for operation of electric storage, electric energy is drawn for storage and same is supplied during high demand period. Therefore for connectivity of storage, there is need to inform maximum quantum of Electric power drawn and during delivery time, the maximum quantum of electric power injected to grid. The transmission planners need to study and analyse the grid adequacy both at time of drawl of power and injection of power and strengthening requirement in the grid if any need to be identified considering both the situations of operation.</p>	GREENKO

22)	RE Connectivity	<p>Basis above we would like to make following suggestion:</p> <ol style="list-style-type: none"> I. Connectivity of transmission access of solar projects should be checked with reference to inverter capacity deployed. II. Connectivity and transmission access of hybrid project should be delinked to the installed capacity of plant. III. If required hybrid projects to be directed to put system in place restricting power injection upto the quantum of transmission access granted. 	ReNew
23)	Operating Philosophy – 5.1 RE frequency response	<p>Frequency response from RE Power Plant is unlikely and impractical. For wind/solar generators, overarching principles on above lines need to be incorporated under the Operating Philosophy as a part of IEGC. Further, expectation of frequency response from RE Power Plant is difficult and goes against principles of “must run” of the installed capacity. Besides, the impact of this on the commercials and the revenue stream of the RE plant based on single part tariff needs to be taken into consideration. For wind/solar generators, overarching principles on above lines need to be incorporated under the Operating Philosophy (5.1) as a part of IEGC.</p>	APP
24)	PART -5, OPERATING CODE	<p>In para 5.1, operating philosophy, following para may be added:</p> <p>There is large RE integration target in future in the country both at CTU and STU connected grid. RE generation has variability and intermittency which require adequate measures to ascertain secure and stable operation of grids. As RE generation addition will be at state and regional level both and due to strong interconnection of state and regional grids, any variation in grid parameters both in state and regional grid will impact both state and regional grids. Therefore, for successful operation of state and regional grid there should be close interaction of data/ information among SLDCs/ RLDCs and NLDC so that and RE curtailment if any due to grid security and stability reasons are analysed in details examining the past operation data so that adequate measures are adopted to avoid any RE curtailment in the state/ regional grids.</p>	GREENKO
25)	5.2 (d)	<ul style="list-style-type: none"> • Any tripping shall be precisely intimated by SLDC /RLDC as soon as possible within 10 minutes of the event. • One of the reasons due to which the DISCOMs under draw is when a section of the load is disconnected due to tripping of transmission lines or power transformers maintained by CTU or STU due to faults. • Further, the problem is compounded by the fact that Delhi DISCOMs procure bulk of the power from generating stations situated outside Delhi, except for some distributed solar (less than 2 MW), and are thus completely dependent on the STU and CTU for delivery of power. Any subsequent corrective action to revise our schedule to the altered demand will take at least 4 time blocks. It has been observed that nearly 70% of the tripping events are restored within 4 time blocks which provides insufficient time to take corrective 	TPDDL

		<p>measures. The Commission may appreciate that, unless intimated beforehand, the DISCOMs /Buyers cannot account for these events in Schedule planning. By their inherent nature, a tripping or fault cannot be predicted. Also as the fault has occurred in a system not maintained by the DISCOM/Buyer, the DISCOM/Buyer cannot take any action to reduce them by predictive or preventive maintenance. Therefore, the DISCOM should not be held liable for any under-drawl on account of any unforeseen failure of a CTU or STU equipment, which resulted in such under-drawl and may be excluded from DSM liability in case of such events.</p>	
26)	Demand Estimation for Operational Purposes – 5.3	<p>At present, demand estimation is not very scientific at all levels and there is need for adopting a robust statistical system for demand estimation which will help operational planning. The provisions related to demand estimation and management measures need to be implemented in timely manner and NLDC / central agency may be given a task to review the implementation progress. This is also the need of the hour in line with the operating frequency band tightening being undertaken through DSM Regulations.</p>	APP
		<p>In regard to demand forecast, it is very important now to estimate not only peak and off peak demand but also the intraday and inter season variation in demand. For this advance tools of demand forecast need to be adopted and continuous augmentation in the technologies of demand forecast shall be done to improve the accuracy in planning and actual demand and its variation.</p>	GREENKO
		<p>As per the current provisions, though the beneficiaries drawal schedules for the next day are decided in the evening before, beneficiaries have to convey their consent by 09:45 Hrs. In the absence of a robust demand forecasting mechanism and uncertainty about the estimated supply positions leads to uncertainty in the URS position for the next day.</p>	NTPC
		<p><i>Each SLDC besides looking peak demand should also look into hourly variation during the day and seasonal variation across the year. This shall be analysed in coordination with generation sources particularly when the states are meeting their part of the demand through variable RE sources. This will help in quantifying the balancing requirement across the year and during intraday in different seasons.</i></p>	GREENKO
		<p>SLDC must have implemented the Online estimation of demand for operational purpose and therefore this clause should be reviewed.</p>	TPDDL
27)	Demand Management – 5.4	<p>Monitoring of demand and deviations w.r.t schedules of Regional entities and State entities should be based on real time AMI/AMR data based on instantaneous meter parameter of Active power and Reactive power (instead of SCADA data as per current practice). Also in order to ensure</p>	APP

		<p>redundancy and accuracy of data, meter wise SCADA data should also be used in such a way that in case of non-availability of some of the meter data due to failure of communication or some other issue, specific meter to be replaced with SCADA data as both systems are independently communicating to the Control centre. Monthly report of the SCADA data and Meter data should be published by all control centres.</p>	
		<p>Meeting the demand through flexible RE sources: Each SLDs are presently facing challenge of large variation both in demand and also generation sources. While meeting variability in both generation and demand, SLDC may explore meeting its demand through flexible sources of electric power with hybrid generation of wind and solar with storage. This will help in reducing the variability in generation and would provide adequate flexibility into the state system.</p>	
28)	5.5 Periodic Reports	<p>A daily report covering This report shall also cover the wind and solar power generation and and injection into grid <i>including the instances of curtailment of solar and wind generation due to grid security issues giving details of grid security issues making the curtailment of RE power.</i></p> <p>In para 5.5.2, Other Reports A new para (c) may be added <i>(c)Report shall also quantify the balancing requirement while absorbing RE power and also ramp up and ramp down requirement of the grid and capability/ limitations to meet the requirements.</i></p> <p>Para 5.6.2(a), following may be added <i>The respective RLDCs may also predict likely wind and solar generation scenarios for the month to predict likely variability and uncertainty in the grid so that adequate measures could be taken up to address these variability and uncertainties.</i></p> <p>In para 5.6.2 (b), following may be added <i>In the near future, since Re generation will have significant penetration in Indian grid and ours is a strong National grid where Re generation located in one region will be required to transfer power to other region, it is very important that different regions share with each other likely estimated variations on the net inter-regional power flows. This will help each of region to plan in advance through various technology options like storage, ancillary services to handle such variations.</i></p>	
29)	COD of Wind, Solar, Hybrid,	Please provide	APP

	Aggregator, BESS		
30)	6.4	In para 6.4 Demarcation of Responsibilities, comments are as follows: After the para 6.4.8 <i>SLDCs/ STUs shall regularly carry out necessary excercises to estimate the requirement of flexibility and balancing in the respective grid based on their load and generation estimation of peak and off peak power and its variation (2)flexible power need and also storage requirement particularly while integrating large RE power into their grid.</i>	
31)	6.4.2 (c) (iii)	Necessary clarification is required in IEGC whether the Regulation 42(3) of CERC Tariff Regulations 2019 shall also be applicable or not to the generators whose tariff is determined by CERC but falling under the control area of SLDC as per IEGC Regulation 6.4(2)(iii).	APP
32)	6.5 Scheduling and Despatch for long term, Medium term, short term open access	RLDCs and SLDCs shall schedule and despatch power from any generator including RE generators to the extent adequate advance payment security mechanism in the form of letter of credit or other payment security mechanism is made available by the concern DISCOM. In the absence of such payment security mechanism, DISCOM shall be liable to pay full tariff in case of RE generators based on forecast of such RE generators and fixed charges <i>in case of conventional generators.</i>	APP
		RLDCs and SLDCs shall schedule and despatch power from any generator including RE generators to the extent adequate advance payment security mechanism in the form of letter of credit or other payment security mechanism is made available by the concern DISCOM. In the absence of such payment security mechanism, DISCOM shall be liable to pay full tariff in case of RE generators based on forecast of such RE generators and fixed charges in case of conventional generators.	GREENKO
		For any revision of scheduled generation including post facto deemed revision; there shall be a corresponding revision in scheduled drawls of beneficiaries.	TPDDL
33)	6.5.19 Reserve shut down	Reserve shutdown (RSD) of unit is done on the instantaneous instructions of concerned SLDC / RLDC and the generator is bound to follow the instructions. Therefore, reserve shutdown of a unit cannot be considered a planned outage since it is immediate & instantaneous in nature, which construes to be forced outage.	APP
34)	Revision of DAM schedules	Further, there is no provision for revision of schedule for collective transactions, in case of forced outage. Due to this, generators participating	APP

		in the power exchange have to face huge DSM liability in case of plant outage incidents which are not in their control.	
35)	6.5 Gate Closure	The sections of capacity declaration and scheduling processes may be appropriately modified to include the procedures, gate closures in view of RRAS and SCED mechanisms. While integrating SCED and RRAS mechanism with day ahead scheduling processes, it may be ensured that minimum time span to be provided to the generators shall not be less than two 15 min time blocks.	APP
		GATE CLOSURE: DEFINITION- provide	IEX
		Introduction of the concept of Gate Closure for the hourly markets	NTPC
		<ul style="list-style-type: none"> I. Defining Gate Closure time with respect to finalization of trade in market. II. Defining Gate Closure time with respect to scheduling. III. Duration of time block to be reduced from 15 minutes to 5 minutes. IV. To amend the minimum time block duration for scheduling and rescheduling from 4 time block to 6 time block 	RENEW
36)	Scheduling PPA in absolute MW	For generators having partially tied up capacity, RLDC should schedule their power even if their PPAs are on MW basis instead of % basis (definition of Share may be amended in the Code). Availability under each PPA should be computed by RLDC with contracted capacity as per that PPA in the denominator instead of Installed Capacity.	APP
37)	Revision of STOA schedules	Intra-day revision of Interstate Short term Open Access schedule may be allowed in line with the Long / Medium Term contracts (Currently advance notice of 2 days is required). Generally DISCOMs undertake Bilateral Transactions to meet the Daily / monthly / seasonal peaks. This will also help generators to tide over deviations in schedule arising out of partial outage etc. These decisions are undertaken well in advance hence it is not possible to forecast accurately. These provisions will also enable effective RE integration.	APP
		Suggestion: Provision for downward/upward revision in STOA power shall made for increasing flexibility in real time operation.	MSEDCL

38)	RSD, start up and shut down timings	Reserve Shutdown (RSD) will vary with, amongst other factors, unit size and so will their start-up and shut-down timings. This should be mandated to be as per OEM guidelines.	APP
39)	Need of mandatory Spinning reserve to be kept by DISCOM	<p>Presently definition of spinning reserve has been included in IEGC, but as mentioned in SOR of 5th amendment of IEGC , the Detailed Procedure for implementation of Spinning Reserve is yet to be published. The same needs to be published at earliest. Further the regulation only specify spinning reserve to be maintained by generator but no specific clause on spinning reserve to be maintained by individual drawy entity. Report of the Committee on Spinning Reserve dated 17 Sep 2018 is attached as Annexure 1.</p> <p>Suggestion: It is necessary that regulation shall also mandate spinning reserve for each drawy entity (irrespective of whether said drawy entity is regional Entity or state Entity). This will help system operator as well as concern DISCOM to meet any eventualit);, in availability without overdrawing from grid.</p> <p>The said spinning reserve shall be based on peak demand and allowable Deviation limit of individual entity.</p>	MSEDCL
40)	Nominal Frequency	<p>Reference / Nominal Frequency: Reference point is an essential part of any control system. In the power systems for effective control of the system frequency, there has to be a reference point. The Committee of Experts formed for this purpose has submitted its recommendations to this effect as under.</p> <p>“Reference frequency for the purpose of control Any control system would need a reference value; in case of frequency control, it would be the target frequency or reference frequency. For the Indian system, the same has to be the nominal frequency of 50.0 Hz. It is therefore recommended that the reference frequency for the purpose of frequency control is considered as 50.0 Hz, and the same is notified in the IEGC.”</p> <p>Therefore, nominal frequency of 50 hertz for the Indian Grid may be considered for incorporation in the IEGC.</p>	NTPC
41)	Primary control (governor control)	<p>Primary control (governor control) is used for frequency stabilization after a large disturbance which operates in seconds (proportional control), the Secondary control restores the primary reserves & frequency to target frequency (50 Hz) and operates in minutes (Integral control) and the tertiary control restores secondary reserves and operates in tens of minutes. For keeping primary reserves, it is necessary to define “event” / “disturbance” and also the quasi steady state frequency by which entire reserves should be harnessed. In absence of secondary control in Indian grid (at present</p>	NTPC

implemented only at Dadri-II, Simhadri-II and Mouda-II only in the form of AGC but restricted), target frequency is also not fixed.

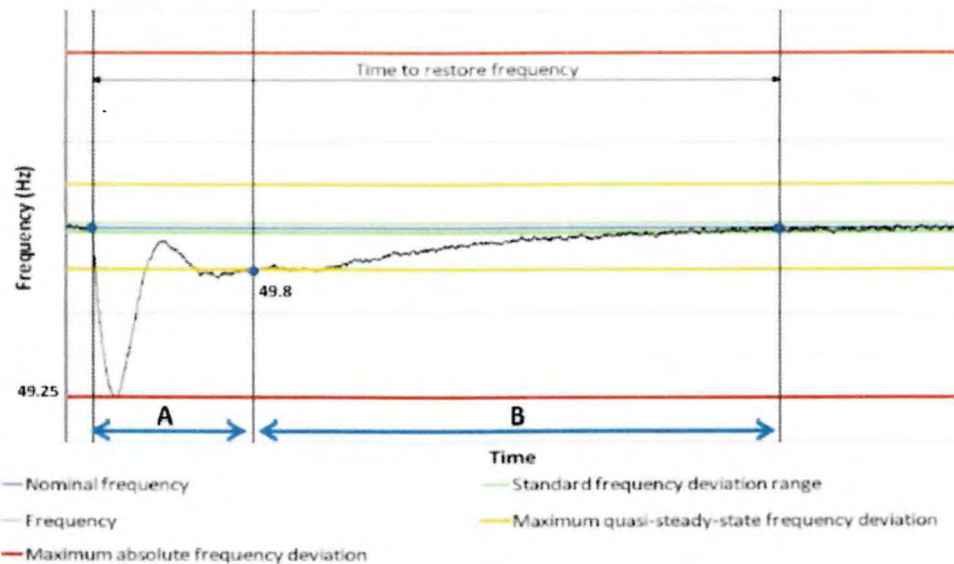
However, considering the target frequency of 50 Hz and a quasi-steady state frequency of 49.8 Hz ($\Delta f = -0.2$ Hz) due to outage of largest power station in the country as a credible contingency, following example can be considered for working out the primary reserve required.

-Power demand and corresponding generation considered as 2,20,000 MW at 50 Hz at the time of disturbance as per CEA estimate for 2021-2022.

- "Disturbance" / "Event": Outage of largest power station i.e., 5,000 MW considered as event of credible contingency.

-Load damping of 4% and Governor Droop setting of 5% assumed.

Parameter	Unit	Peak Load
Demand	MW	2,20,000
Generation	MW	2,20,000
"Disturbance" Generation outage, ΔP_G	MW	5000
Post trip Generation, $P_G' (=P_G - \Delta P_G)$	MW	2,15,000
Capacity of Machines on Governor control to deliver primary UP response.	MW	60,000
D (Load Damping)**	MW/Hz	8,800
1/R (Governing)***	MW/Hz	24,000
AFRC, $\beta = (D + 1/R)$	MW/Hz	32,800
$\Delta f = \Delta P_G \div \beta$	Hz	-0.15
$f = f_N + \Delta f$	Hz	49.85
Load Damping will provide (MW)		1341
Governor response will provide (MW)		3659
Primary Reserve in % of Capacity of Machines earmarked to give UP response		6.10

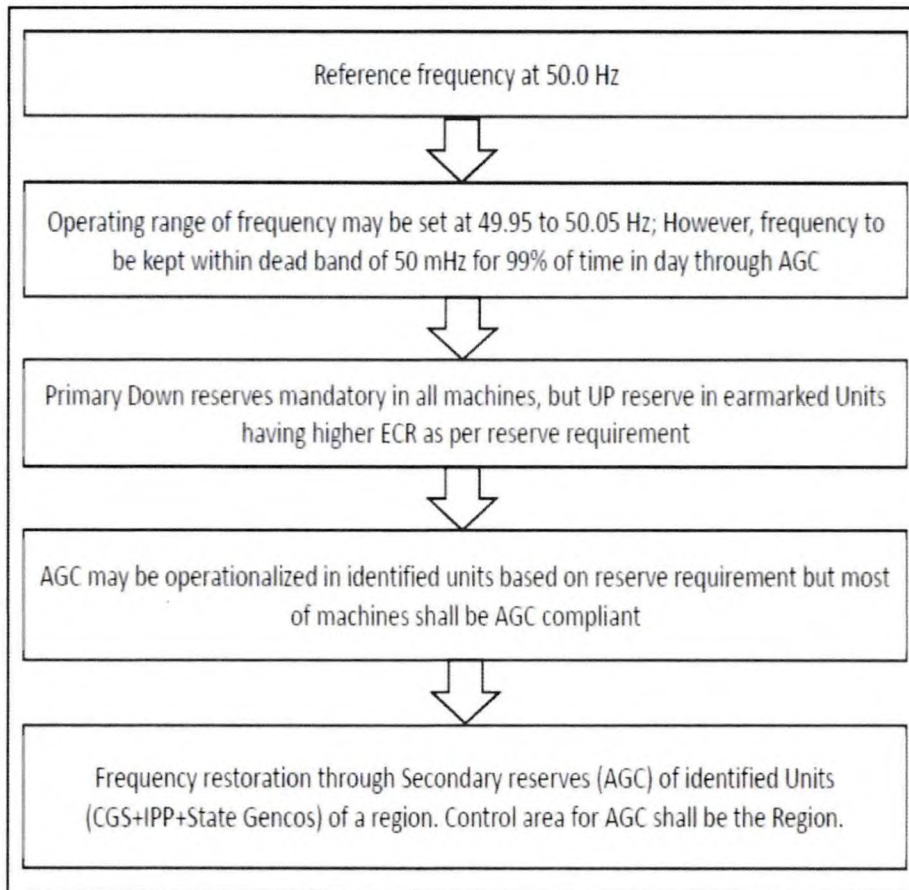


From the above calculation for 2021-22 high RE scenario of Indian grid, it can be seen that the frequency decline can be arrested to -0.15 Hz which is less than -0.2 Hz (quasi-steady state Frequency at 49.8 Hz if nominal frequency is maintained at 50 Hz by Secondary Control) in case of outage of largest power station. This can be achieved if Primary UP reserve is ensured on units having total capacity of only around 60,000 MW in service (synchronized to Grid) out of total thermal generation of around 100,000 MW. The maximum absolute frequency deviation can also be arrested above 49.25 Hz, which is above the acceptable range of UCTE.

Therefore, putting RGMO / FGMO with Manual intervention in almost all machines as stipulated in the IEGC, even for machines with old mechanical governor, 50MW and above Gas Turbines, wind turbines, etc., may not be insisted upon as this entails avoidable expenditure for making the old systems RGMO compliant. 2. Moreover, withholding (by restricting SG to normative DC) cheaper power of pithead stations, like, Sipat, Rihand, Singrauli, Korba, etc., for the purpose of primary response is bottling up cheaper generation, which is also against the theory of economic dispatch. Hence, our suggestion is to identify and keep Primary UP Reserve margin in those machines whose variable cost is moderately high and operating at part load. System operator should carry out such study and earmark those 60,000 MW plus machines which shall carry governor control Up Reserve of ≈ 3700 MW (contingency of 5000 MW generation loss – 1300 MW relief from load damping at 49.85 Hz). However, all the machines in the system must always be operated on Governor control (not RGMO) and support frequency containment in the event of disturbances. Low cost generating units may not keep any Primary UP Reserve Margin or headroom (like Sipat, Rihand, Singrauli, Korba, etc.,) for reducing power purchase cost of the consumers but these machines should participate during high frequency events by Governor Action to reduce generation.

The prerequisite to run machines on Governor Control is to keep frequency within the governor dead band of target frequency of 50 Hz for >99% time by Secondary Control. Hence, AGC in the form of Secondary Control must be implemented across the country on war footing and secondary reserves to be identified and maintained in those units by scheduling them for normal dispatch lower than DC. AGC reserves must be necessarily maintained in machines, which are partially scheduled. Storage Hydro /CCGT units are most suited for this duty. Both up and down changes in generation level by AGC command must be commercially paid for.

Based on the discussions above, the Frequency control regime is proposed as follows:

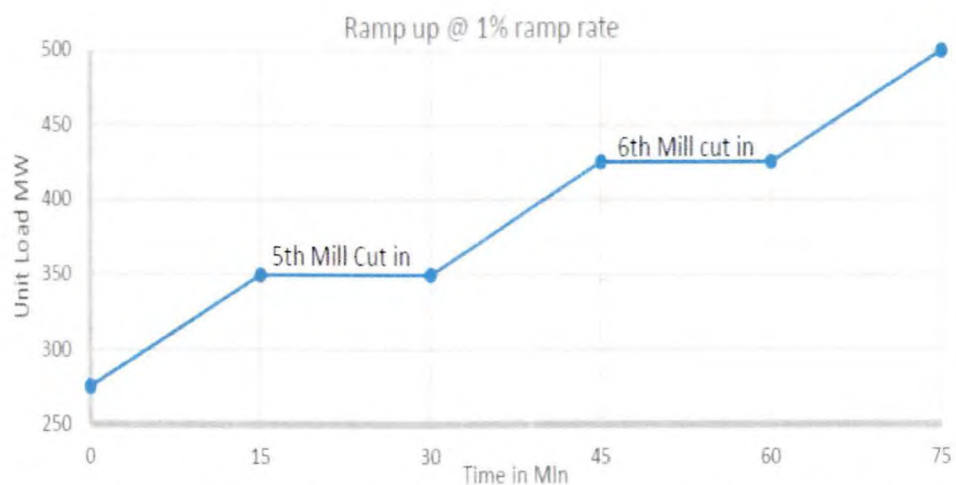


42)	FGMO12 RGMO	<p>FGMO should not be mandatory for Sec 63 projects as it is not essential requirement for AGC implementation. Further, feasibility of FGMO installation needs to be checked for each station.</p> <p>Since RGMO is for system security purpose, the fixed charges for capacity reserve for RGMO provision shall be paid from DSM pool, as in case of RRAS where fixed charges are paid to concern beneficiaries whose surplus is used for system & generator gets paid for variable cost.</p>	APP MSEDCL MSCEDCL
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		Secondly whenever Generators fails to give RGMO response, the said capacity charges shall be borned by concerned generator for said time blocks.	
43)	Strict Enforcement of primary response by generators	<p>The primary spinning reserve which is required to be maintained by generator in term of RGMO is still to be complied by many generators. Regulation 5.2(i) of IEGC 2010 mandate generator for RGMO. However; till date said provision is still violated by many \ c ... \ , . t , generators connected to grid. There is provision for penal actions for Non-compliance of FGMOIRGMO provisi~n. Generator is liable for penal actions under Section 142 /reduction of 1 % on RoE. Further, there is also provision under regulation 5.2(h) that "any generator unit not cO'mplying with RGMO shall be kept in operation (synchronised with regional grid) only after obtaining the permission of RLDe". But even after noncompliance of said provision, initiation of action by RLDC on any of the generator is not in notice. Since action is not initiated, many generators are still under non- compliance. Also, as there is no provision of monetary incentive for RGMO, many generators are under noncompliance for RGMO. Hence monetary penalty need to be introduced so that as per expert committee report on "Spinning reserve in India" primary reserve of 4000MW can be obtained from RGMO. The energy injected into grid in response to RGMO, is compensated through DSM charges and its fix charges are presently being borned by beneficiaries. The issue was discussed in various Western Region OCC meetings during last two years. Report of WRLDC presented in 494th & 517th OCC meetings on response of generator for RGMO are attached for reference as Annexure 2.</p> <p>The expert committee report on spinning reserve has also recommended (21.5, page 51) that Primary reserves of 4000 MW would be maintained on an All India basis considering 4000 MW generation outage as a credible contingency. The same would be provided by generating units in line with the IEGC provisions.</p> <p>Suggestion: It is to be made mandatory for every generator connected with grid to follow the regulation framed in the interest of system security. Action needs to be initiated on Generators not complying with RGMO response.</p>	MSEDCL
44)	Need to remove/reduce mark up incentive to generators for secondary & tertiary reserve	<p>Generator are being incentivised for secondary & Tertiary reserve by commission. As \ regarding secondary reserve, AGC IFRAS has been introduced wherein generator get incentivised by way of mark up. Similarly in. Tertiary reserve, RRAS has been introduced wherein generator get incentivised by way of mark up. The methodology of mark up is different in both mechanisms.</p> <p>Suggestion: Although the mark up is being given from regional DSM pool dccount, if '- generators are incentivised heavily by such mark up, the ultimate result will be burden on DSM pool and amount available for PSDF & thereby for system improvement work wili be reduced by amount of mark</p>	MSEDCL

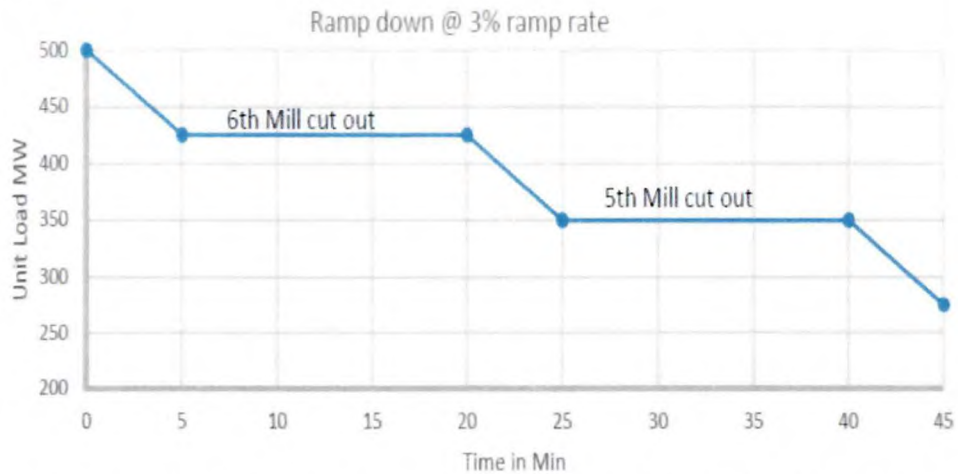
		up paid. Such mark up will only increase the profit of generator and in long run, no much benefit to system. Hence it is suggested that mark up shall either be stopped or shall be nominal.	
45)	Reactive power incentive	Synchronous generators should be incentivized to provide reactive power support	APP
46)	Ramp up and ramp down rates	The actual ramp up and ramp down rates are lower than the design rates under practical conditions. Particularly for high capacity generators, the ramp rate is much less than 1% due to high thermal inertia. Hence, it would be appropriate to decide a normative ramp up rate which may be derived based on the capacity, vintage, technology/make of such generating units. Accordingly, an appropriate methodology may be included in IEGC to work out the normative rate.	APP
		<p>There is need for specifying the permissible step of SG from one time block to the next time block specified and a methodology is described below utilizing the same ramp rate of 1%/min specified under Regulation 5.2 of IEGC: For a 500 MW unit, 1% ramp rate means 5 MW/min increase or decrease. Now to maintain the ramping rate precisely, Control loops are to be tuned so that this ramping may occur smoothly without any major parameters deviation like steam temp, throttle pressure, flue gas O₂ %, drum level etc.</p> <p>Because of RE (wind or solar) integration which is uncontrolled, there is a certain requirement of ramp up or ramp down of power from other power sources mainly from coal based thermal power plants. With reference to grid perspective ramping down or up of thermal capacity cannot be limited to a defined load range. So the ramping requirement of coal based station will be from full load operation to minimum load operation.</p> <p>As per CERC Tariff Regulations 19-24, "Rate of return on equity shall be reduced by 0.25% in case of failure to achieve the ramp rate of 1% per minute; b) an additional rate of return on equity of 0.25% shall be allowed for every incremental ramp rate of 1% per minute achieved over and above the ramp rate of 1% per minute, subject to ceiling of additional rate of return on equity of 1.00%." However, there is certain technical aspects of Ramp rate. The units are provided with varying number of coal mills depending upon the coal characteristics and the unit sizes. When the units load is to be reduced the mill loadings are to be reduced. However certain minimum loadings or turn down of the mills are to be maintained otherwise</p>	NTPC

there is a chance of flame out due to very lean fuel air mixture. Hence, load variation by varying the mill loading can only be achieved within certain range. Beyond this range one or more mills are to be cut in / cut out. During these transient periods, the parameters like temperature and pressure varies. Certain stabilization period is required in this range of load change. The cutting in or out of milling system is to be considered as integral part of ramp up or down operation. Hence achieving continuous load ramp rate from minimum load i.e. 55% till full load (100% load) and vice versa is difficult. The following graph shows practically achievable loads with 1% ramp rate while maintaining safe boiler operation. With 1 % ramp up rate in 15 min time, load may be increased to 350 MW with 4 mills in service and then 5th mill is to be cut in and is to be stabilized in next 15 min for further ramp up to 425MW. Then 6th mill is to be cut in for further increasing to 500 MW. Thus the time required for ramp down is 75 min instead of 45 min by simple calculation of @ 1%~(5MW/min). The same process will be repeated in reverse order for ramp down as shown in the following figure.



Ramp down with 3% : As per OEM recommendation :These control loops are to be tuned up to ramp rate 3% /min or 5%/ min but for a limited time period and in defined load range. For example 3% ramp rate(15MW/ min) for a period of 5 min for a 500 MW unit means load reduction from 500 MW to 425 MW in 5 min duration and vice versa. With this conditions PG tests are conducted to see the deviations of MW achieved in 5 min along with monitoring of important parameters deviation in a limited range. The latest 500 mw unit operating on CMC is capable of this 3% ramping limited to a defined load range e.g. from full load to 425 MW in a period of 5 min but no recommendation is given from OEM for further down below. Thus ramp down with 3% ramp is possible with fine tuning of auto loop and load can be reduced to 425MW in 5 min and subsequently mill to be cut out and allowed to be stabilized for another 15 min and so on. Thus load reduction

from full load to tech min load may be achieved in 40 min as per stair-case curve given below. With block wise ramp down may be to tune of 75 MW per 15 min time block. Similar way ramp up may also be possible at such rate.



Further, with a declared ramp rate of 1% per min, the load needs to be changed by 15% within a block of 15 minutes. If the schedule in block number-1 is, say 60%, then with 1% ramp rate it is only possible to achieve a load of 75% at the end of block-2 only. Hence, the average load during block-2 is 67.5% only which translates into effective ramp rate of 0.5% (not 1%). However, in the present scheduling system, the schedule given in block-1 is 60% and block-2 the schedule is 75%, which requires a ramp rate of 2% to achieve it. While scheduling the loads, above aspects also need to be kept in mind. Further in order that the operating staff prepare for cutting in / cutting out the mills, the schedule should be known at least 4 blocks in advance.

Thus as per table mentioned below the effective ramp rate from full load to 55% tech min load with 1% and 3% ramp rate both up and down are considered for a 500 MW unit

Ramp rate / min	Effective rate	Remark
1%	0.5%	Single Milling system cut in/ out and stabilization time taken 15 min
3%	1.125%	

Thus effective ramp down per 15 min time block will be average of $(500+425)/2$ i.e. 462.5 MW for subsequent block. For 1% ramp down block wise will be (500-462-425-387-350-312-275 MW) on gross generation approximately (37-38) MW per 15 min time block.

47) SCED

SCED payment is received by generating station after getting statement from NLDC (monthly) and the generator has to give payment after getting

APP

		report from RLDC (weekly). This leads to additional working capital requirements.	
48)	Time block wise compensation	Compensation for degradation of performance should be block-wise rather than on monthly basis. Besides, compensation for adverse impact on life of the generating asset may also be provided to enable recovery of capital costs over such reduced life (at least 10% reduction of useful life may be considered).	APP Adani
49)	SCED	SCED is beyond the scope of the original PPA and therefore should be compensated at actual costs as per tariff regulations.	APP
50)	Aux power from tertiary terminal	Grid Code may provide clarity for charges on account of usage of the auxiliary power from transformer tertiary terminal.	APP
51)	Additional Capex for plant renovation to mitigate impact of frequent start/stops on account of RSD	<p>Damage is caused to the metallurgy of the boiler and other parts due to frequent start/stops and the consequential additional capital expenditure is required for renovation of the plant/equipment to mitigate such impact (reduction of the useful life of the plant). The framework of competitive bidding for procurement of thermal power was designed to cater base load of the distribution utilities. Accordingly, the normative availability mandated in section 63 PPAs is 85%. The generators are entitled to receive incentives if the availability is more than 85% and are penalised for availability below the normative availability. Therefore, the scenario of frequent start/stops on account of RSDs and consequential impact on machinery was not envisaged while submitting the bid. While the power plants supplying power under regulated tariffs are allowed relief through additional capital expenditure, such a dispensation is not available for the plants supplying power under competitive bidding regime. The relief available to Section 63 PPA is only in terms of change in law and Force Majeure provisions.</p> <p>Request: It requested that Section 63 projects should be allowed relief available to cost plus PPAs to restore the developer to the same economic position which could not be envisaged at the time of bid. A suitable provision may be incorporated in IEGC.</p>	Adani
52)	Compensation towards increase in Repair &	A suitable provision may be incorporated in Regulation 6.3B of IEGC to allow additional Repair & Maintenance Expense on account of frequent variation in operations for both section 62 and section 63 PPAs.	Adani

	Maintenance Expense		
53)	Compensation towards Secondary Fuel Oil compensation	<p>As per CERC mechanism (also in 4th amendment), no compensation for degradation of Secondary Fuel oil consumption is Payable for the year if total number of start-ups is equal to or less than 7 x no. of units in the generating station or the Actual Secondary Fuel Oil Consumption is less than Normative Fuel Oil Consumption.</p> <p>Submission: Thermal power stations running at 55% are vulnerable for tripping of boilers due to improper flame condition in case of poor coal quality or any tripping of coal mills. Due to this additional oil support will be required for flame stabilization to avoid tripping of Unit thereby ensuring reliability of power supply. The oil required for such incidences is not considered for any compensation in this order and compensation is only considered for solely attributable to reserve shut-downs.</p> <p>Also if loading is not allowed for say more than 100 - 120 hrs of continuous operation at 55% loading, the Unit may be forced to carry out wall soot blowing with oil support.</p>	Adani
54)	No compensation for Heat Rate degradation and Auxiliary Energy Consumption shall be admissible if <i>the actual Heat Rate and / or actual Auxiliary Energy Consumption are lower than the normative</i>	<p>This clause is discouraging to the power stations which are implementing the efficiency improvement measures and reducing the actual Stations heat rate & Auxiliary Energy Consumption for the same output. ADTPS in the past has consistently over performing the efficiency norms and thereby sharing the efficiency gains with the consumers, however, with such onerous condition, it might be possible that entire efficiency gain will be lost. It is submitted that compensation shall also be provided to protect the efficiency gains for performing Generating Stations. The efficiency gain can be compensated by stipulating the condition that in case of part load operation, the degraded Stations Heat Rate and Auxiliary Consumptions shall be considered as the normative parameters and it shall be compared with the actual parameters for computing the efficiency gains / losses.</p>	Adani
55)	PART LOAD COMPENSAT	Present compensation on HR at part load (3% at 50% load for supercritical units while 6% for subcritical units) is not adequate. CEA recommendation	NTPC

	ION FOR THERMAL STATIONS	(during operational norms fixation of Tariff Regulations 2019-24) to CERC regarding degraded HR & APC due to part load operation may please be implemented	
56)	Regulation 6.4(2)(c)(iii) PEAK OFF-PEAK CONCEPT	<p>Regulation 42(3) of the Tariff Regulations, 2019 provides as under “(3) Normative Plant Availability Factor for “Peak” and “Off-Peak” Hours in a month shall be equivalent to the NAPAF specified in Clause (A) of Regulation 49 of these regulations. The number of hours of “Peak” and “Off-Peak” periods during a day shall be four and twenty respectively. The hours of Peak and Off-Peak periods during a day shall be declared by the concerned RLDC at least a week in advance. The High Demand Season (period of three months, consecutive or otherwise) and Low Demand Season (period of remaining nine months, consecutive or otherwise) in a region shall be declared by the concerned RLDC, at least six months in advance: Provided that RLDC, after duly considering the comments of the concerned stakeholders, shall declare Peak Hours and High Demand Season in such a way as to coincide with the majority of the Peak Hours and High Demand Season of the region to the maximum extent possible: Provided further that in respect of a generating station having beneficiaries across different regions, the High Demand Season and the Peak Hours shall correspond to the High Demand Season and Peak Hours of the region in which majority of its beneficiaries, in terms of percentage of allocation of share, are located.”</p> <p>Regulation 6.4(2)(c)(iii) of IEGC provides as under “(iii) If a generating station is connected both to ISTS and the State network, scheduling and other functions performed by the system operator of a control area will be done by SLDC,, only .if state has more than 50% Share of power. The role of concerned RLDC, in such a case, shall be limited to consideration of the schedule for interstate exchange of power on account of this ISGS while determining the net drawal schedules of the respective states. If the State has a Share of 50% or less, the scheduling and other functions shall be performed by RLDC.” Request: It is requested to clarify that the Regulation 42(3) of CERC Tariff Regulations 2019 shall be applicable only to the generators whose tariff is determined by CERC but falling under the control area jurisdiction of RLDC in terms of IEGC Regulation 6.4(2)(c)(iii).This Needs To Be Reviewed</p>	Adani
		Hydro power scheduled from one region to the other region having different peak hour declared by RLDC’s are facing difficulty for PAFM certification which is linked with availability during peak hours which is not uniform across RLDCs.	PTC

57)	6.4 (2) (b) Control Area jurisdiction	<p>6.4 Demarcation of responsibility Regulation 6.4(2) (b) read as under:</p> <p>"2. The following generating stations shall come under the respective Regional ISTS control area and hence the respective RLDC shall coordinate the scheduling of the following generation stations: "</p> <p>(b) Ultra Mega Power Projects including projects based on wind and solar resources and having capacity of 500 MW and above".</p> <p>Suggestion: Accordingly, in a STU substation where 500 MW and more wind and solar generators are connected, its scheduling jurisdiction lies with the RLDC. But RLDC and RPCs are reluctant to implement the same on account of the opposition from the SLDCs. The intent underlying the proposed regulation was to integrate large scale wind/solar generation in the larger grid, where it can be absorbed easily. Therefore, the Regulation 6.4 (2) (b) needs to specifically mandate RLDC/SLDC for implementation of the same.</p> <p>Currently there is lack of clarity in the control area of the RE projects, particularly in case of Solar parks. RE capacity within solar park normally get developed in phases. So initially, a particular RE project gets connected to the State network at a lower voltage and accordingly scheduling is done by the SLDC of that State. Metering is also at the lower voltage level. As RE capacities in other phases are commissioned the solar park gets connected to the ISTS and scheduling is now done by the RLDCs as per the extant provisions. However, as the metering point now gets shifted to higher voltage level, additional transmission losses are loaded on the RE developers. This situation can be avoided if the systems are developed from the beginning as Regional Systems and there is clarity in treatment of losses.</p>	<p>National Solar Mission</p> <p>IWPA</p> <p>NTPC</p>
58)	6.5.19 (a) Reserve shutdown	<p>Reserve shutdown of unit is done on the instantaneous instructions of concerned SLDC / RLDC and the generator is bound to follow the instructions. Therefore, reserve shutdown of a unit cannot be considered a planned outage since it is immediate & instantaneous in nature, which construes to be forced outage. Hence, revision of short term open access transactions should be allowed in case of reserve shutdown and the Regulation 6.5.19 should be modified as follows:</p> <p><i>"Notwithstanding anything contained in Regulation 6.5(18), in case of forced outage and / or Reserve Shut Down (RSD) 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. With the objective of not affecting the existing contracts, the revision of schedule shall be with the consent of</i></p>	<p>Adani</p>

the buyer till 31.07.2010. Thereafter , consent of the buyer shall not be a pre-requisite for such revision of schedule. The schedule of the generator and the buyer shall be revised, accordingly. The revised schedules shall become effective from the 4th time block, counting the time block in which the forced outage is declared to be the first one.. The RLDC shall inform the revised schedule to the seller and the buyer. The original schedule shall become effective from the estimated time of restoration of the unit. However the transmission charges as per original schedule shall continue to be paid for two days."

The Hon'ble commission has approved Detailed Operating Procedure for taking units under Reserve Shut Down which NLDC framed as directed under Regulation 63B.6 and 6.3B.7 of IEGC-2010. As per clause 5.7 of said DOP for taking unit under RSD, the concern RLDC have been vested with power to suo-moto revise the schedule of any generating station as per clauses 6.5.14 and 6.5.20 of IEGC to operate at or above technical minimum in the ratio of under-requisitioned quantum (with respect to technical . minimum) in the interest of smooth system operation under the specified conditions \ mentioned in said procedure. But there is no specific para given in said procedure wherein it is mandatory to RLDC to inform all beneficiaries regarding the clause under which the decision is taken by RLDC to either suo-moto revise the schedule or take unit under RSD. In case RLDC exercises power under clause 5.7 of Detailed Operating Procedure for taking units under Reserve Shut Down, concerned RLDC shall intimate , beneficiaries about same with reason. If unit is withdra\\]l under RSD, then in this case any beneficiaries who is/are ready to take its full oW11 share to support technical minimum shall not be liable for compensation payable to generator for more than 7 start up. The reason is that though beneficiary was ready to take its own share but unit declared under RSD due to less/no schedule from remaining beneficiaries.

In present mechanism, as per clause 4.1 , sub clause (xiv) (b), "the compensation amongst other beneficiaries shall be shared in the ratio of un-requisitioned energy below 85% of their entitlement". It is suggested that instead of taking entitlement which include DC under RSD, sharing of compensation should be in ratio of scheduled energy to total ON BAR DC.

As per provision in fourth amendment of IEGe, clause 6.3B, sub clauses 3 (i) it is mentioned that in case of coal/lignite based generating stations, following station heat rate degradation or actual heat rate, whichever is lower, shall be considered for the purpose of compensation...

It is necessary that while computing compensation, if actual heat rate is lower than given in above table, then actual heat rate should be used instead of calculated heat rate based on above values.

MSEDCL

59)	6.5.19 and 6.5.19 (A)	<p>6.5.19: <i>Notwithstanding anything contained in Regulation 6.5.18, in case of forced outage of a unit of a generating station (having generating capacity of 100 MW or more) and selling power under Short Term bilateral transaction (excluding collective transactions through power exchange), the generator or electricity trader or any other agency selling power from the unit of the generating station shall immediately intimate the outage of the unit along with the requisition for revision of schedule and estimated time of restoration of the unit, to SLDC/RLDC, as the case may be.</i></p> <p>6.5.19(A): <i>In case of revision of schedule of a generating unit, the schedules of all transactions under the long-term access, medium-term open access and short-term open access (except collective transactions through power exchange), shall be reduced on pro-rata basis.</i></p> <p>It is proposed that following text may be deleted from:</p> <p>a. Regulation 6.5.19 <i>"(excluding collective transactions through power exchange)"</i></p> <p>b. Regulation 6.5.19(A) <i>"(except collective transactions through power exchange)"</i></p> <p>Justification: Under the SOR for 1st Amendment to Grid Code, CERC while allowing revision for STOA of short term bilateral transactions had held as below:</p> <p><i>"Regarding the comment by POSOCO, Adani Power, MB Power, JSW Power Trading and R2I, it is observed that the objective of this Regulation is to provide proper signal to all concerned utilities in case of forced outage of the unit by revising the schedules. We are of the view that if generation is reduced from the generating unit, then there is no point in keeping the original schedule which would give wrong signal for the buyer as he would continue overdrawing from the grid even though the generation is reduced and affect the grid security".</i></p>	Teesta Urja
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		<p>Presently, the Grid Code allows revision through real-time curtailment for collective transactions in case of transmission constraints in line with the provisions of Regulation 6.5.28, 6.5.30 and 6.5.31 of Grid Code and the same is also being done by NLDC, being the nodal agency for collective transaction. As such, there is no procedural problem in curtailment of schedule for the buyers and sellers under exchange in the event of any transmission line tripping. Accordingly, the same can be implemented in case of forced outage beyond the control of the generator selling under collective transactions.</p> <p>Accordingly, revision of schedule needs to be permitted in case of collective transactions as well for forced outage of generating unit/power station of more than 100 MW capacity.</p>	
60)	Notice period for RSD (b)	<p>It is suggested that imported coal based project should be given an advance notice of 15 days before instructing such plants for Reserved Shut down. Imported coal based projects need to plan their coal supply in advance and cannot go for RSD on instantaneous instructions. Therefore, a suitable provision may be incorporated in IEGC for imported coal based projects.</p>	Adani
61)	6.4.24	<p>Under this regulation, hydro stations are expected to support the grid during frequency fluctuations. However, deviation on such account is governed by Deviation Settlement Mechanism Regulations.</p> <p>Under the present DSM Regulations (Regulation 7(10)), charges are leviable for sign change. Further, w.e.f. 1st April 2020 additional charges shall be leviable for sustained deviation beyond 6th time block (1st proviso to Regulation 7(10)(b)). Considering hydro projects support the grid both during high & low frequencies, following suggestion is made with respect to levy of charges/additional charges for sign change:</p> <p>a. When the frequency is greater than 50.05 Hz: Under Injection shall be permitted beyond 6-time blocks and no additional charges shall be levied for sign change pursuant to present 1st proviso to Regulation 7(10)(b).</p> <p>b. When the frequency is lesser than 49.85 Hz: Over Injection shall be permitted beyond 12 time/6 time blocks and no charges & additional charges shall be levied for sign change pursuant to present Regulation 7(10).</p>	Teesta Urja
62)	Revision of Interstate Short Term Open Access Transactions	<p>Revision of Interstate Short term Open Access schedule to be made effective on same day basis in line with the Long / Medium Term contracts (Currently advance notice of 2 days is required)</p>	Adani
63)	Clause 5.1.(h):	<p>The said clause mandate power plant/sub-station of 132 kV and above shall be manned round the clock by qualified and adequately trained personnel.</p>	Adani

	Recognition of unmanned sub-station	It is suggested that power transmission substations are now a days very often unmanned and can be physically distributed over quite a large area. They usually not only contain the high voltage level but also the sub-transmission and distribution as well. Substation automation system available for all voltage level provide reliable remote connection for operational purposes and to have a fast and secure operation and the same should be recognized in the Grid Code.	
64)	RE and frequency regulation service	Ontario Independent Electricity System Operator (IESO) is an independent Electricity System Operator (IESO) is the entity responsible for operating the electricity market and the bulk electrical system in the province of Ontario, Canada. IESO mandates that generators, including wind and solar generation, satisfy specific capabilities as part of its connection conditions, namely concerning the maximum deadband, adjustable droop range, and rate of delivery. The requirement to operate with a functioning governor in service satisfying these technical specifications is mandated for units providing IESO's frequency regulation ancillary service. IESO now mandates that wind generators have the capability to provide a synthetic inertia response to the system following a frequency deviation. This response must be activated within one second and maintained for a minimum of ten seconds, for the case where the frequency has not sufficiently recovered. The motivation for this requirement was to enable wind generators to contribute to the Primary Frequency Response (PFR) of the system without needing it to curtail itself to do so. It is suggested that IEGC should enable market based Ancillary Services procurement for large scale integration of wind and solar energy and also allow such wind and solar generators to participate in such market.	Adani
		<p>Optimal Operation of Grid:</p> <ol style="list-style-type: none"> 1. The Solar PV generators above 10 MW shall be obligated to utilise dynamic grid support capabilities of the inverter/PCU like active power regulation and reactive power control. 2. To encourage adoption of capabilities as above, Solar PV Generators should be incentivised for supporting the grid, the mechanism of which could be worked out by a technical work group. 	SECI
65)	Clause 5.2 (u): Backing down of wind and	As per Regulations 5.2 (u) that the SLDC/RLDC can instruct the solar/wind generator to back down only in cases of grid security or safety of any equipment or personnel is endangered. Many SLDCs are asking wind and solar generators to back down in cases other than event of grid security or safety of any equipment or personnel is endangered, like low demand in	Adani

<p>solar generation</p>	<p>the system. There should be strict adherence to the provision of 'Must Run' for renewable energy. Accordingly, it is suggested that any backing down in cases other than grid security or safety of any equipment or personnel is endangered, a provision of deemed generation should be provided and its compensation form the State or regional UI Pool by SLDC /RLDC needs to be mandated. The generator should be compensated for full tariff in order to meet their liability towards debt service. It is further suggested that the term "Grid Security" needs to be specifically defined as the low demand in system cannot be considered as a grid security event. SLDCs in the name of low demand are asking high cost wind and solar generators to back down throughout the day, without asking State thermal generator to back down upto its technical limit or without reducing central sector share. It is suggested that the term "Grid Security" can be defined as below, "Whenever there is change in the basic parameter of power system (i.e. Voltage variation, frequency variation, df/dt and dv/dt response, thermal loading of the equipment) beyond allowable limit which can affect the performance of the system should be considered as GRID SECUTIRY". Hence, it is requested to IEGC to define allowable limits of above parameters for implementation in grid code.</p>	<p>HERO</p>
	<p><i>"States was advised not to curtail wind power plans unless required on technical grounds. Further, all such curtailment should be only on written instructions from SLDC." (Minutes of the MNRE Discussions (Page 12, para 9 (iii))</i></p> <p>Based on above we request to have provision in new IEGC to mandate SLDCs to ensure following while passing backing down instruction.</p> <ul style="list-style-type: none"> a) Written instructions/E-mail communication should be issued to each individual generator and concerned PSS in-charge informing of the back-down. b) The backing down instructions should be certified by a competent authority; c) The reason of back down has to be mentioned in communication. <p>Further IEGC shall provide the standard format on which a back down instruction shall be passed as many states complain of want of standard format.</p>	
	<p>"System operator (SLOC/ RLOC) shall make all efforts to evacuate the available solar and wind power and treat as a must-run station. However, System operator may instruct the solar /wind generator to back down generation on consideration of grid security or safety of any equipment or personnel is endangered and Solar/wind generator shall comply with the same. For this, Data Acquisition System facility shall be provided for transfer of information to concerned SLDC and RLDC: (i) SLDC/RLDC may direct a wind farm to curtail its VAr drawl/injection in case the security of grid or safety of any equipment or personnel is endangered. (ii) During the wind</p>	<p>IWPA</p>

		<p>generator start-up, the wind generator shall ensure that the reactive power drawl (inrush currents in case of induction generators) shall not affect the grid performance."</p> <p>Suggestion: As per Regulations 5.2 (u) the SLDC/RLDC can instruct the solar/wind generator to back down only in cases of grid security or safety of any equipment or personnel is endangered. Many SLDCs are asking wind and solar generators to back down in cases other than event of grid security or safety of any equipment or personnel is endangered, like low demand in the system. Therefore, it is suggested that any backing down in cases other than grid security or safety of any equipment or personnel is endangered, a provision of deemed generation should be provided and its compensation from the State or regional UI Pool by SLDC /RLDC needs to be mandated. It is suggested that the term "Grid Security" needs to be specifically defined as the low demand in system cannot be considered as a grid security event. SLDCs in the name of low demand are asking high cost wind and solar generators to back down throughout the day, without asking State thermal generator to back down up to its technical limit or without reducing central sector share.</p>	
		<p>In para 5.2 (U) ---- System Security Aspects, Special requirement for solar/wind generators:</p> <p>System operator (SLDC/RLDC) shall make all efforts to evacuate the available solar and wind power and treat as must run station. Howeversolar/ wind generator shall comply with the same.Whenever solar/ wind power is curtailed against must run principle, the renewable power will be considered as deemed generation based on forecast provided by generator and will be paid full tarff for such deemed generation.....For thisSLDC and RLDC :</p> <p><i>(iii)In case of any curtailment of RE generation at state or regional level detail analysis may be carried out at regional level by RLDCs as many of RE integration issues require support due to integrated operation and balancing of RE at regional and National level. For carrying out this analysis, the SLDC shall share all the information of the respective state Re curtailment and related grid security issues and causes so that remedial measures are planned and implemented at state/ regional/ National level.</i></p>	<p>GREENKO</p>
		<p>RENew comments</p>	<p>ReNew</p>

		<p>To avoid such discrepancy and to make the grid operation more transparent the system operators at all level should be mandated to communicate the reasons along with the each backing down instruction. Further there is need to establish a mechanism for regular reporting and tracking of curtailment, including reasons thereof. Such information should be collated from all the relevant agencies including the agency issuing curtailment instructions (SLDC and DISCOMs) and the RE generators.</p> <p>Basis above we would like to make following suggestions:</p> <ol style="list-style-type: none"> I. All system operators should be mandated to communicate reasons along with each backing down instruction. II. All system operators i.e State Load Despatch Centre and Regional Load Despatch Centre should mandatorily create a repository containing details of backing down instruction, reasons and grid parameter for the duration of curtailment. III. All system operators should mandatorily report this data to Central Electricity Authority which will then facilitate creation of central curtailment data repository. IV. All stakeholder should be given access to such repository for confirmation and to avoid dispute in future. 	
66)	Applicability of DSM for Renewable Energy participating in collective transaction	<p>1. Renewable Energy (RE) Seller participating in DAM, will be selling Renewable Energy at market determined price, on which DSM charges notified separately for RE generators should be made applicable. Such dispensation would facilitate in boosting RE capacity addition (wind and solar) without entering long-term PPA.</p>	Adani
67)	Centralized Forecasting of wind and solar generation by SLDC/RLDC	<p>Currently there are requirement of forecast by individual wind farm/solar project. Setting up of a reliable and workable mechanism for accurate forecasting and scheduling of wind/solar power involves substantial investment in equipment for telemetry, SCADA, communications etc, and also in human resources and consultant fees. Therefore, the centralized forecasting, covering large number of solar/wind plants spread across large geographical area would be a more suitable arrangement acceptable to all wind and solar generators and SLDC/RLDC.</p> <p>SLDC/RLDC can deploy technology capable of dealing with feeds from multiple forecast engines and blending the same for improved accuracy over time. The costs incurred for undertaking the forecasting and scheduling based on the forecast would, however, be borne by the wind and solar energy generator. A framework as prevalent in some states in the US and in some countries in Europe, wherein the wind/solar generators are allowed to generate as per resource availability and the cost of balancing the variability and uncertainty is socialized across all market participants.</p>	Adani
		<p>1. Responsibility for Scheduling and forecasting should lie with the REMCs equipped with RE forecasting, scheduling & monitoring systems instead of each individual generator/QCA. Further, proposed REMCs shall be mandated with collection and processing of all plant data, including RE</p>	SECI

Plants, in real time from Plant SCADA systems. The REMCs shall work in close coordination with respective Load Dispatch Centres for RE generation and control for smooth grid operation. The Deviation Settlement Mechanism regulation should be pegged to the REMC schedule to implement a coherent strategy for managing RE penetration at state level.

2. The permissible deviation band should be rationalised based on the Forecasting Technology, capabilities and whether data available.

3. As per current regulatory mechanisms, forecast is applicable with a delay of 45- 60 to 90 mins. Since the variations due to cloud movements range from a few seconds to a few minutes, capturing these variations in forecasts would necessarily require high temporal resolution. NWP models are available at a spatial resolution of 50KM. To achieve a higher spatial resolution, local or regional models are necessary which would be costly and inflict financial burden on RE generators. **Instead RE generators can be mandated to maintain minimum smoothing storage reserves to ensure that output is maintained within a stipulated band of 15-30 minute moving average.**

4. Limited Revisions Allowed-

16 Revisions for Wind and 9 revisions for Solar are allowed (One each in 1.5 Hours) as against unrestricted revisions allowed in case of conventional generators. To bring parity, RE generators shall be allowed unrestricted revisions.

5. Detailed Commissioning procedure for Wind and Solar Power generating stations may be appended to Clause 6.3A with due consideration to the notification of Central Electricity Authority (Technical Standards for Connectivity to the Grid) (Amendment) Regulations, 2019.

RENew suggestions

Table below exhibits various aspects of centralized forecasting that is being followed in develop counties:

Item	Denmark	Germany	UK	USA (ERCOT)
Wind penetration in energy terms	30%, target of 52% in 2020	8%, 35% (all renewables) by 2020	6%, 30% (all renewables) by 2020	9%
Markets	Day-ahead. Intra-day market.	Day-ahead. Intra-day market (45 minute gate closure)	Bilateral trading. up to gate closure (1 hour)	Bilateral trading. Wholesale markets (day-ahead and balancing by ERCOT)
Forecasting	TSO responsible. Forecast is published. BRPs may use own forecasts for trading purposes	Forecasting done by energy traders, both independents and TSOs.	Forecasting done by energy traders. TSO has its own forecasting process, for operational purposes.	Forecasting done by energy traders. ERCOT has its own forecasting process, for operational purposes.
Requirement of forecast by individual wind farm	No	No	No	No
Forecasting costs met by	TSO, BRPs (if additional forecast capability is considered useful)	Energy Traders	TSO, Energy Traders	TSO, Energy Traders
Forecast Details	60 minutes for energy trading. TSO uses 5-minute time step for internal short-term forecasts.	15 minutes for energy trading	30 minutes for energy trading	Driven by trading requirements (60-minute time step).

Basis above we would like to make following suggestion:

- I. To introduce concept of forecasting at Regional level mandating RLDC to perform all such related activities as per the DSM regulations concerning wind and solar based generating stations.
- II. RLDC to be empowered to perform the balancing services on real time basis by way of plugging in and/or out the schedule generation.
- III. Cost Incurred for providing balancing services shall be socialised among the states depending upon their contribution in deviation

In case of RE generators, presently responsibility is given to RE generators or by QCA appointed by RE generators. In the present mechanism, there is penalty on each of the generator in case of deviation from the schedule when the deviation of each of the generator is taken care. Whereas if we aggregate at grid pooling station wise or control area wise, the deviation will be less due to diversity of variations among different generators and combined deviation may be less if it is taken on control area wise. In case of state generation and state demand for a particular state, the schedule is given for net injection or net drawl on state basis. Even though there may be variation in individual state load or state generator but combined together as net drawl/ injection, deviation is less. With the same principal RE scheduling/ forecasting and its deviation can be done control area wise. For aggregating the RE generation, QCA may be appointed by

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		<p>SLDCs/ RLDCs and deviation corresponding to total RE may be divided among RE generators based on their declared capacity.</p> <p>It will also be desirable to appoint QCA by SLDCs/ RLDCs as their selection criteria will be more stringent as compare to individual generator.</p>	
68)	INTEGRATION OF RENEWABLE ENERGY IN THE GRID	<p>~ Larger balancing area:</p> <p>~ Operating the balancing power in a Centralized manner:</p> <p>~ Deployment of energy storages</p>	NTPC
69)	Drawl of power from the Grid by RE projects when they are not generating	<p>Renewable Energy projects also need to draw power from the Grid when they are not generating, mostly to meet minor power requirements at the station. For example, during night, most solar plants will need some power for lighting, cleaning and other requirements. At present there is no clarity regarding settlement of this drawl and in the absence of the same different States are following different practices. Some states are charging at the rate of temporary consumer connected at that voltage. To bring uniformity and certainty to the RE developers, Grid Code should provide settlement of such drawl as per the DSM Regulations. Various State Grid Code may then adopt the same approach as well.</p>	NTPC
70)	Commissioning of RE project	<p>30 days prior to the proposed synchronisation/commissioning/COD date developers are required to intimate the procurer.</p> <p>Procurer as per state regulations forms committee comprising of competent authorities to declare and certify the plant as synchronised with grid, commissioned and commencement of commercial operation by the plant.</p> <p>Prior to the date of Synchronisation, commissioning and COD, Developer ensures all the mandatory statutory approval like CEIG certificate, connectivity and charging approval etc. are in place.</p> <p>On the date of synchronisation, commissioning & COD, commissioning committee and developer jointly sign the Installation report, Synchronisation & Commissioning MOM including initial meter reading for billing as per the terms of Power Purchase Agreement (PPA).</p>	Adani
71)	Integrated scheduling software	<p>1. Integrated scheduling software need to be made available wherein communication (revision of schedules) between RLDC, SLDC, Generators and Discoms etc becomes seamless. This is in the current scenario need of hour and is expected to provide a major benefit in case of any contingency scenario especially in case of outage of any major generating station.</p> <p>2. Further, time for processing of Intraday contingency applications, which is presently of 3 hrs and for all practical reasons is not less than 04 hrs, need</p>	BRPL DVC

		<p>to be minimised to 04 time slots by way of integrated consent management software.</p> <p>3. Presently, it can be seen that all RLDCs publishes approx 150 - 200 revisions in a day. Tracking these many revisions may not be feasible by any Discom.</p> <p>4. With DSM 5th Amendment in place, any change in actual generation by a renewable energy plant, without an automated intimation platform wherein any change in schedule by RE generator is known to Discoms, may lead to sustained violation penalties.</p> <p>5. 01 revision for next Day for all ISGS being available on respective RLDC's website doesnot take into consideration the tripping status of the plant, if any and generally depicts the full DC of the plant for the next day. This need to be updated based on the present running condition and outages so that proper planning for the next day can be done by Doscoms.</p>	
	<p>Web based Scheduling & RPC Account Statements</p>		
		<p>Uniformity in web-based schedule publication formats across all RLDCs need to be ensured. There are discrepancies in naming of Gencos and entities across RLDC's web application softwares. ISGS having beneficiaries in multiple regions are scheduled by respective RLDCs but this data may be made available in the website of the RLDC where it is geographically located, for e.g., in case of Kahalgaon-II having beneficiaries in ER, NR and other regions, one has to look for multiple RLDC website to know its drawal schedule of its beneficiaries. It is suggested that the same may be available in one website, e.g., ERLDC. Similarly, RPC energy, DSM, RRAS, SCED account statements are also published in different formats across regions. It is very difficult to automate the account verification process for CGS like NTPC. This also needs to be made uniform across the country.</p>	<p>NTPC</p>
<p>72)</p>	<p>Scheduling procedure adopted by RLDC</p>	<p>A. For ISGS: Only one set of data is punched and the same is reflected across all RLDC's i.e. seller RLDC, buyer RLDC and intervening RLDC (if any). B. For LTA/MTOA Contract of IPPs:</p> <p>i. In case, Supplier and buyer are in same region: Only one set of data is required to punch and the same data is reflected in seller schedule as well as buyer schedule</p> <p>ii. In case, Supplier and buyer are in different region: Both seller and buyer are required to punch in their respective RLDC's. In addition to that, separate punching is also required in intervening RLDC (if any).</p> <p>As both the data i.e. seller RLDC and buyer RLDC are independent, discrepancy occurs many a times due to time mismatch causing dispute in the contracts.</p> <p>A provision is required to be made so that only one set of data should be required to punch in case of IPP also (as for ISGS) and same data should automatically reflect across all concerned RLDCs in order to avoid any discrepancy.</p>	<p>PTC</p> <p>SECI</p>

Off late, many **renewable generators** are getting connected with the grid and supplying the power to the beneficiaries located in different regions and SECI has already processed the bidding of approx. 10,000 MW for wind generation. Since renewable energy is unpredictable in nature, hence to avoid load on grid and to save on DSM charges Renewable generators tend to use 16 revisions in a day. Thus, at many times it becomes very difficult to execute the same and as punching of schedules in all the concerned RLDCs, including intervening RLDC if any, is required within the four time blocks available for revision which leads to discrepancy at many times. For Example: One generator in SRLDC is scheduling power to Punjab (NR), Bihar (ER), thus punching of scheduling will be as follows: SRLDC: Seller schedule block wise details of Punjab and Bihar will be punched NRLDC: Beneficiary (Punjab) Block wise schedule details will be punched ERLDC: Beneficiary (Bihar) Block wise schedule details will be punched WRLDC: Being intervening region, Block wise schedule for Punjab and Bihar will be punched. All the above mentioned activities are to be done within four time blocks allowed for revision, which at times creates discrepancy in schedule. It is requested that since these are long term transactions hence shall be scheduled as per methodology adopted for ISGS long term transaction, where punching should be allowed only in the RLDC where seller is located and data shall be visible to the respective beneficiary (ies) in different regions. Even if that is achieved, it is to be noted that since one company will be coming up with “n” no. of projects thus their login credentials will be different hence API facility shall be provided for allowing them to punch their revision in seller RLDC without any much manual intervention. This will help in seamless large integration of Renewable energy in the grid.

Central Power scheduling and billing software for RLDC, SLDC and DISCOMs:

TPDDL

Without intervention of technology, adherence to timely scheduling is very difficult. Major concern is that while going through acceptance procedure of RLDC and respective SLDC, message reaches to beneficiary or generator before one or two time block of actual implementation resulting in deviation between schedule and drawl and resultant deviation charges.

Further, commercial activities of RLDC and SLDC are still through MS-Excel which is completely manual and needs human intervention. The non-co-ordination of commercial and operational teams is evident as schedule data in real time power management and billing varies to a great extent resulting into issuance of provisional and final REA.

Centralized web-based scheduling and power optimization software is need of an hour for all the entities. Having common platform for scheduling and dispatching shall ensure the transparency and minimize the risk of grid security.

73)	<ul style="list-style-type: none"> • Balancing Resources • RTM • Ancillary Services • DAM • BESS 	Power systems, especially those with a high share of RE, require access to sufficient flexible resources (e.g., demand response, gas turbines, hydroelectricity, etc.) to ensure continued stability of the grid at each moment. Currently, there are no mechanisms in India to ascertain the amount of balancing resources needed and how these can be procured and dispatched.	BRPL
		<p>FREEZING THE DAY AHEAD SCHEDULES OF BENEFICIARIES</p> <p>To facilitate optimum utilization of generation assets & to expedite development of Real Time Market, no revision should be allowed in the Day Ahead Schedule, post finalization by RLDCs. Discoms/buying entities may use the short term Power Market for managing their load.</p>	IEX
		Schedule as decided on Day Ahead basis should be firm with revision allowed before the gate closure on the date of delivery	NTPC
		<p>ALLOW GENERATORS TO PURCHASE</p> <p>As per present framework, in case generator is not able to supply power due to unforeseen event than such generator is exposed to the high penalties under DSM and in case of revision of its scheduled buyer has to face stress. b. To avoid such situation, it is therefore suggested that the generators should be allowed to buy power to fulfill its contractual obligations. This provision will not only help generators to avoid penalties but also help Discoms to manage its demand efficiently.</p>	IEX
		<p>Day ahead: Schedule or leave it for the day</p> <p>Share by beneficiaries, once surrendered on a day-ahead basis should not be allowed to be recalled within the day</p>	APP
		Renewable energy generation is variable in nature (diurnal & seasonal) and implementation of Ancillary Services would facilitate integration of renewable energy generation in the country.	IWPA
		<p>Lack of an alternate market to meet the power demand in case of emergencies in real time. This results in non-utilization of the URS power, sometimes URS from relatively cheaper stations. The proposed solutions are as follows:</p> <p>a) Strengthening of the real time market, as proposed in the staff paper of CERC.</p> <p>b) Introduction of the concept of Gate Closure for the hourly markets;</p> <p>c) Schedule as decided on Day Ahead basis should be firm with revision allowed before the gate closure on the date of delivery.</p>	NTPC

		<p>Increased penetration of RE based sources have increased the frequency and magnitude of balancing requirement for balancing the grid. At present system operators at various level are empowered to finalize schedule and issue real time curtailment and ramp-up instruction to manage the grid. But, it is worth mentioning that at present there is no commercial arrangement under which the system operators can bring in more generations at its own will to balance the Grid. Commercial implications of such activity to be either met through the pool account available with system operators or need to be socialized among the states due to which the need for balancing was required.</p> <p>The proposed system will facilitate creation of Ancillary system at state and regional level and will ensure local balancing of the grid.</p> <p>Basis above we make following suggestion:</p> <ol style="list-style-type: none"> I. Delegate commercial power to system operator to enable grid balancing at real time basis. II. Mechanism to ensure availability of funds for such despatches to be ensured either through allocation of funds from pool account or by way of socialising the cost. 	ReNew
		<p>Battery Storage:</p> <p>To address these pressing requirements, Innovative technologies like Battery Storage would be the driving force to compensate for unpredictable renewable energy sources. Battery Energy storage can help in multiple ways to minimize financial losses through battery discharging for peak shaving, distribution asset life cycle increase, real time power management.</p>	TPDDL
74)	Scheduling Provision for Power Cleared in PX	<p>a) The IEGC Regulation 6.5 (14) RLDCs while finalizing the schedules of stations must consider that the schedules are operationally feasible, particularly with respect to the ramp up/ down rates. Accordingly the final schedules are made as per the declared ramp rates. However it has been seen that 1) As per when URS power is sold in the market and when it get cleared in some sporadic blocks, many times it is above the ramp rates of the generator, which causes DSM liability on the generators. As ramp rates are not part of the bids submitted by the generators, this may be considered by the RLDC/ NLDC while finalizing the total schedule of the generator considering all the schedules. This practice is being followed by RLDC/ NLDC while operating the RRAS and SCED mechanism, the same may be considered for the PX sale also.</p> <p>b) In case of unit tripping, DSM should be exempted for power sold in the Day Ahead Markets of PX. There should be a mechanism for revisions of the schedule in such cases.</p>	NTPC
75)	Open access information to Discom	Schedule of Short term, medium term and long term Open Access consumers should be made available to the respective SEBs/ DISCOMs well in advance for optimization of power purchase. ??	BRPL

76)	To avoid burden of such capacity charges on buyer & ultimately on its consumers in the event of bottleneck in power evacuation, concerned transmission licensee responsible for bottleneck shall pay such charge.	Burden of deemed availability of fix charges of generator in case of bottleneck in evacuation on beneficiaries The clause 6.5.14 of IEGC 2010 states that "In the event of bottleneck in evacuation of power due to any constraint, outage, failure or limitation in the transmission system, associated switch yard and substations owned by the Central Transmission Utility or any other transmission licensee involved in inter- . . . state transmission (as certified by the RLDC) necessitating reduction in generation, the RLDC shall revise the schedules which shall become effective from the 4th time block, counting the time block in which the bottleneck in evacuation of power has taken place to be the first one. Also, during the first, second and third time blocks of such an event, the : scheduled generation of the ISGS shall be deemed to have been revised to be equal to actual generation, and the scheduled draws of the beneficiaries shall be deemed to have been revised accordingly."	MSEDCL
77)	LVRT	Standard methodology' for COD is necessary to ascertain various system security measures taken by concern Renewable generator like LVRT compliance by Wind generators etc. The COD procedure shall also include other Renewable generators connected to grid like battery Storage system, pumped storage Hydro station, bagase, .; 1lf') biomass etc.	MSEDCL
		Fault (under voltage) ride through capability must be included in the Grid code for all types of Generators. Presently this stipulation is only for Wind Generators in the Grid code.	NTPC
78)	TECHNICAL MINIMUM OPERATION OF COAL PLANTS	As per Fourth amendment of IEGC, Technical Minimum load for both supercritical and subcritical units is 55 % for Inter State Generating Stations Coal and Gas Stations only. a) Supercritical units are having much higher capital investment as compared to sub-critical units. In return, they are of higher efficiency than their sub-critical counter parts. Operating a Supercritical/ Ultra Super critical plant in part load reduces the efficiency and hence loses its advantage and the higher investment may not get justified. Variation of parameters of supercritical units shall have higher impact on its life as compared to subcritical units and may necessitate midlife replacement of some critical components. Hence, on economy point of view, supercritical plants should be operated as close as possible to the full load considering the fact that if these plants were operated near full	NTPC

		<p>load would reduce annual CO2 emissions and save precious natural resources. It is proposed that, sub-critical units should back down first and then if required by the grid the supercritical units can operate at part load. Hence, it is suggested that Supercritical plants may be run at near to full load and accordingly fix the minimum load for such units.</p> <p>b) Some relatively costlier stations like at Kudgi/Solapur/Mouda/Vallur and even Simhadri are forced to run at 55% of loading most of the time. Some mandatory critical routine operations like LRSB and some contractual obligation like PG test needs the machines to run at higher loading than 55%. So RLDC must be empowered or there shall be provision in scheduling mechanism to take care of the above requirements time to time.</p> <p>c) Though Inter-state Generating Stations (ISGS) have a technical minimum of 55% as specified in the Grid Code by CERC, Technical minimum in case of State Generators is generally at a substantially higher level. Therefore, while ISGS having lower Energy Charges are backed down, State generators having higher energy charges are not backed down as they have higher technical minimum. This distortion in merit order operation results in increasing the power purchase cost of the Discoms. It is essential that all generators follow uniform technical minimum norms so that merit order operation is not compromised.</p> <p>d) Merit order should not be based on ECR (Energy Charge Rate) alone. Appropriate weightage of Efficiency or net Heat Rate (NHR) may be devised and should be considered while deciding Merit Order for scheduling. High efficient super critical units need to get preference in scheduling in order to reduce CO2 emission.</p> <p>e) While running the stations at Technical minimum level, the credible contingency requirement in case of tripping of various equipment, such as, Mills, Fans and Pumps, etc., needs to be considered.</p>	
		<p>As per IEGC 6.38, CGS or ISGS, whose tariff is either determined or adopted by the commission, technical minimum should be 55% of MCR. As per this provision, in case a generator have 2x300 MW installed capacity and only part capacity is tied up with long term beneficiary and beneficiary refuses to accept schedule of minimum 55% of the installed capacity stating that as per the regulation the beneficiary has to accept upto 55% of MCR or the contracted capacity whichever is lower. In that case, plant would not be able to achieve technical minimum</p>	<p>PTC</p>
<p>79)</p>	<p>Feedback of State QCAs</p>	<p>MP:</p>	<p>Siemens Gamesa</p>

1. No approved procedure for DSM Regulations – Required approved procedure to change software and procedure as per the Regulation
2. Number of revisions to be finalized – currently most of the states following 16 revision per day
3. Need 3 month time frame to implement the procedure after approval
4. IF the customer not provided consent also, with the current regulation QCA need to pay for them.
5. QCA cannot able to make payment behalf of customer, required proper payment mechanism
6. QCA need to provide aggregated day ahead and week ahead forecast for each pooling station- but aggregation should be done for all pooling station under QCA reduce DSM charges for generator

Maharashtra:

1. As per the regulation, Scheduling charges of every day and Revision in schedule charges need to be exempted, these charges affect financial viability of the project.
2. QCA have complete control over wind/solar injection feeder connected to the pooling station with round the clock service – Required clear roles and responsibility of the of QCA
3. QCA request to deposit corpus to maintain payment mechanism
4. Need 13 weeks time frame to implement the procedure after approval
5. QCA need to provide aggregated day ahead and week ahead forecast for each pooling station- but aggregation should be done for all pooling station under QCA reduce DSM charges for generator

Tamilnadu:

1. QCA have complete control over wind/solar injection feeder connected to the pooling station with round the clock service – Required clear roles and responsibility of the of QCA
2. If Curtailment communicated by TNSLDC to QCA, QCA should curtail the generation at site and also amend time block.
3. QCA need to provide aggregated day ahead and week ahead forecast for each pooling station- but aggregation should be done for all pooling station under QCA reduce DSM charges for generator
4. Required portal to upload all PSS revision in a single file.
5. Need monthly settlement instead of weekly settlement
6. Installation of energy meter is not in the scope of QCA

Question raised by Gamesa: Could we have a common QCA system all over India???