

# Central Electricity Regulatory Commission

New Delhi

## **Draft Central Electricity Regulatory Commission (Sharing of Inter-State Transmission Charges and Losses) Regulations, 2019.**

No.L-1/250/2019/CERC

Dated: 3<sup>rd</sup> December 2019

### **Explanatory Memorandum**

#### **1.0 Background**

**1.1** The Central Electricity Regulatory Commission (CERC) (herein after referred as “the Commission”) was constituted under the erstwhile Electricity Regulatory Commissions Act (ERC), 1998 and has been deemed to be constituted under the Electricity Act, 2003 (herein after referred as “the Act”), after enactment of the Act. The Commission has been vested with the power to make regulations in terms of clause (h) of sub-section 2 of section 178 read with Section 79 of the Act to regulate inter-state transmission system of electricity and to determine tariff for inter-State transmission of electricity.

**1.2** The Commission, in exercise of the powers under Section 178 had notified the Central Electricity Regulatory Commission (Sharing of Inter State Transmission Charges and Losses) Regulations, 2010 (hereinafter referred to as Sharing Regulations, 2010) on 15.06.2010. The Sharing Regulations 2010 came into effect from 1.7.2011. Till date there have been six amendments to Sharing Regulations 2010. Keeping in view the fact that CERC (Sharing of inter-state transmission charges and losses) Regulations were issued in 2010 and with time and experience, periodic review of the regulation was envisaged and keeping in view requests of stakeholders, the Commission constituted a taskforce vide CERC’s Office Order dated 10.7.2017 under Chairmanship of Shri A.S. Bakshi (then Member, CERC). to review the framework of Point of Connection (POC) Charges. The terms of Reference (ToR) were interalia to critically examine the efficacy of the existing PoC mechanism, deficiency in the existing mechanism, if any, and in the light of issues and concerns of

various stakeholders suggest modifications required in the existing mechanism. The Task Force submitted its report to the Commission in March 2019 (hereinafter referred to as “Bakshi Taskforce Report”). A copy of the Report is enclosed as Annexure-I. The taskforce suggested two options for transmission pricing viz (a) modifications in the present PoC method and (b) Uniform charges method. The methods as proposed in Bakshi Taskforce Report are quoted as below:

***“Modifications in present PoC method-Modified PoC method***

- (i) *Computation of PoC to be carried out Ex-Post on monthly basis based on actual scenario. Actual All India peak scenario for the month shall be taken for computation of PoC charges.*
- (ii) *The MTC shall be considered under following heads*
  - *AC system*
  - *HVDC system*
  - *Transmission system for Renewable with transmission charges waiver*
- (iii) *The MTC for the entire AC system (for each line) excluding lines identified under renewables (with waiver of charges) shall be divided into three components viz.*
  1. *POC portion: based on ratio of Base case flow in the load flow corresponding to the All India peak scenario for the month and loadability as per CTU website used for TTC/ATC.*
  2. *Reliability Portion –based on difference between base flow corresponding to the All Peak Scenario and the maximum flow observed for the (n-1) contingency divided by loadability.*
  3. *Residual portion - which is balance of the charge for each line after deducting POC and reliability portion.*
- (iv) *The above three portions shall be shared amongst the DICs in the manner as described below:*
  1. *POC portion: This portion shall be shared by each DIC corresponding to the actual utilisation of ISTS in each 15 minutes block. The same shall be arrived at by multiplication of blockwise POC rate (as derived from Webnet software) by actual MW in a given time block. The generation corresponding to untied LTA under All India peak generation shall be considered for generators for cost allocation.*
  2. *Reliability Portion – This portion shall be shared by each in DIC in the ratio of non-coincident Peak power drawn/injected during to the month to the sum of non-coincident Peak power*

*drawn/injected during to the month. The generation corresponding to untied LTA under peak generation shall be considered for generators.*

3. *Residual Portion – This portion shall be shared in ratio of LTA/MTOA of each DIC and the total LTA/MTOA on All India basis in the ISTS. For generators this shall be taken as untied LTA as being done currently.*
- (v) *To arrive at the POC rate, the zonal charges determined for All India peak scenario for the month shall be divided by an entity's ISTS injection / drawal at that block. There is no need for put these rates into slabs. There may be 40-50 such rates depending upon the number of ISTS payers in the grid.*
- (vi) *The charges shall be determined ex-post i.e based on actual scenario. Actual All India peak scenario for the month shall be taken. The actual data at ISTS points is available with POSOCO. The base case file shall be prepared so as to get the actual load/generation for ISTS points and corresponding data for intra-state network should be provided by DICs . However in absence of such actual data for intra-state points, the data for such intra-state points shall be included in simulation, so as to approximate the actual drawal/injection at ISTS interface. This is subject to necessary adjustment required for load generation balance.*
- (vii) *It may happen that an entity was injecting / drawing less at time of All India peak. It is also observed that injection / drawal varies in every block. An entity's PoC rate shall be multiplied by its actual injection/drawal for each block. Due to billing on actual blockwise MWs, there may be over or under-recovery of MTC for PoC portion based on DICs drawal/injection during All India peak vis a vis its blockwise drawal/injection. Any over-underrecovery shall be djusted from next months' MTC.*
- (viii) *There will be no change in the treatment of Merchant generators.*
- (ix) **HVDC**

*The HVDC except back to back HVDC or the one declared as National asset shall be shared on causer pays principle as being done currently and shall not be part of uniform charge or modified PoC charge. The HVDC charges for such HVDC system shall have % reliability component which shall be equivalent to the % reliability component as derived for the entire AC system. The reliability component of HVDC charges shall be added to reliability component for AC system and shared on the basis of non-coincident peak. Back to back HVDC shall be billed*

*under reliability component of AC system. National asset shall be shared based on LTA/MTOA as done currently.*

### ***Uniform Charges method***

*The Monthly transmission charge for AC system and back to back HVDC shall be divided by sum of average ISTS drawal/injection for the month. This rate shall be multiplied by actual ISTS drawal / injection while billing. The HVDC except back to back HVDC or the one declared as National asset shall be shared on causer pays principle as being done currently. Since no reliability component is being calculated separately under Uniform charge method, no reliability component shall be considered for HVDCs except for back to back whose treatment is given above*

*The charges for transmission systems augmented to accommodate renewables shall be kept out of the above systems and shall be separately billed uniformly to all DICs as a public policy asset with its implications transparently available to all payers. “*

**1.3** To formulate the draft Regulations keeping in view the Bakshi Committee Report and future power scenario, the Commission constituted a Committee under Sh. I.S.Jha, Member-Technical (CERC) in May 2019. The Committee submitted its Report (hereinafter called as “Jha Committee Report”) to the Commission in August 2019 along with proposed draft Regulations. A copy of the Report is enclosed at Annexure-II. The Committee broadly suggested that inter-state transmission system should be recovered as follows:

“

- (a) Transmission system is planned based on LTA Applications. The major factors affecting transmission planning and subsequent investments are location of generator, generation capacity, quantum of Long term Access and location of the firmed up beneficiaries.*
- (b) Once transmission lines are constructed, power flow on each line varies under different scenarios such as peak demand, off peak demand, day and night, seasons etc. depending upon demand-generation scenario at a particular instance and it may happen that some lines may be used more and some less by a particular constituent at a particular time.*
- (c) Inter-state Transmission System in India constitutes mainly EHV-AC system with a few HVDC systems which have been planned not only for point to point power transfer but also to improve overall stability of the grid and add flexibility in the system. As such, different approach may be adopted for EHV-AC system and HVDC system.*
- (d) The drawal ICTs at ISTS substations are planned for supplying power to the state based on load projection by the State. Hence it is logical that the state in which drawal ICTs are located, should bear its transmission charges.*

- (e) *Reactive compensation (e.g. Bus reactors, SVC, Statcoms etc.) is planned in transmission system to provide voltage support to the system. Since, its benefits are availed by all the constituents in the region, transmission charge allocation for these assets need to be dealt separately.*
- (f) *As per GoI policy, certain specific renewable energy based generation projects are exempt from paying transmission charges. They are generally planned in potential rich states to inject RE power in the grid and then it is utilized by different DICs to meet their demand and Renewable Purchase Obligations. Sharing of tariff for these RE related system based on utilization through load flow studies shall not be proper. It is suggested to socialize Transmission charges for systems specifically created for renewable energy projects on All India ISTS customers. Bakshi Taskforce report also recommended the same.*

7. *Keeping above aspects in view, the Committee felt that while determining the mechanism for sharing the transmission charges by different DICs, it should take into account quantum of Long term Access granted on the basis of which transmission system have been planned as well as utilisation of different elements by different DICs which will be determined through load flow studies on actual data. Further for deciding the part of tariff based on LTA quantum, objectives of different transmission elements or systems should be taken into account. For example, if some system or element has been planned keeping in view entire grid, tariff of same should be shared by all the DICs of the grid. If they are planned for the benefit of a particular region, same should be shared by DICs of particular region. In case of transformers which are basically planned to supply to individual DICs, such DIC should share the tariff for it. As the grid mainly comprise of AC transmission lines and substation, its tariff should be shared under the head of AC System component which should comprise of two parts-first part based on utilisation and balance on the basis of contracted capacity of LTA+MTOA.*

*Keeping this in view transmission charges for different elements of transmission system shall be allocated under following components:*

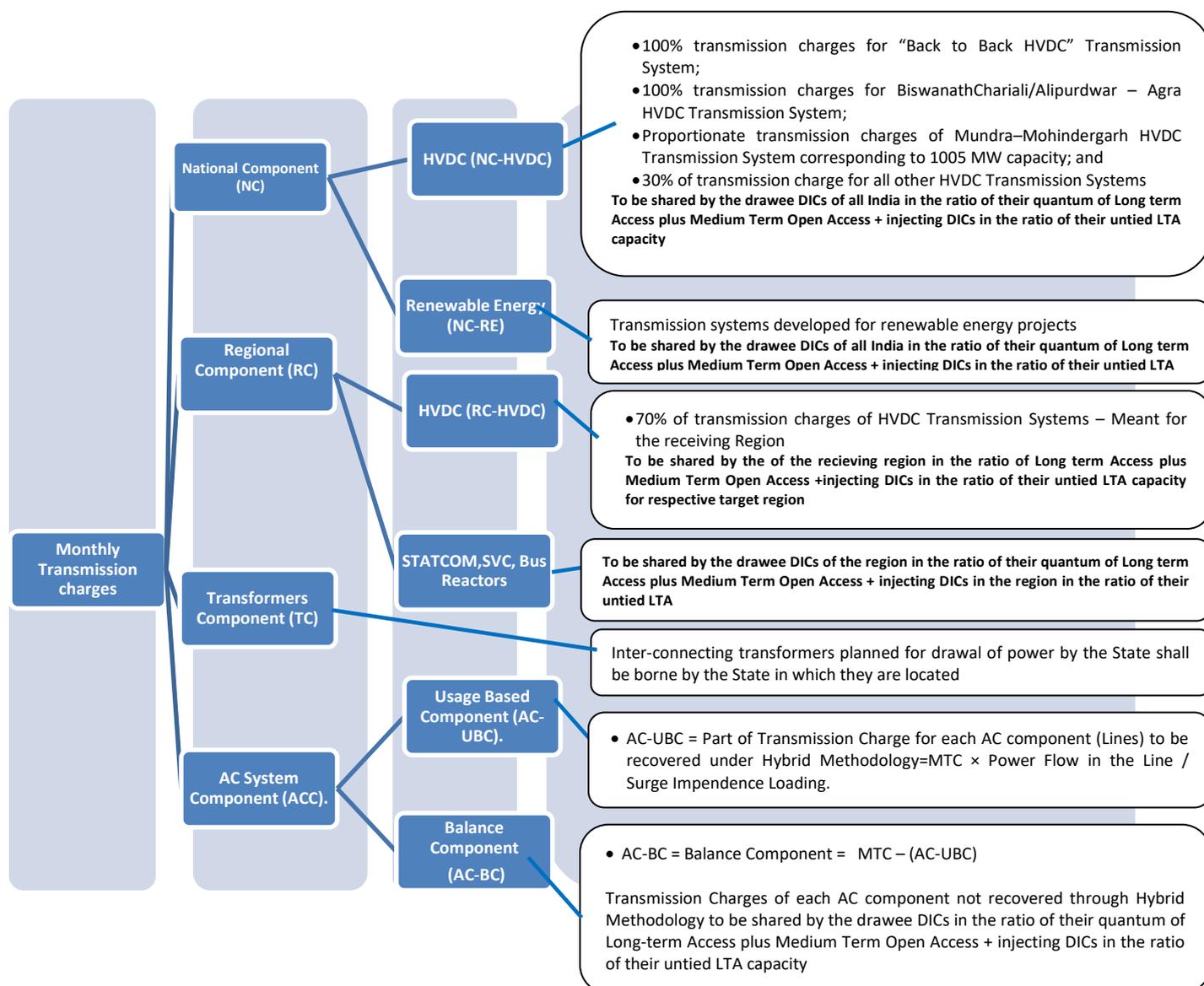
- (a) *National Component (NC);*
- (b) *Regional Component (RC);*
- (c) *Transformers Component (TC); and*
- (d) *AC System Component (ACC).”*

1.4 The detailed explanations of recovery under each component has been described in the Jha Committee Report.

1.5 Therefore, the Commission has now, proposed to notify the Central Electricity Regulatory Commission (Sharing of Inter-State Transmission Charges and Losses) Regulations, 2019 (in short referred to as the “Draft Sharing Regulations, 2019”) in supersession of existing Sharing Regulations 2010.

## 2.0 Basic Framework

2.1 Yearly Transmission Charges comprising of transmission charges of ISTS Licensees and intra-state transmission lines certified by respective Regional Power Committee as being used for inter-State transmission of electricity shall be recovered on monthly basis under the components as identified by Jha Committee Report.



## **2.2 National Component (NC)**

### **2.2.1 National Component-Renewable Energy (NC-RE)**

- (i) The Bakshi Taskforce Report noted that “Recently a few states have raised issues with regards to augmentation of transmission system associated with renewables. Such resistance was due to non-clarity of cost implications of the policy of waiver of transmission charges and losses for specified renewable projects.” Accordingly the report suggested that “Keeping in view that other renewable generators connected to ISTS are getting connected to the grid along with system augmentation, the treatment of such waiver needs to be specified explicitly.” The taskforce having noted that even after waiver, the charges towards such waiver are being borne by existing DICs, recommended that “the new system built for such renewable be identified separately. Such systems should be scaled up on existing DICs in ratio of allocated charges or LTA/MTOA.”
- (ii) It is observed that sometimes there is resistance by states especially for planning of inter-state transmission lines for renewable projects which are covered under waiver of transmission charges within the states, on the apprehension that under the current PoC mechanism there will be increased cost implications on the State, since power may flow by displacement to the State and State may become liable for ISTS charges.
- (iii) Keeping in view the comments of stakeholders and recommendations of Bakshi Taskforce and Jha Committee, it has been proposed that transmission system built for renewables which are covered under waiver of transmission charges shall be separately billed as “National Component” in the ratio of LTA+MTOA of all DICs across the Country.
- (iv) Further to take care of issue of usage of transmission system due to flow of power by displacement, it has been proposed that linewise YTC for such transmission system shall be taken at “zero cost” and hence no cost implication shall be there under usage component for such system.

### 2.2.2 National Component-HVDC (NC-HVDC)

- (i) As observed in the Jha Committee Report that HVDC systems having control features provide flexibility and hence more stability to overall Grid, and that bipole HVDC lines have been strategically planned for not only bulk power transfer but to enhance the overall operational performance of the grid. Therefore, the Committee has suggested that 30% charges for HVDC bipole shall be shared among ISTS customers of all regions in the ratio of their LTA+MTOA unless specifically directed otherwise by the Commission. Accordingly 30% transmission charges for HVDC bipole (other than ones covered at subclause (iii) of this Clause below) is proposed to be shared by DICs of all India in the ratio of LTA+MTOA.
- (ii) HVDC systems such as back to back are used for control function by system operator and hence are proposed to be covered under National Component.
- (iii) For Biswanath Chariali-Agra HVDC system entire Yearly Transmission Charges and for Adani Mundra –Mohindergarh HVDC System, portion of Yearly Transmission Charges is also proposed to be covered under National Component as being done under prevailing Regulations.

## 2.3 Regional Component

- 2.3.1 Regional Component of HVDC (RC-HVDC) It is proposed that since HVDC have largely been created for bulk power transfer to a region, 70% of transmission charges of identified HVDC Transmission Systems shall be shared by DICs of receiving region. For example 70% of transmission charges for Champa-Kurukshetra, Balia-Bhiwadi, Rihand-Dadri shall be shared by drawing DICs of Northern region and injecting DICs with Northern region as target region.

2.3.2 Static Compensator (STATCOM), Static VAR Compensator (SVC), Bus Reactors, and any other transmission element(s) identified by Central Transmission Utility being critical for providing stability, reliability and resilience in the grid are proposed to be shared by DICs in the region in which these devices are located in the ratio of LTA+MTOA, since voltage control systems extend the benefit to local grid. For injecting DICs with LTA to target region, this component shall be payable based on the region in which such DIC is located irrespective of its target region.

## **2.4 Transformers Component (TC)**

2.4.1 The Bakshi Taskforce has recommended as follows with regards to the Transformer Component:

*“The transformers which are commissioned to cater to drawal requirement of States should be billed to the State and other DICs should not bear burden for same. Hence, the taskforce recommends that all transformers which are used for drawal of power should be allocated to DICs of the state (drawal DICs).”*

Accordingly, the above mechanism have been proposed in the draft Regulations. The transformers are planned as ISTS to cater to the drawal requirement of the State by the CTU. Hence CTU shall provide the list of such transformers. However, where the actual tariff for such transformer is not available, CTU shall provide indicative cost in such cases for billing. This cost shall be excluded from Monthly transmission charges to determine AC component transmission charges.

2.4.2 In case, at a 220kV substation feeders are connected to neighbouring state such that drawal transformer is actually catering to drawl requirement of state other than the state in which transformer is located, proportionate transmission charges shall be levied to such state.

For example, suppose at a substation located in U.P there are 3 nos. 400/220 transformers, and there are 5 feeders emanating from 220 kV substation out of which 2 feeders are for drawal by U.P and 3 feeders are connecting to Uttarakhand and for drawal by Uttarakhand. In such cases, if sum of monthly transmission charge for the abovesaid 3 transformers is Rs. 100 Crore, it shall be recovered from U.P and Uttarakhand in the ratio of 2:3 i.e 40 Crore by U.P and 60 Crore by Uttarakhand. CTU shall provide such details while billing.

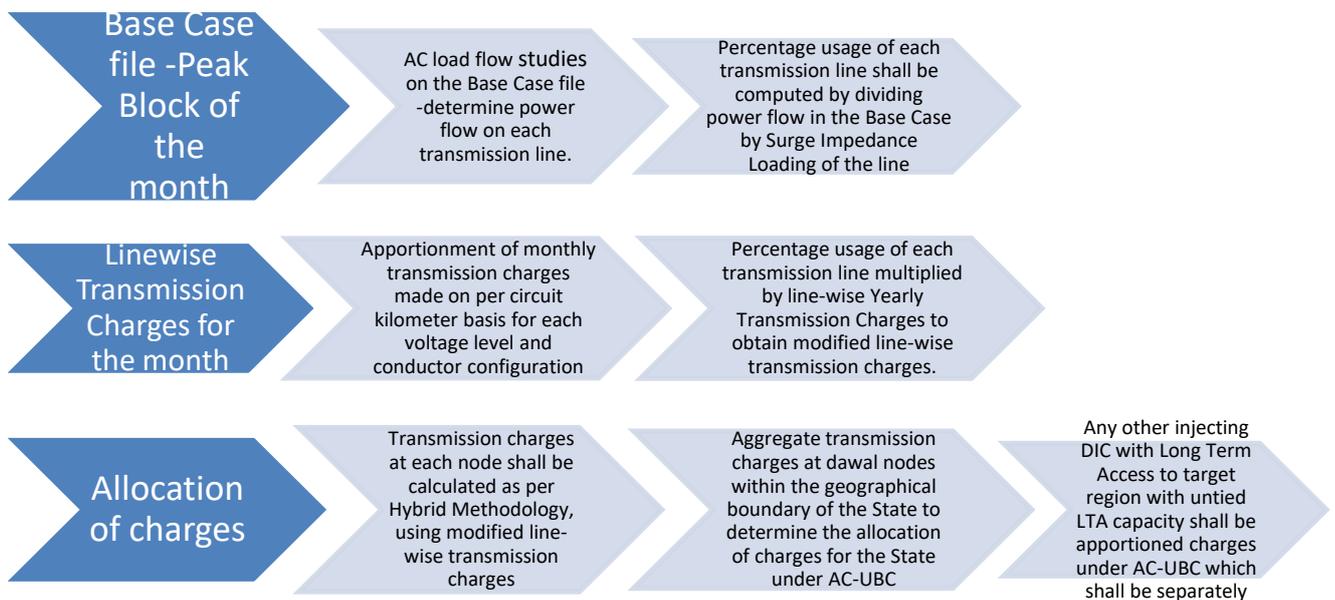
## **2.5 AC System Component (ACC)**

2.5.1 AC System Component includes AC transmission lines, AC substation, line and bus reactor and Inter-connecting transformers (excluding the drawal transformers which have been proposed to be shared by the State, SVCs, STATCOMs and such other devices which have been proposed to be shared by region in which they are located). Monthly Transmission Charges for the AC system component shall further be divided into following parts:

- (i) Usage Based Component (AC-UBC); and
- (ii) Balance Component (AC-BC).

### 2.5.2 Usage Based Component

- (i) The Monthly Transmission Charges to be allocated to each DIC under this component shall be determined using load flow study and prevailing Hybrid method of transmission charge allocation. The flow chart shall be as detailed below:



#### AC transmission charges to be recovered under AC-UBC

- (ii) The transmission charges to be recovered under Usage Component have been suggested by Bakshi Taskforce Report as follows:

“

(a) *The cost of each line has to be recovered in full as per approved tariff of CERC, irrespective of the power carried by the line. To check the impact of less loaded line on the total transmission charge paid by a beneficiary, the cost of such lines were not considered and computation were carried out.*

(b) *It was observed that the cost of less utilised lines were being paid by certain beneficiary as per location of the line and direction of power carried by the line.*

.....

*It is observed that utilisation of lines varies over a day and over the year. Since PoC methodology allocates charges based on utilisation, percentage utilisation for each line may be determined and MTC corresponding to such utilisation for such line should be considered in the base case as per its utilisation.”*

- (iii) It is observed that that since the utilisation of lines varies based on load generation balance, there may be lines which are marginally utilised in a particular scenario which is being considered for allocation of Monthly Transmission Charges. Under

existing Sharing Regulations 2010, the transmission charges for such lines are allocated to entities utilising the line. Stakeholders have raised concerns that, transmission charges allocation on the basis of usage should be restricted to the extent the line is used by the entity. Accordingly, it has been proposed to allocate Usage Based Component limited to the utilisation percentage of line.

For example a transmission line with SIL of 500 MW is carrying 300 MW in the Base case for Peak Block. The transmission charges as per linewise transmission charges (under Clause (3) of regulation 9 of draft Sharing Regulations 2019) for such line is suppose Rs 100 Crore. Then the transmission charges to be considered under AC-UBC for such a line shall be  $(300/500)*100 = \text{Rs. } 60 \text{ Crore}$ .

The balance Rs. 40 Crore shall be considered under AC-BC component.

(iv) Ex-Ante vs Ex-Post

- (a) The mechanism as per prevailing Regulations is Ex-Ante i.e charges are allocated before the start of quarter on the basis of projected data for the next quarter.
- (b) The Bakshi Taskforce had recommended that if the transmission charges have to be shared based on utilisation, then utilisation is best captured on post –fact basis i.e based on actual scenario rather than projected one. Bakshi Taskforce had also observed that ISTS drawal of States vary from month to month. Hence we propose that monthly peak scenario shall be used to determine utilisation component of AC transmission charges. For this purpose “peak block” for the month shall be considered as the block in which sum of ISTS drawal for all States is maximum. While identifying peak block, the injection into ISTS by a State shall be ignored. Only the drawal from ISTS by States shall be considered to identify peak block. This has been considered since maximum ISTS drawal from ISTS represents the most stressed condition of ISTS. Similarly injection by

generators into ISTS shall also be ignored while identifying peak block. Any injection into ISTS is drawn by some State and is captured in the ISTS drawal of State, hence injection is ignored.

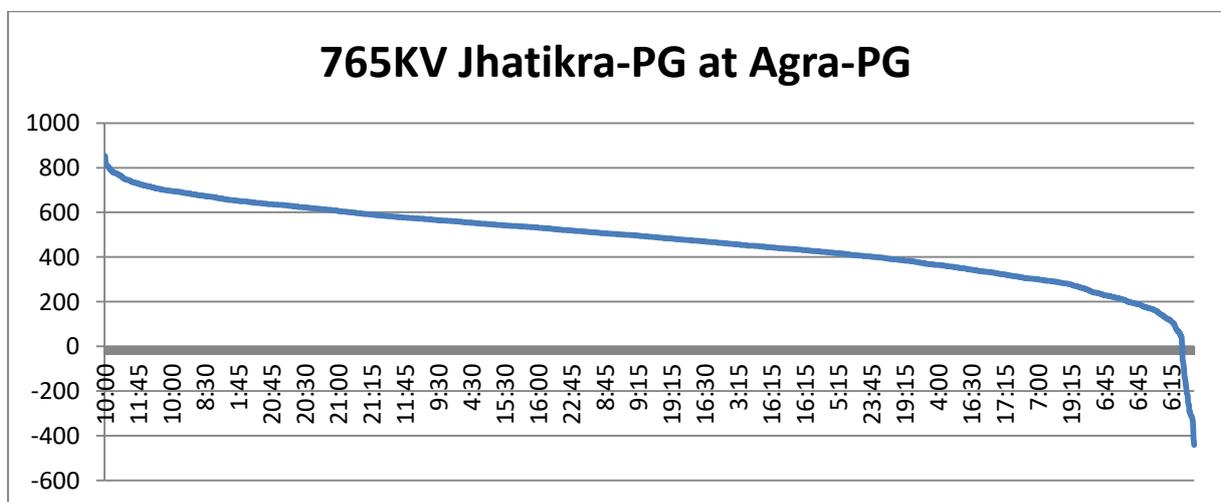
Notwithstanding identification of peak block, base case shall be simulated for the peak block for all entities as per their actual injection or drawal.

(v) Basic Network

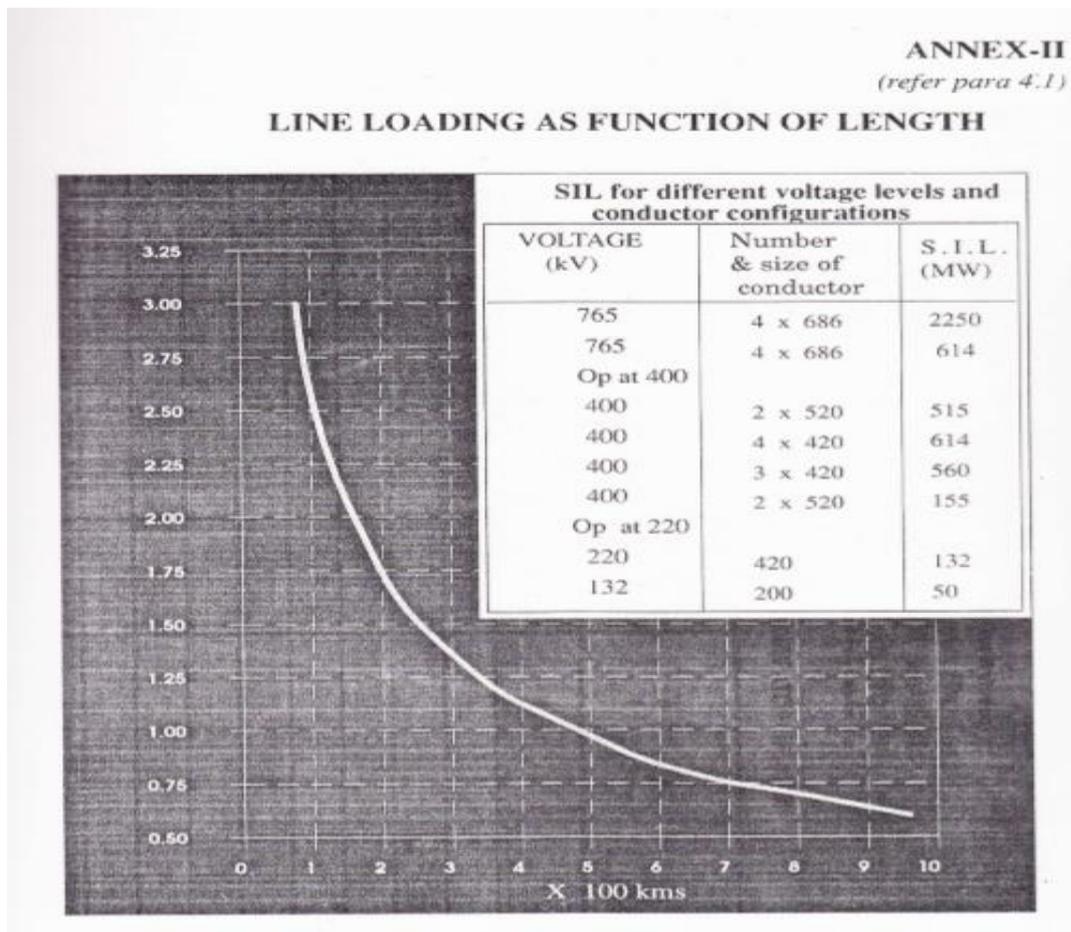
The Basic Network shall contain all elements of the electricity system, electrical plant or line at or above 132 kV or 110 kV as specified in the Regulations. Power flow into a lower voltage system from the voltage levels indicated in the definition of the Basic Network shall be considered as load at that sub-station. Power flow from a lower voltage system into the electricity systems at the voltage levels shall be considered as generation at that sub-station.

(vi) Use of Surge Impedance Loading to determine utilization.

The flow in the line varies across a day as well as across seasons. Typical curve of use of a line as noted by Bakshi Taskforce through flow duration curve for blockwise data for January 2019 is as below:



While the capability of line may be upto thermal limit for short lines or stability limit for long lines, its utilization gets limited by various factors such as load-generation balance, upstream/downstream system, voltage balance, time of day or season etc.. It is proposed to use Surge Impedance loading to determine utilization percentage of a line, since utilization gets limited by aforesaid factors and that utilisation has been proposed to be determined only for a block which shall be taken as representative block. SIL of a transmission line, may vary depending on level of compensation, but for the purpose of these Regulations, SIL have been proposed as that of standard transmission line at a nominal voltage for simplicity. The same is as per CEA Transmission Planning Criteria,1994 as quoted below:



(vii) Zoning of charges

(a) Sharing Regulations 2010 provides at regulation 7(1)(t) as follows:

*“The Implementing Agency shall aggregate Point of Connection charges for the geographically and electrically contiguous nodes on the ISTS to create zones within the geographical boundary of the State, in order to arrive at uniform zonal rate in ₹/MW/month. The Implementing Agency shall create zones for generation and demand. Such zoning shall be governed by the following considerations:*

*(i) Zones shall contain relevant nodes whose costs (as determined from the output from the Hybrid method) are within the same range.*

*(ii) The nodes within zones shall be combined in a manner such that they are geographically and electrically proximate. The demand zones shall be the geographical boundary of the State.*

*(iii) The same zone can act as a generation zone as well as a demand zone for the purpose of calculation of Generation and demand zonal charges respectively. Even as it is preferable to have similar zones for generation and demand, this shall be pursued only when practical, and other conditions for zoning are met*

*(iv) Any inter-State Generating Station connected to the 400 kV inter-State Transmission System (including those connected to both 400 kV ISTS and STU) shall be treated as a separate zone and shall not be clubbed with other generator nodes in the area, for the purpose of calculation of PoC injection rate:*

*Provided that in case of a merchant power plant in a State connected to 400 kV inter-State Transmission System, with zero LTA or part LTA, injection considered in the Base Case or LTA, whichever is higher, shall be considered to arrive at the PoC injection rate.*

- (b) The above method of zoning was relevant when PoC rates were determined under Short term and Long term for generating stations and States. For example, for determining PoC rates for a State, charges at various nodes were aggregated into zone and for determination of PoC rate applicable to a generating station, any ISGS connected to 400 kV ISTS was treated as a separate zone.
- (c) Under the proposed framework of Draft Sharing Regulations 2019, methodology of PoC rates have been revised. It has been proposed that charges on each node shall be determined only under AC-UBC component. Such charges allocated to each node shall be aggregated for a State for nodes within the State.
- (d) Any other entity within the State with Long term Access or Medium Term Open Access to ISTS shall also be allocated charges under AC-UBC at their node. It is suggested that such entity shall pay charges as allocated to its node and shall not be clubbed with other nodes. Charges for other components such as AC-BC, NC, RC are proposed to be allocated on LTA+MTOA and hence shall be determined directly for such entity.

### 2.5.3 Balance Component-AC-BC

- (i) The transmission charges under AC system component after allocating the charges under "Usage based" component –AC-UBC shall be shared as balance component – AC-BC in the ratio of Contracted capacity of LTA and MTOA.
- (ii) Bakshi Taskforce has recommended as follows:

*"Residual Portion – This portion shall be shared in ratio of LTA/MTOA of each DIC and the total LTA/MTOA on All India basis in the ISTS. For generators this shall be taken as untied LTA as being done currently."*

- (iii) Jha Committee has recommended as follows:

*"After carrying out a number of simulations, the Committee observed that difference in transmission charges liability for DICs considering MW-kM concept vs MW concept is not significant. As such the Committee recommends that Balance transmission charges should be allocated to different DICs in proportion to their Long term Access and Medium Term Open Access keeping in view simplicity of the method."*

- (iv) Keeping in view the above, it has been proposed that balance charges shall be recovered in ratio of LTA+MTOA.

### 2.6 ISTS charges for generators connected to both ISTS and STU

- (i) It is observed that a number of generating stations are connected to both CTU and STU network. Keeping this in view, the Commission in Petition No. 20/MP/2017 vide order dated 9.3.2018, directed as follows.

***"Treatment of generic issue where generator is connected to both STU System and ISTS system:***

*56. Grid Code recognizes that a generator may be connected to both State network and ISTS. Further, Regulation 6.4 of the Grid Code deals with the framework for scheduling jurisdiction of RLDCs and SLDCs in so far as Central Generating Stations and inter-State generating stations are concerned.*

*57. Regulation 8 (1) of the Connectivity Regulations provides as under:*

*"8. Grant of Connectivity*

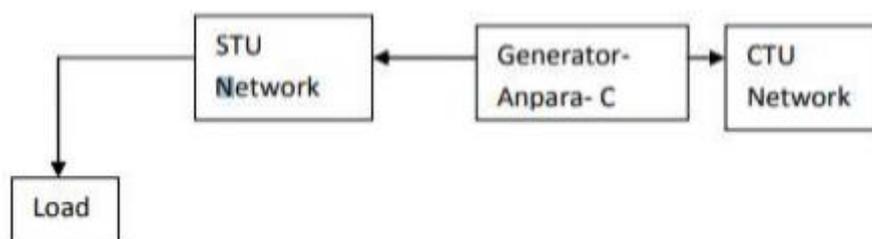
*(1) The application for connectivity shall contain details such as, proposed geographical location of the applicant, quantum of power to be*

*interchanged that is the quantum of power to be injected in the case of a generating station including a captive generating plant and quantum of power to be drawn in the case of a bulk consumer, with the inter-State transmission system and such other details as may be laid down by the Central Transmission Utility in the detailed procedure.”*

58. *It would be pertinent to mention that in accordance with the Detailed Procedure, the application for grant of connectivity to ISTS is required to be submitted alongwith above details as per the Format CON-2. The details sought in the application also include the capacity (MW) for which connectivity is required and the installed capacity of the generation station. Therefore, CTU has the information about installed capacity of the generating station and capacity (MW) for which connectivity is sought from ISTS. In case, a generator plans to get connected to both ISTS and State network, while granting connectivity CTU should ensure that adequate State system is available or shall be made available. In such cases, scheduling may be either with RLDC or SLDC as per applicable provisions of the Grid Code. In case, SLDC carries out scheduling, STU charges and losses shall not be applicable to schedules on ISTS. In case, RLDC carries out scheduling, ISTS charges and losses shall not be applicable to schedules on State network. It is also pertinent to mention that an associated issue may arise regarding treatment of UI/deviation charges. We are of the view that Deviation charges shall be considered pro-rata on the schedules on the State network and ISTS network.”*

- (ii) The Commission vide order dated 8.6.2013 in Petition No. 189/MP/2012 with IA No. 47 of 2012 (Lanco Anpara Power Limited, Hyderabad Vs Uttar Pradesh Power Transmission Corporation Limited, Lucknow & others) had observed and directed as under:

*“16. We have considered the submissions of the petitioner, respondent UPPTCL and CTU. As per Regulation 8(3) of the Connectivity Regulations, while granting connectivity, the nodal agency is required to specify the name of the sub-station or pooling station or switchyard where connectivity is to be granted. Connectivity Regulations clearly provides that a switchyard may be connected to the other switchyard. Thus, Anpara-C switchyard is connected to Anpara A & B Switchyard through contiguous bus. It is noted that the generating station of the petitioner viz Anpara-C is an embedded entity of UP. Anpara-C is connected to the common bus of Anpara A & B which is further connected to 400 kV Anpara-Singrauli ISTS line. Further, Anpara C is directly connected to 765 kV STU network and majority of the power flow is through STU network. So on one side the petitioner's generating station is connected to STU and on the other side to CTU as depicted below:*



22. *In the present case, it is also evident from the study conducted by CTU that majority of power of Anpara-C is consumed in the State of Uttar Pradesh itself. The transmission system of STU does not act as intervening system in the present case as State transmission network is not used in the access as a part of inter-State transmission system for the conveyance of electricity, i.e. power is not conveyed to ISTS through STU network and a contract path*

cannot be identified. Therefore, in terms of provisions of Central Electricity Regulatory Commission (Rates, Charges and Terms and Conditions for use of Intervening Transmission Facilities) Regulations, 2010 as per Intervening Transmission Facilities Regulations, 2010, the charges are not applicable in the present case.

23. The petitioner in its submission dated 22.3.2013 has stated that if the contentions of respondent are taken correct then in that event all the Central Generating Stations connected to ISTS will have to pay STU charges as the power from the above generating station can flow into intra-state system more than what has been allocated to the state. It is noted that transmission charges and losses are applicable on schedule of energy and not on actual energy flow. In PoC mechanism as well, for computing the rates only actual flows are considered. Once rates are determined, they are applied on scheduled energy. The actual energy flows are different from scheduled flow and sometimes power from State generating stations flows on ISTS and sometimes ISGS power flows on state transmission network. However, such phenomenon cannot be the basis for claim of the STU charges. Also, for same energy, two charges cannot be applied, when the entity is connected to both STU/ CTU network. The transmission charges and losses are applied on the basis of Scheduled power not on actual flow of power which depends on system condition. Therefore, the intra-State transmission charges or losses as per Central Electricity Regulatory Commission (Open Access In Interstate transmission) Regulation.2008 are not applicable.

24. For embedded entity, i.e. entity committed to STU only the STU charges are applicable on the premise that State transmission system is being used for flow of power upto ISTS and therefore, it flows further in ISTS. Further, UPPTCL is benefitted due to the fact that by consuming 100 MW power, its drawal from ISTS decreases, which is reflected in the PoC.

25. In view of the above, the petitioner is not liable to pay the transmission charges of STU network. The payment of transmission charges and losses for 100 MW from Anpara-C shall be governed by Central Electricity Regulatory Commission (Sharing of Inter-State Transmission Charges and Losses) Regulations, 2010.”

- (iii) As per the above findings of the Commission, the State charges are not payable on the conveyance of power through ISTS network. The generic treatment as per Order in 20/MP/2017 have been included in the proposed draft Regulations for clarity on transmission charges and losses treatment as follows:

*“Where a generating station is connected to both ISTS and intra-State Transmission System, the ISTS charges and losses shall be applicable only on quantum of Long Term Access and Medium Term Open Access connected through ISTS and STU charges and losses shall not be applicable on such capacity connected through ISTS.*

*Provided that this provision shall be subject to availability of adequate capacity in the intra-State Transmission System to draw allocated quantum of Long Term Access or Medium Term Access as certified by the Central Transmission Utility.”*

- (iv) The above provides that before the liability towards ISTS charges and losses is determined, CTU shall ensure that adequate State system is available for drawal of

power by State. In case a generating station is connected to State through inadequate capacity, and the power envisaged to be flowing through the State network actually flows into ISTS, then LTA Customer shall be liable for ISTS transmission charges and losses.

## 2.7 Intra-state lines certified by RPC

- (i) It has also been observed by the Commission that in a few cases tariff was granted by the Commission for 2011-14 period and the respective STU did not approach the Commission for tariff for period 2014-2019. This was observed by Commission vide Order dated 5.9.2018 in 7/SM/2017 as follows:

*“It was noticed by the Commission that a number of State Utilities, owners /developers of the inter-State transmission lines connecting two States have not filed the tariff petitions in terms of the Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2014 (hereinafter referred to as “the 2014 Tariff Regulations”).*

*...  
We direct the above utilities to file the tariff petitions within two months in respect of the transmission lines connecting two States which are within their purview in terms of the 2014 Tariff Regulations.*

*.....  
If the tariff petitions are not filed by the concerned State Utilities, within two months from the date of issue of this order it will be presumed that these utilities are not interested to claim the tariff for the inter-State transmission lines within their control and the tariff wherever earlier granted for these lines would be taken off from the computation of PoC charges on expiry of two months from the date of issue of this order.”*

- (ii) Jha Committee has observed regarding inclusion of intra-state lines certified by RPC under ISTS pool as follows:

*“Intra-state transmission lines certified by respective Regional Power Committee being used for inter-State transmission:*

*Intra-state system is generally planned for transfer of power within the State. Similarly adequate inter-state system has generally been planned for transfer of inter-state power. Under this situation, if intra-state system carries inter-state power or vice versa it is basically due to meshed network. Further, it is observed that such assets are already being included in ARR of the State system. As such, it is not appropriate to include such intra-state system under ISTS on the basis of load flow. Further since AC system has been divided into “AC-UBC” and “AC-BC” and as per simulations, only a portion of lines shall be included under “AC-UBC”. Hence it would not be appropriate to allocate charges of such system under “balance component” on other DICs. It is suggested that such systems should be included for recovery under these Regulations only for the tariff period for which tariff has already been approved by this Commission as on date of notification of these Regulations. No intra-state transmission system other than the one*

*already included that too for the period for which tariff has already been approved shall be considered for allocation of transmission charges under ISTS.”*

Accordingly it is proposed at regulation 11(12) as follows:

*“An Intra-State Transmission System already certified by the respective Regional Power Committees being used for inter-State transmission of electricity and for which tariff has already been approved by the Commission, shall be covered under these Regulations:*

*Provided that such intra-State Transmission System shall be included under these Regulations only for the tariff period for which tariff has already been approved by this Commission.”*

## **2.8 Average Transmission loss**

(i) The Bakshi Taskforce has noted as follows regarding allocation of losses:

“

- a. *WebNet software allocates losses for each node based on its usage of all India network. Whereas losses are computed at regional level and only for ISTS element. There is difference in methodology of loss computation at regional level for ISTS element and the methodology of sharing of losses as per Hybrid methodology. It is suggested that a national loss be computed for ISTS element rather than at regional level. As of now the methodology followed is (All generation at regional level- All demand at regional level)/ (All generation at regional level).*
- b. *The same to be substituted with (All generation at national level- All demand at national level)/ (All generation at national level).*
- c. *The losses of only those lines to be considered in WebNet whose cost is recovered through WebNet, rather than considering all the lines as the purpose is sharing of losses in ISTS. A state may incur more loss in state system than in ISTS but may be placed in higher slab rate for sharing ISTS losses.*
- d. *The loss percentage at national level is the loss in MW for evacuation ISTS drawl. Loss allocation for each beneficiary should be such that their percentage loss multiplied by Schedule should be more or less equitable to the loss arrived at National Level, Which means a similar to PoC Charge sharing system should exist for loss sharing.*
- e. *However this may lead to some complexities. As such it is suggested that matter may be deliberated further with all stakeholders.”*

(ii) Further Jha Committee has recommended as follows:

*“Sharing of transmission Losses: It is suggested that calculation of losses on the basis of slabs as being done currently should be changed as All India Average ISTS loss should be calculated for the week as difference of net injection into ISTS grid for the week at regional nodes and net drawl from ISTS grid for the week at regional nodes divided by Injection into ISTS grid at regional nodes for the week.”*

- (iii) The Commission observes that the slabs for ISTS transmission loss is calculated based on Hybrid Methodology which runs on all India base case. The slabs are identified based on usage of transmission system across the Grid. The losses are put into slabs of Average loss  $\pm 0.25\%$  under each slab.
- (iv) It is observed that actual loss in the ISTS system is total injection into ISTS – total drawl from ISTS. The actual loss do not have any regional boundaries. Further the slabs of losses with a difference of 0.25% for each slab needs deliberation. Hence for simplicity and to correspond to actual loss, average loss for all India shall be calculated.
- (v) We further observe that losses are currently determined for injection nodes as well as drawl nodes. However while scheduling losses for scheduling under long term access or medium term open access is payable by drawl entities only. Currently, the losses in ISTS are calculated regionally as total loss and it is divided by 2 to determine average loss for injection and average loss for drawl which is in approximation.

For example , if total injection into ISTS is 40000 MW and total drawal from ISTS is 39500 MW, loss is 500 MW,

$$\text{Average injection loss} = (500/40000)*(1/2) = 0.625\%$$

$$\text{Average drawl loss} = (500/40000)*(1/2) = 0.625\%$$

- (vi) It is proposed that average loss shall be used for adjusting schedules at drawal end only. No injection loss shall be considered as being done currently. Injection loss is attributed to injecting entity only for transactions under STOA or collective transactions. Injection loss under LTA or MTOA is accounted at drawal end only. Further injecting DICs paying for injection loss accounts the same in its energy charge and is ultimately paid for by drawing entity only. Further dividing total loss into

injection loss and drawl loss in equal portions is an approximation. Hence it has been proposed to account for losses only at drawl end.

## 2.9 Transmission charges for Short Term Open Access

(i) Sharing Regulations 2010 provides for STOA rates for each DIC and same are payable as per Open Access Regulations 2008.

(ii) Further Sharing Regulations 2010 provide for offsetting of STOA charges under regulation 11(10) for DICs with Long term Access as follows:

*“(10) The offset for STOA for a DIC paying charges under LTA shall be as follows:*

*(a) If a DIC, having LTA to a target region without identified beneficiaries and paying injection charges for Long Term Access, avails Short Term Open Access to any region:*

*(i) The charges for the quantum of Short Term Open Access shall be adjusted in the following month against the charges for Long Term Access of such DIC limited to the granted quantum of Long Term Access.*

*(ii) This offset shall be limited to the extent of the quantum for which DIC has paid transmission charges towards long term access.*

*(b) The quantum of power for which a DIC is granted STOA shall be offset against the Approved withdrawal for which Withdrawal PoC charges are paid by the concerned DIC. This offset shall be limited to difference between Approved Withdrawal and Net withdrawal (load minus own injection) considered in base case, if Approved withdrawal is less than the Net Withdrawal.*

*(c) For Withdrawal DIC, this adjustment shall be given only for STOA transaction by DIC, and shall not be applicable to intra-State entities embedded in State network and availing STOA:*

*(d) The adjustment for STOA availed by a DIC having LTA to target region without identified beneficiaries shall also be applicable in case of collective transactions undertaken by concerned DIC. In such cases, Injection DICs shall be given adjustment corresponding to injection charges and withdrawal DICs shall be given adjustment corresponding to withdrawal charges.*

*(e) The adjustment of STOA against LTA shall not be applicable for collective transactions and bilateral transactions undertaken by a trading licensee, who has a portfolio of generators in a State for which LTA was obtained by the trading licensee to a target region.”*

(iii) The concept of offsetting has been clarified in Statement of Reasons dated 15.12.2017 issued with Central Electricity Regulatory Commission (Sharing of inter-State Transmission Charges and Losses) Regulations (5th Amendment), 2017 as follows:

*“7.4.3. We do not agree to suggestion of ESSAR Power, JITPL and SEL that offset should be on Rupee terms. The concept of offset has been introduced to make sure an entity is not billed twice for the same quantum of power. An MTOA transaction is with identified beneficiary for which Withdrawal PoC rates shall be applicable. A DIC with LTA to target region should be liable to pay Withdrawal charges in case it agrees into firm contract for part/full of its power with a firm beneficiary subject to terms of its contract with beneficiary related to liability of the charge. Hence for such a transaction LTA quantum to be billed should reduce by the quantum for which firm contract has been entered into. Hence offset shall be on quantum only.*

.....

*9.3.2. We do not agree with suggestion of NTPC to provide offset to generating Company for sale by it since any offset can be extended to an entity which is liable to pay charges for it to avoid double charging. Hence suggestion of NTPC is not accepted.”*

The above provides for offset of STOA charges to avoid double charging from same entity for same power.

(iv) The Jha Committee has thus observed as follows:

*“STOA charges:*

- a. It is observed that buying DICs may not buy power under LTA and may buy power under STOA keeping in view economics of transaction. Such DICs who actually draw power within their LTA quantum should not be charged separately for STOA. Selling DICs who have LTA with identified beneficiaries may not get schedule from such beneficiaries and may sell power under STOA. An entity should be charged transmission charges for power injected or drawn beyond their LTA or MTOA. Hence it is suggested that separate charges for STOA shall not be collected from entities having LTA or MTOA. However they shall be charged deviation bill as per following paragraphs:*
- b. The third Bill shall comprise of transmission deviation bill and shall be billed along with first bill by the CTU. In case the metered MWs (ex-bus) of a power station or the aggregate demand of a Designated ISTS Customer exceeds, in any time block, the sum of LTA and MTOA, the Designated ISTS Customers shall be charged for such deviations. This part of the bill shall be computed as detailed below:*
  - i. Transmission Deviation Rate (TDR) for a DIC shall be calculated as follows:*
    - 2.9.1.1.1 TDR for a State = 1.2\* (Transmission charges of the State for the month) / (Long Term Access +Medium Term Open Access of the State for the month)*
    - 2.9.1.1.2 TDR for Generators = @TDR for State where the Generator is located.*

- ii. *For hydro generators, the deviation shall be calculated after considering overload capacity of 10% over LTA and MTOA.*
- iii. *Any payment on account of additional charges for deviation by the generator shall not be charged to its long term customer and shall be payable by the generator;*
- iv. *The agency of the State responsible for the intimation of deviation on account of deviations under CERC DSM Regulations shall be the agency responsible for the intimation of deviation on account of the transmission usage to the respective RPCs, for inclusion of the same in their Regional Transmission Deviation Account (RTDA):*
- v. *The charges attributable to a State for deviations shall be calculated for a State as a whole. The contribution of an embedded entity towards such deviation shall be charged by State to its embedded entity.*

*The governance of the Short Term Open Access Transactions shall be as per the Central Electricity Regulatory Commission (Open Access in inter-State Transmission) Regulations, 2008 and as amended by the Commission from time to time. No separate transmission Charges for Short Term Open Access Transactions should be Charged”*

(v) Keeping in view suggestions of Jha Committee, it has been proposed that no separate charges shall be levied for STOA including collective transactions.

(vi) The Commission observes that under current proposal, the transmission charges shall be determined on post-fact basis, based on actual load generation of peak block. The actual drawal and generation shall be available with Implementing Agency (IA) once the month is over. The Implementing Agency shall also have details of Long term Access and medium Term Open Access with DICs. Hence it will be able to calculate the deviation by each DIC for each block of month with respect to its LTA+MTOA. The actual utilisation of network by a DIC is based on its actual injection / drawal. It may however happen that an entity has scheduled for STOA of 500 MW but is not injecting due to partial outage or is injecting more than 500 MW under DSM. In both the cases actual injection will be captured to determine the liability of transmission charges for the entity.

(vii) Illustrative examples for various cases of STOA are detailed below for clarity in treatment.

### **Example-I**

Suppose a State has LTA of 5000 MW, it schedules power under LTA as 3000 MW, schedules power under STOA as 1000 MW and under collective transaction as 1200 MW. It shall not be charged any STOA charges while scheduling 1000 MW+ 1200 MW under Short term / collective. If it draws upto 5000 MW in a block , it shall not be levied any transmission deviation charges @TDR. However if it draws 5100 MW in a block , it shall pay for 100 MW@TDR.

### **Example-II**

Suppose a generating station with Installed capacity of 1200 MW has LTA of 1000 MW and firm PPA for 500 MW. The transmission charges corresponding to 500 MW shall be determined at drawl end. Suppose generator injects 800MW out of which 500 MW is scheduled under long term, 300 MW under STOA, it shall not pay any charges for deviations under TDR since its LTA is 1000 MW. Now if it injects 1100 MW, out of which 600 MW is under STOA and 500 under LTA, it shall pay for transmission deviation @TDR for 100 MW. This deviation is payable on actual injection and not on schedule. For example this generator has scheduled STOA for 650 MW and LTA for 500 MW, however it injects 1100 MW in a block, it shall pay for transmission deviation @ TDR only for 100 MW and not for 150 MW scheduled over LTA.

The Regulations proposes to levy transmission deviation charges only on actual deviations from LTA+MTOA.

### **Example-III**

- (i) A Generator, suppose NTPC Kudgi has LTA of 2000 MW from NTPC Kudgi to its beneficiaries with firm PPA with Karnataka and T.N for 1000 MW each. Suppose Kudgi has not got day ahead schedule despatch from its beneficiaries for 2.1.2020 and

has unrequisioned surplus of 500 MW. Kudgi sells 250 MW in power exchange. It shall not be charged anything towards transmission charge while scheduling under power exchange. If schedule of Kudgi is 1750 MW for 2.1.2020, however Kudgi injects 1800 MW in a block, it shall not be charged anything under deviation charges since LTA is 2000 MW. If it injects 2050 MW, it shall be charged for deviation charges for 50 MW overinjection above its LTA.

(ii) The Bakshi Taskforce has noted regarding payment of deviation charges for generators:

*“Further few stakeholders have pointed out that for a generating company, deviations upto 20% are borne by their identified beneficiaries. They have suggested that such deviations should be borne by injecting utility itself. We agree with the suggestion that no Charges for deviation should be borne by drawing utility on behalf of injecting utility.”*

(iii) We observe that Central Electricity Regulatory Commission (Indian Electricity Grid Code) (Fifth Amendment) Regulations, 2017.5.2(h) provides as follows:

*“For the purpose of ensuring primary response, RLDCs/SLDCs shall not schedule the generating station or unit(s) thereof beyond exbus generation corresponding to 100% of the Installed capacity of the generating station or unit(s) thereof. The generating station shall not resort to Valve Wide Open (VWO) operation of units whether running on full load or part load, and shall ensure that there is margin available for providing Governor action as primary response.”*

As per above the schedule of generating station shall be restricted to ex-bus corresponding to 100% of the Installed capacity. Further for the cases where, Long term Access is as per allocation by GoI, Long term Access is considered as installed capacity of the generating unit excluding the auxiliary power consumption. Hence any overinjection beyond such long term access shall be payable by generating stations only and shall not be charged to its beneficiary.

#### **Example-IV**

Suppose a generating station has PPA with a Buyer State for 500 MW. Buyer obtains LTA from generating station to buyer periphery. Suppose the buyer schedules only 300 MW from such generating station and generating station obtains STOA for 200 MW. If generating station injects 500 MW, no deviation charges shall be levied on such generating station @TDR since it is within LTA from its injection point.

### **Example-V**

Suppose a state has embedded consumer which doesnot have any LTA or MTOA, however it schedules power under collective transaction, the charges to be levied for such embedded customer have been proposed to be determined by the State. Keeping in view the following:

<b>S No</b>	<b>Scenario of (LTA+ MToA) of the State Vs Actual drawl</b>	<b>Deviation charges on State</b>	<b>Suggestion for STOA charges collection from Embedded Utilities</b>
<b>1</b>	$(LTA+MToA) \geq \text{Actual drawl}$	State does not pay deviation transmission charges	
<b>2</b>	$(LTA+MToA) < \text{Actual drawl of State}$	State pays for transmission deviation charges @TDR for drawl in excess of its LTA+MTOA.	The transmission deviation charges paid by the State may be divided among embedded entities and State based on actual charges paid by the State. Or STOA charges @ rate of TDR may be collected by the State upfront.

## **2.10 Transmission Deviation Rate**

- (i) Sharing Regulations, 2010 provides for transmission charges to be paid for deviations from LTA+MTOA+STOA at Regulation 11(7) as follows:

*“(7) Deviations shall be billed separately by the CTU. This bill shall charge the Designated ISTS Customer s for deviations from the sum of the Approved Withdrawal, Approved Additional Medium Term Withdrawal and Approved Short Term Withdrawal (MW) or*

*Approved Injection, Approved Additional Medium Term Injection and Approved Short Term Injection (MW). This part of the bill shall be computed as:*

*For Generators:*

*In case Average MW injected during time block of positive deviation is greater the sum of Approved Injection, Approved Additional Medium Term Injection and Approved Short Term Injection, then for the first 20% deviation, transmission charges shall be at the zonal Point of Connection charges for the generation zone.*

*For deviation beyond 20%, the additional transmission charges shall be 1.25 times the zonal Point of Connection charges for the generation zone.*

*In case a generator instead of injecting, withdraws from the grid, the additional transmission charges shall be computed as*

$$\left[1.25 \times \text{PoC Transmission [rates] for the demand zone in Rs / MW / time block}\right] \times \left[\text{Average MW Withdrawal during time blocks of such negative deviation}\right]$$

*For Demand:*

*In case Average MW withdrawal during time block of positive deviation is greater the sum of Approved Withdrawal, Approved Additional Medium Term Withdrawal and Approved Short Term Withdrawal, then for the first 20% deviation, transmission charges shall be at the zonal Point of Connection charges for the demand zone.*

*For deviation beyond 20%, the additional transmission charges shall be 1.25 times the zonal Point of Connection charges for the demand zone.*

*In case a withdrawing DIC becomes a net injector the additional transmission charges shall be computed as*

$$\left[1.25 \times \text{PoC Transmission [rates] for the generation zone in Rs / MW / time block}\right] \times \left[\text{Average MW Injected during time blocks of such negative deviation}\right]$$

- (ii) As per above transmission deviation charges were 1.25 times the PoC rate for the DIC and was billed based on actual injection or actual drawl as the case may be blockwise. We observe that transmission charges are allocated on DICs with Long term Access or Medium term open Access under first bill. Hence any deviation should be calculated for use of transmission system vis a vis such LTA+MTOA. In the current Regulations if a DIC is actually not utilising its LTA+MTOA to the full extent through actual injection / drawl, it still pays additional charges for STOA which are offset later based on certain conditions.
- (iii) It is proposed that deviation shall be calculated on actual injection /drawl over LTA+MTOA of a DIC @ 1.2 \*Transmission charges for the State.

For example, if the First bill of Maharashtra comes out as Rs. 300 Crore for January 2020 (which is proposed to be billed in March 2020). Suppose its LTA+MTOA is 9000 MW. The TDR for Maharashtra shall be calculated as

$$1.2 * (300/9000) * (1,00,00,000/96*31) = \text{Rs. } 134/\text{MW/block}$$

Now suppose Maharashtra draws 9100 in a block in January 2020, its liability under deviation charges for the block shall be Rs 134\*100 = Rs 13,400. Similarly deviation charges shall be calculated for total deviation for all blocks of the month and billed accordingly.

- (iv) The existing deviation rates are 1.25 times normal PoC rate. The deviation rates proposed to be reduced to 1.2 times normal charges for the State.
- (v) The deviation charges for a generating station is proposed to be same as that of the State where it is located. This is so because AC-UBC is only a portion of total transmission charges. Rest all components are proposed to be shared on LTA+MTOA. For generating stations, transmission charges shall be billed to buyer as per proposed Regulations. Hence TDR for generating station separately cannot be determined reflecting transmission charges for entire system because for generating station without any LTA or MTOA, charges under first bill shall not be determined and for generators with LTA+MTOA charges shall be determined on buyer to the extent of firm PPA.

## **2.11 Transmission charges liability in case of delay of generating station**

- (i) Sharing Regulations 2010 provides for liability of a generating station in case of delay at

Regulation 8(5) and Regulation 8(6) as follows:

*“8(5) Where the Approved Withdrawal or Approved Injection in case of a DIC is not materializing either partly or fully for any reason whatsoever, the concerned DIC shall be obliged to pay the transmission charges allocated under these regulations:*

*Provided that in case the commissioning of a generating station or unit thereof is delayed, the generator shall be liable to pay Withdrawal Charges corresponding to its Long term Access from*

*the date the Long Term Access granted by CTU becomes effective. The Withdrawal Charges shall be at the average withdrawal rate of the target region:*

*.....”*

*“8(6) For Long Term Transmission Customers availing power supply from inter-State generating stations, the charges attributable to such generation for long term supply shall be calculated directly at drawal nodes as per methodology given in the Annexure-I. Such mechanism shall be effective only after commercial operation of the generator. Till then it shall be the responsibility of the generator to pay transmission charges.”*

(ii) Commission vide Order dated 6.11.2018 in Petition No. 261/MP/2018 directed as follows:

*“(vi) In the light of the above, as per Regulation 8(6) of the Sharing Regulations, the petitioner is liable to pay the transmission charges till COD of its delayed units. Hence, we direct that the annual transmission charges of the associated transmission system (i.e Kudgi-Narendra, Narendra-Madhugiri and Madhugiri Bidadi and associated bays) as determined or adopted by the Commission shall be considered in PoC mechanism corresponding only to the unit declared under commercial operation i.e Unit-I (as per records available in this petition) and the balance transmission charges shall be recovered from NTPC till the remaining units are declared under commercial operation. On COD of Unit-II & Unit-III, proportionate transmission charges corresponding to Unit-II & Unit-III, shall be considered in PoC from their respective CODs.*

***The illustrative example is given below for clarity:***

*i. “The planned Installed capacity for the station is 2400 MW. The station has 3 units. If capacity is broken up unit wise it comes out to 800 MW corresponding to each unit. Suppose the Annual transmission charges are Rs. 300 Crore. Once first unit is declared COD Rs. 100 Crore shall be considered in PoC mechanism and Rs. 200 Crore shall be billed to NTPC. Once 2nd unit is declared COD, Rs. 200 Crore will be included in PoC and Rs. 100 Crore shall be billed to NTPC and so on. “*

The above Order clarified the liability of a generating station under 8(6) as that of Associated Transmission System for the generating station.

(iii) Commission vide Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2019 dated 7.3.2019 provides as follows:

*“6. Treatment of mismatch in date of commercial operation: (1) In case of mismatch of the date of commercial operation of the generating station and the transmission system, the liability for the transmission charges shall be determined as under:*

*(a) Where the generating station has not achieved the commercial operation as on the date of commercial operation of the associated transmission system (which is not before the SCOD of the generating station) and the Commission has approved the date of commercial operation of such transmission system in terms of clause (2) of the Regulation 5 of these regulations, the generating company shall be liable to pay the transmission charges of the associated transmission system in accordance with clause (5) of Regulation 14 of these*

*regulations to the transmission licensee till the generating station or unit thereof achieves commercial operation:*

“

The above provides that in case of delay, the generating station is liable for transmission charges of Associated transmission system.

- (iv) Keeping in view the above decisions, it has been proposed that in case of delay of generating station, it shall be liable for transmission charges of Associated Transmission System i.e Yearly Transmission charges of such transmission elements which have specifically been indicated as generator's ATS. This is proposed to be levied on generating station incase it is delayed irrespective of the fact that Long term Access may be taken by its beneficiary. This is to ensure that beneficiary is not burdened with liability of transmission charges till it is supplied power from the generating station. It has also been clearly provided that such transmission elements which are directly payable by a generating station under this Clause shall not be included in pool so that liability of such elements doesnt fall on other DICs. Accordingly following has been proposed:

*“11(4)Where COD of a generating station or unit(s) thereof is delayed and the Associated Transmission System has achieved COD, which is not earlier than its SCOD, the generating station shall pay Yearly Transmission Charges for the Associated Transmission System corresponding to capacity of generating station or unit(s) thereof which have not achieved COD.*

*Provided that such transmission charges shall not be considered under Regulations 5 to 8 of these Regulations.”*

- (v) There may be generating stations for whose Long term Access no additional investment is required i.e there is no Associated transmission system and the Long term Access is granted on existing margins. If such a generating station gets delayed, it would be difficult to levy transmission charges for specific transmission elements to such generator because no such element is identified. However the existing system is allocated such generator from a specific date which may lead to construction of new elements for Applicants who

apply for LTA post this generator. Hence to ensure that generating stations apply for date of start of Access prudently and other entities donot suffer, it is proposed that such generating station shall pay transmission charges @10% \*TDR for the period of delay of the generating station.

## **2.12 Liability of transmission licensee in case it is delayed vis a vis generating station**

- (i) Commission vide Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2019 dated 7.3.2019 have provided as follows:

*“6. Treatment of mismatch in date of commercial operation: (1) In case of mismatch of the date of commercial operation of the generating station and the transmission system, the liability for the transmission charges shall be determined as under:*

.....

*(b) Where the associated transmission system has not achieved the commercial operation as on the date of commercial operation of the concerned generating station or unit thereof (which is not before the SCOD of the transmission system), the transmission licensee shall make alternate arrangement for the evacuation from the generating station at its own cost, failing which, the transmission licensee shall be liable to pay the transmission charges to the generating company as determined by the Commission, in accordance with clause (5) of Regulation 14 of these regulations, till the transmission system achieves the commercial operation.”*

- (ii) Keeping in view above provision, following has been proposed:

*“In case the generating station or unit(s) thereof has achieved COD and transmission system is delayed, the concerned transmission licensee(s) shall make alternate arrangement for dispatch of power in consultation with Central Transmission Utility at the cost of the transmission licensee(s).*

*Provided that till such alternative arrangement is made, the transmission licensee(s) shall pay to the generating station the transmission charges proportionate to Long Term Access for the transmission system which is delayed.”*

Suppose a 765 kV D/C transmission line from Ajmer to Phagi is delayed. The line is Associated Transmission System for two generators with Long term Access on as 500 MW and 1000 MW respectively. In case such line is delayed for 6 months , it shall pay its Yearly Transmission Charges corresponding to 6 months to these two generators in the ratio of 500:1000. Suppose Yearly Transmission charges for this line is Rs. 100 Crore, charges corresponding to 6 months is Rs. 50 Crore, it

shall pay  $1/3 * 50$  Crore= Rs 16.67 Crore to generator with LTA of 500 MW and Rs. 33.33 Crore to generator with LTA of 1000 MW.

### **2.13 Transmission charges liability in case of delay of upstream or downstream system**

(i) It is observed that there are cases where a transmission element is ready to be put to use but is prevented from so due to non-availability of upstream/downstream system. For example a transmission line may be ready but the substation to which it is to be connected is not ready or the associated generation switchyard has not come up. There may also be cases where both upstream and downstream system is not there.

(ii) The Commission vide Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2019 dated 7.3.2019 provides at Regulation 6 as follows:

*“(2) In case of mismatch of the date of commercial operation of the transmission system and the transmission system of other transmission licensee, the liability for the transmission charges shall be determined as under:*

*(a) Where an interconnected transmission system of other transmission licensee has not achieved the commercial operation as on the date of commercial operation of the transmission system (which is not before the SCOD of the interconnected transmission system) and the Commission has approved the date of commercial operation of such transmission system in terms of clause (2) of Regulation 5 of these regulations, the other transmission licensee shall be liable to pay the transmission charges of the transmission system in accordance with clause (5) of Regulation 14 of these regulations to the transmission licensee till the interconnected transmission system achieves commercial operation:*

*(a) Where the transmission system has not achieved the commercial operation as on the date of commercial operation of the interconnected transmission system of other transmission licensee (which is not before the SCOD of the transmission system), the transmission licensee shall be liable to pay the transmission charges of such interconnected transmission system to the other transmission licensee or as may be determined by the Commission, in accordance with clause (5) of Regulation 14 of these regulations, till the transmission system achieves the commercial operation. “*

(iii) Further the case of non-availability of both upstream and downstream system was dealt by Commission vide Order dated 27.6.2016 in Petition No. 236/MP/2015 directed as follows:

*“42. It is noted that 400 kV D/C Kudgi TPS-Narendra (New) transmission line is connectivity line for NTPC Kudgi STPP and obtained clearance from CEA on 28.7.2015. However, NTPC Kudgi STPP switchyard obtained clearance from CEA on 24.8.2015 and charged the switchyard on 16.11.2015, after PGCIL’s sub-station was made ready. 400 kV Narendra (new) sub-station pertaining to PGCIL was charged on 15.11.2015. In view of the above, the transmission charges shall be payable by NTPC and PGCIL in the following manner:*

- (a) *It is noted that the petitioner completed its entire scope of the work on 27.3.2015. However, due to non-availability of inter-connection facility required to be developed by NTPC and PGCIL at each end, it could not commission the transmission line. Therefore, the transmission charges for the period from 4.8.2015 to 23.8.2015 shall be shared by both NTPC and PGCIL in the ratio of 50:50.....”.*
- (iv) Keeping in view above decisions it is proposed that in case either upstream or down-stream system is not ready due to which an element cannot be put in regular service , the transmission charges for such element shall be payable by owner of upstream or downstream system which is delayed. For cases where both upstream and downstream system is delayed, transmission charges for the element shall be shared by owner of upstream and downstream system in the ratio to be decided by the Commission, Transmission licensee may approach the Commission imploding owner of upstream and downstream system. Accordingly proposed Regulation 11(11) provides as follows:

*“Where a transmission system has been declared to have achieved deemed COD in terms of Transmission Service Agreement under Tariff Based Competitive Bidding (TBCB) or the Commission has approved the date of commercial operation of such transmission system in terms of clause (2) of Regulation 5 of Tariff Regulations, 2019 or proviso (ii) to clause (3) of Regulation 4 of the Tariff Regulations, 2014, the transmission licensee or generating company whose transmission system or generating station or unit thereof is delayed shall pay the transmission charges of the transmission system till the generating station or unit thereof or the transmission system achieves COD.*

*Provided that where more than one transmission licensee or both transmission licensee and generating station are getting delayed, the proportionate sharing of above transmission charges shall be as decided by Commission.”*

## **2.14 Treatment of part operationalization of generator**

- (i) CTU while granting Long term Access identifies the transmission elements which are required for such Long Term Access. CTU grants Long Term Access from an identified date indicating that same is “subject to availability of listed transmission system”.
- (ii) It happens in a few cases that only some of the identified elements are commissioned on date from which Long term Access has been granted while some identified elements gets delayed.
- (iii) Suppose a generating station(G1) was granted Long Term Access for 1000 MW with identified transmission elements for this Long Term Access as 3 transmission lines (L1,L2,L3) and 2 substations (S1,S2).Suppose as on date from which Long term Access was granted, generating station is commissioned part or full and only L1,L2 and S2 are commissioned, other elements being delayed. Suppose the commissioned elements are connected to the grid and starts carrying power. Such elements were considered part of PoC pool under existing Sharing Regulations 2010. If the elements couldnot be not put into regular service due to delay of upstream/downstream system, they were treated separately. To cover such cases existing Sharing Regulations 2010 provides at Regulation 8(5) as follows:

*“Where the Approved Withdrawal or Approved Injection in case of a DIC is not materializing either partly or fully for any reason whatsoever, the concerned DIC shall be obliged to pay the transmission charges allocated under these regulations:*

.....

*Provided further that where the operationalization of LTA is contingent upon commissioning of several transmission lines or elements and only some of the transmission lines or elements have been declared commercial, the generator shall pay the transmission charges for LTA operationalised corresponding to the transmission system commissioned: “*

- (iv) Statement of reasons dated 26.10.2015 for Sharing Regulations 2010 issued for third amendment provides as follows:

*“32.20 We have also noted that the substantial part of the system required for LTA gets commissioned but the LTA does not get operationalized on the ground that the full system*

*identified for grant of LTA has not been commissioned. It is possible that substantial changes happen in the load-generation balance and commissioning of some of the transmission lines gets affected. Hence, CTU should inform generator, the quantum of power that can be evacuated on the scheduled date of commencement of LTA. If the system is ready to evacuate full LTA quantum, the generator shall have to pay the transmission charges corresponding to the full quantum w.e.f. commencement date of LTA. However, when some of the required transmission system considered for full LTA are not Page 74 available by the scheduled date and full LTA cannot be operationalized, part operationalisation of LTA shall be done after the scheduled date of operationalization. In case of generating station with multiple units, LTA shall be operationalised if the transmission systems are available for evacuation of entire contracted power from a particular unit.”*

- (v) Further vide Order dated 8.3.2018 in Petition No. 229/RC/2015 following was directed regarding part operationalization:

*“With regard to part transmission system commissioned post 1.5.2015, CTU shall operationalize part LTA in terms of Regulation 8(5) of Sharing Regulations and shall raise the bills as per Regulations in vogue. In case, a particular generator has carried out certain transactions under STOA/MTOA after the date of commencement of the LTA, the charges already paid towards such transactions shall be offset from the bills to be raised for the LTA. “*

- (vi) The relevant portion of the order dated 6.7.2017 in Petition No. 103/MP/2017 which dealt with issue of part operationalization is extracted as under:

*“15. We also observe that even though the transmission lines were ready in February, 2016, PGCIL has operationalized the LTA only in July, 2016. Since the LTA customers carry the liability to pay the transmission charges from the date of commissioning of the transmission system based on which LTA has been granted, any delay in operationalization of the LTA beyond the COD of the concerned transmission system goes against the letter and spirit of the Connectivity Regulations and BPTA. In our view, CTU should take immediate steps to operationalize the LTA after commissioning of the transmission system without being at the mercy of the LTA customers to open the LC in order to operationalize the LTA.”*

- (vii) However vide Order dated 9.4.2019 in Petition No 318/MP/2018 following was observed.

*“18. PGCIL has also relied upon following para of the order dated 16.2.2015 passed by the Commission in Petition No.92/MP/2014.*

*“129. .... In case of generation station with multiple units, LTA shall be operationalized if the transmission system are available for evacuation of entire contracted power from a particular unit.”*

*PGCIL has contended that if the implementation of identified transmission system reached a stage where the LTA quantum (from a unit or a generating station) could be evacuated through it, then the LTA has to be operationalized. Thus, the PGCIL has argued that the LTA has to be operationalized either after 30.9.2016 or from the date when the elements of the identified transmission system are capable of carrying the LTA quantum of 180 MW. We have gone through the above Order. It is observed that the*

*said order nowhere requires the CTU to operationalise the LTA with the part transmission system in the event of non-commissioning of the generating station“*

- (viii) The Commission observes that in case CTU identifies several transmission elements to operationalize LTA for a LTA customer, however only a few elements are commissioned, then CTU should operationalize LTA partly only when LTA Customer seeks such part operationalization upto its transmission capacity.
- (ix) It may happen that due to change in load-generation balance, or due to any other reasons CTU observes that it is possible to operationalize full LTA granted even without availability of all elements of Associated Transmission System, in such cases CTU may operationalize LTA as per availability in transmission system even without availability of full ATS, if LTA customer seeks such operationalisation. Similarly for cases where LTA Customer seeks operationalisation of LTA from a date prior to the date from which LTA is granted, should be allowed as per availability of transmission system.
- (x) For the cases where some of transmission elements of Associated Transmission System have been commissioned and LTA customer has sought part or full operationalization of LTA, once the LTA for such LTA Customer is operationalized i.e billing of ISTS charges to the Customer or its buyer for such Long term Access starts, the elements of Associated Transmission System which have achieved COD with regular service shall be included in ISTS pool for recovery under Regulation 5 to Regulation 8 of Draft Sharing Regulations 2019.
- (xi) In case, some of transmission elements of Associated Transmission System have been commissioned and LTA customer has not sought part or full operationalization of LTA, the elements which have achieved COD shall be included in ISTS pool under Regulation 5 to 8 of proposed Draft Regulations only

if such elements are certified by RPC as required for improving the performance, safety and security of the grid security.

- (xii) Accordingly, Regulation 11(6) of proposed Draft Sharing Regulations 2019 provides as follows:

*“Where operationalization of Long Term Access granted to a generating station is contingent upon COD of Associated Transmission System consisting of several transmission elements and only some of the transmission elements have achieved COD, the generating station may seek part operationalisation of Long Term Access. The Central Transmission Utility shall part operationalize Long Term Access corresponding to the capacity sought to be operationalised by the generating station, subject to availability of transmission system. The Yearly Transmission Charges for such transmission elements shall be included in Regulations 5 to 8 of these Regulations.*

*Provided that for cases not covered above, when only some of the elements of the Associated Transmission System have achieved COD and if such transmission system is certified by the respective Regional Power Committee(s) for improving the performance, safety and security of the grid, such transmission system shall be included under Regulations 5 to 8 of these regulations. “*

## **2.15 Liability of generating station for drawl of start-up power from ISTS.**

- (i) A generating station may draw start-up power from ISTS. Regulation 8(7) of CERC(Grant of Connectivity, Long-term Access and Medium-term Open Access in inter-State Transmission and related matters)Regulations 2009 provides for drawl of start-up power through ISTS as follows:

*"(7) Notwithstanding anything contained in Clause (6) of this Regulation and any provision with regard to sale of infirm power in the Power Purchase Agreement, a unit of a generating station including a captive generating plant which has been granted connectivity to the inter-State Transmission System in accordance with these regulations shall be allowed to inter-change infirm power with the grid during the commissioning period, including testing and full load testing before the COD, after obtaining prior permission of the concerned Regional Load Despatch Centre for the periods mentioned as under:-*

*(a) Drawal of Start-up power shall not exceed 15 months prior to the expected date of first synchronization and 6 months after the date of first synchronization.....“*

- (ii) The abovesaid generating station is required to pay transmission charges towards use of transmission system as per Regulation 8(5) of Sharing Regulations 2010 as follows:

“(5)

*.....Provided also that a generating station drawing start-up power or injecting infirm power before commencement of LTA shall be liable to pay the withdrawal or injection charges corresponding to the actual injection of infirm power or withdrawal start-up power during a month (concerned month) and the amount received on account of such payments shall be reimbursed to the DICs in the month following the month of billing, in proportion to the billing of the DICs during the concerned month:”*

(iii) We observe that a generating station may gets delayed and its Associated Transmission System is commissioned. Under the Regulation 11(4) of proposed Draft Sharing Regulations 2019, such generating station shall pay Yeraly Transmission Charges for Associated Transmission System. It has been proposed that for a generating station which is already paying charges for its Associated Transmission System, shall not be liable for additional charges @TDR towards drawl of start-up power.

(iv) Accordingly proposed Regulation 11(9) provides as follows:

*“Generating stations drawing start-up power shall pay the transmission charges @Transmission Deviation Rate for the State in which they are physically located.*

*Provided that the amount received on account of payments towards drawal of start-up power shall be reimbursed to the DICs under the First Bill in proportion to their shares in the First Bill in the month next to Billing month.*

*Provided that where transmission element(s) have been declared COD before its SCOD on request of a generating station for drawal of start-up power, the generating station shall instead pay Yearly Transmission Charges for such transmission element(s) till the generating station achieves COD.*

*Provided further that Transmission Deviation Rate shall not be applicable for generating stations covered under clause (4) of this Regulation for drawal of start-up power.”*

## **2.16 Transmission Service Agreement, Revenue Sharing Agreement and Billing**

### **Collection and Disbursement Procedure**

(i) The Jha Committee has recommended as follows:

“

- *Transmission Service Agreement: It is suggested that Model TSA shall not be issued separately as main features of TSA have been included in draft Regulations. Hence signing of TSA under the Sharing regulations have been dispensed with.*
- *Revenue Sharing Agreement: It is suggested that Model RSA shall not be issued separately since main features of RSA have been included in draft Regulations. If CTU finds need of signing separate Agreement, it may devise such Agreement.*
- *It is suggested that separate procedure for billing, collection and disbursement shall not be issued by Commission. The salient features of current Procedure have been included in draft regulations. CTU in discharge of its functions under these Regulations may make such procedure and prescribe such forms as may be necessary for the purpose of Billing, Collection and Disbursement, which is not inconsistent with these regulations or any other regulations of the Commission.”*

(ii) Accordingly relevant features of TSA, RSA and BCD Procedure have been included in the regulations including payment security mechanism, Event of default etc. It has also been provided that Central Transmission Utility in discharge of its functions under these Regulations may make such procedure and prescribe such forms as may be necessary for the purpose of Billing, Collection and Disbursement, which is not inconsistent with these regulations or any other regulations of the Commission, as required by Central Transmission Utility. Transmission Service Agreements and Revenue Sharing Agreements as on date of commencement of these Regulations shall be saved till expiry of the Agreements to the extent they are not in conflict with provisions of 2019 Sharing Regulations as and when it becomes effective

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