संदर्भ.सं.: POSOCO/NLDC/IEGC/ **दिनांक:** 12th Jul 2019

सेवा में,

The Chief (Engg.)
Central Electricity Regulatory Commission
3 rd & 4 th Floor, Chanderlok Building,
36, Janpath, New Delhi- 110001

विषय: Regarding: ***Comments on behalf of Regional Load Despatch Centres (RLDCs)/National Load Despatch Centre (NLDC) on the Indian Electricity Grid Code***

संदर्भ: 1. CERC Notice: Ref no. No. ENGG/2012/1/2019-CERC dated 21st Jun 2019

महोदय,

The comments/suggestions on behalf of Regional Load Despatch Centres (RLDCs)/National Load Despatch Centre (NLDC) on the existing Indian Electricity Grid Code as desired vide CERC notice Ref. no: ENGG/2012/1/2019-CERC dated 21st Jun 2019 are enclosed with this letter.

सधन्यवाद

भवदीय

देबाशिष

(देबाशिस दे)
मुख्य-महाप्रबंधक(रा.भा.प्रे.के.)

संलग्न: उपरोक्त अनुसार

POWER SYSTEM OPERATION CORPORATION LIMITED

Comments on behalf of RLDCs/NLDC on Indian Electricity Grid Code

12-Jul-19

Chapter-wise Comments

Power System Operation Corporation Limited

New Delhi

Date: 12th July 2019

Sub: Comments on behalf of Regional Load Despatch Centres (RLDCs)/National Load Despatch Centre (NLDC) on the Indian Electricity Grid Code

Background

The journey of Indian Electricity Grid Code from 2000 onwards (initially a document of the Central transmission Utility and approved by the Commission) has been evolutionary in nature. The first IEGC Regulations in 2006 (Regulation notified by the CERC in line with provisions of Electricity Act 2003) came after introduction of open access at the inter-state level in 2004. The second IEGC Regulations in 2010 came at a time when renewable energy was just appearing on the horizon necessitating suitable provisions regarding the same.

In this last decade there have been significant changes both in the power supply scenario as well as energy mix besides integration of the entire country's electricity grid into one synchronous system which is the third largest in the world. Cross border interconnections with the Nepal, Bhutan and Bangladesh has now changed the entire landscape. In the meantime the CERC has notified more than 20 regulations covering various aspects from power system planning to communication system besides electricity markets. Thus there is a need for comprehensive review of the IEGC to encompass the above areas besides avoiding the overlap with other regulations. Chapter wise comments are indicated in foregoing pages.

RLDCs/NLDC may come up with further comments if considered necessary before finalisation of committee's proceedings which may also be considered.

Chapter-1: Definitions

Following new terms may be defined:

1. '**Operational Security**' means the transmission system's capability to retain a normal state or to return to a normal state as soon as possible, and which is characterized by operational security limits;
2. '**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;
3. '**System state**' means the operational state of the transmission system in relation to the operational security limits which can be normal state, alert state, emergency state, blackout state and restoration state;
4. '**N-situation**' means the situation where no system element is unavailable due to occurrence of a contingency;
5. '**normal state**' means a situation in which the system is within operational security limits in the N-situation and after the occurrence of any contingency from the contingency list, taking into account the effect of the available remedial actions;
6. '**(N-1) criterion**' means the rule according to which the elements remaining in operation after occurrence of a contingency are capable of accommodating the new operational situation without violating operational security limits;
7. '**frequency stability**' means the ability of the transmission system to maintain frequency stable in the normal state and after being subjected to a disturbance;
8. '**voltage stability**' means the ability of a transmission system to maintain acceptable voltages at all nodes in the transmission system in the N-situation and after being subjected to a disturbance;
9. "**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.
10. "**Communication system**" is 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. It also includes existing communication system of Inter State Transmission System, Satellite and Radio Communication System and their auxiliary power supply system, etc. used for regulation of inter- State and intra-State transmission of electricity;

11. **"contingency analysis"** means a computer based simulation of contingencies from the contingency list;
12. **"Grid Resiliency"**: a suitable definition needs to be added encompassing planning as well as operational time horizons. Specific definition relevant to Indian context would be forwarded later considering the extensive discussions still ongoing in international forums e.g. CIGRE, IEEE etc.
13. '**Qualified Coordinating Agency or QCA**' means the agency coordinating on behalf of Wind/Solar Generators connected to a pooling station(s). QCA may be one of the generators or any other mutually agreed agency .
14. "**Frequency Control Continuum**" means the set of frequency control actions identified by the grid code for the purpose of operating the grid at Reference Frequency.
15. "**Dead Band**" of the speed governing system means, the grid frequency range within which there is no resultant change in the position of the generating unit governing valves.
16. "**Reference contingency**" for speed control with droop the maximum positive or negative power deviation occurring instantaneously between generation and demand in a synchronous area,;
17. **"Minimum frequency"** means the nadir frequency till which grid frequency dip immediately after a reference contingency. Minimum frequency shall be 49.5 Hz.
18. **"Quasi steady state frequency**" means the value till which grid frequency is expected to get restored within 30 seconds after a reference contingency. Quasi steady state frequency shall be 49.80 Hz.
19. **"Frequency Response Characteristics (FRC)"** is defined as the 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

    FRC = Change in Power (ΔP) / Change in Frequency (Δf)

20. **"Area Control Error"** or 'ACE' Area Control Error (ACE) is 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 = Deviation (ΔP) + (Frequency Bias) (K) * (Deviation from Scheduled Frequency) (Δf)
21. **"Rate of change of frequency RoCoF"** is the time derivative of the power system frequency(df/dt) which negates short term transients and therefore reflects the actual change in synchronous network frequency.
22. **"Frequency Response Obligation (FRO)"** is defined as the minimum frequency response a control area has to provide in the event of any frequency deviation.
23. **"Frequency Response Performance (FRP)"** is defined as the ratio of actual frequency response with frequency response obligation.
24. **"Frequency Bias"** is defined as MW/Hz associated with a control area that approximates its response to Interconnection frequency error.
25. **"Target Frequency Response (TFR)"** is defined as the frequency response the synchronously integrated All India grid must provide so that the frequency deviation in case of outage of any generating station is within the defined limit.
26. **"Secondary Control"** is an automatic function to regulate the generation in a control area based on secondary control reserves in order to maintain its interchange power flow at the scheduled value with all other control areas (and to correct the loss of capacity in a control area affected by a loss of production).
27. **"Primary Reserve"** is defined as the maximum quantum of power which will instantaneously come into service in the event of sudden change in frequency through governor action of the generator.
28. **"Reference Event"** shall be defined as the largest credible contingency of generation in the grid.
29. **"Load-Damping constant"** shall be defined as the percentage change in power consumption of load with one percent change in frequency.
30. **"Secondary Reserve"** is defined as the maximum quantum of power which can be activated through Automatic Generation Control (AGC) to free the capacity engaged by the

primary control.

31. **"Tertiary Control"** is any (automatic or) manual change in the working points of generators (mainly by re-scheduling), in order to restore an adequate secondary reserve.

32. **"Tertiary Reserve"** is defined as the quantum of power which can be activated (mainly by re-scheduling), in order to restore an adequate secondary reserve.

33. **"Target Quasi Steady State Frequency"** shall be defined as the frequency at which all the primary reserves in the grid shall be activated.

34. "**Inertia**" is 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 synchronised to the frequency of the power system.

35. **"Automatic Generation Control (AGC)"** is a mechanism that automatically adjusts the generation of a control area to maintain its Interchange Schedule Plus its share of frequency response.

36. **Security-Constrained Unit Commitment (SCUC)** commits/de-commits units while respecting limitations of the transmission system and unit operating characteristics

37. '**Security Constrained Economic Despatch (SCED)**': Operation of generation facilities to produce energy at lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities.

38. "**Critical Information Infrastructure (CII)**" means the computer resource, the incapacitation or destruction of which, shall have debilitating impact on national security, economy, public health or safety.

Chapter-2: Role of various organizations and their linkages

The roles of following organizations may be expanded/modified to include the responsibilities as mentioned below:

1. Role of NLDC, following may be added *"Coordination with designated power system operator of countries with cross border connection for achieving maximum economy and efficiency in the operation of National Grid."*
2. Role of RPC, following may be added *"To undertake operational planning studies including protection studies for stable operation of the grid. A database of protection settings in this regard shall be maintained by RPC which will be updated time to time."*
3. Role of RPC, clause may be modified as *"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"*
4. A new section may be added as Section 2.10, which will elaborate the Role of National Power Committee (NPC) and its linkages to LDCs/RPCs.
5. 'Qualified Coordinating Agency or QCA' means the agency coordinating on behalf of Wind/Solar Generators connected to a pooling station. QCA may be one of the generators or any other mutually agreed agency for the following purposes:
    - Provide schedules with periodic revisions to the concerned LDCs as per Grid Code on behalf of all the Wind/Solar Generators connected to the pooling station(s)
    - Responsible for metering, data collection/transmission, communication, coordination with DISCOMS, LDCs, REMCs and other agencies.
    - Undertake commercial settlement of all charges on behalf of the generators, including payments to the State Deviation pool accounts through the concerned SLDC.
    - Undertake de-pooling of payments received on behalf of the generators from the State Deviation Pool account and settling them with the individual generators.
    - Undertake commercial settlement of any other charges on behalf of the generators e.g. as user of the inter-State transmission network or the associated facilities and services of LDCs and any other charges as may be mandated from time to time.

    QCA shall be treated as a State Entity.
6. **Definition and Role of SNA for Cross Border Transactions**

    'Settlement Nodal Agency or SNA' means the Nodal Agency notified by Ministry of Power for each neighbouring country which shall be responsible for settlement of grid operation related charges as per CERC regulations. SNA may perform the following activities as per the CERC regulations inter-alia:

- Responsible for settling all charges pertaining to grid operations including Fees and charges, user registration charges, operating charges, charges for deviation, reactive energy charges and other charges related to transactions with a particular neighbouring country in the course of cross border trade of electricity.
- Shall be a member of the deviation pool, reactive energy pool and other regulatory pools for payment and settlement of the corresponding charges in the pool accounts of the region having connectivity with any neighbouring country
- Shall co-ordinate with System Operators of respective neighbouring countries for scheduling of cross border transactions and revisions during the day of operation
- Shall provide Weekly meter readings (import or export in terms of MWh and MVArh) for actual injection or drawl by entities located in neighbouring country to the concerned RLDC(s) or NLDC
- Shall put in place a suitable payment security mechanism for charges to be collected by it
- Any other functions assigned by Government of India and Central Commission from time to time.

Chapter-3: Planning code for inter-state transmission

1. Section 3.2 (c), Objective, Planning code for inter-state transmission, *"To provide methodology and information exchange amongst Users, STU/SLDC and CTU/RLDC, RPC , NLDC and CEA in the planning and development of the ISTS."* The availability of accurate model data for simulating the load flow has gained importance. The accuracy of these models is a key factor in preserving system reliability and it also affects significant economic decisions regarding system expansion and operation. Since the decisions based on the results of system studies are of such importance, system representation should be sufficiently accurate to ensure that system parameters measured in simulating a disturbance are close to those that would be measured on the actual power system under the same conditions. Therefore, the accuracy of the model data that used to represent the system steady-state and dynamic characteristics is imperative as it's relied on to support informed decisions regarding power system expansion and operation. Following may be added in the end of 3.2 (c) ,

   "....development of the ISTS and establish consistent validation requirements to facilitate the collection of accurate data and building of planning models to analyze the reliability of the interconnected transmission system."

2. Section 3.4 (d), Planning Philosophy, "All, STUs and Users will supply to the CTU, the desired planning data from time to time to enable to formulate and finalize its plan." It has been regularly observed that incomplete data is furnished by users to CTU which give incorrect results when used in study, a check on the data submission will resolve the problem. It is very important that a methodology for building common grid models be formulated, following may be added

   "By 6 months after entry into force of this Regulation, CTU shall develop a proposal for the methodology for building the day-ahead common grid models from the individual grid models and for saving them. That methodology shall take into account the operational conditions of the common grid model methodology developed in accordance with Section 3.2 (c) , as regards the following elements:

   (a) definition of timestamps;

   (b) deadlines for gathering the individual grid models, for merging them into a common grid model and for saving individual and common grid models. The deadlines shall be compatible with the regional processes established for preparing and activating remedial actions;

   (c) quality control of individual grid models and the common grid model to be implemented to ensure their completeness and consistency;

(d) correction and improvement of individual and common grid models, implementing at least the quality controls referred to in point (c); and
(e) handling additional information related to operational arrangements, such as protection set points or system protection schemes, single line diagrams and configuration of substations in order to manage operational security.

3. Following new clauses of Section 3.4 (d) may be added :
   CTU shall perform year-ahead operational security analyses in order to detect at least the following constraints:
   (a) Power flows and voltages exceeding operational security limits;
   (b) Violations of stability limits of the transmission system
   (c) Violations of short-circuit thresholds of the transmission system.
   (d) CTU shall carry out planning studies to analyse the impact of reduction in rotating mass in grid under high RE penetration scenario
   (e) When CTU detects a possible constraint, it shall design remedial actions.

   CTU shall perform the Generating plant Interconnection study to analyse the impact of individual new power plant on the grid and vice versa as per the Model Data provided by the Generator prior to actual commissioning of the power plant as per the CEA transmission planning criteria (Load Flow, Short Circuit, Transient Stability and Small Signal Stability, EMTP). CTU will share the report of interconnection with CEA/NLDC/RLDC/RPC/User along with the model data for feedback.

4. Section 3.5 (a) (i) (a), Planning criterion,"..... As a general rule, the ISTS shall be capable of withstanding and be secured against the following contingency outages." Apart from line loadings it is also important that sufficient active power and reactive power shall be present to support the system in times of need. The clause may be modified as "..... *As a general rule, the ISTS shall be capable of withstanding and be secured with sufficient active and reactive power reserves against the following contingency outages."*

5. In the Section 3.4(i) ,Planning Philosophy may be added,*"For RE integration planning, maximum renewable that can be connected to substation may be considered based on the Equivalent Short Circuit Ratio (ESCR). Special attention may be accorded for reactive exchange by RE sources. Further studies may be focussed on effect of large scale integration of inverter based resources."*

6. In Planning Philosophy following may be added *"Under certain extreme circumstances for operation appropriate LDC can take cognizance of (n-G-1) & (n-2) and may consider them as credible contingency. Outage of single Bus at 220kV/400kV/765kV may also be included in n-1 criterion."*

7. In transmission planning criteria it may be added,

- *a dynamic voltage criterion in transmission planning criteria, to identify unacceptable contingencies that cause delayed voltage recovery after the fault is cleared.*
- *LVRT (as well as HVRT) criterion in transmission planning criteria that shall be met by all generation sources*

8. *Addition of new clause : Section 3.5(f) , Planning Criterion may be added,"CTU shall carry out more accurate short circuit calculations where measured short circuit currents are close to equipment rating. Proper X/R ratio studies be carried out so that associated switchgear operate correctly i.e. protection system behave as they are desired."* Switchgear operation reliability reduces with high DC time constant, high transient recovery voltages are observed in such cases. The incidents of CB failures are increasing on this account as improper time constant settings are affecting the damping out of DC component.

9. Synchronous condensers are economic sources for providing reactive support as well as inertia under high RE penetration scenario, in the planning horizon it can be envisaged as important grid element and following may be added *"Wherever necessary the synchronous condensers may be planned at appropriate locations."*

Chapter-4: Connection Code

1. Section 4.6.3, System Recording Instruments, Connection Code, "Recording instruments such as Data Acquisition System/Disturbance Recorder/Event Logging Facilities/Fault Locator (including time synchronization equipment) shall be provided and shall always be kept in working condition in the ISTS for recording of dynamic performance of the system. All Users, STUs and CTU shall provide all the requisite recording instruments and shall always keep them in working condition." The time synchronization of recording instruments with adjacent stations is very important to analyse the sequence of events. The clause may be added as *"The ISTS owner shall maintain the evidence (in hard copy or electronic format) for time synchronization of system recording instrument with adjacent stations."*

2. Existing Clause: Section 4.6.2, Data and Communication facilities, Connection Code, "Reliable and efficient speech and data communication systems shall be provided to facilitate necessary communication and data exchange, and supervision/control of the grid by the RLDC, under normal and abnormal conditions." In view of the requirement of uninterruptible communication to control centres the clause may be modified as *"A common communication guideline for SCADA, PMU, Meteorological Data and Forecast Data telemetered at respective RLDC shall be developed. These need to be specified along with accuracy, redundancy and resolution with alternate technology. Installation of high-resolution Phasor Measurement Unit at all outgoing feeders for all New substation, FACTS, generating station including Renewable Energy connected to ISTS be ensured. Availability of synchronisation display at operator console in all SAS substation may be ensured to help restoration/recovery."*

3. Following new clause may be added *"Communication load must run off battery and be identified as a critical restoration load. Regulation must enforce periodic mock exercise for the restoration participants."*

4. The reporting of data from RE generation sources to control centres, *"In case of a pooling station with RE generation connected to it, PMU shall be placed by owner of pooling station which will report parameters of low voltage side bus to control centres."*

5. Power electronic devices need to be monitored closely and it is very important that the response is analyzed over different operating range and conditions, following clause may be added *"In order to determine the performance of power electronic devices, PMU data shall report at respective RLDC/NLDC. To analyse the dynamic performance of such devices when PMU is not available, high resolution data of these devices should be stored and shared with RLDC/NLDC."*

6. Considering expected commissioning of Voltage Source Converter (VSC) based HVDC in the Indian grid, features to be adopted for VSC HVDC need to be suitably formulated. Since VSCs are self-commutated, they do not necessarily require a strong AC bus for stable operation. The black start feature in VSC based HVDC can be used for system restoration. During islanded operation the DC terminal independently controls both the AC voltage and the frequency of the islanded network to set reference points, i.e., it provides voltage and

frequency control. System restoration can be performed in a careful and structured manner, with proper coordination. Therefore following may be added *"VSC based HVDC transmission system shall be declared under commercial operation after testing of black start and reactive power support features."*

7. To provide proper visualization at control centres, following may be added "The owner of substations/Generating stations/RE stations/HVDC stations shall make necessary arrangements to provide reliable telemetry at control centres as per details mentioned in the respective operating procedures of SLDC/RLDC/NLDC".

Chapter-5: Operating Philosophy

1. Existing Clause: Under Section 5.1(g) , Operating philosophy, "A set of detailed operating procedures for each state grid shall be developed and maintained by the respective SLDC in consultation with the concerned persons for guidance of the staff of SLDC and shall be consistent with IEGC to facilitate compliance with the requirement of this IEGC." The operating procedures may be shared across the different utilities/control centres so that coordinated steps may be taken in real time to ensure integrated grid operation. The clause may be modified as *"The updated copy of SLDC operating procedure shall be published on its website at the start of each financial year."*

2. With the integration of large number of control devices, FACTS,HVDC etc. in the grid, it is very important that proper tuning of the devices is carried out, the following clause may be added *"All users having control devices (FACTS, HVDC) will have their automatic controller in operation. These include the Power Oscillation Damping (POD), Reactive Power Controller (RPC), frequency controller, Blackstart feature (in case of VSC based HVDC) or any other controller specific to these devices. If any of these devices is required to be operated without any of its controller in service, the RLDC shall be immediately intimated about the reason and duration, and its permission obtained. The control devices wherever provided shall be properly tuned by the respective user as per the plan prepared for the purpose by the CTU/RPC/RLDC/NLDC from time to time."*

3. Section 5.2 (c) of existing IEGC mentions "No important element of the National/Regional grid shall be deliberately opened or removed from service at any time, except when specifically instructed by RLDC or with specific and prior clearance of RLDC." In the same Clause following may be added *"Also any important element which was in open condition shall not be closed except when specifically instructed by RLDC."*

4. Section 5.6.2 (b), Procedure for Operational Liaison, mentions "All operational instructions given by RLDC and SLDC shall have unique codes which shall be recorded and maintained as specified in Central Electricity Authority (Grid Standards) Regulations, 2010." In this regard clause may be modified as *"Any Operation code provided by SLDC/RLDC will be valid for next 30 minutes. In case the specified switching operation could not be completed by the utility then a new code will be taken from respective SLDC/RLDC by providing details as to why the operation could not be completed in the previous code."*

5. To assess the import/export capability of states, following may be added "SLDC shall also furnish in consultation with RLDC, the import/export capability of their control area for estimation of inter-state Total Transfer Capability/Available Transfer Capability."

6. Following Clause may be added in reference to monitoring of under frequency load shedding(UFLS) at regional level:

- RPC shall monitor the event that resulted in system frequency excursions below the initializing set points of the UFLS program, and shall carry out a joint assessment report describing likely reasons for differences in conclusions and recommendations.
- The pump storage plants operating in pumping mode should be tripped before the activation of first stage of under frequency load shedding.

7. SPS shall be planned with adequate redundancy for correct operation. The reliability index (similar to those defined in SOPR regulations of CERC on protection operation) shall be computed by respective RLDC and will be informed to RPC for assessment on periodic intervals.

8. In case of Outage Planning, following clauses may be added at Section 5.7 (k):
    - Any shutdown proposal which requires approval of another RPC shall be considered approved only if it is approved by the indenting RPC as well as all other concerned RPCs. Necessary coordination may be done by indenting RPC.
    - An outage planning procedure has to be formulated by NPC/NLDC in consultation with all stakeholders viz all SEBs/STUs, transmission licensees, CTU, ISGS, IPPs, MPPs and other generating stations to avail the outages for the next month.

9. In reference to Post Despatch Analysis related issues, methodology can be adopted on these lines:
    - Section 5.2 (r), Operating Philosophy, mentions "All the Users, STU/SLDC and CTU shall send information/data including disturbance recorder/sequential event recorder output to RLDC within [24 hours] for purpose of analysis of any grid disturbance/event. The following clause may be modified as *"All the Users, STU/SLDC or entity assigned in site responsibility schedule (of the asset) shall upload the desired information (format agreed in respective RPC) on a dedicated portal managed by RLDC within [24 hours) for purpose of analysis of any grid disturbance/event. The monthly violations i.e. failure or delay in uploading the details in desired format will be reported by RLDC to the commission."*

    - Existing Clause : Section 5.2(g) , System Security Aspects, Operating Code; "Provided that periodic checkups by third party should be conducted at regular interval once in two years through independent agencies selected by RLDCs or SLDCs as the case may be………" The exercise is being done for primary response only, however for system security it is important that AVR/PSS also remain in service and tuned properly. It is important that all these parameters are also tested by RLDC time to time. The testing of all these parameters can be bundled together and common package for testing can be awarded. *"Provided that periodic checkups by third party should be conducted at regular interval once in two years through independent agencies selected by RLDCs or SLDCs as the case may be for governor response/model validation/AVR/PSS and generator capability curve assessment………"*

    - The following clause may be added for testing of transmission system *"Periodic third-party protection audit of all station above 132/110/100 kV shall be prepared by* *the protection Sub-Committee of the RPC at every five-year basis and compliance of the audit to be monitored by the respective RPC."*

- The following clause may be added for compliance on Grid Event analysis "*All events discussed in RPC Protection sub-committee should come with various findings which need to be categorized under two parts: Category 1 (the ones which need additional finance) and Category 2 (the ones which do not need additional finance). RPC to share the compliance of both Category on Quarterly basis to NPC and CERC. Any operational issue in the grid affecting the system security and reliability adversely if could not be resolved within three months after discussion in the respective RPC Forum, shall be notified to the commission on priority by respective RPC or RLDC/NLDC."*

- In case of major outages a report comprising of findings and recommendations shall be submitted by a committee formed at RPC level after detailed analysis of the event. Visit to the affected Sub-station/ power station helps to know the real issues persisting there and also helps in getting familiarized to the personnel.

- The National Power Committee (NPC) can play a key role in harmonizing practices across all the RPCs and ensuring that improvements done in one region are also replicated in other regions. The Constituent utilities must also contribute and provide full support to the RPC Special teams constituted after each major event.

Chapter-6: Scheduling & Despatch Code

1. A set of norms may be developed for COD declaration of RE based generation sources.

2. Clause no. 6.3A.1.(iv) may be modified as *"The certificates as required under clause (iii) 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 the concerned RLDC / SLDC before declaration of COD. The generating company shall submit approval of Board of Directors to the certificates as required under clause (iii) within a period of 3 months of the COD to* ***RPC / RLDC"***

3. Clause no. 6.3A.2.(iv) may be modified to add to whom the certificate is to be submitted as *" The certificates as required under clause (iii) 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 as required under clause (iii) within a period of 3 months of COD (to* ***RPC/RLDC).***"

   Reason of 1,2: Earlier it was not explicitly mentioned to whom the certificate is to be submitted.

4. Clause no. 6.3A.1.(x) may be modified as *"Scheduling of power from the generating station or unit thereof shall commence* ***from 00:00 hrs of D+2 day considering D as the day of receipt of COD declaration from generator at RLDC/SLDC/RPC***."

   Reason: It is seen that RLDC often receive intimation for COD declaration few hours before 00:00 Hrs and are forced to give schedule to the generators from 00:00 Hrs. This violates the day ahead scheduling timeline mandated by IEGC.

5. New clause 6.3A.1.(xi) may be added as ***"COD shall have to be declared within 7 days after obtaining the trial run clearance as mentioned in clause 6.3A.1.viii. All necessary testing shall be completed before trial run. In case of delay, the generator will have to explain the reason with appropriate records."***

6. New clause 6.3A.2.(xii) may be added as "~~COD shall have to be declared within 7 days after obtaining the trial run clearance as mentioned in clause 6.3A.2.ix. All necessary testing shall be completed before trial run. In case of delay, the generator will have to explain the reason with appropriate records.~~ "

   "After generator announces start of 72 hour trial & completes the same, it shall be incumbent on the generator to either declare COD or communicate the deficiencies observed in trial run & intimate likely dates of next trial or communicate the expected date of COD."

   Reason of 4&5: On number of occasions, generator is delaying COD after successful trial run.

7. Clause no. 6.3A.2. (ix) may be modified as *"Scheduling shall commence from **0000 hrs of D+2 day considering D as the receipt day of COD declaration from the generator at RLDC/SLDC/RPC** "*

   Reason: It is seen that RLDC often receives intimation for COD declaration few hours before 00:00 Hrs and has to give schedule to the generators at 00:00 Hrs.This violates the day ahead scheduling timeline

8. Clause 6.3A.3.(i) may be modified as *"The short interruptions, for a cumulative duration of 4 hours, shall be permissible, with corresponding increase in the duration of the test. Cumulative Interruptions of more than 4 hours shall call for repeat of trial operation or trial run **which can be commenced at any time on intimation to beneficiaries and after obtaining clearance from concerned RLDC or SLDC , as the case may be**."*

   Reason: For short interruptions, serving seven day notice before resumption of trial run may not be necessary.

9. Clause 6.4.10(a) may be updated as *"The treatment of injection of infirm power by generating stations during testing shall be in accordance with Central Electricity Regulatory Commission (Grant of Connectivity, Long-term Access and Medium-term Open Access in inter-State Transmission and related matters) Regulations, 2009, and the Central Electricity Regulatory Commission **(Deviation Settlement mechanism and related matters) Regulations, 2014**, amended time to time."*

   Reason: Changing Unscheduled Interchange by Deviation.

10. Clause 6.4.16 may be modified as *"The ISGS shall make an advance declaration of ex-power plant MW and MWh capabilities foreseen for the next day, i.e., from 0000 hrs to 2400 hrs. During fuel shortage condition, in case of thermal stations, they may specify minimum MW, maximum MW, MWh capability and declaration of fuel shortage. The generating stations shall also declare the possible ramping up / ramping down in a block. In case of a gas turbine generating station or a combined cycle generating station, the generating station shall declare the capacity for units and modules on APM gas, RLNG and liquid fuel separately, and these shall be scheduled separately. **The RE generators shall also make an advance declaration of available capacity foreseen for the next day, i.e., from 00:00 hrs to 24:00 hrs**."*

    Reason: Day ahead declaration of Available Capacity for RE generators is not present in existing IEGC.

11. Clause 6.4.18 may be modified as *"It shall be incumbent upon the ISGS to declare the plant capabilities and **available capacity, in case of RE generators,** faithfully, i.e., according to their best assessment. In case, it is suspected that they have deliberately over/under declared the plant capability contemplating to deviate from the schedules given on the basis of their capability declarations (and thus make money either as undue capacity charge or as the charge for deviations from schedule), the RLDC may ask the ISGS to explain the situation with necessary back up data"*

Reason: For wind and solar based RE generating stations, the deviation settlement rates are based on percentage deviation given on the basis of Available Capacity.

12. Clause 6.4.21 may be modified as *"The CTU shall install special energy meters on all inter connections between the regional entities and other identified points for recording of actual net MWh interchanges and MVArh drawals. The installation, operation and maintenance of special energy meters shall be in accordance with Central Electricity Authority (Installation and Operation of Meters) Regulations, 2006. All concerned entities (in whose premises the special energy meters are installed) shall take weekly meter readings and transmit them to the RLDC by Tuesday noon.* ***The concerned entity shall be responsible for monitoring time drift in SEM and correction of the time drift as and when required. Utilities shall promptly intimate the CT and PT ratio to RLDC in case of any changes****. The SLDC must ensure that the meter data from all installations within their control area are transmitted to the RLDC within the above schedule."*

    Reason: Issue of time drift and record of CT& PT ratio are required to be looked into and maintained regularly by the respective utilities.

13. Clause 6.4.22 may be updated as *"The RLDC shall be responsible for computation of actual net injection / drawal of concerned regional entities, 15 minute-wise, based on the above meter readings. The above data along with the processed data of meters shall be forwarded by the RLDC to the RPC secretariat on a weekly basis by each Friday noon for the seven day period ending on the previous Sunday mid-night, to enable the latter to prepare and issue the* ***Deviation Settlement Mechnism (DSM)*** *account in accordance with the* ***CERC(Deviation Settlement Mechanism and related matters) Regulations,2014*** *, as amended form time to time. . All computations carried out by RLDC shall be open to all regional entities for checking/verifications for a period of 15 days. In case any mistake/omission is detected, the RLDC shall forthwith make a complete check and rectify the same."*

    Reason: Changing Unscheduled Interchange by Deviation.

14. *Clause 6.5.1 may be modified as "All inter-State generating stations (ISGS) shall be duly listed on the respective RLDC and SLDC web-sites. The station capacities and allocated/contracted Shares of different beneficiaries shall also be listed out.* ***The allocated share along with distribution of unallocated quantum shall be as intimated by RPC in line with Govt. of India allocation. The contracted quantum shall be as per LTA/MTOA approval issued by CTU****"*

    Reason: It has been observed that CTU is operationalizing LTA but the same is not coordinated with actual COD. This clause is intended to specify the procedure for RLDC to go by the CTU approval.

15. Clause 6.5.3 may be modified as *"By 6 AM every day, the ISGS shall advise the concerned RLDC, the station-wise ex-power plant MW and MWh capabilities* ***and available capacity, in case of RE generators*** *foreseen for the next day, i.e., from 0000 hrs to 2400 hrs of the following day."*

Reason: Day ahead declaration of Available Capacity for RE generators is not present in existing IEGC

16. Clause 6.5.10. may be updated as "*The declaration of the generating capability by hydro ISGS should include limitation on generation during specific time periods, if any, on account of restriction(s) on water use due to irrigation, drinking water, industrial, environmental considerations etc. The concerned Load Despatch Centre shall periodically check that the generating station is declaring the capacity and energy sincerely~~, and is not manipulating the declaration with the intent of making undue money through~~ Unscheduled Interchange ~~.~~"*

17. Clause 6.5.14 may be modified as "*While finalizing the above daily despatch schedules for the ISGS, RLDC shall ensure that the same are operationally reasonable, particularly in terms of ramping-up/ramping-down rates and the ratio between minimum and maximum generation levels.* ***A minimum ramping rate of 1% of per minute or as stipulated in Central Electricity Regulatory Commission (Terms & Conditions of Tariff) Regulations, as revised control period wise, should generally be acceptable for an ISGS and for a regional entity, except for hydro-electric and Gas based generating stations which may be able to ramp up/ramp down at a faster rate. The ramp rate should also be considered in short-term bilateral and collective transactions** ."

    Reason: Ramp rate of 200MW/Hz mentioned in the present IEGC is replaced by minimum 1% per minute in line with Central Electricity Regulatory Commission (Terms & Conditions of Tariff 2019-2014) Regulations
    At present, ramp rate violation is not considered in case of STOA bilateral and collective. This is being explicitly mentioned in IEGC.

18. Clause 6.5.16 may be modified as "*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 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* ***under long term/medium term/RRAS/SCED (without revising short term)*** *shall be deemed to have been revised to be equal to actual generation, and the scheduled drawals of the beneficiaries shall be deemed to have been revised accordingly.* ***RRAS schedule shall be revised first followed by SCED followed by medium term followed by long term.***"

    Reason: Priority order for revision of different part of schedule of a generator in case of evacuation bottleneck is defined in the modified clause.

19. First paragraph of clause 6.5.17 may be modified as "*In case of any grid disturbance, scheduled generation of all the ISGSs supplying power under long term / medium term/[] /**RRAS/SCED (without revising short term)** shall be deemed to have been revised to be equal to their actual generation and the scheduled drawals of the beneficiaries/buyers shall be deemed to have been revised accordingly for all the time blocks affected by the grid*

*disturbance **<u>and for the time blocks required by the ISGS after the period of grid disturbance is over to revive of the unit(s) under different conditions such as HOT, WARM and COLD . The time to start a machine under HOT, WARM and COLD conditions shall be as per the declaration given by the generating station on 1st April every year</u>**. Certification of grid disturbance and its duration shall be done by the RLDC. **<u>RRAS schedule shall be revised first followed by SCED followed by medium term followed by long term</u>**."*

<u>Reason: Priority order for revision of different part of schedule of a generator in case of grid disturbance is defined in the modified clause. Also, provision of time to be provided to a generator for revival of units after grid disturbance is over is specified.</u>

20. First paragraph of Clause 6.5.19. may be modified as " *~~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 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 4th time block, counting the time block in which the forced outage is declared to be the first one. The 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. However, the transmission charges as per original schedule shall continue to be paid for two days~~*

    <u>Reason: Clause may be deleted as parallel actins are being undertaken to bring in the real time market where opportunity would be available to generator to make good his obligations through purchase of power in case of forced outage.</u>

21. Clause 6.5.19A. may be deleted as 19 A. "*~~In case of revision of schedule of a , the schedules of all transactions under the long term access, medium term open access shall be reduced on pro rata basis~~*

    <u>Reason: Clause may be deleted as parallel actins are being undertaken to bring in the real time market where opportunity would be available to generator to make good his obligations through purchase of power in case of forced outage.</u>

22. Clause 6.5.23. (iii). may be modified as "*The schedule **<u>and available capacity</u>** by wind and solar generators which are regional entities **<u>(excluding short term bilateral and collective transactions)</u>** may be revised by giving advance notice to the concerned RLDC, as the case may be. Such revisions shall be effective from 4th time block, the first being the time-block in which notice was given. There may be one revision for ea.ch time slot of one and half hours starting from 00:00 hours of a particular day subject to maximum of 16 revisions during the day.*"

Reason: To make an explicit mention that 16 revisions per day in respect of wind and solar generators can be done excluding short term bilateral and collective transactions.

23. Clause 6.5.30 may be modified as "*Collective Transaction through Power Exchange(s) would be curtailed* ***during extreme exigencies only****, subsequent to the Short Term Bilateral Transaction(s).*"

    Reason: Collective Transaction through Power Exchange(s) are not curtailed under normal circumstances, same is to appear in IEGC.

24. New clause 6.5.35 may be added as ***"Scheduling Procedure and time line for RRAS, FRAS, SCED and secondary reserve shall be adopted as per relevant regulations/procedures issued or approved by Central Electricity Regulatory Commission, amended time to time."***

    Reason: Scheduling Procedure and time line for RRAS, FRAS, SCED and secondary reserve is not mentioned in the present IEGC.

25. Clause 6.6.6. may be modified as "*The ISGS and other generating stations* ***including RE generators*** *connected to regional grid shall generate/absorb reactive power as per instructions of RLDC, within capability limits of the respective generating units, that is without sacrificing on the active generation required at that time. No payments shall be made to the generating companies for such VAr generation/absorption.* ***In case, generating station do not absorb/ inject reactive power as per the capability curve , then RLDC/RPC based on non-performance details may ask generators to undergo Reactive Capability testing."***

    Reason: RE Generators are also brought into the ambit.
    It is to ensure that all generators absorb/ inject reactive power as per the capability curve.

26. Clause 6.6.1 and 6.6.2 may be deleted and moved to Ancillary Services regulations as part of Voltage Control Ancillary Services.

27. Complementary Commercial Mechanisms (Annexure-I) may be deleted. A separate regulation covering the operation and maintenance of the regulatory pool accounts may be formulated.

Chapter-7: General Points for facilitating electricity markets

The following points for facilitating electricity markets may be suitably incorporated in the relevant chapters in Grid Code.

1. Unit Commitment and De-commitment Procedure

In electrical energy production and distribution systems, an important problem deals with computing the production schedule of the available generating units, accordingly with their different technologies, in order to meet their technical and operational constraints and to satisfy several system-wide constraints, e.g., global equilibrium between energy production and energy demand or voltage profile bounds at each node of the grid. The constraints of the units are very complex; for instance, some units may require upto 24-48 hours to start. Therefore, such a schedule must be computed (well) in advance of real time. The resulting family of mathematical models is usually referred to as the Unit Commitment problem (UC).

Despite research and applications all over the world for many decades, UC still cannot be considered a "well-solved" problem. In almost all cases the problem is large- to very-large-scale, non-linear, non-convex and combinatorial. This is partly due to the need of continuously adapting to the ever-changing demands of practical operational environments, in turn caused by technological and regulatory changes which significantly alter the characteristics of the problem to be solved. Furthermore, UC is a large-scale, non-convex optimization problem that, due to operational requirements, has to be solved in an "unreasonably" small time. Finally, as methodological and technological advances make previous versions of UC more accessible, practitioners have a chance to challenge the simplifications that have traditionally been made, for purely computational reasons, about the actual behaviour of generating units. This leads to the development of models incorporating considerably more detail than in the past, which can significantly stretch the capabilities of solution methods.

A particularly relevant trend in current electrical systems is the ever-increasing use of intermittent (renewable) production sources such as wind and solar power. India is on its way towards 175 GW of renewables by 2022. This has significantly increased the underlying uncertainty in the system, previously almost completely due to variation of users' demand (which could however be forecast quite effectively) and occurrence of faults (which was taken into account by requiring some amount of spinning reserve). Ignoring such a substantial increase in uncertainty levels w.r.t. the common existing models incurs an unacceptable risk that the computed production schedules be significantly more costly than anticipated, or even infeasible. Therefore, incorporating such uncertainty in the models is very challenging, in particular in view of the difficulty of deterministic versions of UC.

The CERC approved Detailed Procedure for taking unit(s) under Reserve Shut Down notified in May, 2017 does not deal with start-up of the units when needed for the system conditions. Therefore, there is a need to introduce Unit Commitment and De-commitment procedure in Indian electricity market. The thermal, hydro and renewables unit commitment alongwith emerging technologies such as electric vehicles, storage, etc. have also to be factored. All these provisions may be incorporated in the Scheduling and Despatch Code.

2. 05-Minute Scheduling, Metering and Settlement

The need has been recognized to move to faster scheduling and settlement (i.e. 05-minute) in view of the increasing RE penetration. The international experience is that shorter dispatch and settlement period such as 5-minutes offers a lot of advantages, particularly in terms of reduction in the requirement of reserve, robust price discovery and bringing out the value of flexibility. 5-minute scheduling has reportedly helped in reducing regulation requirements to below 1% of peak daily load in many ISO/RTOs In advanced markets like in Australia and USA, the framework of 5-minute scheduling, dispatch and settlement has already been introduced.

CERC vide order in July, 2018, directed that, on a pilot basis, 5-minute capable meters may be installed at Thermal power stations with AGC installations and Hydro Power Stations to gain practical experience in 5-minute metering, interfacing requirements/ file interchange formats and develop data analytics/ tools for 5-minute metering, data validation, reporting, etc. It was recognized that pilot project would help in formulation/ refinements of Technical specifications and Software Requirement Specifications (SRS) for Metering Software at RLDCs and Accounting Software at RPCs for 5-minute metering. This pilot will also provide insight for implementation of other competing resources like Battery Storage, Electric Vehicles, Demand Response as Ancillary Services. The 05-minute meters are under procurement process by CTU.

It has been directed by CERC, in the above-said order, that all future procurements of Interface Energy Meters should ideally have recording at 05-minute interval and frequency resolution of 0.01 Hz. They should be capable of recording Voltage and Reactive Energy at every 05-minutes and should have feature of auto-time synchronization through GPS. The CEA Standards for the Meters are also under amendment process incorporating these features.

Therefore, suitable amendments in IEGC regarding forecasting, scheduling, despatch, metering, accounting and settlement may be incorporated so as to have the capabilities of both 15-minute and 05-minute recording as per CEA standards.

3. Characteristic Curves of Generating Units

Four characteristic curves describe the efficiency and resulting costs associated with operating a particular generating unit which are essential for Economic Despatch and Unit Commitment solution. These four curves plot Fuel Cost, Heat Rate, Input-Output and Incremental Cost.

<u>Fuel Cost Curve</u>

The fuel cost curve specifies the cost of fuel used per hour by the generating unit as a function of the unit's MW output. This is a monotonically increasing convex function.

<u>Heat-rate Curve</u>

The heat rate curve plots the heat energy required per MWH of generated electrical output for the generator as a function of the generator's MW output. Thus, the heat rate curve indicates the efficiency of the unit over its operating range.

<u>Input-Output Curve</u>

The input-output curve is derived simply from the heat-rate curve by multiplying it by the MW output of the unit. This yields a curve showing the amount of heat input energy required per hour as a function of the generator's output.

<u>Incremental Cost Curve</u>

By multiplying the input-output curve by the cost of the fuel, one obtains the cost curve for the unit in ₹/hr. By taking the derivative of the cost curve, one obtains the incremental cost curve, which indicates the marginal cost of the unit: the cost of producing one more MW of power at that unit.

Therefore, in order to have proper solution for the unit commitment and de-commitment problem as well as proper Economic Despatch , there is a need for mandate through the Grid Code for provision of four curves i.e. Fuel Cost curve, Heat Rate curve, Input-Output curve and Incremental Cost curve.

4. Declaration of commercial operation for a large wind farm or solar park

It is pertinent to state that the modalities regarding declaration of commercial operation for a large wind farm or solar park also needs to be specified in the Grid Code so that it leads to a dispute free commissioning of RE resources.

5. Scheduling of Gas Generation

The availability of domestic gas for the gas power plants is limited and hence its utilization should be optimized considering the power system requirements. This aspect has also been brought out in renewable integration study under Greening the Grid program where it emerged that gas power plants shall be required to provide peaking support instead of flat generation round the clock in high renewable scenario.A study was also conducted by POSOCO on the request of Ministry of Power to look into the possibility of gas generation optimization. This study also recommended optimization of gas generation and scheduling of gas generation connected to gas grid in following manner:

- Such generating stations shall declare maximum declared capacity (DC) for the entire plant for 3 hours and MWh capability separately on domestic gas, RLNG and liquid fuel for the next day.
- Such stations shall also declare weekly energy (MWh) quantum on domestic gas, RLNG and liquid based on discussion with the supplier. The week for this purpose would start from Saturday.
- The weekly energy quantum shall be divided into weekdays and weekends with weekend allocation less than the weekday allocation as agreed mutually between the generating station and the gas supplier/transporter and based on the advice of concerned RLDC duly taking into account the constraints of gas transport pipelines.
- RLDCs shall optimally schedule these power plants based onthe requisitions received from the beneficiaries and power system requirement and intimate the schedule and allocated quantum to each generating station and beneficiary respectively.
- The schedules so prepared by RLDCs would consider 55% technical minimum schedule for the capacity on bar and higher peaking may necessitate synchronization of additional gas turbines before the peak hours and closing down at night hours on some days.
- In case, any beneficiary surrenders power from the gas power plants, RLDCs shall revise the schedule based on technical feasibility only.
- Depending upon power system requirement, such gas generating stations shall have the flexibility to consume more or less domestic gas during the day. The maximum allowable deviation quantum on daily basis would be intimated by GAIL which shall be compensated within the same week by RLDCs in the schedule.

- A mechanism may be identified for recording the consumption of Gas/APM/RLNG/Liquid by plant so that actual fuel used may be accounted.
- Suitable compensation for loss in efficiency during above cyclic operation may be determined by Hon'ble commission.

Considering the above, it is proposed that the above provisions may be included in the Indian Electricity Grid Code (IEGC) for scheduling of gas based generation connected to gas grid. This would mean that such gas generators would submit max DC for 3 hours for the entire plant and MWh capability separately on domestic gas, RLNG and liquid fuel for the next day for the entire plant. The monthly availability may be calculated based on the max DC given for 3 hours for the entire plant.

6. Declaration of DC

As per extant Grid Code, it is being ensured that declared capacity (DC) of all the regional entities does not exceed the capacity on bar less normative auxiliary consumption for scheduling purposes. The Statement of Reasons (SoR) dated 13th April 2018, for 5th amendment to the IEGC was updated on the website of the CERC, wherein following has been stated:

Quote

"13.2.8 We are of the view that declaration of capacity including overload margins is the prerogative of the generator. Generator based on its experience about the healthiness of the units is allowed to declare its declared capability based on machine and fuel/water availability. However, it was being observed that units which were scheduled beyond ex-bus capability corresponding to 100% of IC were not able to provide primary response as these units were operating on VWO mode leaving no margins for further valve opening by governor action during frequency decrease. As such, through the addition in Regulation 5.2 (h), of IEGC, RLDCs/SLDCs have been allowed not to schedule the units beyond ex - bus generation corresponding to 100% of installed capacity. However, for the purpose of calculation of PAF, DC declared by the generator is not to be reduced. This would ensure proper incentive for the generator for keeping units in readiness for providing much needed grid support in case of frequency excursion."

Unquote

From the above, it is clear that it is the prerogative of the generators to intimate the declare capacity including overload capacity but the schedule to the beneficiaries would be restricted to Installed Capacity (IC) minus normative auxiliary consumption or the DC by generator whichever is less. However to ensure the spirit of the SoR, the following methodology is further proposed:

i) The generator would indicate the reasons for DC being higher than normative viz. lower ambient temperature, lower auxiliary consumption, inherent overload capability, overflowing hydro etc.

ii) Primary response would be closely observed for different events in the system and failure to provide the same despite declaring a DC higher than normative DC would be recorded and periodically reported.

iii) In case of overflowing hydro and higher than normative DC, the actual MWh generated during the day would be closely observed to ensure that there is no gaming. The generator would also forward the water spillage data on daily basis to RLDC for the previous day.

iv) The generator would also ensure that the gap between the DC and normative DC (in case former is higher) is not utilized for generating under Deviation Settlement Mechanism (DSM) on continuous basis but only used for providing primary response.

v) In case any unit is under Reserve Shutdown, the DC for the unit under RSD would not exceed the normative DC since the overload capability would not really be available to the system.

7. Inclusion of merchant ISGS generators

The share in a generating station has been defined as percentage share of a beneficiary in an ISGS either notified by Government of India or agreed through contracts and implemented through long term access. There is a need to include Generating station selling power in only Short Term market (Bilateral/Collective) / Medium Term but having regional entity status as such entity is not covered as ISGS, as per the extant definition in IEGC.

8. Additional Roles and Demarcation of responsibilities

It may be mentioned in the Grid Code that CEA shall be the Designated Authority for facilitating the process of approval and laying down the procedure for import and export of transnational exchange of electricity. It shall coordinate with any authority designated by the concerned neighbouring country for all purposes stated in the Approved Guidelines.

In the extant Grid Code, irrespective of the control area the jurisdiction, if a generating station is connected both to the ISTS and the STU, the load despatch centre of the control area under whose jurisdiction the generating station falls, shall take into account grid security implication in the control area of the other load dispatch centre. However, there are several generating stations (Chuzachen HEP, Jorethang HEP) connected only to STU, but schedule 100% power selling in power exchange or outside state are being scheduled by RLDCs. Therefore, corresponding amendments have to be incorporated in the Grid Code.

9. Introduction of the National Pool Account

At present, India has cross-border interconnections with Nepal, Bhutan, Bangladesh and Myanmar. For the purpose of cross-border interconnections, the country needs to be treated as a single control area for the purpose of transnational exchanges and transactions have to be reconciled on National basis. Further, in line with the mandate provided, NLDC is responsible for all trans-national exchanges. A vibrant electricity market is functioning in the country and many regulatory changes have been implemented to address new challenges from the changing scenario which is also leading to increased complexities.

Some of the significant changes that have already been implemented at the National level such as Collective Transactions through Power Exchanges, Ancillary Services (RRAS), Fast Response Ancillary Services (FRAS), Secondary Frequency Control through Automatic Generation Control (AGC) and Security Constrained Economic Despatch. Some of the other proposals which are under various stages of deliberations or implementation are Replacement of thermal generation by RE generation (Ministry of Power, April 2018), Real Time Markets (CERC, July 2018) for facilitating balancing closer to the time of delivery, Flexibility in scheduling of thermal generation (Ministry of Power, August 2018) to achieve economy in despatch at the national level.

Almost all of the above-mentioned proposals are intended for scheduling, despatch, accounting and settlement at the national level. The complexity in settlement needs to be streamlined at the national level keeping in view the changing paradigm and new challenges. In order to streamline the accounting and settlement at the national level there is a need for implementing a National Deviation Pool based on the National Energy Account. In this regard, the following methodology is proposed.

(a) Scheduling: Corridor-wise (e.g., ER-NR, etc.) scheduling of inter-regional transactions is presently being carried out. However, actual power flows as per the laws of physics. In case of collective transactions, one to one correspondence of source and sink is not there and scheduling on a particular inter-regional corridor may at best be notional. Hence, there is a need to migrate to scheduling inter-regional transactions on a net basis for each region. However, while accepting the transactions for scheduling, corridor-wise TTC/ATC/available margin etc. may be duly taken care of. Inter-regional corridor-wise schedules may also be continued based on the physical power flow patterns as the same is useful for grid security monitoring and checking for any discrepancies. NLDC shall communicate the net inter-regional schedules to the NPC for the purpose of accounting.

    Schedules for cross-border transactions shall also be prepared by NLDC on a net-basis to facilitate accounting of cross-border transactions by the NPC. However, individual schedules of the concerned neighboring country with different region regions shall also be continued at RLDC level for the purpose of grid security monitoring and checking for discrepancies.

(b) Metering: The existing practice for metering of the inter-regional points shall continue as per the IEGC and the SEM data shall be collected by the RLDCs, processed and made available to the RPCs. In addition, the processed meter data shall also be made available to the NPC through NLDC. A similar practice shall be adopted for the cross-border metering locations, where the processed meter data shall be provided by the respective RLDCs to the RPCs and NPC (through NLDC).

(c) Accounting & Settlement: Based on the scheduling and meter data provided, NPC shall prepare the National Energy Account (NEA) including the National Deviation Account for the inter-regional and trans-national transactions. The NEA will reflect the payables/receivables for each region on a net-basis and this amount shall be payable/receivable to the National Deviation Pool Account which shall be operated by NLDC. The NEA shall also reflect the cross-border or trans-national transactions and the neighboring countries shall be paying/receiving to/from the National Deviation Pool Account operated by NLDC. Payment to the National DSM Pool shall have the highest priority.

(d) Handling Surplus/Deficit in Regional Pool Accounts and transfer of residual to PSDF: As has already been mentioned above, sometimes the regional DSM pool may face shortfalls on account of disbursals for reliability support such as RRAS, FRAS, AGC, etc. in accordance with the relevant regulations of CERC. Once the National DSM Pool becomes operational, all residual/surplus amount in the regional DSM pools shall be transferred to the National DSM pool account. The NPC accounts would also facilitate the transfer of funds from the surplus available in the National DSM pool to the deficit regional DSM pool accounts as a single transaction thereby simplifying the process. Once all liabilities have been met, any residual in National DSM Pool shall be transferred periodically to the PSDF in accordance with the extant CERC Regulations.

Suitable changes/modifications are required to be carried out in the Grid Code and the functions of NPC also need to be recognized in the regulatory framework.

10. Must Run Status for Competitively Bid Renewables

In Section 6.5.11, it has been mentioned that as variation of generation in run-of-river power stations shall lead to spillage, these shall be treated as must run stations. All renewable energy power plants, except for biomass power plants, and non-fossil fuel based cogeneration plants whose tariff is determined by the CERC shall be treated as 'MUST RUN' power plants and shall not be subjected to 'merit order despatch' principles. However, nowadays, all renewables based projects are competitively procured at inter-state and intra-state level. Therefore, suitable amendments may be incorporated for the renewable plants coming under competitive bidding route.

11. Transparency and Information Dissemination of Curtailment Data of Renewables

There is an urgent need for transparency and Information Dissemination of Curtailment Data related to Renewables. The incumbent regulatory framework accords 'must-run' status to renewables. However, curtailment phenomena is being experienced especially at intra-state levels on account of various reasons. Therefore, as a safeguard mechanism, the stakeholders may be provided with an information portal maintained by statutory organization such as CEA (also mandated as per the Act) for day to day tracking and reporting of renewable curtailment on all-India basis. This would be in coordination with both the state utilities and RE developers. This would benefit the entire power sector and provide valuable signals for investments in required areas for RE-rich states.

12. Provision of Voltage Control and Black-start service as Essential Reliability Service

The power stations in the country have significantly contributed to the voltage stability of the grid by absorbing reactive power from the grid by running as synchronous condenser during off-peak hours. Presently, the synchronous condenser operation of hydro power stations is being done as per instructions of system operators (RLDCs/SLDCs) under the regulatory framework of grid code.

The static reactive power (VAR) exchange by a load serving entity with the Extra High Voltage (EHV) grid (at a voltage level > 33 kV) is priced at ₹ 14 paise/ KVArh under the grid code (IEGC) for keeping voltage within 97% to 103% of nominal value. This provision excludes the generating stations. Thus, an incentive scheme linked to the dynamic reactive support from power stations running as synchronous condensers may be considered by the appropriate commission to promote this essential ancillary service for the EHV grid. The same may be extended to renewable energy generation for providing reactive power support.

The black-start service is an essential and unique service available from a limited number of power stations in the country. At present, most of the black-start capable power stations in the country are hydro power stations. However, the success rate of black start from a hydro power station depends largely on healthiness of the black-start diesel generator sets available at the power station with redundancy. Also, the black start capable hydro stations are strategic assets for ensuring grid resilience and hence, reliable & uninterrupted supply of survival power is a must. As per the provisions in the IEGC, the black start capable power stations are mandated to demonstrate black start capability once in every six months through conduction of mock drills, under intimation to respective Regional /State Load Despatch Centres (RLDCs/SLDCs).

However, there is no scheme for incentivizing black start service rendered by the power stations. In the absence of any compensation, the upcoming power stations may give black-start facility least priority and in the worst case, it may not be commissioned for cost optimization. Thus, the appropriate financial incentive as compensation through provision of black-start ancillary services may be linked to compliance mandated in the IEGC.

13. Forecasting of Load and Renewables along with Adequacy Statements

The forecasting of Load and RE is to be done at state, region and national level by the Load Despatch Centres on sub-hourly basis. The implementation of REMCs is to be expedited. The intra-state generation adequacy statement (covering reserves) is required in all time horizons.

Resource adequacy assessments at national, state and DISCOM level: given the evolving supply mix, the growing need for power system flexibility, and the diversifying options to meet resource adequacy (demand response, storage, etc), it is desirable that the framework for resource adequacy evolve. In particular, resource adequacy assessments should include a more forward-looking assessment, given the time it may take to procure new generation / flexibility requirements, and the large projected mid-term changes in the flexibility needs of the power system. There is a need for the system operator to become more involved in the process for determination of resource adequacy, given that the procurement actions of DISCOMS will need to be optimized not just to meet energy requirements, but also other flexibility needs. It would be desirable that a framework for resource adequacy assessments be developed, and its use progressively introduced among all relevant actors.

Load forecasting on 15-minute block basis to be done at state, region and national level by the appropriate Load Despatch Centres (LDCs) duly considering weather parameters and other factors. Within the state, each DISCOM would be responsible for load forecasting and submitting the same to SLDC. The RE rich states would also be responsible for RE generation forecasting and its revision thereof. Load forecasting along with generation adequacy statement (covering reserves) is required in all time horizons viz. long term i.e. 5-7 years, year to month ahead as well as short term i.e. month to day ahead. SLDCs shall publish the day-ahead adequacy figures on the respective websites. The fuel supply aspect should also be factored in the Load Generation Balance Review (LGBR) published by CEA.

14. Real Time Market

In view of the target of 175 GW for large scale grid integration of renewables, there is a need for introduction of new and multiple market opportunities for the participants to balance their portfolio. The suggestions on behalf of NLDC/RLDCs on the CERC Discussion Paper on Re-Designing Real Time Electricity Markets in India are placed at ***Annexure – I.***

Chapter-8: Frequency Control Philosophy

1. Introduction

i. The National Reference Frequency is 50.000 Hz.

ii. All Users, SEB, SLDCs , RLDCs, and NLDC shall measure the grid frequency with a resolution of +/-0.001 Hz. The frequency data is expected to be stored at the rate of one sample every second as well as 10 seconds.

iii. Frequency control continuum schematic as given in the ***Annexure-II*** may be included.

iv. All Users, SEB, SLDCs , RLDCs, and NLDC shall take all possible measures to ensure that the grid frequency always remains within the 49.95-50.05 Hz band.

v. Need to suitably replace the terms Free Governor Mode of Operation (FGMO) and Restricted Governor Mode of Operation (RGMO) by "Primary Frequency Control with droop." The wind and solar generators need to provide frequency response in line with CEA Grid Standards.

vi. All the generators shall keep their machines under Primary Frequency Control with droop at all times. Any generating unit not complying with this requirement shall be kept in operation only after obtaining permission from RLDC.

vii. The governors of all the generating units shall be free to respond to change in frequency from the nominal frequency of 50 Hz without involving any intentional dead band.

viii. Renewable Energy sources with inverter coupling to the grid shall provide fast frequency response immediately within few milliseconds after an event similar to conventional generation.

ix. NLDC/RLDC/SLDC shall calculate Actual Frequency Response of the respective control areas in accordance with "Approved Procedure for Assessment of Frequency Response Characteristics of control area in Indian Power System" in line with CERC order on Petition no. 47/MP/2012 available at http://www.cercind.gov.in/2013/orders/SO47.pdf. The FRC so calculated need to be posted on LDC website within three working days.

x. Each state control area, region shall work out the Area Control Error (ACE), display, monitor and archive the same.

xi. For the purpose of ACE calculation, the bias could be set as Frequency Bias shall be equal to FRO of each control area as a starting point* which can be refined over time. In case of smaller demand control areas where accurate FRC results may not be available**, bias may be set as 2-3% demand per Hz.

*Measurement, Monitoring, and Reliability Issues Related to Primary Governing Frequency Response, Technical Report, IEEE Power & Energy Society

** For smaller control areas FRC values vary a lot on incident basis

xii. The ISGS,Cross-Border,inter-state and inter-regional tie line values as well as frequency measurements should be treated as Class A telemetry values and updated at a faster rate than ten (10) seconds at SLDCs/RLDCs/NLDC. ACE data is also required to be stored every 10 seconds.

xiii. The ACE, worked out as above, should cross zero value and change sign at least once every hour to start with which would be narrowed down to half an hour. Persistent violation of this condition would render the utility liable for penalties.

xiv. The performance of frequency response will be evaluated on the basis of parameters defined using ACE and FRO.

xv. The power system must be operated at all the times with a specified minimum inertia so that minimum nadir frequency post reference frequency contingency stays above threshold set for UFLS.

xvi. The speed control with droop shall pick in before the frequency touches nadir during an incident.

xvii. The primary response shall be withdrawn once quasi steady state settling frequency becomes stable or before secondary response comes in operation.

xviii. In networks where non rotational generation(Solar PV) is in abundance, islanding schemes must be designed to take care of high Rate of change of frequency(ROCOF).

2. **Primary Control**

i. Primary reserve shall be maintained at All India level considering the reference event. The quantum of primary reserve shall be currently 5000 MW considering the credible contingency of outage of an entire 5000 MW generation in complex such as Vindhyachal/Sasan, CGPL and Bhuj Pool, Hydro complex in Sikkim and Bhutan during high hydro season and other solar/wind complexes and in case of loads for Fault Induced delayed voltage recovery(FIDVR) incidents observed in Kalwa/Delhi/Haryana.

ii. The primary reserves shall be activated immediately when the frequency deviates from 50 Hz and & fully come into service by 49.80 Hz, the quasi steady state frequency.

iii. All the control areas shall ensure that the maximum primary reserve available with them is fully activated within 30 sec (50% within 15 sec & Balance 50% within next 15 sec).

iv. All the control areas shall ensure that the primary reserve remains activated for at least 5 mins.

v. The Target Frequency Response of All India grid is assessed as 27250 MW/Hz assuming

a. Full activation of 5000 MW primary reserves by quasi steady state frequency of 49.80 Hz (25000 MW/Hz)

b. 1.5% Load-Damping constant @ average load of 150 GW (2250 MW/Hz).

vi. The Frequency Response Obligation (FRO) of each control area shall be calculated as:
FRO = (Control Area Demand + Control Area Generation) *Target Frequency Response / (Sum of peak demand of all control areas + Sum of peak generation of all control areas)

vii. The Target Frequency Response and Frequency Response Obligation shall be assessed by NLDC and approved by CERC. This shall be updated annually.

viii. NLDC in consultation with RLDC shall calculate Actual Frequency Response of all the control areas in accordance with "Approved Procedure for Assessment of Frequency Response Characteristics of control area in Indian Power System".

ix. The performance of each control area in providing frequency response shall be calculated:

Frequency Response Performance (FRP) = Actual Frequency Response (AFR)/Target Frequency Response (TFR)

x. The frequency response performance (FRP) of each control area shall be graded as per following criteria:

i.	FRP >=1	Excellent
ii.	0.75 <= FRP < 1	Average
iii.	0.5 <= FRP < 0.75	Below Average
iv.	FRP< 0.5	Poor

xi. The frequency response of each control area shall be calculated for each frequency deviation incidence in accordance with "Approved Procedure for Assessment of Frequency Response Characteristics of control area in Indian Power System" and reported to CERC on quarterly basis.

xii. Each power plant should have adequate facilities to log unit wise MW generation & frequency at 1 second resolution & submit the same to RLDCs / SLDCs whenever required by the latter.

xiii. The frequency influence in/out signal from unit control should also be telemetered to RLDC/SLDC SCADA.

3. Secondary and Tertiary Control

i. Each region shall maintain secondary reserves corresponding to the largest unit size in the region. These reserves shall be maintained in inter-state Generating Stations which are scheduled by RLDCs considering the merit order dispatch in accordance with the detailed procedure for operationalizing reserves and associated unit commitment, prepared by NLDC. Automatic Generation Control shall be operational at RLDC level as well as at SLDC level as per Section (vi) below.

ii. ACE of each control area / region shall be calculated as per following formula: ACE = Deviation + (Frequency Bias) * (Deviation from Scheduled Frequency)

iii. Frequency Bias shall be equal to FRO of each control area as a starting point.

iv. The secondary reserves shall be activated within 10 seconds of ACE of a particular control area going beyond the minimum threshold limit to be identified in the detailed procedure for operationalizing reserves to be prepared by NLDC.

v. The secondary reserves shall be fully activated within 15 mins.

vi. The secondary reserves shall also be maintained by large state control area (loads greater than 10000 MW) and states with high renewable energy penetration.

vii. Tertiary reserves shall be maintained in a de-centralized fashion by each state control area for at least 50% of the largest generating unit available in the state control area.

viii. The tertiary reserve shall be fully activated within 4 time blocks from the time ACE going beyond the minimum threshold limit.

ix. The performance of secondary control shall be assessed in accordance with the detailed procedure prepared by NLDC after the AGC is implemented at multiple locations in the country.

a. For tertiary control performance by each control area, RLDCs would work out the box plots for each control area deviation on monthly basis for the following time blocks based on SEM data:

    i. Average Frequency < 49.95 Hz

    ii. Average Frequency > 50.05 Hz

   For each state control area, the 75th percentile of box plot should be below 100 MW threshold for frequency < 49.95 Hz and 25th percentile should be above 100 MW threshold for frequency > 50.05 Hz. For generators, the MW ceiling value would be +/- 25 MW correspondingly.

   NLDC will provide the formulation in this regard.

Chapter -9: Cyber Security Infrastructure, Policies and Procedures

Power system becomes very large interconnected network which is being maintained by various utilities. As per requirement of various regulatory guidelines and standards issued by regulatory body and Government departments, there is a need to exchange various information across various organization/utilities along-with the Power System Operators. The IT and OT systems are getting interconnected accordingly and getting exposed to public networks. Hence to ensure availability of the system and to ensure Confidentiality, Integrity & Availability (CIA), necessary security measures are to be taken by grid connected entities, SLDC/RLDC/NLDC. Accordingly, Security measures are recommended in the Information Technology Act 2000 and are amended time to time.

IT & OT infrastructure of the Indian Power System is being identified as Critical Information Infrastructure (CII) and all precaution needs to be taken to protect the system from any internal and external threats to continue the business process. The following may be mandated:

1. All grid connected entities, SLDC/RLDC/NLDC shall identify and maintain a list of Critical Infrastructure and the interfaces available in their possession or are being used by them to continue operation. The list shall be updated every year.
2. Shall prepare Risk Assessment Chart to identify all the risks associated to each identified CII and prepare a plan to protect the risk as per ISO 27001.
3. SCADA/Industrial Control Systems (OT System) and IT System shall ensure adequate protections built in on both sides or, with adequate protection built in to withstand denial / disruption / damage from the interfacing network.
4. Adequate Access Control Policy shall be implemented to ensure access of CII by authenticated uses only.
5. An effective Disaster Recovery plan shall be prepared and periodic mock-drill shall be carried out at least once in a year.
6. A secure disposal and transfer policy with appropriate safety measures for all the media storing the critical information should be in place.
7. The entities shall ensure adequate and effective mechanism to periodically review and audit the effectiveness of control as well as shall conduct proper root cause analysis and correction of the incidences and findings.
8. The entities shall conduct periodic (at least once in a year) VAPT (Vulnerability Assessment & Penetration testing) of its CII through certified third party auditor (preferably CERT-In approved) and shall ensure effective implementation of the recommendations thereof.

References

S.No.	Date	Document Name	Entity
1	Mar-19	Global Electricity NetworkFeasibility Study	CIGRE
2	Jul-19	South African Grid Code Requirements for Renewable Power Plants - Version 2 8	National Energy Regulator of South Africa (NERSA)
3	Apr-19	NERC_US_Reliability_Standards	North American Electric Reliability Corporation (NERC)
4	2016	IRENA_Grid_Codes_2016	International Renewable Energy Agency (IRENA)
5	Feb-18	Review of International Grid Codes	Electric Reliability Federal Energy Regulatory Commission
6	Nov-18	COORDINATION OF GRID CODES AND GENERATOR STANDARDS: Consequences of Diverse Grid Code Requirements on Synchronous Machine Design and Standards	IEEE Power & Energy Society
7	Oct-18	Best Practices for Grid Codes for Renewable Energy Generators	National Renewable Energy Laboratory & United States Agency for International Development
8	Jul-18	All TSOs' scenario definition and scenario description for the year 2019 CGM creation	European Network of Transmission System Operators for Electricity
9	Aug-17	Establishing a guideline on electricity transmission system operation	European Union
10	Aug-18	All CE TSOs' agreement on frequency estoration control error target parameters in accordance with Article 128 of the Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation	European Network of Transmission System Operators for Electricity
11	Jan-19	CONTINENTAL EUROPE SIGNIFICANT FREQUENCY DEVIATIONS	European Network of Transmission System Operators for Electricity
12	Feb-19	Energy Code Reviews	ELEXON
13	2015	Reliability Standards issued by North American Electric Reliability Corporation Ltd. (NERC) and corresponding provisions in CEA/CERC Regulations	North American Electric Reliability Corporation (NERC)
14	Sep-18	Guide on new generator-grid interaction requirements	CIGRE
15	May-19	National Electricity Rules	Australia
16	Oct-18	REPORT ON ASEAN GRID CODE COMPARISON REVIEW	ASEAN Centre for Energy
17	May-19	THE GRID CODE- Revision 35	National Grid Electricity System Operator Limited

Annexure - I

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CIN: U40105DL2009GOI188682

पोसोको/ के.वि.वि.आ/

दिनांक : 31st August, 2018

सेवा में,

सचिव,
केन्द्रीय विद्युत् विनियामक आयोग,
तृतीय और चतुर्थ तल, चंद्रलोक बिल्डिंग
36, जनपथ
नई दिल्ली-110001

Subject: Views/Suggestions on the discussion Paper on "Re -Designing Real Time Electricity Market in India"

Ref.: 1. CERC Public Notice RA-14026(11)/2/2018-CERC

महोदय,

With reference to the above-mentioned notice of the Honourable Commission, the views/suggestions of RLDCs/NLDC on the discussion Paper on "Re -Designing Real Time Electricity Market in India" are enclosed for your kind perusal.

सादर धन्यवाद,

भवदीय,

एस आर नरसिम्हन

संलग्न : यथोपरी

(एस.आर.नरसिम्हन)

कार्यकारी निदेशक,रा.भा.प्रे.के.

Power System Operation Corporation Ltd.
New Delhi

Suggestions on Behalf of NLDC/RLDCs on the
CERC Discussion Paper on Re-Designing Real Time Electricity Markets in India

At the outset, the CERC Discussion Paper on Re-Designing Real Time Electricity Markets in India is a welcome, very timely and forward-looking step by the Hon'ble Commission. Given the ambitious target of 175 GW for large scale grid integration of renewables, this paper suggests introduction of new and multiple market opportunities for the participants to balance their portfolio. This discussion paper seen along with the recent amendments in the CERC Short Term Open Access in Inter-State Transmission Regulations which purports to bring in the 'National Open Access Registry' is expected to take the Indian Electricity Market to the next level.

Suggestions on various aspects brought out in the CERC Discussion Paper are given as follows.

1. Introduction of Gate Closure

There is an urgent need for introduction of 'Gate Closure' in Indian Electricity Market. The following two aspects become important from a market design perspective in reference to 'gate closure'.

(a) How far ahead of the beginning of the despatch period does the gate need to close? The discussion paper proposes that the gate closes 90 minutes before the beginning of the despatch period.

(b) How long should the duration of the gate closure be? The discussion paper proposes that the gate should remain closed for 60 minutes duration.

IEGC provides for giving effect to revised schedules from the 4th time block considering the time block in which revision has been requested as the 1st time block. The following aspects are important in this regard:

(a) The above provision effectively closes the window only for 1-time block of 15-minutes making it difficult for any form of market to work.

(b) With coordinated multilateral scheduling process, the schedule modifications are being carried out continuously by the concerned RLDC as one or the other participant request keeps pouring in. For example, re-scheduling of un-despatched surplus on the request of one of the beneficiaries, tripping of power system elements, natural variations, revision in schedule of generators due to changes in requisition, revision in the schedule of beneficiaries due to change in DC of generators, transmission corridor availability etc. This also leads to uncertainty in terms of the available reserves for despatch under Ancillary Services (refer NLDC Feedback on Implementation of Ancillary Services).

(c) There is a need for making the schedules, which are nothing but contracts, financially binding for the participants while at the same time bringing in certainty of despatch.

Hence, there is a need for review of the current provisions with the objective of introducing gate closure.

While the market participants may argue that some degree of flexibility to re-balance portfolio that is available presently is being withdrawn with the introduction of gate closure, there also needs to be an appreciation for the fact that an alternate mechanism is being provided to re-balance their portfolio closer to the time of delivery. The alternate mechanism proposed is the Real Time Market (RTM) through Power Exchanges which provides access to a larger market & participating resources with a competitive price formation mechanism. Bidding of URS by ISGS in RTM would dissolve the existing limitation of URS scheduling only amongst co-beneficiaries of the same station. RTM would create an organized market for ISGS and intrastate generators.

Once the gate closes, the following activities are envisaged to be carried out during the gate closure period for the identified delivery period of one hour:

(a) RTM Auction period
(b) RTM Market Clearing & Scheduling
(c) Assessment of the requirement for despatch of Ancillary Services
(d) Communication of schedules by the RLDCs to the market participants and adequate time for the generators to ramp-up or ramp-down

From an implementation perspective, the proposed timelines for gate closure allow only 90 minutes ahead of the delivery period which is inadequate for all of the above activities. Further, this concept is being implemented for the first time in the country and there may be unforeseen implementation issues. For example, in the implementation of Ancillary Services, initially it was proposed to send the Ancillary Schedules directly to the participating generators from NLDC so as to obtain fast response. However, immediately after implementation, scheduling and ramping related difficulties were experienced and the schedules for ancillary services had to be routed through the RLDCs. Once we gain experience, the Hon'ble Commission can review the timelines based on the experience gained. In view of above, it is suggested that the gate closure should be 120 minutes ahead of the identified delivery period of one hour. An illustration is given below in Figure-1 for better clarity.

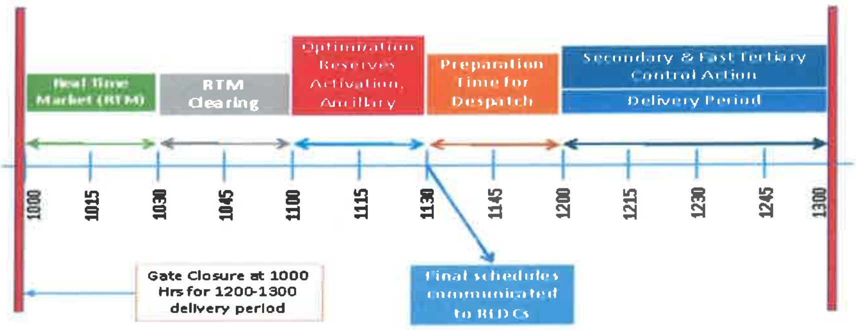


Figure-1: Illustration of Suggested Gate Closure

2. Existing Market Options and the Real Time Market

Various market options are presently available to the market participants through bilateral transactions (advance, first-come-first-serve, day-ahead bilateral and contingency) and collective transactions (day ahead market) through the Power Exchanges. The 'Term Ahead Market (TAM)' falls under the category of bilateral transactions. Under the present mechanism, window for only one product is open at any given point in time so as to facilitate electricity market administration in terms of margin determination and other activities. This is extremely important from an implementation perspective.

The Discussion Paper proposes to introduce a new market segment 'Real Time Market (RTM)' which is envisaged to run on every hour i.e., there shall be 24 market runs. Implementation of the RTM would require some modifications in the timelines of existing market products. While doing so, it may be ensured that window for only one product is open at any given point in time so as to facilitate electricity market administration.

Moreover, in order to process the multiple market transactions, a high degree of automation is required without which, implementation of RTM may be extremely difficult. The Hon'ble Commission has already taken steps to introduce the 'National Open Access Registry (NOAR)' and necessary draft amendments have already been notified.

3. Market Design Issues associated with the Real Time Market (RTM)

The Discussion Paper proposes a closed double-sided auction for the RTM with price formation taking place based on the principles of social welfare maximization. Following market design issues need to be addressed while implementing the RTM.

(a) Should participation in the RTM be voluntary or mandatory (say for example, is there a need for withdrawl of some existing market product e.g., contingency category transactions)? Should there be a linkage between the participation in the day-ahead market and the RTM? Participation in RTM can be made mandatory for at least some types of the participants such as generators.

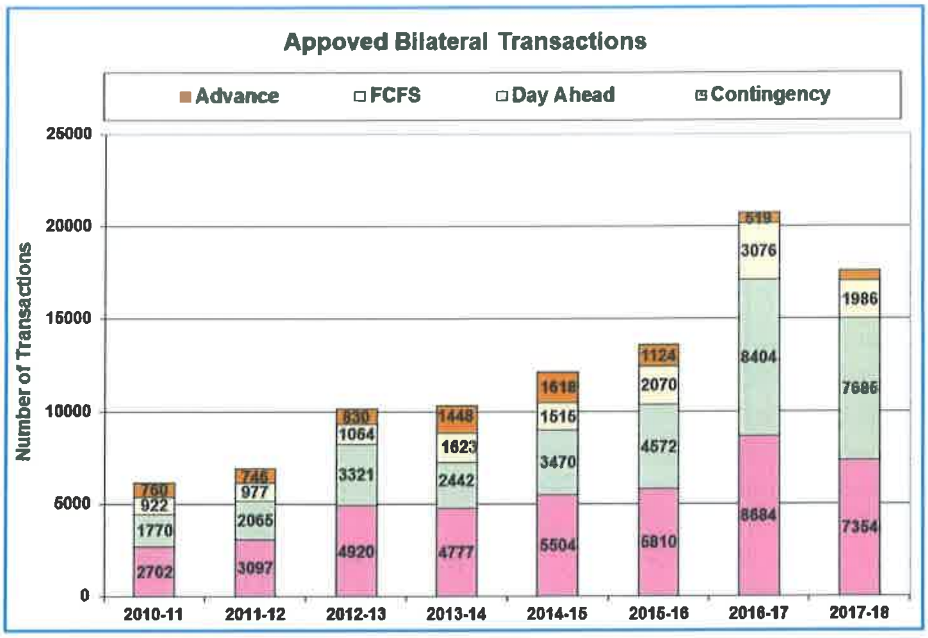
(b) RTM has to be a liquid market so as to facilitate a robust price discovery. The price discovered in the RTM can also be considered for linking to the DSM prices ultimately at a later date.

(c) Enough liquidity is also necessary to reduce the possibilities of market manipulation

(d) While the day-ahead market can continue to run as it is, the design of RTM has to be such that it attracts participants from the OTC market, which has higher transaction costs, to the more organized platform, i.e., RTM. The present volumes in the different products in the OTC market as shown in Figure-2 below which shows the kind of potential that exists for the RTM.

(e) Scheduling and Settlement also need attention and it needs to be clearly specified that all transactions are for physical delivery and financially binding for the participants.

(f) Presently, the prices are available for the day-ahead market operating in the Power Exchanges (IEX and PXIL). More than one prices are discovered in case of congestion and market splitting in the day-ahead market. With the RTM coming into picture two (2) prices (one for DAM and one for RTM) are going to be discovered. Interplay in the different market segments needs to be considered.



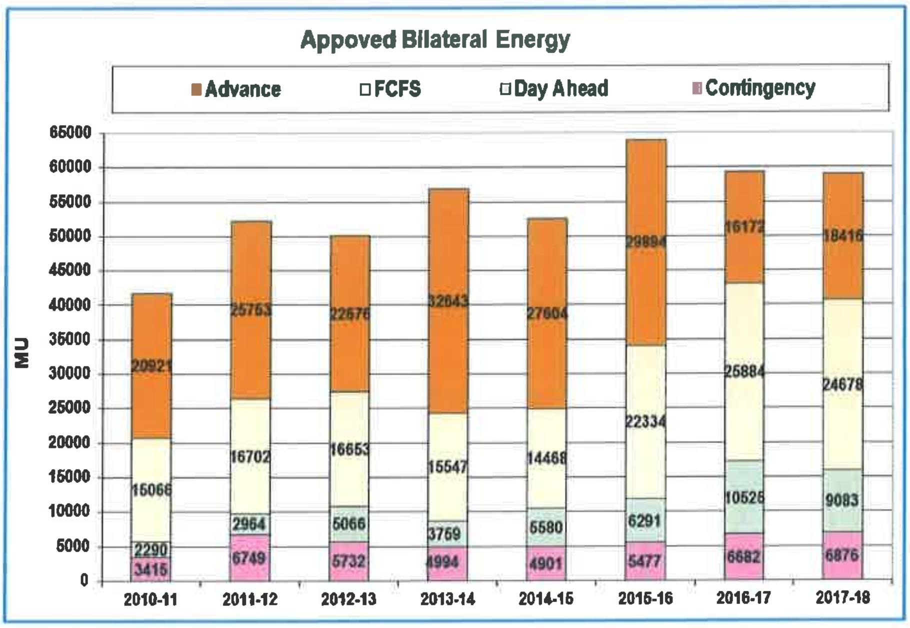


Figure -2: Multi-year trend of trades in different segment, viz. Advance, FCFS, Day-ahead bilateral and contingency categories

(g) Presently, a 15-minute scheduling, metering, accounting and settlement mechanisms are in place. Deliberations have begun for migrating to 5-minute from 15-minute scheduling, metering, accounting and settlement. Switching to 5-minute systems in the future (as also prevalent worldwide) may also be kept in view.

4. Congestion Management in the RTM

Transmission Congestion Management in the RTM is proposed using market splitting and shall be on similar lines as in the day-ahead market in the Power Exchange(s). The time lines for RTM are short and tight with the bidding window and market clearing window proposed to be 30 minutes each only. The discussion paper (section 5.8) proposes that margins will be provided in advance to the Power Exchanges so as to avoid two step clearing (Provisional Market Solution and Final Market Solution) of the RTM market.

While it is appreciated that the objective is to facilitate faster processing of the RTM transactions, such a step will have a bearing on the price discovery in the RTM market segment. It is pertinent to mention that in the process of providing the transmission corridor margins in advance, we are implicitly declaring transmission as a 'scarce commodity' in economic terms. As soon as such a declaration is made in advance of the trading session, the behavior of market participants changes (even if it is found after clearing that there is no congestion) and aggressive bidding takes place thereby impacting the price discovery.

Implementation of National Open Access Registry (NOAR) is already being carried out and margins will be readily available for passing on to the Power Exchanges as soon the bidding session closes. Thus, the Power Exchanges can still clear the RTM in one iteration ensuring quick market clearing avoiding possible distortion in the price discovery on this account.

5. Revision in Schedules by Generators

Presently, IEGC Clause 6.5.19 provides that generators can revise schedules in case of unit tripping (unit size more than 100 MW). This provision hampers the development and prevents liquidity in organized market segments. In this regard, attention is also drawn to the POSOCO Suggestions on Draft Amendments to the Short Term Open Access Regulations dated 20th March 2009 (enclosed at Annex – I for ready reference), wherein the generic market design issues in allowing revisions have been mentioned. These are very relevant in the present context also. It is once again re-iterated that revisions in scheduled short-term transactions on account of generator unit tripping should be disallowed.

In the context of the above, it is further suggested that the generators may be allowed in the event of unit tripping to purchase power in the RTM to make up for their contractual liability.

6. Deviation Settlement Mechanism

The Hon'ble Commission has already notified the 4th Amendment to the Deviation Settlement Mechanism Regulations which propose linking the DSM rates to the daily average Area Clearing Price (ACP) market rates discovered in the day ahead market (DAM). This is a forward-looking step and needs to be quickly implemented. As we move further on with the implementation of RTM, the DSM rates may be linked to the market clearing price discovered in the RTM. It is pertinent to mention here that the DSM has played in important role in complementing grid security through a commercial mechanism.

7. Market Information and Market Monitoring

With further development of the electricity market in the country and introduction of new market segments, market information dissemination systems and market monitoring mechanisms need to be reviewed and strengthened. Information dissemination by the Power Exchanges needs to be reviewed and provisions for more elaborate information dissemination are needed e.g., social welfare, consumer surplus, producer surplus, etc. need to be incorporated. Multiplicity of prices and interplay between market segments has already been mentioned as areas which would require close monitoring. In this regard, the provisions under Part – 7 on Market Oversight of the Power Market Regulations 2010 are pertinent and relevant. These may be kept in view while designing the market information system and market monitoring mechanisms for RTM. Market surveillance tools would be required to take care of market power in congested systems, provision of purchase by generators in case of unit tripping and so on.

8. Demand Forecasting to ensure Resource Adequacy

Electricity market design should complement reliability and resource adequacy is key towards ensuring reliability of supply. It is in this context that the provisions of Clauses 5.3 and 5.4 of the IEGC pertaining to demand estimation, forecasting and demand management, need to reiterated and enforced.

9. Need for Automatic Controls in the Grid

After the gate closes, RTM is cleared and ancillary has been dispatched for the designated delivery period, a contingency can still occur, say, for example a generator unit tripping. It is in this context that automatic controls in the grid such as Primary Response and Secondary Response through Automatic Generation Control (AGC) assume great importance in the interest of secure and reliable grid operation. It is hereby reiterated that Primary Frequency Control may be enforced and secondary control through AGC be rolled out for all ISGS.

10. Reserves and Ancillary Services at the State Level

While Ancillary Services has been successfully implemented at the inter-state level, similar mechanism for maintenance of reserves and ancillary services needs to be implemented at the intra-state level.

11. Implementation of SAMAST at the State Level

An important stepping stone for taking the electricity market to the next level is the implementation of (Scheduling Accounting Metering and Settlement of transaction) SAMAST also and this needs to be pursued.

12. Pilot Project – Running Multiple iterations for Collective Transactions in Power Exchanges

The RTM envisages running of the electricity market in collective mode 24 times per day. Implementation of the RTM is dependent upon the implementation of the National Open Access Registry (NOAR) and the NOAR implementation is still under process. In the meanwhile, in order to gain experience in running multiple iterations of the market in the Power Exchanges, it is proposed that a pilot may be carried out to run multiple iterations on a 6-hourly or 12 hourly basis. In this regard, POSOCO proposal for running an 'Evening Market' dated 18th May 2010 is also enclosed for ready reference (Annex-II). It is pertinent to mention here that by implementing such a pilot, deep insights will be obtained into

(a) Various market design issues such as liquidity, price discovery, interplay of prices, bidding by participants, etc.

(b) Implementation related aspects such as ramping up of the infrastructure, market clearing process etc.
(c) Capacity building requirements for all stakeholders i.e., market participants, system operators (NLDC/RLDCs/SLDCs) and the Power Exchanges

Hence, it is hereby proposed that the Hon'ble Commission may consider implementation of the above mentioned pilot.

Annex - I

पावर ग्रिड कारपोरेशन ऑफ इंडिया लिमिटेड
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पावरग्रिड

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Tel : 2571700 - 719, Fax : 2571760, 2571761 Gram : 'NATGRID'

संदर्भ संख्या /Ref. Number **: CSO/** **Dated: 20th March, 2009**

To,

The Secretary,
Central Electricity Regulatory Commission,
3rd & 4th Floor, Chanderlok Building,
36, Janpath, New Delhi- 110001

Sub : Suggestions on proposed Amendments to Open Access in Inter-State Transmission 2008

Dear Sir,

The Hon'ble Commission has proposed Amendments to the Open Access Regulations, 2008. In the proposed amendments, two major issues arise:

a) In case the SLDC has not refused concurrence or 'no objection' or standing clearance , as the case may be, within the specified period of 3 or 7 working days, as the case may be, of receipt of the application, concurrence or 'no objection' or standing clearance, as the case may be, shall be deemed to have been granted.
b) Allowing revision of the schedules on the day on which the transaction is scheduled or on the day-ahead basis.

Our detailed views on the above and other minor issues are enclosed herewith for the kind consideration of the Hon'ble Commission.

Thanking you,

Yours faithfully,

20/03/09

(S.K.Soonee)
Executive Director(SO)

Encl: A/a

Comments on the Draft Amendment Regulations on Open Access in inter-State transmission system issued vide public notice dated 27th February, 2009

CERC vide its public notice dated 27th February 2009 has invited comments/ suggestions/ objections on the draft Regulations by 20th March 2009. Most of the changes as proposed are bringing out more clarity on the subject. However, some of the changes as proposed in the draft regulation are against the spirit of CERC (Open Access) Regulations 2008 which evolved over time based on experience after the first set of regulations issued in January 2004 and amended in February 2005 and December 2006.

Comments on the Draft CERC Open Access, (Amendment) Regulations, 2009 are as follows:

1. **Clause (4) of the Regulations 8:**

   As per the proposed draft amendments, the last para of the Clause (4) of Regulation 8, states that:

   Quote
   "Provided that where the State Load Despatch Centre has not refused concurrence or 'no objection' or standing clearance, as the case may be, within the specified period of three (3) working days or seven (7) working days, as the case may be, of receipt of the application, concurrence or 'no objection' or standing clearance, as the case may be, shall be deemed to have been granted."
   Unquote

   As per the above proposed amendment, if a SLDC has not processed the application for issuance of "Standing clearance" or "No Objection" by an applicant, in the specified time frame the same shall deemed to have been granted. The above amendment may cause dispute in implementation of Open Access Regulations. Proper record of SLDC's consent is required on account of the following reasons:

   - SLDC is the apex body for system operation in the state
   - SLDCs are to be empowered and not to be bypassed
   - SLDC has to check for availability of adequate transmission margin so that there are no network constraints in real time operation
   - Energy transactions have to be accounted for and SLDC has to ensure that necessary infrastructure for energy accounting is available

   The issues that arise out of this proposed amendment are outlined below.

(a) Empowerment of SLDC

Regarding whether or not prior consent of SLDC is required was much deliberated during the hearing on draft CERC Open Access Regulations 2008. CERC vide para 8 of the "Statement of Reasons" dated 4th March 2008 on the CERC (Open Access) Regulations, 2008 has expressed its views as follows (emphasis supplied):

Quote
8. In our view SLDC is the apex body to ensure integrated operation of the power system in the State as per the provision of the Act. ***For the overall benefit of sector, it is necessary that SLDCs act impartially in the matters of system operation and take responsibility for their actions. The scheme proposed in the draft regulations is designed to propel SLDCs in this direction.*** *Therefore, this proposal has been retained in the final regulations.*
Unquote

The rapidly changing scenario in the power sector has resulted in changes in the role of LDC at all levels. Further, it is essential that the industry has a confidence on the competence of the System Operator and their conduct is above suspicion. This is all more important especially with the rapidly growing economy, unbundling of State Electricity Boards, increasing participation of Private Sector players, open access in transmission and distribution, power exchange and other market mechanisms. Therefore, the State Load Despatch Centres must be provided with an enabling environment to help them to deliver the desired result while performing their duties for ensuring integrate operation of the power system with in their State, non-discriminatory open access to all and bringing overall economy and efficiency in the State Power Sector.

(b) Network Security

Section 32(1) of the Electricity Act, 2003 provides that State Load Despatch Centre (SLDC) is the apex body to ensure integrated power system operation within that State. While granting "No Objection" or "Standing Clearance" for Open Access, it has to check for the congestion in the State network and carry out studies etc if required. In case an SLDC has not processed the application in time and it is presumed that there is no network constraint it would lead to more serious error.

In case sufficient transfer capability to accommodate the proposed open access transaction is not available and due to some or other reason the respective SLDC has not processed the application and open access has been granted based on deemed consent, it may endanger the security of the grid. In statistical term this shall lead to type II error (false negative).

Statisticians speak of two significant sorts of statistical error. The context is that there is a "null hypothesis" which corresponds to a presumed default "state of nature", e.g., that an individual is free of disease, that an accused is innocent, or that a potential login candidate is not authorized. Corresponding to the null hypothesis is an "alternative hypothesis" which corresponds to the opposite situation, that is, that the individual has the disease, that the accused is guilty, or that the login candidate is an authorized user. The goal is to determine accurately if the null hypothesis can be discarded in favor of the alternative. A test of some sort is conducted (a blood test, a legal trial, a login attempt), and data is obtained. The result of the test may be negative (that is, it does not indicate disease, guilt, or authorized identity). On the other hand, it may be positive (that is, it may indicate disease, guilt, or identity). If the result of the test does not correspond with the actual state of nature, then an error has occurred, but if the result of the test corresponds with the actual state of nature, then a correct decision has been made. There are two kinds of error, classified as "Type I error" and "Type II error," depending upon which hypothesis has incorrectly been identified as the true state of nature.

In this case the "Null Hypothesis" is that there is there is existense of infrastructrue necessary for time block wise energy metering and accounting and availability of surplus transfer capability in the State network. Type –I, error means, that the hypothesis is true but consent is not accorded. Type-II error means, either there does not exist necessary infrastructure and/or surplus transfer capability is not there and approval is granted. In more common parlance, a Type I error can usually be interpreted as a false alarm or insufficient specificity. A Type II error could be similarly interpreted as an oversight, a lapse in attention or inadequate sensitivity. In this case, Type-II error is costlier than the Type-I error and therefore to reduce Type-I error one cannot increase the probability of the Type-II error.

(c) **Dispute Free Implementation**

Further, if prior consent is not on record, then it may lead to many disputes and it will be very difficult to implement the CERC Open Access Regulation. The Hon'ble Commission vide para 11 (c) of its Order dated 07.03.2007 in Petition No. 24/2007, in the matter of "Refusal No 131 of 25.1.2007 by the Western Regional Load Despatch Centre of the open access application filed by Tata Power Trading Company Limited for transmission of 27 MW power through Eastern Regional Load Despatch Centre and Orissa State Load Despatch Centre from Nava Bharat Ventures Ltd, on the ground of "No consent from OPTCL", has placed its views on record as quoted below:

Quote
11. Before parting, we would like to place on record our observation on certain issues which have come to light during the hearing of this petition.
(a) ……………
(b) …………
(c) In case an inter-State open access involves buying/selling power from/to an entity embedded in the State grid, the concerned RLDC must obtain the prior consent of the concerned SLDC, since the open access transaction has to be duly accounted for in

the net drawal schedule of that State. If prior consent is not on record, there could be intractable disputes regarding scheduling, etc. later on.
(d)………………………

Unquote

From, the observation of the Hon'ble Commission it is abundantly clear that the prior consent should be on record otherwise there could be intractable disputes regarding scheduling etc.

Therefore it is requested that the last para of the proposed modification i.e.; *"Provided that where…………………………………………………………… ………… shall be deemed to have been granted"* should be deleted.

2. **Clause (1) of Regulation 14**

Replace "notice the nodal agency:" with "notice to the nodal agency:" at the end of the first paragraph of the clause (1) of Regulations 14.

3. **Clause (2) and Clause (3) of Regulation 14**

As per the draft amendment, transmission charges are to be paid for notice period of two (2) days. If an applicant gives notice two days in advance, then as per the proposed amendment he will not have to pay any charges for exercising exit option. In most of the trades/ agreements, exit has some charges, either in the name of cancellation charges or any other name. It is a well settled issue that an exit option must have some charge/cost. How much shall be quantum of this charges would depend on the degree of seriousness required or impact such exit would have on either party. CERC OA Regulations, 2008 had specified minimum 5 days charges and now the intent of the Commission is to reduce these charges from 5 days to 2 days. In order to have clarity on the issue it is proposed that the clause (2) and clause (3) of the Regulation should be replaced with the following (similar to clause 2, 3 and 4 of Regulation 14 of CERC OA Regulations, 2008):

(2) The applicant shall continue to be liable to pay transmission charges as per the schedules originally approved, if the period of curtailment or cancellation is upto two (2) days.
(3) If the period of curtailment or cancellation exceeds two(2) days, transmission charges for the period beyond two (2) days shall be payable in accordance with the curtailed schedule and for the first two (2) days in accordance with the original schedule.
(4) In case of cancellation, operating charges shall be payable for two (2) days or the period of cancellation in days, whichever is less.

4. **Regulations 14 (A) – Revision of Daily Schedule**

The Draft Amendment of Open Access Regulations provides for a new regulation 14A which will entitle flexibility to cancel/curtail the scheduled bilateral transactions. In this context, it would be seen that long-term contracts have the provision for any number of schedule revisions in a day. The Regulations in respect of medium term access has not yet been released by the Honourable Commission. Revision in schedules on daily basis is a cause for concern.

The proposed amendment will seriously hamper the development of Short-Term Electricity Market in India on account of the following reasons cited below:

i. **"Contract" vs "Option"**

If cancellation/curtailment of scheduled bilateral transaction is permitted than the bilateral contract shall no longer remain a "Contract" and will virtually convert into "Option" with "ZERO" or negligible premium. Seriousness of contracts or firmness of delivery would be lost. With such easy exit options, volumes might shift to advance bilateral contracts with possibility of inflated requests for transmission capacity and frequent revisions.

ii. **Pseudo Congestion : Blocking of Transfer Capability, Easy Exit Option**

In the earlier Open Access Regulation (2004), there was a provision for daily scheduling of bilateral transactions. Market Players used to reserve/block the transmission corridors in advance as exit option was very easy. This had resulted in under utilization of the transmission corridors and many a time pseudo congestion was observed. The above anomaly was removed in CERC Open Access Regulations 2008. The issue of providing flexibility to stakeholders to revise the daily schedule was discussed in detail and the Hon'ble Commission in the Statement of Reasons for CERC Open Access Regulations 2008 has stated as quoted below (emphasis supplied):

Quote

Flexibility to revise the schedule and exit option

4. Most of the stakeholders have observed that it is impractical to schedule a transaction too much in advance. Global Energy Limited has observed that the prohibition against revision and cancellation of schedules would put the generating companies to undue hardship, as they would be exposed to uncertain UI charges even on account of shutdown of generating units for genuine and unforeseeable reasons. Some stakeholders have stated that hydro generators should be allowed to revise the schedule as their generation is dependent of uncertain water flows. Similar reason has been advanced for *wind generation by GFL. Some stakeholders have suggested that period of advance scheduling should be reduced further for simplification and certainty.*

*5. **In the draft regulations, the proposal to fix the schedule for the entire period of transaction while approving the application of open access customer was intended to prevent blocking of the transmission capacity. For the same reason, no exit option was provided to the open access customers whose applications have been approved by the nodal agency.** This issue has been reconsidered in view of the comments/suggestions of the stakeholders and it has now been decided to grant a limited flexibility of revising or canceling previously approved schedules by giving 5 days notice. If the period of revision/cancellation is up to 5 days, the customer will pay transmission charges as per the originally approved schedule. If the period of revision or cancellation is more than 5 days, the customer will be liable to pay first 5 days transmission charges as per the originally approved schedule and for the remaining period as per the revised schedule. Operating charges shall be payable as per the original number of days during the period of scheduling, if the period of cancellation is up to 5 days. If the cancellation period is longer, operating charges for the period beyond five days shall be refunded. **Since, the revised provision will give some flexibility of revision/cancellation in case of contingencies, the provision in the draft proposing powers to the nodal agency to allow revision/cancellation in extraordinary circumstances has been omitted. The regulations provide full freedom to the applicants to apply over a period of three months. Those, who are comfortable only few days before or even a day before the date of actual transaction to commit to the transaction, can choose to do so. When viewed in this manner, there is no need to change regulations further.***

*6. **To recapitulate, one can apply for open access and scheduling three months in advance, two months in advance, one month in advance and one or more days in advance, depending on when he is able to commit to the schedule being applied for. Exit option is also available up to five days ahead of the day for which schedule is proposed to be curtailed or cancelled, but without refund of any transmission charges for first five days of curtailment/cancellation. We believe that the final regulations adequately address the concerns expressed by the stakeholders.***

Unquote

From the above mentioned extracts from Statement of Reasons, it is abundantly clear that the Hon'ble Commission has given due thought on the issue and after considering views of all stakeholders and experience gained over the years, the CERC Open Access Regulations 2008 was finalized. Insertion of the proposed new clause will tantamount to revision of own order of CERC without any new material evidence being brought to the notice of the Commission to incorporate such changes. In fact, in the proposed amendment, the exit option has been relaxed further. The notice period has been reduced form 5 days to 2 days. This sufficiently takes care of the issue.

Therefore, provision for revision of schedule on daily basis will be a retrograde step knowing in advance the pitfalls involved.

iii. Interplay between bilateral and balancing market

Allowing cancellation/curtailment of schedule on Daily basis shall mean the Day-Ahead schedules are no longer financially binding. There is a possibility of inter-play between the bilateral market and the real-time balancing market. The Paper titled "ELECTRICITY MARKET DESIGN: THE GOOD, THE BAD AND THE UGLY", by Peter Cramton, University of Maryland examines the principles for market design as applied to Electricity Markets. As we move closer to real-time, the system becomes less responsive as options vanish. The supply curve becomes steeper. Hence, the vulnerability to gaming near real time is great, especially if a lot of value is riding on the real time prices. The author has strongly advocated that the day-ahead contracts should be financially binding. As per the Author the one solution to this issue is either forbidding changes, and the other better solution is to make the day-ahead schedule financially binding, as quoted below:

Quote:

One solution to this problem is forbidding changes. This may be effective for bid changes, but outages are often necessary and it is difficult for the regulator to distinguish between legitimate outages and those intended to raise the price. Also, generators often have good reason to change bids in response to export opportunities, revised fuel prices, or other changes.

A better solution is to make the day-ahead schedule financially binding. This is called a multiple settlement system, sincere there are at least two sets of prices and quantities. Those in the day-ahead schedule and those at real time. Having the day-ahead bids financially binding does two things. First, it makes the bids credible, since successful bids involve a financial commitment. This is a general principle of market design. Bids should be financially binding. Second, a multiple settlement system mitigates incentives to manipulate the real-time price. Most of the pricing and allocation is done day-ahead. The real-time market is only to price deviations from the day-ahead plans. Those scheduled day-ahead have no incentive to manipulate the real-time price. Rather their incentive is to make adjustments to bids in response to changes in their economic situation. **Unquote**

It is important to mention here the fundamental difference in the charges for the long term contracts and bilateral contracts. Long term contracts have a multiple settlement system (separate capacity and energy charges) whereas the short term bilaterals have a single settlement system (energy charges only). Revisions are allowed for long term contracts and by design there is no incentive for gaming. Allowing revision of bilateral contracts would provide an opportunity for gaming besides bringing bilateral contracts at par with long term contracts by defective market design.

In this context, it is pertinent to quote Power System Economics by Steven Stoft, wherein it is stated that ***"All except the real time markets are financial markets in the sense that the delivery of power is optional and the seller's only real obligation is financial"***.

iv. "No Show" : Past Experience

Based on its operational experience, POWERGRID System Operation vide letter dated 15.07.2006 gave feedback to the Hon'ble Commission that a few of the Short-Term Open Customers are under-utilizing the transmission capacity, resulting in blocking of transmission capacity which could have been utilized by other prospective customers. The Hon'ble Commission examined the issue and subsequently issued an amendment in December 2006 to the Open Access Regulations whereby any transmission capacity available after catering to the requirements of long-term and short-term customers, as advised by the eligible entities by 3:00 PM of the day preceding the day for which schedules are being prepared, may be released for use of other perspective users. The utilization of transmission capacity increased significantly after the amendment of the Regulation. Moving further, the Honourable Commission in the 2008 Regulations further used the term 'scheduling of transactions' instead of 'reservation of transmission capacity' indicating higher firmness.

v. Congestion Management

Electricity markets can operate only with some level of certainty in respect of transmission capacity. This has been ensured through specifying 'window closing and opening times'. Thus while the PX window is 'open', the bilateral window is 'closed' and vice-versa.

While assessing the transfer capability for day-ahead transactions, counter-trades are accounted for optimum utilization of the transmission corridors. Collective Transactions through Power Exchange (PX) are scheduled based on the available margin after considering the net scheduled transaction. Cancellation / curtailment of scheduled bilateral transaction on day of operation or on day ahead basis will be known only after PX transactions are cleared at 1400 hours. This would lead to the following scenarios:

a) Sub-optimal utilization of transfer capability – more margin could have been allocated to the PX if the revision was known in advance.
b) Congestion in real time and grid security may get endangered—if the wrong set of transactions gets revised.

vi. Ripple Effect

If the schedule for bilateral transaction is allowed to be cancelled / curtailed on daily basis then the same will create a ripple effect in the whole market. For example, a State Utility has entered into a bilateral agreement for purchase of 'X' MW power from some generator. Because of some or other reason the generator is not able to deliver the contracted power and therefore revised the transaction. The State Utility may now have to revise its requisition from other generating stations from which it has not requisitioned its full entitlement. In case this State Utility has sold power to some other party, then it may like to cancel/curtail its scheduled bilateral transaction.

Accordingly, allowing cancellation/curtailment of scheduled bilateral transaction on daily basis will create a ripple effect.

vii. Transfer of wealth

Any cancellation/curtailment of schedule shall result in a shift of the liability for payment of Unscheduled Interchange (UI) charges from supplier to buyer and is in effect transfer of wealth from one party to other. By allowing cancellation/curtailment of scheduled bilateral transaction, the financial liability of the party who is not able to deliver as per contract is getting obviated.

viii. Risk allocation of unsystematic risk of Private Goods

In Electricity Market, risk mitigation is avoiding risk and bringing in more certainty and Risk Allocation describes who shares the cost of risk in case it actually happens. Presently a number of Short-term open access products are available to market participants and they can utilize the same for risk mitigation. A systematic risk affects the whole group and not individuals, but the Unsystematic risk affects only few. Unsystematic risks may be due to non performance of individuals. Cancellation/Curtailment of schedules shall tantamount to entering into the domain of risk allocation of unsystematic risks of private goods. Normally this should be responsibility of the parties entering into the contract. In case of two part tariff for ISGS (long-term contracts), the risk is allocated to the party by way of capacity charges payment or reduction but such is not the case in short-term or energy only contracts.

ix. Trading License Regulations,2009

Even after the above aspects are considered and the Commission decides to accept revision in schedules, it would open the doors for innumerable disputes. Chapter IV, 7(i) of the Trading License Regulations 2009 by CERC states as under:

'(i) The licensee shall ensure that appropriate agreement for purchase and sale of electricity are entered into by him with the sellers and the buyers prior to scheduling a transaction, and that the agreement shall specify the following, namely-
(i) the boundaries, that is to say, upper and lower MW limits of electricity to be purchased or sold,
(ii) modalities for scheduling,
(iii) persons authorized to specify the schedule, or to modify it after it has been intimated to the Regional Load Despatch Centre or the State Load Despatch Centre,
(iv) whether the buyer or the seller can unilaterally advise modification of the schedule, or whether the modification can only be advised jointly by the buyer and the seller,
(v) the liabilities of the parties (seller, buyer and licensee) in case the scheduled quantum (MW) and time of scheduling differs from the agreed terms, or in case of modification in schedule, and in the latter case, the party that will bear non-refundable part of short-term open access charges.

In the Statement of Reasons dated 16th February 2009, the Honourable Commission in response to POWERGRID's suggestion had remarked as under:

"31. PGCIL has pointed out that though modification of schedule for long-term (and medium-term) transactions are allowed, such freedom to allow scheduling advice by either or both would lead to confusion and should be avoided. Hence it has suggested that a provision may be made that only the applicant can advise modification of schedule to RLDCs, if required, after taking consent from the parties involved. We do not think that any modification on the lines suggested by PGCIL is necessary, since the clause is only to ensure that the party which can advise a schedule change is duly identified in the contract, and there is no dispute on this account later on."

The Hon'ble Commission has ordered that SLDCs should only check whether the necessary infrastructure for metering and accounting is in place and there is surplus transfer capability to accommodate the transaction. If the above is to be accepted, it would involve subjectivity of SLDCs/RLDCs and every application has to be judged on merit. All this has the potential to create disputes, particularly when there could be 40-50 bilateral transactions on any given day. More so since in any schedule revision there are three parties involved viz. the buyer, seller and the trader and each would have different objectives which are contradictory.

In view of the above facts, RLDCs would earnestly request the Commission not to accept any request for schedule revision.

x. Un Requisitioned Surplus (URS) of Inter State Generating Stations (ISGS)

In the background note for the meeting of the Central Advisory Committee (CAC) on 18th March 2009, the issue of revision in schedules for Open Access transactions has been mentioned. One of the main drivers appears to be the URS from ISGS as evident from the extracts below.

"Flexibility of revision is also desirable to remove difficulties faced by the central generating companies with regard to un-requisitioned surplus capacity. When a beneficiary which is entitled to a capacity does not give requisition, such un-requisitioned capacity can be sold through open access. However, when original beneficiary wants it back, difficulty is faced because of not-so-flexible provision for revision of schedule for open access transaction."

In this connection it is stated that the issue of Un Requisitioned Surplus (URS) is essentially a concept from the pre-Open Access era. After the introduction of Inter State Open Access in May 2004, any URS of ISGS has a status similar to any other latent generation capacity in the grid (captive or otherwise). The provisions of 'non-discriminatory' open access apply to all such latent embedded generators and a vividness bias caused on account of ISGS URS should not distort the Electricity Market Design. In order to overcome the problem caused by recall of URS by original beneficiary, the ISGS may obtain prior consent and enter into a no-recall understanding with the original beneficiary before selling the URS through Open Access.

ISGS need to take some amount of risk while scheduling their URS through Open Access and through their trading arms, if any. Change in Open Access rules sought on account of ISGS status might therefore not strictly be in order.

xi. <u>Impact on Power Exchange:</u>

The development of Electricity Market in India has received a major impetus with the introduction of Power Exchange(s) in the Country in 2008. Two Power Exchanges are functioning presently. Collective transactions through

Power Exchange are processed before Day Ahead transactions and they are accommodated in the margins available after approving Advance and First Come First Serve category bilateral transactions. Collective Transactions once approved by NLDC are **'deemed delivered'** subject to any real-time curtailment by the NLDC on account of transmission constraints.

a) Revision of Collective Transactions through Power Exchange:

As per the Procedure for Scheduling of Collective Transactions, the Power Exchanges send an unconstrained solution (provisional trade result) to NLDC at 1300 Hrs and NLDC, after checking for congestion (if any), reverts back by 1400 Hrs. The final trade results along with the Application for scheduling of Collective Transactions is submitted by the Power Exchanges at 1500 Hrs. The Power Exchange simultaneously checks for availability of funds in the member's accounts commensurate to the provisional trade result. In order to cover business risk, the rules of Power Exchange provide for rejection of bids in case of inadequate funds available in the member's account. Even this provision which inadvertently provides an easy exit option to the members of the Power Exchange and has been strongly opposed by NLDC (vide NLDC Comments on 'Application of Setting up Power Exchange by IEX' dated 21-April-2008).

As per the Procedure for Scheduling of Collective Transactions, the provisional trade results may be revised by the Power Exchange only in case of transmission congestion on the advice of NLDC. No revision is thus possible in the case of Collective Transactions through Power Exchange. In this context, it may be clarified here that **the Collective Transactions have never been revised till date**.

b) Level Playing Field for Power Exchange vis-à-vis other Market Segments:

Short Term Open Access Transactions provide for two categories namely, Bilateral and Collective (through Power Exchange). It has already been explained above that Collective Transactions cannot be revised. Allowing revision of bilateral transactions would clearly discriminate against the Collective Transactions through Power Exchange and level playing field would no longer exist. With an easy exit option available in the Bilateral Market at zero or a nominal cost, the volumes in short term market may shift out from the Power Exchanges to the Bilateral Market. The institution of Power Exchange which has only recently been added to the Indian Electricity Market may become unviable.

xii. **<u>Promotion of Renewable Source of Energy Generation</u>**

In the draft amendment, different treatment has been proposed if source of power is from Wind Generation Power Plants. Nodal RLDC while approving open access transactions, checks only for the following two things:

- Concurrence of respective SLDCs : To ensure proper recording of transaction for metering and accounting and available surplus transfer capability in the intra-State System
- Availability of Surplus transfer capability in the inter-State transmission system to accommodate the transaction

Nodal RLDCs does not go on merit of the case and is practically not possible for nodal RLDC to verify the same. Therefore, different treatment for different type of source of energy may result difficulties in implementation of the open access regulations.

One of the objectives of the Electricity Act, 2003 is promotion of efficient and environmentally benign policies and to meet this objective, harnessing of generation from renewable sources has to be attached top priority. Renewable energy sources in the country are non-uniformly distributed and some states are more endowed than others. The generation from the renewable energy source at one location is small when compared to the conventional energy sources. Further the output from these sources is inherently intermittent and hence non-firm. These characteristics make them difficult to dispatch. There are a number of other issues involved in promotion of Renewable Source of Energy Generation and Hon'ble Commission has taken a lot of initiatives to promote the Renewable Sources of Energy Generation. **Therefore, it is proposed this issue may be covered separately.**

In view of the above, it is strongly suggested that the proposed new Regulation 14(A) should not be inserted in the CERC Open Access in inter-State Transmission System (Amendment) Regulation, 2009.

5. **Clause (1) Regulation 16**

It is proposed that in the first sentence after " *In case of the bilateral transactions* ", *"for use of the inter-State transmission system,"* is to be inserted.

6. **Clause (2) Regulation 16**

It is proposed that in the first sentence after " *In case of the collective transactions* ", *"for use of the inter-State transmission system,"* is to be inserted.

7. **Clause (5) and Clause (6) of the Regulation 17**

   These clauses shall become ineffective if our proposal for deleting the Regulation 14(A) is accepted.

8. **Clause 6 of Regulation 20**

   In order to have clarity on the issue it is proposed that the para may be modified as quoted below:

   "(6) Charges, other than those specified under regulation 16 and regulation 17 (such as standby charges, grid support charges, parallel operation charges) shall not be imposed by the State Utilities on the customers of inter-State open access."

9. Regulation 27/27A:

   The title might read only 'Information System' and the term Regional Load Despatch Centre and State Load Despatch Centre may be removed.

XXXXXXXXXXXXXX

Annex - II

पावर ग्रिड कारपोरेशन ऑफ इंडिया लिमिटेड
(भारत सरकार का उद्यम)
POWER GRID CORPORATION OF INDIA LIMITED
(A Government of India Enterprise)
पावरग्रिड

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संदर्भ संख्या / Ref. No.
CSO/CERC/

केन्द्रीय कार्यालय / CORPORATE CENTRE

Dated: 18th May 2010

The Secretary,
Central Electricity Regulatory Commission,
3rd & 4th Floor, Chandralok Building
36, Janpath,
New Delhi – 110 001

Subject: Unmatched and Uncleared volume in Power Exchanges - Suggestion for Evening Market

Sir,

The opportunity lost due to Uncleared and Un-matched volume in the Power Exchanges is nearly four times the volume lost due transmission congestion.

Normally, congestion has been occurring seasonally, that too, only in few corridors in a particular direction and the available margins remain unutilized in the many other corridors.

The option of reservation of corridors for the Power Exchange trades would have many associated contentious issues like Transmission Rights besides issues like where, how much to reserve and in what direction, in which corridor etc besides subsequent under-utilization due to fragmentation.

Considering the above, a subsequent round of trading in the Power Exchange Market may be considered say, in the late evening to provide another opportunity for players to optimise their portfolio and take a more informed position in the market. This in all likelihood would lead to more cleared volume, better utilization of the other un-congested and under-utilized corridors, more social welfare maximization and consumer satisfaction.

The evening market should be totally independent of morning market and all the rules could continue to be same for the evening market too. There would be a change in the strategy of the players and the overall satisfaction is expected to improve. Though this may require realignment of the present timelines etc. and would increase the work volume at NLDC and Power Exchanges, the same is being proposed to cause more economy & efficiency, better utilization of the available infrastructure and take the market to the next trajectory.

The proposal could be implemented in a relatively short time frame and the details could be discussed with the Power Exchanges and experts. Hon'ble CERC may consider the proposal for further directions, please.

Thanking you,

Yours faithfully,

18/05/10

(S. K. Soonee)
Executive Director (SO & NLDC)

पावर सिस्टम ऑपरेशन कारपोरेशन लिमिटेड
(पावरग्रिड की पूर्ण स्वामित्व प्राप्त सहायक कंपनी)
POWER SYSTEM OPERATION CORPORATION LIMITED
(A wholly owned subsidiary company of POWERGRID)

केन्द्रीय कार्यालय: बी-9, कुतब इंस्टीट्यूशनल एरिया, कटवारिया सराय, नई दिल्ली - 110 016
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संदर्भ संख्या/Ref No.

Dated: 26th July 2010

POSOCO/CERC/123

To
Chief, Engineering
Central Electricity Regulatory Commission,
3rd & 4th Floor, Chandralok Building
36, Janpath
NEW DELHI – 110 001

Subject: Proposal for Evening Market in Power Exchanges

Reference:

1. Minutes of Meeting on Evening Markets in Power Exchanges vide CERC letter dated 9th July, 2010
2. Letter to CERC on suggestion for Evening Market dated 18th May,2010

Dear Sir,

Further to meeting held in CERC on 28th June, 2010 to discuss the feasibility of introduction of Evening Market in Power Exchanges, it transpired that Evening Market may in all likelihood lead to an increase in volumes and thus the model can be tried out on a pilot basis. As desired, the proposed timelines for Evening Market in Power Exchanges is enclosed at Annex – 1. The timelines for Morning Session in the Power Exchanges continue to be the same as per existing detailed procedure for Scheduling of Collective Transactions.

Further, the need for introducing bidding at 15 – minute interval in the Power Exchanges was proposed vide letter dated 26th March 2010 may also be considered for overall economy and efficiency.

Thanking you,

Yours faithfully,

26/7/2010

(S. S. Barpanda)
Dy. General Manager

Enclosure: as above

CC: **Secretary, CERC**
MD, IEX / CEO, PXI

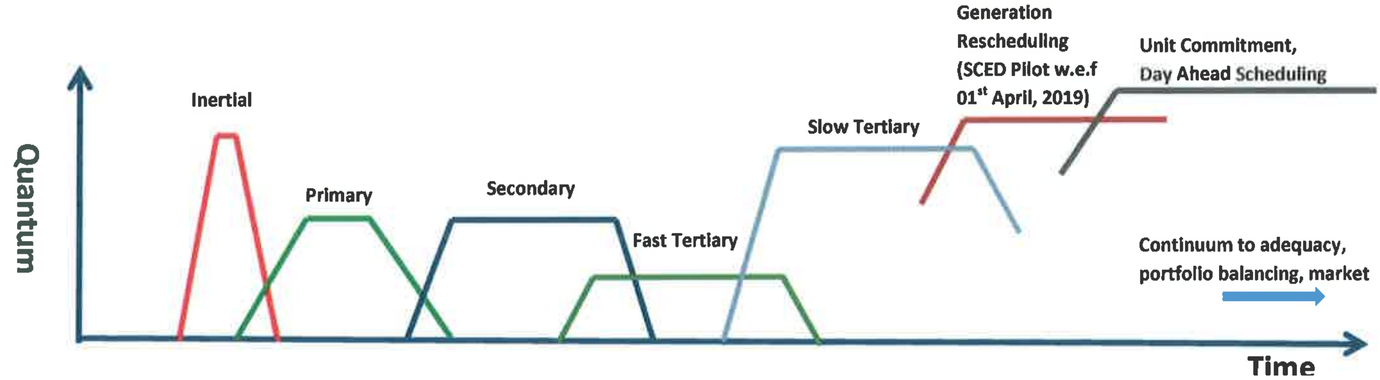
Annex – I

PROPOSED TIMELINE FOR THE MORNING AND EVEING MARKETS IN POWER EXCHANGES

S.No.	Morning/ Evening Session	Processing of Application	Timeline
1	Morning session	Market participant to place bids at Power Exchange platform	10:00-12:00 Hrs
2	Morning session	NLDC to indicate Power Exchanges the list of interfaces/control areas/regional Transmission system *(Common for Morning & Evening Session)*	11:00 Hrs
3	Morning session	Power Exchange to send provisional unconstrained solution to NLDC and flow on TS as informed by NLDC	13:00 Hrs
4	Morning session	NLDC to check for congestion. In case of congestion shall intimate PX regarding the period for congestion and available margins	14:00 Hrs
5	Morning session	PX to send Scheduling Request to NLDC based on margin specified by NLDC/SLDCs	15:00 Hrs
6	Morning session	NLDC to send details to RLDCs for scheduling	16:00 Hrs
7	Morning session	RLDC to confirm its acceptance to NLDC	17:00 Hrs
8	Morning session	NLDC to confirm acceptance. PX to send files to SLDCs for scheduling	17:30 Hrs
9	Morning session	RLDCs/SLDCs to incorporate Collective Transactions in the Daily Schedule	18:00 Hrs
10	Evening Session	Trading Session: Market participant to place bids in Power Exchange	16:00-17:00 Hrs
11	Evening Session	Power Exchange to send provisional unconstrained solution to NLDC	17:30 Hrs
12	Evening Session	NLDC to check for congestion. In case of congestion shall intimate PX regarding the period of congestion and available margins	18:00 Hrs
13	Evening Session	PX to send Scheduling Request to NLDC based on margin specified by NLDC/SLDCs	18:30 Hrs
14	Evening Session	NLDC to send details to RLDCs for scheduling	19:30 Hrs
15	Evening Session	NLDC to confirm acceptance for Scheduling of Collective Transactions PX to send files to SLDCs for scheduling	21:00 Hrs
16	Evening Session	RLDCs/SLDCs to incorporate Collective Transactions in the Daily Schedule (Revision 1)	23:00 Hrs

Annexure-II

Schematic of Reserves, Balancing and Frequency Control Continuum in India



Response → Attribute ↓	Inertial	Primary	Secondary	Fast Tertiary	Slow Tertiary	Generation Rescheduling/Market	Unit Commitment
Time	First few secs	Few sec - 5 min	30 s – 15 min	5 - 30 min	> 15 – 60 min	> 60 min	Hours/ day-ahead
Quantum	~ 10000 MW/Hz	~ 5000 MW	~ 4000 MW	~ 1000 MW	~ 8000-9000 MW	Load Generation Balance	Load Generation Balance
Local / LDC	Local	Local	NLDC/RLDC	NLDC	NLDC/SLDC	RLDC / SLDC	RLDC / SLDC
Manual /Automatic	Automatic	Automatic	Automatic	Manual	Manual	Manual	Manual
Centralized / Decentralized	Decentralized	Decentralized	Centralized	Centralized	Centralized/ Decentralized	Decentralized	Decentralized
Code / Order	IEGC / CEA Standard (?)	IEGC / CEA Standard	Roadmap on Reserves	CERC Order on FRAS Pilot	RRAS Regulations	IEGC	IEGC
Paid / Mandated	Mandated	Mandated	Paid	Paid	Paid	Paid	Paid
Regulated / Market	Regulated	Regulated	Regulated	Regulated	Regulated / Market	Regulated / Market	Regulated / Market
Implementation (Present Status)	Existing	Partly Existing	Pilot 3 plants	Pilot 19 plants	Existing	Existing	Existing