**CENTRAL ELECTRICITY REGULATORY COMMISSION**

**NEW DELHI**

**No.L-1/250/2019/CERC**

**Coram:**

**Shri P.K Pujari, Chairperson**
**Shri I.S. Jha, Member**
**Shri Arun Goyal, Member**

**Date: 10th August 2020**

**In the matter of**

Central Electricity Regulatory Commission (Sharing of Inter State Transmission Charges and Losses) Regulations, 2020

## Statement of Reasons

### 1. Introduction

1.1. Section 61 of the Electricity Act, 2003 (hereinafter referred to as the "Act") provides as under:

*"The Appropriate Commission shall, subject to the provisions of this Act, specify the terms and conditions for the determination of tariff, and in doing so, shall be guided by the following, namely:-*

*(a) The principles and methodologies specified by the Central Commission for determination of the tariff applicable to generating companies and transmission licensees;*

*(b) the generation, transmission, distribution and supply of electricity are conducted on commercial principles;*

*(c) the factors which would encourage competition, efficiency, economical use of the resources, good performance and optimum investments;*

*(d) Safeguarding of consumers' interest and at the same time, recovery of the cost of electricity in a reasonable manner;*

*(e) the principles rewarding efficiency in performance;*

*(f) Multiyear tariff principles;*

(g) *that the tariff progressively reflects the cost of supply of electricity and also, reduces and eliminates cross-subsidies within the period to be specified by the Appropriate Commission;*

(h) *the promotion of co-generation and generation of electricity from renewable sources of energy;*

(i) *the National Electricity Policy and tariff policy:"*

1.2. Para 5.3.4 of the National Electricity Policy notified by the Ministry of Power, Government of India, under Section 3 of the Act vide Resolution No.23/40/2004-R&R (Vol.II) dated 12.1.2005 provides as under:

*"To facilitate cost effective transmission of power across the region, a national transmission tariff framework needs to be implemented by CERC. The tariff mechanism would be sensitive to distance, direction and related to quantum of flow."*

1.3. Further, Para 7.2(1) of Tariff Policy notified vide Resolution No. No.23/2/2005-R&R (Vol.III) dated 6.1.2006 of Ministry of Power, Government of India provides as under:

*"Transactions should be charged on the basis of average losses arrived at after appropriately considering the distance and directional sensitivity, as applicable to relevant voltage level, on the transmission system."*

1.4. The provisions of the Act and the policies issued by the Central Government enjoin upon the Central Electricity Regulatory Commission (hereinafter also referred to as the "Commission" or "CERC") to develop and implement a national transmission tariff framework sensitive to distance, direction and quantum of flow.

1.5. The Commission, in exercise of the powers under Section 178 of the Act had notified the Central Electricity Regulatory Commission (Sharing of Inter-State Transmission Charges and Losses) Regulations, 2010 (hereinafter referred to as the "2010 Sharing Regulations"). The 2010 Sharing Regulations came into force with effect from 1.7.2011 and there had been six amendments to the 2010 Sharing Regulations. Keeping in view the changes in the transmission segment since 2010 and requests of stakeholders, the Commission constituted a Task Force vide Office Order dated 10.7.2017 under the Chairmanship of Shri A.S. Bakshi (the then Member, CERC) to review the framework of Point of Connection (POC) charges. The terms of reference (ToR) were *inter alia* to critically examine the efficacy of the existing PoC mechanism, indicate deficiency in the existing mechanism, if any, and suggest modifications in the existing mechanism in the light of issues and concerns of various stakeholders. The Task Force submitted its report (hereinafter referred to as the “Bakshi Committee Report”) to the Commission in March 2019.

1.6. The Commission constituted a Committee under Shri I.S.Jha, Member, CERC in May 2019 to formulate draft regulations keeping in view the Bakshi Committee Report and future power scenario. The Committee submitted its Report (hereinafter referred to as the “Jha Committee Report”) to the Commission in August 2019 along with the proposed draft regulations.

1.7. Taking into consideration the Bakshi Committee Report and the Jha Committee Report, the Commission notified the draft Central Electricity Regulatory Commission (Sharing of Inter-State Transmission Charges and Losses) Regulations, 2019 (hereinafter referred to as the “2019 Draft Sharing Regulations”) on 31st October 2019 seeking comments/ suggestions/ observations from the stakeholders/ public. Comments were received from 68 stakeholders, organizations, and individuals, which included State Power utilities, inter-State transmission licensees, generating companies in central sector and private sector and associations. The Commission conducted a public hearing on 29.1.2020 wherein Eighteen (18) organizations/ individuals including NTPC, NHPC and other generating companies, associations and individuals made their oral submissions and/ or presentations. List of stakeholders/ individuals who submitted written comments and who made oral submissions/ power point presentation during the public hearing is given at Appendix-I and Appendix-II respectively. After due considerations of the comments/ suggestions/ objections received, the Commission finalized and notified the Central Electricity Regulatory Commission (Sharing of Inter-State Transmission Charges and Losses) Regulations, 2020, (hereinafter referred to as the “2020 Sharing Regulations”) on 4th May 2020. This Statement of Reasons seeks to discuss and explain the rationale behind the provisions included in the 2020 Sharing Regulations.

1.8. Deliberation on the comments/ suggestions offered by the stakeholders, statutory bodies and individuals on the Draft 2019 Sharing Regulations and the rationale behind decisions of the Commission are discussed in the succeeding paragraphs. While an attempt has been made to consider all the comments/ suggestions received, the names of all the stakeholders may not appear in the deliberations. However, comments of all the stakeholders have been uploaded on the website of the Commission.

## 2. Sub-clause (b) of clause (1) of Draft Regulation 2: Definition of "Basic Network"

2.1. The draft regulation provided as under:

*" '**Basic Network**' means the power system of the country at voltage levels 132 kV and above including HVDC transmission network, to which the Generating Stations and loads are connected; and at voltage level of 110 kV and above to which Generating Stations are connected;"*

2.2. Comments have been received from TANGEDCO and KPTCL.

2.2.1. TANGEDCO has suggested that definition of Basic Network should be modified to include network at voltage level of 110 kV and above where generating stations and loads are connected as most of STU's network are at the basic voltage level of 110 kV.

2.2.2. KPTCL has suggested that the Basic Network of the country should be modelled up to 66 kV voltage level.

2.3. Analysis and Decision

2.3.1. Inter State Transmission System mainly consists of 400kV and above transmission system. As such including the network up to 2 levels below i.e. up to 132kV would suffice. However, as 110 kV also comes under the same voltage class as that of 132kV level, network at 110 kV and above have been included in Basic Network.

## 3. Sub-clause (d) of clause (1) of Draft Regulation 2

3.1. The draft regulation provided as under:

*"'**buyer'** means a person, including beneficiary, purchasing electricity through a transaction scheduled in accordance with the regulations applicable for short-term open access, medium-term open access and long-term access;"*

3.2. GRIDCO has suggested that instead of defining "Buyer" separately, the same may be endorsed to the definition given in CERC (Deviation Settlement Mechanism and related matters) Regulations, 2014.

3.3. Analysis and Decision

The definition of buyer has been modified as follows at Regulation 2(1)(f):

*"**'buyer'** shall have the same meaning as defined in Central Electricity Regulatory Commission (Deviation Settlement Mechanism and Related Matters) Regulation, 2014 and any subsequent amendments or re-enactments thereof;"*

**4. Sub-clause (f) of clause (1) of Draft Regulation 2**

4.1. The draft regulation provided as under:

*" **'Designated ISTS Customer' or 'DIC'** means the user of any element(s) of the Inter-State Transmission System (ISTS) and shall include generating station, State Transmission Utility, Distribution Licensee including State Electricity Board or its successor company, Electricity Department of State, Bulk Consumer and any other entity directly connected to the ISTS and shall further include any intra-State entity or any trading licensee who has obtained Medium Term Open Access or Long Term Access to ISTS;"*

4.2. Comments have been received from GRIDCO, HPSEBL and TANGEDCO.

4.2.1. GRIDCO and HPSEBL have suggested that definition of 'Designated ISTS Customer' must include the entity connected at ISTS and drawing power in Short Term Open Access/ embedded generators as no free riding should be allowed in the form of zero transmission charge for STOA. Cross-subsidizing in any form should not be allowed.

4.2.2. TANGEDCO has suggested that RE generators who are not eligible for waiver of transmission charges may also be included in the definition of DIC. Also, Solar/ Wind Power Park Developers (SPPDs/WPPDs) may be included in the definition of DICs.

4.3. Analysis and Decision

4.3.1. The Commission observes that the definition of 'Designated ISTS Customer' already covers entities which are users of any element(s) of the Inter-Sate Transmission System.

4.3.2. The word 'Bulk Consumer' has been removed, as such entities are covered under "any other entity connected directly to ISTS".

**5. Sub-clause (m) of clause (1) of Draft Regulation 2**

5.1. The draft Regulation provided as under:

*" **'Peak block'** means the block in which sum of net ISTS drawals by all States is*

*maximum during the month."*

5.2. Comments have been received from DNHPDCL, HPPTCL, PXIL, TANGEDCO, and RPG Trading.

5.2.1. DNHPDCL has suggested that Peak block is to be determined based on maximum net drawl by all States during the month. It is inferred that all India peak is considered even though the regional peaks differ widely. States who are having their peak far away from national peak have less usage of ISTS at the time of national peak which may lead to reduced sharing of POC Charges.

5.2.2. HPPTCL has suggested that Peak block should be based on regional peaks. Himachal Pradesh, a hydro-rich State, gets its peak power during winter season for drawl purpose whereas for other States, peak occurs in summer season for similar condition of drawl.

5.2.3. PXIL has suggested that the transmission charges may be computed for all the DICs with respect to their peak blocks while keeping the other DICs at the demand level witnessed corresponding to the DIC for which the transmission charges are being computed.

5.2.4. TANGEDCO has suggested that the Base Case should be prepared for aggregate of Peak blocks of all the States scaled down to match with the all India Peak block for the month.

5.2.5. RPG Trading has suggested that average of the monthly Peak blocks on all working days may be considered.

5.3. Analysis and Decision

5.3.1. The Commission is of the view that "peak block" as proposed in the Draft 2019 Sharing Regulations represents the condition when ISTS is stressed to the maximum, as simultaneous ISTS drawl by all States is at the highest. Considering the peak drawl by each State as suggested by some stakeholders, would require large number of studies to be done for each billing month as peak of different States occur at different times. Collection of data for the entire grid with respect to each State, followed by simulation studies for each case would only add to the complexity, without any commensurate benefit. Moreover, the results arrived at by such simulation studies would not be representative of the state of the ISTS. The Commission is of the view that charges should be allocated based on the same Base Case for all the entities. Considering multiple cases to allocate charges would mean that for each Base Case, the underlying data of load, generation and transmission system would be different. The Commission feels that it would not be fair to allocate charges based on different Base Cases for different entities.

5.3.2. Further, single Base Case arrived at either by scaling the data for multiple peaks of each entity or averaging the daily peak blocks would not reflect the actual data. The Draft 2019 Sharing Regulations provided for considering, during the peak block, actual data for load, generation, and transmission system, with minimal changes required for load generation balance.

5.3.3. Accordingly, the definition of Peak Block has been retained as proposed in the Draft 2019 Sharing Regulations.

## 6. Sub-clause (q) of clause (1) of Draft Regulation 2

6.1. The draft Regulation provided as under:

*“ **‘Target Region’** means the region to which a Generating Station proposes to sell power after obtaining Long-term Access from the Central Transmission Utility and for which beneficiaries in the said region have not been identified;”*

6.2. TANGEDCO has suggested that Solar Power Park Developers/ Wind Power Park Developers may be included in the Regulation.

6.3. Analysis and Decision

6.3.1. The word ‘generating station’ has been replaced with word ‘DIC’ to include all entities who propose to sell power in the Target region after obtaining Long-term Access from the Central Transmission Utility in the instant Regulation and for which beneficiaries in the said region have not been identified. Accordingly the definition of “Target Region” has been modified at Regulation 2(1)(y) as follows:

*“**‘Target Region’** means the region to which Long Term Access is granted to a DIC, without identified beneficiaries in the said region;”*

## 7. Sub-clause (u) of clause (1) of Draft Regulation 2

7.1. The draft Regulation provided as under:

*“ **‘Untied LTA Capacity’** means the quantum of Long Term Access for which buyers have not been identified;”*

7.2. HPSEBL has suggested that definition does not clarify whether generators opting for Short Term Transactions for their untied capacity are covered.

7.3. Analysis and Decision

7.3.1. The Commission has reviewed and decided that the quantum for which buyers have been identified under Long Term Access or Medium Term Open Access or both would be considered under tied capacity and short term transactions shall not be considered under tied capacity. Accordingly, definition of "Untied LTA" has been modified at Regulation 2(1)(dd) as follows:

> ***"'Untied LTA'** means the quantum of Long Term Access granted to a DIC less the quantum for which buyers have been identified under Long Term Access or Medium Term Open Access or both;"*

*<u>Illustration</u>*

(a) If a generator with 1,000 MW LTA to target region enters into a PPA for 400 MW for a term of 4 months and obtains MTOA for the same, and also enters into another PPA for 500 MW with a term of 8 years, the "Untied LTA" for such a generator shall be taken as 100 MW.

(b) If a similar generator as in example (a) above, with 1,000 MW LTA to target region enters into a PPA for 400 MW for a term of 4 months and obtains MTOA for same, and also obtains STOA for 2 months in advance for 500 MW, the "Untied LTA" for such a generator shall be taken as 600 MW.

## 8. Sub-clause (v) of clause (1) of Draft Regulation 2

8.1. The draft Regulation provided as under:

> ***" 'Yearly Transmission Charges' or 'YTC'** means the Annual Transmission Charges as determined or adopted by the Commission for all elements of ISTS which have achieved COD as on the last day of Billing month, and for the transmission lines connecting two States and intra-State transmission lines certified by respective Regional Power Committee as being used for inter-State transmission of electricity;"*

8.2. Comments have been received from GRIDCO and SRPC.

8.2.1. GRIDCO has suggested that COD of 765/ 400 kV line will significantly alter the flow pattern and accordingly the usage pattern of DICs will get altered. Hence, GRIDCO has proposed that in order to avoid such flow alteration in the billing month, only that transmission element which has achieved COD till the last day of the month prior to the Billing month, may be considered for YTC calculation so that in the billing month, line flow stability won't get affected by addition of new element.

8.2.2. SRPC has also suggested that 'last day of Billing Month' be replaced by 'last day of month prior to billing month'.

8.3. Analysis and Decision

8.3.1. The 2020 Sharing Regulations has introduced provision of "Billing month" and "Billing period" at Regulation 2(1)(d) and 2(1)(e), respectively as follows:

> ***"(d)'Billing month'*** *means the month in which bills for transmission charges are raised by the Central Transmission Utility in accordance with these regulations;*
>
> ***(e)'Billing period'*** *means the month for which bills are raised in a billing month by the Central Transmission Utility**;"***

Thus, Billing Period is the period for which transmission charges are raised in the Billing Month.

*Illustration*

If based on data, including peak block data, bills for the transmission system already existing and new transmission elements that have achieved COD in a particular month, say, January 2021, are raised in the month of March 2021, then January 2021 is the Billing period and March 2021 is the Billing month.

8.3.2. Accordingly, any transmission element that has achieved COD by the last day of the billing period shall be included in the bills of the corresponding billing month. Further, any transmission system, which is declared under commercial operation prior to the peak block, shall be included while preparing the Base Case for such peak block.

*Illustration*

Suppose the peak block for January 2021 occurs on 15.1.2021 and a transmission element "X" has achieved COD on 16.1.2021 while another transmission element "Y" has achieved COD on 10.1.2021. For the Billing period of January 2021, the transmission element ''X" shall not be included while preparing the Base Case (since it has achieved COD after the peak block of January 2021) while transmission element "Y" shall be included for the purpose of preparing the Base Case. However, both the transmission element "X" and transmission element "Y" shall be included in the bills for the billing period January 2021.

**9. Clause (3) of Draft Regulation 3**

9.1. The draft Regulation provided as under:

*"The transmission charges for transmission system after such transmission system has achieved COD with regular service, shall be shared by DICs in accordance with Regulations 5 to 8 of these regulations.*

*Provided that in case of a transmission system where COD has been approved in terms of proviso (ii) of clause (3) of Regulation 4 of the Tariff Regulations, 2014 or clause (2) of Regulation 5 of the Tariff Regulations, 2019 or transmission system which has been declared deemed COD in terms of Transmission Service Agreement under Tariff based Competitive Bidding, the Yearly Transmission Charges shall be shared by DICs in accordance with clause (11) of Regulation 11 of these regulations.*

*Provided further that the transmission charges for transmission system governed by provisions of clause (4) and clause (8) of Regulation 11 of these regulations shall not be shared by DICs in accordance with Regulations 5 to 8 of these regulations."*

9.2. Comments have been received from HPPTCL, KSEBL, L&T IDPL, ATL and CII.

9.2.1. HPPTCL has suggested that recovery of entire transmission charges through scaling has been proposed even in case the asset is grossly underutilized which is against the objectives of Tariff Policy. There must be some cut-off level of utilization below which if asset remains underutilized, considering the loading for the entire year, the proportionate impact may be borne by the developers.

9.2.2. KSEBL has suggested to bring down the tariff for un-utilised assets by reducing the return on equity so that burden on utilities gets reduced.

9.2.3. L&T IDPL, ATL and CII have suggested that the proposed provision ignores the fact that transmission licensee provides a number of non-regular services such as start-up power/ auxiliary power and, therefore, there is need to bring clarity regarding payment of transmission charges for such non-regular services.

9.3. Analysis and Decision

9.3.1. The transmission system is planned based on installed capacity of generating station and expected peak demand as provided by CEA and States, while the flow in transmission line depends on various factors such as level of generation, demand at a particular point of time, upstream/downstream system, voltage balance, time of day and season. As such, if any transmission line remains underutilised at a particular time, it is attributable to the system condition and not to the transmission licensee. Therefore, the suggestion to prescribe a minimum cut-off for utilisation of assets and reduction of return on equity is not agreed to.

9.3.2. The payment of transmission charges for transmission systems that have been declared under commercial operation, shall be governed by provisions of Regulations 5, 6, 7 and 8 of the 2020 Sharing Regulations, subject to the exceptions provided in Clauses (3), (6), (9) and (12) of Regulation 13. Further, the word "regular service" as was proposed in the Draft 2019 Sharing Regulations has been removed and the provision in the 2020 Sharing Regulations has been modified at Regulation 3(2) as follows:

> *"3(2) Yearly Transmission Charges for transmission system shall be shared on monthly basis by DICs in accordance with Regulations 5 to 8 of these regulations subject to the exceptions provided in Clauses (3), (6), (9) and (12) of Regulation 13 of these regulations."*

## 10. Draft Regulation 4

10.1. The draft Regulation provided as under:

> ***"Components of transmission charges***
> *Transmission charges for each DIC shall have the following components:*
> *a. National Component (NC);*
> *b. Regional Component (RC);*
> *c. Transformers Component (TC); and*
> *d. AC System Component (ACC)."*

10.2. Comments have been received from BRPL, FICCI, PXIL, IEX, GUVNL, Adani Mundra, APP and Torrent Power.

10.2.1. BRPL has suggested to introduce a separate component as evacuation system component. A transmission network built specifically for evacuation of power from generators/ LTA applicants which do not have firm beneficiaries should be covered under this component and cost of such transmission corridors should be recovered from only those generators for whom such transmission network was built and that all efforts should be made to recover such cost from generators/ LTA applicants.

10.2.2. FICCI and PXIL have suggested that there is a need for clarity through a detailed study about the amount of Yearly Transmission Charges (YTC) that are being socialized and the amount of YTC that are being allocated as per the actual usage of the grid.

10.2.3. IEX and GUVNL have suggested to provide indicative transmission charges based on past 3-6 months data available with CTU or the implementing agency.

10.2.4. Adani Mundra and APP have suggested that for better understanding, CERC should conduct a study of at least 3 high injecting States and also drawal States to present scenarios that shall arise under the Draft 2019 Sharing Regulations.

10.2.5. Torrent Power has suggested that YTC should be recovered under following three components:

a) Usage based component wherein TC (transformer component) may be merged (TC usage based);

b) National Component (all other components); and

c) Regional Component (RC) having 100% cost of HVDC systems since HVDC systems are designed for a specific region. Hence, 100% cost should be recovered from such drawee region.

10.3. Analysis and Decision

10.3.1. Dedicated transmission lines are constructed by generator itself as per provisions of the Central Electricity Regulatory Commission (Grant of Connectivity, Long-term Access and Medium-term Open Access in inter-State Transmission and related matters) Regulations, 2009 (hereinafter referred to as the 2009 Connectivity Regulations). Treatment of dedicated transmission lines constructed under coordinated transmission planning of the Central Transmission Utility is specified in Regulation 13(9) of the 2020 Sharing Regulations. Further, the liability of payment of charges towards Associated Transmission System (ATS) of a generator remains with generator till it achieves COD as specified in Regulation 13(3) of the 2020 Sharing Regulations.

10.3.2. With regard to the suggestions of stakeholders for conducting a study, a number of cases were simulated based on the past data in consultation with POSOCO and CTU by the Jha Committee, which formed part of the Explanatory Memorandum to the Draft 2019 Sharing Regulations. Accordingly, the Regulations have been finalised.

**11. Clause (2) of Draft Regulation 5**

11.1. The draft Regulation provided as under:

*"National Component-Renewable Energy shall comprise of transmission charges for transmission systems developed for renewable energy projects as identified by the Central Transmission Utility."*

11.2. Comments have been received from RUVNL, KSK Mahanadi, TANGEDCO, DNHPDCL, GMR, NTPC, Renew Power and WIPPA.

11.2.1. RUVNL has suggested that National Component-Renewable Energy should comprise of transmission charges for transmission systems developed for renewable energy projects and which fall under the transmission charges waiver scheme.

11.2.2. KSK Mahanadi has suggested that transformers in NC-RE Component should go in Transformer Component (TC).

11.2.3. TANGEDCO has suggested that the transmission systems developed for renewable energy projects as identified by CTU should be approved by Standing Committee, RPCs and CERC.

11.2.4. DNHPDCL has suggested that since all States are sharing the burden of high capacity green corridors, it is prudent to issue RECs corresponding to the cost booked to the States to compensate the burden.

11.2.5. GMR has suggested that no transmission cost of renewable projects should be loaded on other DICs. GMR has sought to know whether HVDC-RE and STATCOM for RE will be part of NC-RE. GMR has also suggested that NC-RE may be allocated to those DICs which have inter-State LTA from RE projects.

11.2.6. NTPC has suggested that transmission capacity and YTC blocked in existing ISTS to grant transmission access to RE capacity should also be included in NC-RE.

11.2.7. Renew Power and WIPPA have suggested that CTU should publish, on its website, the details of transmission system to be developed for RE under CTU planning, along with break-up of asset base for public consultation.

11.3. Analysis and Decision

11.3.1. NC-RE includes transmission systems developed for RE projects as identified by the CTU. These systems are proposed by the CTU based on the discussions in the Standing Committee, National Committee and RPC. The Commission believes that the details of such proposed systems must be disclosed transparently. Accordingly, it is provided in the Regulation 22(1) of the 2020 Sharing Regulations that Implementing Agency shall publish such data on its website.

11.3.2. Transformer component shall consist of drawl transformers only. Other transformers are to be considered under AC-UBC and AC-BC components. Further, the transformers planned as transmission system for renewable projects as identified by the CTU shall be considered under NC-RE component.

11.3.3. The systems to be included under NC-RE shall be identified by CTU, which may also include HVDC or STATCOMs, if they are technically required and satisfy the overall requirement of NC-RE component. The CTU shall identify the transmission systems developed for renewable projects to be covered under NC-RE prior to the first billing period under the 2020 Sharing Regulations. Thereafter, the CTU shall identify such systems from time to time.

11.3.4. The issue of RECs is beyond the scope of these Regulations.

**12. Clause (3) of Draft Regulation 5**

12.1. The draft Regulation provided as under:

"National Component-HVDC shall comprise of the following:

> *(a) 100% transmission charges for "Back to Back HVDC" Transmission System;*
> *(b) 100% transmission charges for Biswanath Chariali/Alipurdwar – Agra HVDC Transmission System;*
> *(c) Proportionate transmission charges of Mundra–Mohindergarh HVDC Transmission System corresponding to 1005 MW capacity; and*
> *(d) 30% of transmission charge for all other HVDC Transmission Systems except those covered under subclauses (a), (b) and (c) of this Clause of these regulations."*

12.2. Comments have been received from ATL, RPG Trading, BRPL, GMR, Torrent Power, RUVNL, HVPN, MBPMPL, TPDDL, JSW, MSEDCL, HPTCL GUVNL, APPCC, SRPC, DNHPDCL, TANGEDCO and BSPHCL.

12.2.1. ATL and RPG Trading have sought rationale for allocation of 30% for NC and 70% for RC in the transmission charges of Bi-Pole HVDC System.

12.2.2. RPG Trading has suggested to consider only 10% of transmission charges in the National Component to avoid excessive socialising of cost of HVDC system at national level.

12.2.3. BRPL has suggested that 100% Back to Back HVDC system should be considered under NC-HVDC Component and RECs for such charges may be issued. Other HVDC system should be booked to States using them (e.g. RE rich, Surplus exporting States).

12.2.4. GMR has suggested that transmission charges for HVDC system should also be based on the usage and there should not be any normative allocation of 30% to all ISTS customers.

12.2.5. Torrent Power has suggested that 100% charges for HVDC system should be under RC. RUVNL, HVPN and MBPMPL have suggested that 50% transmission charges for HVDC should be under NC-HVDC. TPDDL has suggested that entire HVDC should be under NC-HVDC. JSW, MSEDCL and HPTCL have suggested that 10% of HVDC should be under NC-HVDC.

12.2.6. GUVNL has suggested that HVDC lines were planned/ constructed based on commitment from generators/ States for enabling evacuation of contracted power from other regions to the targeted region. Therefore, sharing of such HVDC elements should not be under National Component/ Regional Component, but the same should be recovered from the generator/ States which committed for setting up of such HVDC system. Only the charges of HVDC system which have been planned under system strengthening need to be shared by DICs as National Component/ Regional Component.

12.2.7. APPCC has suggested that all High Capacity Power Transmission Corridors consisting of HVDC transmission systems connecting two different regions should be treated as Regional Assets duly taking into account the objective and purpose of the project.

12.2.8. SRPC has suggested that all HVDC systems are likely to be used to transfer bulk power in a perspective plan based on RE, Hydro and other energy resources potential. Some of the links may be used in both the directions based on season and sometimes on intra-day basis also. These links are conceived with national perspective in mind and could be shared by all the DICs of the country. 100% transmission charges of all HVDC system (including back to back) except 1,495 MW capacity of Mundra - Mohindergarh HVDC transmission system should be under NC-HVDC. Further 70% of transmission charges for 1,005 MW of Mundra-Mohindergarh HVDC transmission system should be shared under Regional Component.

12.2.9. DNHPDCL has suggested that sharing of 100% transmission charges for "back to back HVDC" transmission system; and transmission system corresponding to 1,005 MW capacity are reasonable. Other HVDC systems proposed for socializing the transmission charges were primarily built for evacuating surplus power in generation-rich States and now due to cancellation/ postponement of several large sized hydro projects, these charges should be booked to States having surplus generation and exporting power or to States that are under-drawing power.

12.2.10. DNHPDCL has further suggested that NC-RE and NC-HVDC components are basically due to over-built and stranded infrastructure. CERC may consider creating regulatory asset corresponding to such sunk cost or may recover the tariff over longer period (more than 35 years). Presently, since 10% of MTC and 10% of charges for HVDC system are treated as "Reliability Support Charges" and shared by all the DICs, socialisation to the extent of 10% is already being done and fully justified as reliability is a common good and is the responsibility of all DICs.

12.2.11. TANGEDCO has suggested that the Raigarh-Pugalur HVDC system should be declared as an asset of national importance since it is going to be used for transfer of RE power from Southern region to rest of the country. KSEBL has suggested that Raigarh-Pugalur-Madakkathara HVDC system is being created in view of long term necessity for surplus RE evacuation from SR to the rest of the country and also for strengthening of the transmission system connecting SR with NEW grid in view of huge surplus thermal generation capacity created in Chhattisgarh. The ±800 kV Raigar-Pugalur HVDC Corridor is being constructed as a system strengthening scheme for inter-regional power transfer between SR and WR. It is evident that the system was not based on any LTA applications. In the present context of huge RE target of 175 GW by 2022 and 450 GW by 2030, the 6 GW Raigar-Pugalur HVDC system is an asset of national importance, similar to Biswanath - Agra HVDC system. Hence, the transmission charges for this transmission system should also be included under 100% National Component category and shared by all DICs.

12.2.12. BSPHCL during the public hearing has suggested that certain HVDC system which are located in particular regions like Rihand-Dadri and Balia-Bhivadi, are serving particular regions only and transmission charges for such transmission system should be borne by regions for whom they have been created. Other transmission systems like Biswanath Chariali-Agra HVDC system should be paid by the concerned Regions for whom it is created and should not be socialised.

12.3. Analysis and Decision

12.3.1. Sharing mechanism of HVDC transmission system by the beneficiary regions is based on the basic purpose of HVDC system i.e. bulk power transfer to receiving States and providing flexibility and stability to overall grid. Detailed explanation of the basis of sharing was provided in the Explanatory Memorandum to the Draft 2019 Sharing Regulations.

12.3.2. Allocation of transmission charges of HVDC system on usage basis is not feasible since marginal participation method cannot be used to determine the usage of HVDC. This was deliberated in the Statement of Reasons dated 26.10.2015, while issuing third amendment to the 2010 Sharing regulations.

12.3.3. HVDC system covered under Regional Component have been planned to cater to requirement of drawl by a particular region. With developments in sector and change in load-generation mix, if need arises to consider the sharing based on bidirectional flow of power, the same shall be dealt with by the Commission at the appropriate time.

12.3.4. The sharing mechanism of transmission charges in respect of HVDC transmission system as proposed in the Draft 2019 Sharing Regulations has been retained in the 2020 Sharing Regulations.

## 13. Clause (4) and Clause (5) of Draft Regulation 5

13.1 The draft Regulation provided as under:

*"4. Transmission charges for the National Component shall be shared by the drawee DICs in the ratio of their quantum of Long term Access plus Medium Term Open Access.*

*5. Transmission charges for National Component in respect of injecting DICs with untied LTA capacity shall be shared by such injecting DICs in the ratio of their untied LTA capacity."*

13.2 Comments have been received from PXIL, WBSEDCL, TANGEDCO, MBPMPL, Sembcorp, Azure Power, RUVNL, GMR, Torrent Power, JSW and BSPHCL.

13.2.1 PXIL has suggested that the allocation of transmission charges should be computed based on the maximum of LTA plus MTOA and net ISTS drawal by the DICs rather than on LTA plus MTOA only. This will result in better representation of the reliability considerations of the grid usage.

13.2.2 WBSEDCL and TANGEDCO have suggested that NC-RE should be billed on usage basis.

13.2.3 MBPMPL, Sembcorp and Azure Power have suggested that since the benefit from RE projects are being taken by drawee DICs in order to meet their RPO, transmission charges for the transmission system developed for evacuation of power from RE projects need to be borne only by the drawee DICs and should not be shared with the injecting DIC.

13.2.4 RUVNL has suggested to allocate National Component-Renewable Energy to those DICs which have inter-State RE LTA, the RE component can be allocated in the ratio of RE LTA of the DIC and RE LTA for the whole country.

13.2.5 GMR has suggested that waivers provided to renewable projects should be met with direct government subsidies.

13.2.6 Torrent Power has suggested that in case of RE network development without any Open Access, unrecovered capital cost may be funded through Government assistance.

13.2.7 JSW has suggested that in order to keep both the renewable and conventional generation separate and to ensure that the transmission charges for untied capacities of renewable projects do not get loaded on the conventional generation, the transmission charges for the National Component - Renewable Energy should be shared by only renewable generators including the untied capacities.

13.2.8 BSPHCL during the public hearing has suggested that there should be no loading of RE charges on DICs on States like Bihar as Bihar is not in a position to bear additional burden and the same should come from budgetary support.

13.3 Analysis and Decision

13.3.1 ISTS drawl represents usage of transmission system which has been separately identified as AC-UBC. Further, transmission deviation charges are leviable time-block wise for ISTS drawl higher than LTA plus MTOA. The other components are proposed to be shared on the basis of contract i.e. LTA plus MTOA. Hence, sharing of NC-RE on the basis of higher of ISTS drawl or LTA plus MTOA/ usage basis will not be appropriate.

13.3.2 Any generator having untied LTA is liable to pay transmission charges for the quantum remaining untied for the entire ISTS network as per the regulations.

13.3.3 A DIC having LTA for RE projects may be covered under the provisions related to waiver from payment of ISTS transmission charges and losses as per regulation 13(1) of the 2020 Sharing Regulations and hence, transmission charges are not levied on such DICs.

13.3.4 Any subsidies granted by the Government shall be considered towards reducing the transmission charges to be shared by DICs.

**14. Sub-clause (a) of clause (1) of Draft Regulation 6**

14.1 The draft Regulation provided as under:

*"Regional Component of HVDC (RC-HVDC) -70% of transmission charges of HVDC Transmission Systems except those covered under clause (3) of Regulation 5 and clause (6) of Regulation 6; and"*

14.2 Comments have been received from RUVNL.

14.2.1 RUVNL has suggested to provide details of HVDC lines and the region where they are falling into. Further, it has suggested to clarify whether Regional Component is applicable on DICs in a particular region and using the particular network or on all DICs.

14.3 Analysis and Decision

14.3.1 HVDC Charges under RC-HVDC shall be shared by drawee DICs of the receiving region and injecting DICs with untied LTA having receiving region as the target region, in proportion to their quantum of Long Term Access plus Medium Term Open Access and untied LTA, respectively.

*Illustration*

For Talcher-Kolar HVDC, suppose the total quantum of LTA plus MTOA for Southern Region States is 30,000 MW and united LTA of generators located in Western Region having Southern region as the "target region" is for 2,000 MW. If RC-HVDC component of Talcher-Kolar is Rs. 'X' per month, then it shall be shared @ Rs. 'X'/32000 per MW per month and billed to drawee DICs of Southern region (States + any other embedded consumer who has obtained LTA or MTOA or both) and such generating stations with united LTA having Southern region as the target region.

14.3.2 Charges under RC-HVDC shall be shared on basis of LTA plus MTOA and not on usage basis as provided in Regulation 5(3) of the 2020 Sharing Regulations.

**15. Sub clause (b) of clause (1) of Draft Regulation 6**

15.1 The draft Regulation provided as under:

*"Transmission charges for 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.*

*Provided that where separate transmission charges are not available in respect of specific elements, the transmission charges shall be computed based on indicative capital cost to be provided by Central Transmission Utility."*

15.2 Comments have been received from RUVNL, TANGEDCO and BSPHCL.

15.2.1 RUVNL has suggested naming and defining the elements or components critical for stability, reliability and resilience in the grid. It has also requested to provide tentative list of all such elements and also to fix normative element-wise cost of such elements if actual cost of element is not available.

15.2.2 TANGEDCO has suggested that string 'identified by CTU' should be replaced with 'identified by CTU and approved by Standing Committee, RPCs and CERC'.

15.2.3 TANGEDCO has also suggested that in case of non-availability of costs in respect of specific elements, the indicative capital cost provided by CTU should be as per benchmark norms.

15.2.4 TANGEDCO has suggested to include a proviso in the Regulations to account for sharing of cost of spare transformers.

15.2.5 BSPHCL during the public hearing has suggested that transmission charges in respect of STATCOMs and SVCs should be charged on regional basis since they are serving a particular region and charges on account of these should not be shared by others.

15.3 Analysis and Decision

15.3.1 The elements such as STATCOM, SVC and Bus reactors already installed or planned by CTU shall be included in the Regional Component. However, with advancement of technology, there may be new elements which are required to be installed in the region for the purpose of stability, reliability and resilience in the grid. CTU is, therefore, required to share such elements as and when identified to be covered under such component with all the stakeholders.

15.3.2 Cost of elements to be included in Regional component shall depend on various factors such as age of the element, tariff granted by the Commission for the entire substation where such element is located etc.

*Illustration*

Suppose a reactor is located at Wardha sub-station and the Commission has approved tariff for entire Wardha sub-station which includes such reactor apart from other ICT bays and line bays. To segregate charges for such reactor to be considered under the Regional Component, CTU shall finalise a procedure after public consultation, clearly specifying the methodology using indicative capital cost for elements covered in entire sub-station and the tariff granted by the Commission for the entire sub-station.

15.3.3 The regulation has been modified to include spare transformers and spare reactors.

**16. Clause (2), (3), (4) and (5) of Draft Regulation 6**

16.1 The draft Regulation provided as under:

*"2. Transmission charges covered under sub-clause (a) of clause (1) of this Regulation shall be shared by the Drawee DICs in the ratio of their quantum of Long Term Access plus Medium Term Open Access.*

*3. Transmission charges covered under sub-clause (a) of clause (1) of this Regulation in respect of injecting DICs with untied LTA capacity, shall be shared by such injecting DICs in the ratio of their untied LTA capacity for the respective target region.*

*4. Transmission charges covered under sub-clause (b) of clause (1) of this Regulation shall be shared by DICs of the same region in the ratio of their quantum of Long Term Access plus Medium Term Open Access.*

*5. Transmission charges covered under sub-clause (b) of clause (1) of this Regulation, in respect of injecting DICs with untied LTA capacity, shall be shared by such injecting DICs in the ratio of their untied LTA capacity for the respective target region."*

16.2 APPCC has suggested that the words 'Drawee DIC' should be replaced with the words 'Drawee DIC of the same region'.

16.3 Analysis and Decision

16.1.1 The proposed provisions have been modified at Regulation 6(2) and 6(3) as follows:

“

*(2) Yearly Transmission Charges covered under sub-clause (a) of Clause (1) of this Regulation shall be shared by drawee DICs of the receiving region and injecting DICs with untied LTA in the receiving region, in proportion to their quantum of Long Term Access plus Medium Term Open Access and untied LTA, respectively.*

*(3) Yearly Transmission Charges covered under sub-clause (b) of Clause (1) of this Regulation shall be shared by drawee DICs of the region and injecting DICs (with untied LTA) of the same region, in proportion to their quantum of Long Term Access plus Medium Term Open Access and untied LTA, respectively.”*

<u>*Illustration*</u>

If for the Southern region, total LTA plus MTOA for drawee DICs is 30,000 MW and there are 2 (two) generators which are geographically located in the Southern Region with untied LTA to the Western region for 3,000 MW. If charges to be shared under Regulation 6(1)(b) for STATCOM, SVC etc. is Rs.’X’, then such charges shall be shared @ Rs. “X/33000 per MW per month by the drawee DICs for the quantum of LTA plus MTOA and generators for quantum of united LTA.

## 17. Clause (6) of Draft Regulation 6

17.1 The draft Regulation provided as under:

*For Mundra-Mohindergarh HVDC transmission system, proportionate transmission charges towards 1495 MW shall be borne by M/s Adani Power (Mundra) Limited or its successor company.*

17.2 WBSEDCL has submitted that Mundra-Mohindergarh HVDC transmission system should neither be considered as part of the National Component nor of the Regional Component.

17.3 Analysis and Decision:

17.3.1 The treatment of charges for Mundra-Mohindergarh HVDC transmission system is as per previous Orders of the Commission. Accordingly, charges for 1,495 MW is to be billed to M/s Adani Mundra. and charges for remaining 1,005 MW are to be shared under NC-HVDC.

## 18. Draft Regulation 7

18.1 The draft Regulation provided as under:

*“(1) Transformers Component shall comprise of transmission charges for inter-connecting transformers planned for drawal of power by the State. The list of such transformers for each State shall be provided by the Central Transmission Utility to the Implementing Agency.*

*(2) Transformers Component of transmission charges shall be borne by the State in which*

*they are located.*

*(3) Where separate transmission charges under clause (1) of this Regulation are not available, the transmission charges shall be computed based on indicative capital cost to be provided by the Central Transmission Utility."*

18.2 Comments have been received from Azure Power, GUVNL, RUVNL, RPG Trading, GETCL, MSEDCL, HPSEBL, HVPN, APDCL, HPPTCL, KPTCL, Tstransco, MSEDCL, BYPL, GETCL, WBSEDCL, RPG Trading, BRPL, TANGEDCO,SRPC, KSK Mahanadi, GUVNL, Kreate Energy and BSPHCL.

18.2.1 Azure Power has suggested specifying the State entity that is required to bear the charges for Transformer Component.

18.2.2 GUVNL has suggested that there could be transformers located in the State from which embedded entities may be drawing power. Therefore, it is appropriate that instead of recovery of transmission charges for such transformers from the host State, the applicable charges may be proportionately recovered from the embedded entity as provided in Regulation 9(9) of the Draft 2019 Sharing Regulations regarding recovery of AC-UBC.

18.2.3 MBPMPL has suggested clarifying that there would be no incidence of the same on the injecting DICs with untied LTA capacity.

18.2.4 RUVNL has suggested that the Commission in the Explanatory Memorandum has explained that the transmission charges for inter-connecting transformers shall be shared among the DICs in the ratio of number of feeders connected to each state. This clarity may be provided in the Regulation itself. Similar clarification has been sought by RPG Trading, GETCL, and MSEDCL.

18.2.5 HPSEBL has suggested that a proviso after clause 7(1) may be added as under:

> *'and details of such transformers & substation feeders connected to neighbouring state actually catering to drawl requirement of state other than the state in which transformer is located are to be given to respective State Discoms / Generators and proportionate transmission charges shall be levied to such state.'*

18.2.6 HVPN and APDCL have suggested that the actual cost of drawl transformers of ISTS network should be recovered from DICs for whom such transformers have been planned.

18.2.7 GMR has suggested that as per Explanatory Memorandum, Transformer Component (TC) should be excluded from monthly transmission charges to determine AC component transmission charges. However, it is not clear as to how the cost of TC will be ascertained as CERC determines capital cost and ARR for transmission lines and sub-stations and there is no segregation of TC. It has requested to bring more clarity on this part to ensure that there is no under-invoicing or over-invoicing problem in future.

18.2.8 HPPTCL has suggested that computation of transformer charges should be usage-based. It should be treated on monthly peak loadings for transformers installed in hydro-rich States. Further, Transformers Component should be identified by CTU and the indicative capital cost should be finalized in consultation and with approval of the State.

18.2.9 KPTCL and Tstransco have suggested that the Transformers Component charges should be based on the drawl of power by the States through downstream network irrespective of the State in which they are located.

18.2.10 GRIDCO has suggested that transformer being part of the AC network, their cost may be included in the YTC of total AC system and for recovery of YTC, allocation may be done on usage basis.

18.2.11 Stakeholders such as MSEDCL, BYPL and GETCL have emphasised that mere location of transformer i.e. ICT or power transformer should not be the criteria for bearing cost rather cost must be shared based on usage basis.

18.2.12 WBSEDCL has suggested that Transformers Component ought to be computed on regional basis instead of State-specific computation.

18.2.13 RPG Trading has suggested that in case of drawal by more than one DIC/ State, it should be proportionate to the respective LTA plus MTOA with appropriate rationale.

18.2.14 BRPL has suggested to include provisions for events where transformers are used by two or more States/ DICs. It has also sought to have clarification as regards ICTs (owned by ISTS or owned by STU or by both) would be included in this component.

18.2.15 TANGEDCO has suggested that list of transformers for each State should be certified by the concerned RPC. Also cost of spare transformer may be included. Indicative cost provided by CTU should be as per benchmark norms decided by the Commission.

18.2.16 HVPN and APDCL have suggested that list of ICTs planned for drawl of power by State should be decided by CTU only in consultation with STU, SLDC and concerned State Discom. CTU should demonstrate through power flow study that said ICT is planned only for drawl of State.

18.2.17 TANGEDCO and SRPC have suggested that ICTs at 765 kV and above level are used for bulk transfer of power and can be shared by all the DICs of the region rather than by a particular State due to its geographical location. SRPC has suggested that transmission charges for transformer below 765 kV should be included under this Regulation. Capacity for 765 kV and above can be shared by all DICs of the region.

18.2.18 KSK Mahanadi has suggested that Transformers Component of NC-RE should be included under said Regulation.

18.2.19 GUVNL has suggested that there is no clarity with regard to the Transformers Component which is located in the State and which is created for evacuation of renewable power as identified by CTU. It may be clarified that Transformers Component shall not be included for computation of Transformers Component charges for the host State since the same is not utilized for drawl by the State.

18.2.20 Kreate Energy during the public hearing has submitted that Transformers Component should be shared on regional basis instead of being shared on State basis based on hybrid methodology.

18.2.21 BSPHCL during the public hearing has suggested that some transformers are located in Bihar but serving the purpose of more than one State. It has requested that such transformers should be proportionately billed.

18.3 Analysis and Decision

18.3.1 Transformers Component for a State shall be borne and shared by the drawee DICs (Discoms) located in that State in proportion to their LTA plus MTOA and shall not be payable by injecting DICs. Charges towards such transformers can be levied on an embedded customer only if such an embedded customer is availing LTA or MTOA from ISTS. The rationale for billing Transformers Component on State Discoms is the fact that such transformers have been planned by CTU specifically for drawl of power by the State as per the requirement of the State. The details of transformers to be included under Transformers Component shall be worked out by CTU after consultations with stakeholders. It is further clarified that transformers shall include its associated bays and downstream bays such as 220 KV bays wherever constructed as part of ISTS.

18.3.2 The treatment of transformers used for drawl requirement of more than one State has been included in the 2020 Sharing Regulations as follows:

*"transmission charges shall be apportioned to each State in the ratio of number of feeders from such transformer for each State".*

18.3.3 Only the transformers under ISTS shall be billed under this component and CTU shall provide the list of such transformers along with their treatment after due consultative process. CTU shall consider only drawl transformers in Transformers Component, while transformers used for evacuation of power shall be included under AC-System Component.

18.3.4 Drawl transformers are not included in the Regional Component since these have been planned for specific drawl requirement of a State and do not cater to requirement of region.

18.3.5 The CTU shall identify elements to be covered under NC-RE component. A drawl transformer shall come under the Transformers Component only if it has not been considered under NC-RE.

18.3.6 There may be cases where separate approved tariff for such transformers is not available. In such cases, CTU shall provide the transmission charges to be considered for such transformers based on approved tariff for the integrated project and the indicative capital cost. The cost of such elements shall depend on various factors such as age of element, tariff granted by the Commission for the entire substation where such element is located etc. The illustration at Para 15.3 may be referred to for clarification.

## 19. Clause (2), (3) and (4) of Regulation 8

19.1 The draft Regulation provided as under:

"2. *AC System Component shall be the divided into the following components:*

*(i) Usage Based Component (AC-UBC); and*

*(ii) Balance Component (AC-BC).*

*3. Transmission charges for AC-UBC shall be shared by DICs corresponding to their respective usage of transmission lines, in accordance with Regulation 9 of these regulations.*

*4. Transmission charges under AC-BC shall be the balance transmission charges for AC transmission system after apportioning the charges for AC-UBC."*

19.2 Comments have been received from KSEBL, GRIDCO, WBSEDCL, NTPC and MBPMPL.

19.2.1 KSEBL and GRIDCO have suggested that the proposal to share the cost of under-utilized AC assets also on LTA plus MTOA basis is highly unscientific and goes against the mandate in the Tariff Policy as it will be against distance, direction and usage sensitivity and discourage optimum transmission investment. Further, transmission lines are planned and constructed based on the LTA request of DICs. Therefore, responsibility of bearing transmission charges of the transmission line is on the DIC for whom it has been constructed. Full cost of AC transmission lines may be shared based on usage of transmission system in line with Tariff Policy. GRIDCO has suggested that both AC-BC and AC-UBC should be merged and complete cost should be on usage basis.

19.2.2 WBSEDCL has suggested that the charges ought to be shared by regions which are being directly benefited by the concerned AC-BC, taking into consideration power flow and SIL (Surge Impedance Loading).

19.2.3 NTPC has suggested that word ‘DIC’ be replaced with the words “Drawee DIC”.

19.2.4 MBPMPL has suggested that AC-UBC is essentially computed on the basis of actual usage of AC System by the drawee State/ DIC. In such a scenario, any injecting DIC with untied LTA capacity shall not be utilizing the AC System for such untied LTA capacity as this capacity is not being injected into grid for supply to any firmed-up buyer/ beneficiary under PPA. Hence, such untied LTA capacity does not contribute to actual usage of AC system and charges under AC-UBC should not be levied on such DIC with untied LTA capacity.

19.2.5 KSEBL has suggested to bring in charges for connectivity on monthly basis and on per MW basis stating that merchant generators are enjoying connectivity for entire installed capacity and utilising the system without making any permanent commitment to the system. Monthly charges for connectivity would help reduce cost of AC transmission system and also help in sharing of transmission charges equitably.

19.3 Analysis and Decision

19.3.1 The prevailing 2010 Sharing Regulations provide for 90% of charges based on usage and 10% as reliability (apart from charges for HVDC transmission system).

To address the concerns of the stakeholders on the methodology, the Commission had constituted a taskforce under Chairmanship of Shri A.S. Bakshi (the then Member, CERC) to review the framework of Point of Connection (POC) Charges. The Task Force, after due consultation with stakeholders, proposed the sharing mechanism as has been proposed in the Draft 2019 Sharing Regulations. The reasons for sharing the transmission charges under AC Usage-based Component (AC-UBC) and AC Balance Component (AC-BC) have been provided in the Explanatory memorandum to the Draft 2019 Sharing Regulations, which are as follows:

> *"(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 (Surge Impedance Loading) of 500 MW is carrying 300 MW in the Base case during Peak Block. If line-wise transmission charges under Clause (3) of regulation 9 of Draft 2019 Sharing Regulations for such transmission line is Rs. 100 crore, the transmission charges to be considered under AC-UBC for such a line shall be (300/500)*100= Rs. 60 crore. The balance transmission charges of Rs. 40 crore shall be considered under AC-BC component."*

19.3.2 The Tariff Policy dated 28.1.2016 provides as follows:

> *"7.1….*
>
> *(2) The National Electricity Policy mandates that the national tariff framework implemented should be sensitive to distance, direction and related to quantum of power flow. This has been developed by CERC taking into consideration the advice of the CEA. Sharing of transmission charges shall be done in accordance with such tariff mechanism as amended from time to time.*

*(3) Transmission charges, under this framework, can be determined on MW per circuit kilometer basis, zonal postage stamp basis, or some other pragmatic variant, the ultimate objective being to get the transmission system users to share the total transmission cost in proportion to their respective utilization of the transmission system. The utilization factor should duly capture the advantage of reliability reaped by all. The spread between minimum and maximum transmission rates should be such as not to inhibit planned development/augmentation of the transmission system but should discourage non-optimal transmission investment."*

19.3.3 Thus, according to Tariff Policy 2016, the framework of sharing of transmission charges should be sensitive to distance, direction and quantum of power flow and that 'utilization' factor should duly capture the advantage of reliability reaped by all. Further, the spread between minimum and maximum transmission rates should be such as not to inhibit planned development/ augmentation of the transmission system but should discourage non-optimal transmission investment.

19.3.4 In view of the provisions in the Tariff Policy 2016 and the reasons stated in Explanatory Memorandum as quoted above, AC-UBC component, which reflects the tariff sensitivity to distance, direction and quantum of flow and AC-BC component which satisfies the other requirements of Tariff Policy 2016 have been retained.

19.3.5 DICs to whom AC-UBC charges are allocated are drawee DICs with LTA or MTOA or both and injecting DICs with Untied LTA. Accordingly, the provisions in the Clauses (2), (3) and (4) of Regulation 8 of Draft 2019 Sharing Regulations have been modified as follows:

"

*(2) AC System Component shall have following components:*

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

*(3) The Yearly Transmission Charges of AC-UBC shall be shared by drawee DICs and injecting DICs with untied LTA corresponding to their respective usage of the transmission lines, in accordance with Regulation 9 of these regulations.*

*(4) The Yearly Transmission Charges under AC-BC shall be the balance Yearly Transmission Charges for AC System Component after apportioning the charges for AC-UBC."*

## 20. Clauses (5) and (6) of Draft Regulation 8

20.1 The draft Regulation provided as under:

*"5. Transmission charges covered under AC-BC shall be apportioned to all drawee DICs in the ratio of their quantum of Long term Access plus Medium Term Open Access.*

*6. Transmission charges covered under AC-BC in respect of injecting DICs with untied LTA capacity shall be shared by such injecting DICs in the ratio of their untied LTA capacity."*

20.2 Comments have been received from MBPMPL, Azure Power, HPSEBL, KSK Mahanadi, SRPC, BSPHCL and KSEBL.

20.2.1 MBPMPL has sought clarification as to whether AC-BC would be computed on Regional Basis or on National Basis and also whether per MW transmission charges of AC-BC would differ for different Regions/ States or would be same for all the DICs across the Country, irrespective of their location and status.

20.2.2 Azure Power has suggested that no transmission charges should be levied for injecting DICs in case of tied LTA capacity.

20.2.3 HPSEBL has suggested that following proviso should be added after regulation 8(5):

"*If a particular transmission system is commissioned for any planned upcoming generating station and the same is not actually commissioned, the charges of such system should not be charged from the DICs and instead these charges be borne by transmission licensees who have constructed the line without any provision for recovery of charges in the case of non- commissioning of such generating station. In case licensee have made provision for liquidity damages, in such cases the liquidity damages recovered / recoverable as per agreement be deducted to arrive the capital cost of transmission asset."*

20.2.4 KSK Mahanadi has suggested that transmission charges payable in respect of untied LTA Capacity by injecting DICs/ generators should be after netting off the STOA charges, if any, paid by the generator.

20.2.5 SRPC has suggested that Regulations 8(5) and 8(6) may be merged together.

20.2.6 BSPHCL, during the public hearing, has suggested that if transmission system is utilised to the extent of 30%, balance component should be shared by those DICs for whom it is created to avoid cross-subsidisation. Further, reduction of RoE for such system may be thought of.

20.2.7 KSEBL, during public hearing, also suggested reduction of RoE for reducing burden of balance component on DICs.

20.3 Analysis and Decision

20.3.1 The charges under AC-BC shall be shared by all India DICs in accordance with Regulation 8(5) of the 2020 Sharing Regulations.

20.3.2 Cases of mismatch between generating station and transmission line are covered under Regulation 13 of the 2020 Sharing Regulations. As per Regulation 13(3), transmission charges for any transmission line for which bills are raised on a particular generator due to delay in commissioning of generating station shall not be included under Regulation 5 to 8 of these Regulations till generating station has achieved COD.

20.3.3 Clauses 5 and 6 of Regulation 8 of the Draft 2019 Sharing Regulations have been merged in the 2020 Sharing Regulations. The offset of STOA charges paid by a generating station against bills for untied LTA is provided in Regulation 11(4) of 2020 Sharing Regulations.

20.3.4 Issues related to RoE are not the subject matter of this regulation. Further, it is not possible for a transmission service provider to affect flow in a transmission line, which depends on several factors. Once a transmission system is commissioned in meshed network, the entire grid is used with varying flows from time to time depending on load and generation. Under AC-BC, a particular system cannot be identified for a particular DIC. Therefore, transmission charges under AC-BC cannot be levied only on DICs for whom it is created, since usage of transmission system varies from time to time and power flows through displacement.

**21. Clause (1) of Draft Regulation 9**

21.1 The draft Regulation provided as under:

*"(1) The Base Case file shall be prepared by the Implementing Agency for the Peak Block of the month comprising of the following:*

*(a) Basic Network, which shall be the network file for the power system for the peak block of the month; and.*

*(b) Actual generation and demand, in MW, at each node of the Basic Network for the Peak Block."*

21.2 Comments have been received from TANGEDCO, GRIDCO, GUVNL, APDCL and RUVNL.

21.2.1 TANGEDCO and GRIDCO have welcomed the proposal of shifting to actual Base Case on ex-post basis instead of projected Base Case i.e. on ex-ante basis being considered.

21.2.2 GUVNL has suggested considering the suggestion made in the Bakshi Committee Report for computation of actual utilization during the month by DICs based on each 15 minute time block.

21.2.3 APDCL has suggested that it is possible that in a particular peak block, a generator is under shut down or a transmission line is under outage which otherwise generates or transmits power at other time blocks, then the peak block will not properly represent the normal usage of network. In this case, there should be a mechanism so that generator or transmission line under outage can also be considered under the Base Case file. Further, the peak block should be considered based on data reading through Special Energy Meter and not that through SCADA as SCADA data is erroneous.

21.2.4 GUVNL has stated that there is no clarity in the Draft 2019 Sharing Regulations as to how Implementing Agency will work out AC-UBC for the untied capacity of a generator. However, as mentioned in the Explanatory Memorandum to the Draft 2019 Sharing Regulations, it appears that the Regulation intends to recover AC-UBC from untied LTA of generator based on actual injection only. In the event the generator having untied LTA does not inject any power, the utilization becomes 'NIL' and there is no recovery of AC-UBC. In such cases, the entire charges would be socialized under AC-BC even when the transmission system may have been set up for the evacuation of power under LTA tied up by such generator. Therefore, irrespective of actual generation, the generator should share the AC-UBC based on untied LTA capacity considering deemed generation.

21.2.5 RUVNL has stated that the Draft 2019 Sharing Regulations has no mention of existence and functioning of validation committee that existed in the 2010 Sharing Regulations.

21.3 Analysis and Decision

21.3.1 Preparation of Base Case considering actual utilization by DICs for each 15 minute time block during the month will be a tedious and time-consuming exercise. For this, all DICs shall have to provide node-wise load and generation data for each 15 minute time block, resulting in 96X30 Base Cases for a month. The processing time available for these Base Cases is only about 15 days after obtaining the data. Obtaining data and preparing such a large number of Base

Cases is not possible within the available timeframe. Further, such exercise has to be repeated each month. In the 2020 Sharing Regulations, the Peak block has been taken as the block when the sum of ISTS drawl is at maximum in a month. This is the time when the ISTS is under maximum stress. The Bakshi Committee Report, after considering all aspects, also recommended preparation of single Base Case for the month based on actual data which has been adopted in these Regulations.

21.3.2 The computation of AC-UBC is post facto on actual basis. Consideration of any generation other than the actual, like deemed generation, would change the load generation balance, since to balance such generation, load would also be required to be modified and hence would not represent the actual case. Further AC-UBC is only a percentage of total transmission charges to be shared by DICs including untied generators.

21.3.3 Since the timelines are fixed, and the Implementing Agency shall have to publish the Peak Block immediately after end of the month so that DICs can provide load/ generation data for the Peak Block, Implementing Agency may use SCADA data, in case SEM data is not available.

21.3.4 No Validation Committee is envisaged in the 2020 Sharing Regulations since the load/ generation is on post facto actual basis and validation of actual data can be done by the Implementing Agency.

## 22. Clause (2) of Draft Regulation 9

22.1 The draft Regulation provided as under:

*"(2) The Implementing Agency shall collect the data for (a) and (b) above and the Yearly Transmission Charges from DICs, transmission licensees, NLDC, RLDCs, SLDCs, RPCs and STUs as per timelines specified in Regulation 21 of these regulations."*

22.2 Comments have been received from BYPL, MSEDCL and HVPN.

22.2.1 BYPL and MSEDCL have suggested that the responsibility of submission of node-wise actual generation and demand data should be given to respective SLDCs. MSEDCL has also stated that it is mainly considered as DIC but there are also other DISCOMs like railways, BEST, TPC, AEML, MBPL etc. which are scheduling power mainly under STOA (except Railways). For MSEDCL as a DIC, it will be difficult to obtain data from other DISCOMs.

22.2.2 HVPN has suggested that CERC or NLDC should formulate a detailed procedure for getting data for computation of transmission charges under AC-UBC and subsequently the agency may be defined (STU/ SLDC/ DISCOMs) who shall be having the Data with respect to computation of the share of transmission charges i.e. SEM data or manual load and generation data.

22.3 Analysis and Decision

22.3.1 The Implementing Agency shall issue a detailed procedure on collection of data as per Regulation 23 of the 2020 Sharing Regulations after consultation with stakeholders. Detailing of the responsibility to provide data for areas not under control of a particular Discom shall be dealt with in the detailed procedure and the same can be provided by the concerned SLDC.

**23. Clause (3) of Draft Regulation 9**

23.1 The draft Regulation provided as under:

*"(3) The Monthly Transmission Charges covered under AC-UBC shall be apportioned on transmission lines of the Basic Network whose charges have been included in Yearly Transmission Charge. Such apportionment shall be made on per circuit kilometer basis for each voltage level and conductor configuration as per methodology in Annexure-I to obtain line-wise transmission charges for each voltage level and conductor configuration respectively."*

23.2 Comments have been received from BYPL and MSEDCL.

23.2.1 BYPL and MSEDCL have suggested that instead of apportionment of cost of transmission line on per circuit kilometre basis for each voltage level and conductor configuration, actual MTC should be used.

23.3 Analysis and Decision

23.3.1 The issue of using actual MTC vs average cost on per circuit kilometre basis for each voltage level and conductor configuration was considered while issuing the 2010 Sharing Regulations. The issue has been deliberated in the Bakshi Committee Report as under:

***(a) Analysis and Recommendations***

*(i) The issue of cross subsidizing was raised by stakeholders while issuing Principal Regulations in 2010. Statement of Reasons dated 11.6.2010 issued with CERC Sharing Regulations 2010 notes as follows.*

*"3.3.49 Comments: In the determination of transmission pricing, the revenue requirements of transmission assets of the same voltage class are pooled. The*

*addition of new transmission assets will increase the tariff as the old assets have been depreciated. Therefore, the transmission tariff charged to those utilities on the basis of old assets may be affected. (GETCO)*
*3.3.50 Order / Analysis: Nearly all states require more generation and associated transmission assets. The loss because of having to pay more on an average of old assets gets neutralized to an extent by having to pay less for new lines."*

*(ii) Further the possible benefits of averaging cost across voltage class can as follows:*

*1. To make allocation of transmission charge on a node as distance sensitive, equalization of value of all transmission lines whether old or new was required. Otherwise, the charges for specified quantum of flow of power for same distance on new line and old line would be different and results may not reflect distance sensitivity. For example it may happen that a State is drawing power from larger distances i.e from faraway generators. Suppose the power which reaches the State flows through old lines (which will have less tariff). Similarly another State draws power from relatively nearby generators, but since tariff for new lines is higher will be levied higher charges under the mechanism. Hence the results will not satisfy tariff policy objectives.*
*2. Equalization of all transmission lines of the same voltage level cannot be termed as discriminatory as the States use both old and new transmission lines and the loss on account of having to pay more on an average of old assets get neutralized for having to pay less for the new assets. However States may raise an issue that they are not utilising new lines and hence should not cross subsidise.*
*3. In a few cases tariff for transmission lines are not available assetwise i.e line wise and clubbed tariff is being approved. Averaging of the cost helps to handle such cases.*

*(iii) The Taskforce observes that electricity flows through laws of physics and not through contract path or desired path except for dedicated lines. Hence it is not the drawing entity or injecting entity which decides which line ie. Old line or new line is to be used for its drawal. Hence there shouldnot be difference in tariffs considered for such lines. Non averaging of cost may lead payers of transmission to indulge into such activities so that the power is wheeled to them through old assets which may be a non-optimal solution. The taskforce recommends to continue the averaging of cost across voltage class so that distance, direction and quantum of flow sensitivity is maintained for modified PoC method. In case of Uniform charges method, the issue of averaging does not arise since the entire system except HVDC is averaged out."*

23.3.2 Based on the recommendations of the Bakshi Committee Report, the methodology of averaging the transmission charges for each voltage level and conductor configuration has been adopted.

## 24. Clause (4) of Draft Regulation 9

24.1 The draft Regulation provided as under:

*"(4) Implementing Agency shall run AC load flow studies on the Base Case file stated at clause (1) of this Regulation for the month and determine power flow on each transmission line.*

*Provided that while carrying out the load flow studies, the Implementing Agency may make minor adjustment in the generation and demand data, if required, to ensure load-generation balance."*

24.2 Comments have been received from PXIL, KSEBL, MSEDCL, Tstransco, HVPN and DNHPDCL.

24.2.1 PXIL and DNHPDCL have suggested that the Commission may identify norms for minor adjustments so that equitable modifications are made in the generation and demand data for benefit of market participants.

24.2.2 KSEBL has suggested that limit of such adjustment to be made in generation and demand data may be fixed as ±2.5% of demand of the State.

24.2.3 MSEDCL and HVPN have suggested that changes done by the Implementing Agency in generation and demand data should be displayed on web portal made available for displaying various information as per Regulation 20 of the Draft 2019 Sharing Regulations.

24.2.4 Tstransco has suggested that Implementing Agency (IA) should ensure that actual generation and ISTS drawl of DIC is communicated. Further, IA should also confirm the final values of drawl of DICs from States that is going to be considered for finalization of charges in case of any adjustments.

24.3 Analysis and Decision

24.3.1 Any adjustments made in load and generation data shall be communicated to stakeholders by Implementing Agency by uploading the final data considered on its website. Further, there is no need to fix any norm with respect to adjustments that can be made since it has already been provided that only minor adjustments can be made. Such adjustments are necessary to ensure load and generation balance in the Base Case and hence fixing any upper limit may result in a Base Case that is not balanced.

## 25. Clauses (5) and (6) of Draft Regulation 9

25.1 The draft Regulation provides as under:

*"(5) Percentage usage of each transmission line shall be computed by dividing power flow in the Base Case as obtained at clause (4) of this Regulation by Surge Impedance Loading of the line.*

*(6) Percentage usage of each transmission line computed at clause (5) of this Regulation shall be multiplied by line-wise Yearly Transmission Charges obtained as per clause (3) of this Regulation to obtain modified line-wise transmission charges."*

25.2 Comments have been received from HPPTCL, KPTCL, NTPC, GUVNL, DNHPDCL and KSEBL.

25.2.1 HPPTCL and KPTCL have suggested that thermal loading should be used instead of Surge Impedance Loading (SIL). Thermal loading limits are higher than Surge Impedance loading. KPTCL has further suggested that in "Manual of Transmission Planning Criteria" of CEA in para 5 (5.2a), it is specified that the loading limit for transmission element shall be its thermal loading.

25.2.2 NTPC has suggested that it is usual to load the short lines above SIL and long lines lower than SIL. Therefore, loadability of transmission line should be assumed as per the methodology decided by the Commission in order dated 08.03.2019 in petition no 92/MP/2015. Else it may be taken as stability limit for long lines and thermal limit for short lines.

25.2.3 DNHPDCL has suggested that Instead of surge impedance loading, line loadability as per St. Claire's Curve can be a better option.

25.2.4 GUVNL has suggested that the Commission may clarify the treatment of transmission charges in the scenario when the actual loading is higher than SIL.

25.2.5 DNHPDCL has suggested that Clauses 5 and 6 propose to book higher transmission charges to the lines heavily loaded and lesser transmission charges to lines lightly loaded (possibly due to over-capacities). Thus, higher cost is supposed to be socialised by all for the transmission lines that have lower power flow, thereby subsidising utilities for whom such under-utilised network was built. This amounts to encouraging inefficiencies in the planning process.

25.2.6 KSEBL, during the public hearing, has suggested that AC-UBC is taken as difference between loading at peak block time and SIL. It does not take into account of N-1 and N-1-1 contingency for which the system has been planned. There is reason for socialising if the benefit of N-1 and N-1-1 contingency in a particular region is equally distributed among the DICs which is not happening in present scenario. Balance component should also be made related to N-1 and N-1-1 contingency. When there is curtailment for Kerala and unutilised capacity is in some other State, it is not logical for Kerala to pay for balance component. Therefore, KSEBL has suggested that cost on account of N-1, N-1-1 contingency should be shared by DICs which benefit from it.

25.3 Analysis and Decision

25.3.1 The detailed reasoning for using Surge Impedance Loading in place of Thermal Loading has been provided in the Explanatory Memorandum of the Draft 2019 Sharing Regulations.

25.3.2 It is usual to load the short transmission lines above SIL and long transmission lines lower than SIL. However, loadability of each transmission line is different. The loadability may vary with changes in configuration of the system. As the peak block is considered as a representative block for the entire month to determine the usage component, SIL as per Annexure-II of the 2020 Sharing Regulations is to be used as representative loadability to determine percentage utilisation of the transmission line. However, it has been provided in Annexure-II that "*SIL for Transmission line built with HTLS conductor or Quad conductor shall be considered, as twice the above said values for respective voltage, for the purpose of these Regulations.*" This shall take care of enhanced loadability of a transmission line with HTLS conductor or Quad conductor.

25.3.3 To cover the scenario when actual loading of a transmission line is higher than SIL, it has been provided that usage shall be capped at 100%.

25.3.4 Once a transmission system has been connected in a meshed network, its benefits vary from entity to entity and also vary with load and generation.

**26. Clause (8) of Draft Regulation 9**

26.1 The draft Regulation provided as under:

> *"(8). The Implementing Agency shall aggregate transmission charges at dawal nodes within the geographical boundary of the State to determine the allocation of charges for the State under AC-UBC."*

26.2 Comments have been received from MSEDCL, BYPL and TPDDL.

26.2.1 MSEDCL has suggested that instead of aggregating transmission charges at drawl nodes within geographical boundary of the State, Implementing Agency should do aggregation of individual DIC in the State based on its drawl node.

26.2.2 BYPL and TPDDL have suggested that illustrative example may be provided by the Implementing Agency for proper understanding of DICs. TPDDL has further submitted that if there is more than one beneficiary in a State, methodology for sharing of transmission charges within the State on usage basis may also be notified.

26.3 Analysis and Decision

26.3.1 Charges under AC-UBC are levied on entities which have LTA or MTOA or both in ISTS. Hence, the DICs in the State who have obtained such LTA or MTOA shall bear the charges towards AC-UBC. The Commission observes that segregation of charges within a State varies from State to State. Hence, no methodology of sharing the charges within the State has been provided and the same may be done as per the methodology adopted by the respective State.

26.3.2 To cover any embedded entity other than distribution licensee who has taken LTA/MTOA, a separate provision has been included in the 2020 Sharing Regulations to the effect that transmission charges shall be apportioned at their drawl node(s) separately and shall not be included in the aggregate transmission charges.

*Illustration*

If an open access consumer, such as a sugar factory "A" located in State 'K', has taken LTA to ISTS for 500 MW and is connected at 132 kV node (node 'B') of 'K' and that 'K' has LTA of 5,000 MW and has 200 drawl nodes (including node "B") where charges are allocated under AC-UBC. Then, the charges under AC-UBC shall be aggregated for 199 nodes (200 nodes minus node 'B' of the sugar factory) for 'K' and that calculated at node "B" shall be billed to the sugar factory "A".

**27. Clause (1) of Draft Regulation 10**

27.1 The draft Regulation provided as under:

*"(1) All India Average Transmission losses for ISTS shall be calculated by Implementing Agency for each week, from Monday to Sunday, as follows:*

*{(Sum of injection into the ISTS at regional nodes for the week) minus (Sum of drawal from the ISTS at regional nodes for the week)}/ Sum of injection into the ISTS at regional nodes for the week X 100 %"*

27.2 Comments have been received from PXIL, Torrent Power, TANGEDCO, HPPTCL, MSEDCL, BYPL, Kreate Energy, WIPPA, RPG Trading and BRPL.

27.2.1 PXIL has suggested that the proposed methodology will result in compromising the distance related sensitivity of the transmission losses.

27.2.2 Torrent Power, TANGEDCO, HPPTCL, MSEDCL and BYPL have proposed that instead of deriving drawl loss from all India average loss, same should be computed on regional loss.

27.2.3 Kreate Energy, during the public hearing, has suggested that transmission losses may be computed region-wise.

27.2.4 WIPPA has sought the rationale behind calculation of transmission losses on all India basis when hybrid methodology is being considered which motivates the generating company to implement its projects at location where there is less congestion.

27.2.5 RPG Trading has suggested that calculation should be block-wise. Net sale in some block by a DIC/State should be considered as injection. The formula proposed by RPG Trading is as under:

*(Sum of Mod of all +ve values of interchange in nth block minus Sum of Mod of all -ve values of interchange in the nth block)/sum of Mod of all +ve values in the nth block x 100 %.).*

27.2.6 BRPL has commented that it is not clear as to how the transmission losses for renewable energy shall be accounted for.

27.3 Analysis and Decision

27.3.1 The Commission observes that transmission losses do not have any regional boundaries. The detailed reasons for considering all-India average transmission loss was provided in the Explanatory Memorandum to the Draft 2019 Sharing Regulations.

27.3.2 The transmission losses as calculated (for week A) are used for scheduling of power 2 weeks after week A. Therefore, no benefit is achieved by calculating losses block-wise since average loss over the week is the representative loss for the week.

27.3.3 The formula for losses provide for waiver of transmission losses in case of projects identified under Regulation 13(1) of the 2020 Sharing Regulations. The formula is as follows:

*"Transmission losses for ISTS shall be calculated on all India average basis by the Implementing Agency for each week, from Monday to Sunday, as under:*

*[(In – Dr) / (Ir)] X 100*

*Where:*
*'In' denotes sum of injection into the ISTS at regional nodes for the week;*
*'Dr' denotes sum of drawal from the ISTS at regional nodes for the week;*

*'Ir' denotes sum of injection into the ISTS at regional nodes less injection from projects covered under Clause (1) of Regulation 13 of these regulations for the week."*

*Illustration*

a. Sum of injection into the ISTS at regional nodes for week $W_1$ = 24000 MU

b. Sum of drawal into the ISTS at regional nodes for week $W_1$ = 23600 MU

c. Sum of injection into the ISTS at regional nodes by projects covered under Clause (1) of Regulation 13 for week $W_1$ = 150 MU

d. Then, average all-India transmission loss for ISTS shall be [(24000 – 23600)/ (24000-150)] x 100 = 1.677%

**28. Clause (2) and (3) of Draft Regulation 10**

28.1 The draft Regulation provided as under:

*"(2) Drawal Schedule of DICs shall be worked out as per provisions of Grid Code after taking into account the transmission losses of previous week as calculated in accordance with clause (1) of this Regulation.*

*(3) No transmission loss for ISTS shall be applicable while preparing schedule for injection node including that for Collective Transactions over the Power Exchanges."*

28.2 Comments have been received from SRPC, PTC and APPCC.

28.2.1 SRPC has suggested that the words 'previous week' should be replaced by the words 'W-2 week'.

28.2.2 PTC has suggested to clarify whether transmission losses shall be applicable at drawal node and also to clarify the treatment at injection/ drawal node under bilateral transactions over the power exchange. Since collective transaction under Power Exchange is considered to be residual power, same treatment may be given to power transacted under short term mechanism.

28.2.3 APPCC has commented that as per the existing practice, in terms of the 2010 Sharing Regulations, the losses are also attributed to injection entities in collective and short term transactions. The losses are to be shared by both the seller and the buyer and hence, exemption to seller alone cannot be admitted.

28.3 Analysis and Decision

28.3.1 Regulations 10(2) and 10(3) have been modified as follows in the 2020 Sharing Regulations:

*"(2)Drawal schedule of DICs shall be prepared as per provisions of the Grid Code taking into account the transmission losses of the week preceding the last week as calculated in accordance with Clause (1) of this Regulation:*

*Provided that while preparing drawal schedule of DICs in respect of projects covered under Clause (1) of Regulation 13, transmission losses shall be considered as zero.*

*(3) Transmission losses for ISTS shall be considered as zero while preparing injection schedule of DICs including that for Collective Transactions in the Power Exchanges."*

28.3.2 Transmission losses for ISTS shall be considered while preparing drawl schedule and shall be taken as zero while preparing injection schedule of DICs including that for Collective Transactions in the Power Exchanges.

28.3.3 In the 2010 Sharing Regulations, injection loss was being considered only for STOA and Collective Transactions in the Power Exchanges. The Explanatory Memorandum issued along with the Draft 2019 Sharing Regulations stated that "*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.*" Hence, the proposal of doing away with injection loss is retained in the 2020 Sharing Regulations.

**29. Sub clause (a), b), (c) and (d) of clause (1) of Draft Regulation 11**

29.1 The draft Regulation provided as under:

*"(1)*

*(a) No transmission charges and losses for the use of ISTS shall be payable for solar generation for the useful life of the projects commissioned from 1.7.2011 to 30.6.2017.*

*(b) No transmission charges and losses for the use of ISTS shall be payable for the capacity of the generation projects based on solar or wind resources for a period of 25 years from the date of commercial operation of the such generation projects if they fulfill the following conditions:*

*(i) Such generation capacity has been awarded through competitive bidding; and*

*(ii) Such generation capacity has been declared under commercial operation between 1.7.2017 and 12.2.2018 for solar based resources or between 30.9.2016 till12.2.2018 for wind based resources; and*

*(iii) Power Purchase Agreement(s) have been executed for sale of power from such generation capacity to the Distribution Companies for compliance of their renewable purchase obligation.*

*(c) No transmission charges and losses shall be payable for the generation projects based on solar or wind resources for the use of ISTS, for a period of 25 years from the date of commercial operation of such generation projects if they fulfill the following*

*conditions:*

*(i) Such generation capacity has been awarded through competitive bidding process in accordance with the guidelines issued by the Central Government; and*

*(ii) Such generation capacity has been declared under commercial operation between 13.2.2018 and31.3.2022; and*

*(iii) Power Purchase Agreement(s) have been executed for sale of such generation capacity to all entities including Distribution Companies for compliance of their renewable purchase obligations.*

(d) *Long Term Access and Medium Term Open Access for Cases covered under sub-clause (a), (b) and (c) of this Clause shall be excluded from the computation of transmission charges under Regulations 5 to 8 of these Regulations."*

29.2 Comments have been received from PTC, PXIL, GUVNL, Mytrah Energy, WIPPA, Hero Future, Azure Power, HPPTCL, TANGEDCO, APPCC, SECI, Tata Power, Azure Power, ACME Solar, Torrent Power, Renew Power, WIPPA, Gati Infrastructure, NTPC and SRPC.

29.2.1 PTC and PXIL have suggested that waiver from payment of inter-State transmission charges and losses should also be extended to wind, solar and other renewable projects that sell power in the short-term market and on Power Exchanges.

29.2.2 GUVNL has suggested that the waiver from payment of inter-State transmission charges and losses should be applicable for 25 years or actual life whichever is earlier.

29.2.3 Mytrah Energy and WIPPA have suggested that bidding agencies, i.e. SECI and NTPC are allowing extension of Power Purchase Agreement (PPA) based on mutually agreed terms and conditions and developer has an option to operate its plant for more than 25 Years. Therefore, it has requested to consider the period as "Useful Life" instead of 25 years, as the prudent operational life expectancy is more than 25 years for wind and solar projects.

29.2.4 Hero Future has commented to remove criteria of competitive bidding from waiver clause and to extend the waiver for non-RPO solar and wind generation.

29.2.5 Azure Power has suggested to remove the requirement of RPO to avail the waiver.

29.2.6 HPPTCL has suggested that extension of waiver of solar and wind energy projects from payment of transmission charges and losses is not required any more as the cost of RE generation has dropped below the tariff of conventional power plants. Hence, beneficiaries of such power should be paying the charges on ‘causer pays’ basis. Further, it is impossible to pinpoint which RE source has been utilized to meet the RPO compliance condition i.e., sub-clause b(iii) and c(iii). The same needs to be looked into from enforcement point of view. Even if the waiver is granted, the impact of the same needs to be loaded directly on the State consuming such RE Power as some of the States being RE-rich, do not use such power for meeting its RPO.

29.2.7 TANGEDCO has suggested that the words ‘solar generation’ may be replaced with the words ‘solar generators’.

29.2.8 APPCC has suggested that the concessions have been granted at the insistence of MoP/ MNRE in Government of India and, therefore, MoP/MNRE has to arrange to compensate for the waivers or concessions extended towards transmission charges and losses. The States should not be asked to bear the burden. The allocated cost component should be directly chargeable to GoI. For this purpose, suitable amendments may be incorporated in the Regulations.

29.2.9 SECI has suggested that ISTS waiver may be continued up to 31$^{st}$ December, 2022 for all the renewable projects which shall be awarded before that date. This will ensure proper utilization of transmission system and give boost to the renewable generation.

29.2.10 Tata Power and Azure Power have suggested that wind/ solar project developer should be allowed to extend date of operationalization/ SCOD of project due to force majeure/ unforeseen events beyond the control of developers, subject to getting necessary extension of SCOD and there should not be any levy of transmission charges in such cases. In cases where the developers have obtained consent from bidding agencies for extension of SCOD, CTU/PGCIL should accept the revision in LTA operationalization dates in line with revised SCOD. Accordingly, they have requested to incorporate suitable provisions in the Regulations.

29.2.11 ACME Solar has suggested that the Regulations should provide appropriate relief to developers in case of force majeure events as it is beyond the control of developers and there should be no penalty or liability to the generating stations in such cases.

29.2.12 Torrent Power has suggested that no discrimination should be made as regards waiver of transmission charges and losses between projects under Section 62 or 63 of the Act.

29.2.13 Renew Power and WIPPA have suggested that an additional proviso may be added after Regulation 11(1)(C) as under:

> *"Provided that the Provision of Regulations 11 (a) to (c) shall be also applicable to generating station integrated with battery storage technologies either co-located and/or de-located with wind solar and/or hybrid projects."*

29.2.14 Gati Infrastructure has suggested that re-classification of large hydro projects (>25 MW) as renewable energy source may be provided in line with MoP office Memo dated 8.3.2019 and these may also be exempted from the payment of transmission charges and losses.

29.2.15 Azure Power has suggested to add transmission charges waiver clause for SECI's manufacturing linked bid (RfS No. SECI/C&P/RfS/2GW MANUFACTURING /P-3/R1/062019) wherein solar projects have been linked with solar manufacturing. As per the guidelines, ISTS transmission charges for the projects under such bids are eligible for waiver, in line with MNRE directives.

29.2.16 SRPC has suggested that certificate from all entities including distribution companies would be required to be furnished certifying that the purchase of such generation capacity is for compliance of their renewable purchase obligations for compliance of Regulation 11(b)(iii) and 11(c)(iii). Suitable clause for vetting exemption of RE transmission charges/ losses needs to be included in Regulations.

29.2.17 NTPC, during the public hearing, has suggested that to facilitate renewable energy generation through various policy interventions of GOI following provisions may be included:

- Transmission charges and losses for the generation projects based on solar or wind resources may be waived if the renewable power generated is used for replacement of thermal power as per GOI Scheme on Flexibility in generation.
- No transmission charges and losses should be payable for solar photo voltaic generation projects based on domestically manufactured content under the CPSU Scheme.

29.3 Analysis and Decision

29.3.1 The terms and conditions of waiver of transmission charges and losses are as per the notifications of the Ministry of Power from time to time.

29.3.2 Considering the notification dated 06.11.2019 of the Ministry of Power, wherein waiver of inter-State transmission charges and losses on transmission of the electricity generated from solar and wind sources of energy has been extended up to 31.12.2022 instead of 31.03.2022, the date "31.3.2022" in the Draft 2019 Sharing Regulations has been replaced by 31.12.2022 in the 2020 Sharing Regulations.

29.3.3 The subject of LTA operationalization is outside the scope of these Regulations.

29.3.4 CTU shall verify whether conditions of waiver are met under Regulation 13(1) of the 2020 Sharing Regulations. The documents required for such verification may be stipulated in the detailed procedure to be issued by CTU under these Regulations. Similar view was taken by the Commission vide Order dated 5.2.2020 in Petition No. 195/MP/2019 along with I.A. No. 65/IA/2019 and 88/IA/2019 as per provisions of Regulation 7(1)(aa) of the 2010 Sharing Regulations.

**30. Clause (2) and (3) of Draft Regulation 11**

30.1 The draft Regulation provided as under:

*"(2) Where Generating Stations or sellers have been granted Long term Access or Medium Term Open Access and have entered into Power Purchase Agreement for supply of power under such Long Term Access or Medium Term Open Access, the transmission charges attributable for such tied up power shall be calculated at drawal nodes for AC-UBC.*

*Provided that prior to COD of the Generating Station, the transmission charges under AC-UBC shall be in terms of clause (4) of this Regulation.*

*(3) Where Generating Stations or sellers have been granted Long term Access or Medium Term Open Access and have entered into Power Purchase Agreement for supply of power under such Long Term Access or Medium Term Open Access, the transmission charges towards such Long Term Access or Medium Term Open Access for components identified under Regulations 5 to 8 of these regulations shall be determined at the drawal nodes and zone and billed to the buyer.*

*Provided that sellers and buyers shall make necessary adjustment or settlement among themselves for transmission charges in terms of their respective Power Purchase Agreements"*

30.2 Comments have been received from KSEBL and MSEDCL.

30.2.1 KSEBL has suggested that prior to COD of the generating station, the charges payable by the generating station comes under bilateral billing between generator and transmission licensee as per Regulation 11(4) and there will be no AC-UBC component.

30.2.2 MSEDCL has suggested that in line with provision in Regulation 16B of the 2009 Connectivity Regulations, the concerned DIC willing to reallocate capacity which is going to be un-utilised, shall inform reason and RLDC after confirmation of the same from generator shall schedule such corridor for scheduling under MTOA or STOA transaction depending upon the period of such underutilization with a condition that such transaction shall be curtailed in the event original LTA or MTOA customer seeks to utilize its capacity. Once a DIC surrenders such LTA for specific period, it shall not be liable to pay transmission charges for said LTA. The same may be incorporated.

30.2.3 MSEDCL has also suggested that the transmission charges shall be borne by buyers or generators as per respective power purchase agreements and hence bills should be issued by CTU to only the DICs which have liability for payment of transmission charges. This would avoid future legal complication related to payment of transmission charges.

30.3 Analysis and Decision

30.3.1 In case of sale of power by a generating company to distribution licensees (buyers) under Long Term Access or Medium Term Open Access, the buyers are ultimately responsible for payment of transmission charges. Where the generating company has been granted LTA, the generating company is liable to pay the transmission charges but it gets the transmission charges reimbursed from the buyers either as part of integrated tariff quoted by it or separately from the buyer. To have uniformity in approach for recovery of transmission charges by CTU, it has been provided that the buyer shall be responsible for payment of transmission charges to CTU and shall settle the transmission charges with the generating company inter se in accordance with the Power Purchase Agreement.

30.3.2 A generating station, in case of delay, prior to COD shall be liable to pay transmission charges as per Clause 3 or Clause 7 of Regulation 13 of 2020

Sharing Regulations, as the case may be. A generating station with untied LTA shall be liable for AC-UBC component only after its COD.

30.3.3 Any adjustment of billing in case of reallocation of LTA as provided in the 2009 Connectivity Regulations shall be governed in terms of the provisions of the 2009 Connectivity Regulations.

**31. Clause (4) of Draft Regulation 11**

31.1 The draft Regulation provided as under:

*"(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."*

31.2 Comments have been received from SECI, ACME Solar, Renew Power, Hero Future, Sprng Energy, Torrent Power, KSK Mahanadi, NHPC, NEEPCO, MSEDCL and Azure power.

31.2.1 SECI has suggested that the transmission projects being erected/to be erected for carrying RE power once completed may be put under pool without linking it to commercial operation of the planned renewable generation projects. This will secure the interest of the transmission system provider, who are constructing the transmission lines.

31.2.2 SECI has suggested that this clause may be removed else it may be applicable only for those cases where delay is on account of developers alone and no extension is granted by Government Nodal Agency. The transmission charges collected may be kept in a pool for deduction of transmission charges of respective DISCOMs. SECI has suggested that an exception may be carved out for the solar/ wind power parks being developed under MNRE schemes for the benefit of State Buying Utilities and that a maximum time period of around 4 years or time period as deemed fit by the Commission may be allowed for utilization of transmission capacity being created for such parks to a reasonable level. Transmission system once completed may be put under the existing POC mechanism. Transmission charges will be levied on such solar/ wind/ hybrid parks, if they are not completed within four years and if no extension is given to them for completion by any Government agency. Till such time, available capacity may be utilized for the usage under short term and/ or medium-term access.

31.2.3 ACME Solar and Renew Power have suggested that once the transmission charges and losses are waived off for wind/ solar projects, this clause should not be made applicable to developers in any case. There is clause under PPA to address such issue.

31.2.4 Hero Future and Sprng Energy have suggested that there are instances where delay in achieving COD by solar/ wind generators is on account of reasons not attributable to them. Few such reasons are:

- Delay in adoption of tariff by the respective State Electricity Regulatory Commission (SERC).
- Delay in providing land by the Solar Park agencies.
- Changes in the State Land Policies.
- Changes in the Environment related policies/ Acts leading to delay in getting environmental/ wildlife clearances/ approvals.
- Cases filed by NGOs/ social activists before various legal forums leading to delay in getting clearances/ approvals.
- Force Majeure events covered under PPA.
- Delay in providing NOCs by Ministry of Defence for wind generating stations.

31.2.5 Hero Future and Sprng Energy have further stated that due to above-stated uncontrollable reasons, projects get delayed and SCOD gets revised by bidding agencies. Therefore, in such cases, it is unfair and unjust to ask for submission of LC and payment of transmission charges. It is appropriate to incorporate the provisions for revision of SCOD as approved by bidding agency such as SECI. Sembcorp has made similar comments.

31.2.6 Torrent Power has suggested that no transmission charges should be levied on RE generators in case of delay. Accordingly, an exception should be added that the clause will not be applicable to the renewable energy generators. CTU may seek appropriate remedies such as grants and/or subsidies from GOI/ State Governments till the associated renewable energy generating stations achieve COD.

31.2.7 KSK Mahanadi has suggested that this clause requires to be re-looked into with respect to the fact that transmission charges would be payable only to the extent of BPTA/LTA signed with the Associated Transmission system and it cannot be for the entire plant capacity.

31.2.8 NHPC and NEEPCO have suggested that availability of transmission system, 30-45 days prior to COD of the first generating unit of a hydro generating station, is essential for testing and commissioning of hydro generating units/ station. During the testing and commissioning period and till declaration of COD of first unit, hydro generating stations should be excluded from the purview of payment of any Yearly Transmission Charges. If the COD of the first unit of the generating station gets delayed, a provision may be made for payment of transmission charges by the generating station pro-rata for the period of delay instead of payment of Yearly Transmission Charges so as to bring consistency with the 2019 Tariff Regulations. Further, in that situation, the transmission charges to be paid should be set off against the revenue generated from sale of infirm power and the balance amount (if any) should only be deducted from the capital cost for the purpose of tariff.

31.1.10 MSEDCL has suggested that in case associated transmission system has achieved COD before its scheduled COD and before generating station gets commissioned, the transmission charges of transmission line should not be allowed to be recovered under POC mechanism under Regulations 5 to 8 of the Draft 2019 Sharing Regulations. In case of such delays, only after scheduled COD and till the generating station achieves COD that the transmission charges should be recovered from generator. The buyer would pay transmission charges if generating station achieves COD as per its schedule COD.

31.2.10 Azure power has suggested to add the following after Regulation 11(4):

> *"If there is a change in the project SCOD as approved by the Procurer/ appropriate Commission, the same extension shall also be provided to the SPD under its obligations to CTU/ PGCIL as well. In case, the generating station is delayed, beyond the SCOD, then the charges should apply from the SCOD of generating station or COD of the transmission station, whichever is later."*

31.3 Analysis and Decision

31.3.1 The draft Regulation has been modified as Regulation 13(4) in the 2020 Sharing Regulations as follows:

*“(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 Long Term Access granted for the generating station or unit(s) thereof, which have not achieved COD:*

*Provided that Yearly Transmission Charges in respect of Associated Transmission System shall be included for determination of transmission charges of DICs in accordance with Regulations 5 to 8 of these regulations upon the generating station or unit(s) thereof achieving COD.”*

31.3.2 Subject to provisions of the Grid Code, a transmission system shall be entitled for tariff after its COD which shall not be before its SCOD. In case of delay in achievement of COD of generating station or unit(s) thereof, the generating station shall pay Yearly Transmission Charges for the Associated Transmission System corresponding to Long Term Access granted for the generating station or unit(s) thereof, which have not achieved COD.

31.3.3 Regarding availability of transmission system for drawl of start-up power or power for testing and commissioning, the Commission observes that in case such transmission system has been built as per timeline given by the generating station for start-up power or for trial operation, the generating station can always enter into an agreement regarding terms and conditions for payment of such tariff.

31.3.4 Further, the payment of charges as per the Regulations is pro-rata for the period of delay only and not for the entire year. For example, if a generating station gets delayed by 6 months, it shall pay YTC corresponding to six months only. Adjustment of transmission charges payable for the period of delay against the capital cost for such generating station or sale of infirm power is outside the scope of this Regulation.

31.3.5 The associated transmission system is not utilised optimally till generating station is declared under commercial operation. In case of projects eligible for waiver of inter-State transmission charges and losses, waiver is applicable only after the project achieves COD. Therefore, a RE generating station has to pay transmission charges in case of any delay in COD. Non-payment of transmission charges by such generators would either result in the transmission service provider not recovering the tariff even when it has declared its system under commercial operation or it would lead to burdening of existing DICs even when they are not getting any benefit from such generating station. Both cases result in penalising entities who are not responsible for delay of the RE generating station. Irrespective of whether a generating station is covered under provisions of waiver of transmission charges and losses scheme or not, it shall be liable to pay charges as per Clause 3 or Clause 7 of Regulation 13 of the 2020 Sharing regulations, as the case may be.

## 32. Clause (5) of Draft Regulation 11

32.1 The draft Regulation provided as under:

*"(5) Where Long Term Access to ISTS is granted to a generating station on existing margins and COD of the generating station or unit(s) thereof is delayed, the generating station shall pay transmission charges @10% of transmission charge for the State where it is located for the quantum of such Long Term Access.*

*Provided that the amount received on account of payments in the month towards such Long Term Access shall be reimbursed to the DICs in proportion to their shares under the First Bill in the following month.*

*Provided that such Long Term Access shall be excluded for computation under Regulations 5 to 8 of these regulations."*

32.2 Comments have been received from NEEPCO, NTPC, Adani Mundra, Sembcorp, Tata Power, WIPPA, APP, Renew Power, Sembcorp, TANGEDCO, ATL, CII, L&T IDPL, BYPL, GUVNL, KPTCL, Hero Future, Sprng Energy and SRPC.

32.2.1 NEEPCO, NTPC, Adani Mundra, Sembcorp, Tata Power, WIPPA and APP have suggested that when LTA has been granted on existing margins and if delay in COD of generating station has not caused any extra burden on the existing users, no transmission charges may be charged during the period of delay of the generating station in such cases. The margin may be used by other DICs during the period of delay.

32.2.2 Renew Power has suggested that following proviso may be added after Regulation 11(5):

*"Provided further that, the above provisions are not applicable to the cases specified under Regulation 11(1) of these Regulations, where awarded through competitive bidding process in accordance with the guidelines issued by the Central Government."*

32.2.3 Sembcorp has suggested adding a proviso as under:

*"no charges shall be applicable, where MTOA to ISTS is granted to a generating station on existing margins and COD of the generating station or unit(s) thereof is delayed."*

32.2.4 TANGEDCO has suggested that 20% transmission charges may be levied in place of proposed 10%.

32.2.5 ATL, CII and L&T IDPL have suggested that if only 10% of transmission charges will be paid, then the transmission licensee would not be able to recover the full transmission charges. Therefore, 100% of transmission charges should be recovered in cases where LTA is granted and CoD of generating station is delayed.

32.2.6 BYPL has suggested that the amount of transmission charges should be 100% irrespective of whether it is given on existing margin or otherwise because the transmission charges of ISTS which is under-utilized due to wrong planning is borne mainly by DISCOMs.

32.2.7 GUVNL has suggested that 100% transmission charges should be payable by the generator instead of 10% as it will lead to declaration of advanced date of commissioning for availing LTA on existing margins whereas the project would come only at a later stage. This would also deprive genuine applicants from availing LTA on existing margin.

32.2.8 KPTCL has suggested that the rationale for charging generator to an extent of only 10% is not justified. It has suggested to have uniform charges for delay by generator or by transmission licensee.

32.2.9 Hero Future and Sprng Energy have suggested that if the project gets delayed for reasons not attributable to the generator, it is inappropriate to ask for submission of LC and payment of transmission charges.

32.2.10 SRPC has suggested that the words 'transmission charge for the State' may be replaced with the words 'transmission charge for the State per MW'.

32.3 Analysis and Decision

32.3.1 The following rationale for the draft Regulation was given in the Explanatory Memorandum to the Draft 2019 Sharing 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."*

32.3.2 Therefore, generators shall be levied transmission charges if they are delayed, even in cases where they have been granted LTA on existing system. Further, such charges shall also be applicable for the renewable projects covered under waiver of transmission charges.

32.3.3 Billing for the transmission system covered under Regulations 5 to 8 shall be included in the first bill. Billing for delay of generating station under this Clause i.e. 10% of transmission charges for the State, shall be over and above the charges covered under the first bill and hence the same shall be reimbursed to the DICs in proportion to the first bill. There is no under-recovery to the transmission licensees on this count.

32.3.4 The Regulations provide for payment of transmission charges for delay by all generating stations covered under the clause, irrespective of whether the same is due to uncontrollable reasons.

32.3.5 Levying 10% transmission charges for delay by a generating station is fair as no additional expenditure on transmission has been made for such a generator. The treatment of recovery made under this provision has been included in the Regulation 13(7) of the 2020 Sharing Regulations.

32.3.6 Applicability of per MW transmission charges of State has been incorporated in Regulation 13(7) of the 2020 Sharing Regulations as follows:

"*Where Long Term Access is granted to a generating station on existing margins and COD of the generating station or unit(s) thereof is delayed, the generating station shall, corresponding to the capacity that is delayed, pay transmission charges at the rate of 10% of transmission charge per MW for the State where such generating station is located:*

*Provided that the amount so received in a billing month, shall be reimbursed to the DICs in proportion to their share in the first bill in the following billing month."*

*Illustration*

Suppose that a generating station "G" located in a State 'C' had obtained Long term Access of 400 MW from 1.1.2020 and such Long term Access was granted by CTU on the existing margins in ISTS. Suppose that commercial operation of 'G' gets delayed and that it achieves COD only on 1.1.2021. Also suppose that transmission charges under "first bill" for 'C' is Rs. 200 crore for the billing period January 2020 (billed in the billing month of March 2020). If LTA+MTOA for 'C' is 3,000 MW for billing period of January 2020, transmission charge per MW for 'C' shall be Rs. 200/(3000) crore/MW = Rs. 6.67 lakh/MW. Hence, "G" shall be liable to pay transmission charges @10% of 6.67 Rs. lakh/MW for 400 MW i.e. Rs. 2.67 crore for the billing period of January 2020. Similarly, "G" shall be liable to pay transmission charges for each month till it achieves COD

## 33. Clause (6) of Draft Regulation 11

33.1 The draft Regulation provided as under:

*"(6) 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."*

33.2 Comments have been received from HPPTCL, MSEDCL, NTPC, NEEPCO, TANGEDCO and Sembcorp.

33.2.1 HPPTCL has commented that Regional Power Committee is not a body under the Act and entrusting it with certifying whether the transmission system will serve the purpose of system strengthening may not be appropriate. The work should be entrusted to CEA that may do so in consultation with STU.

33.2.2 MSEDCL has suggested that before certification by RPC regarding any transmission line being useful for improving the performance, safety and security of the grid, the system study report should be shared with all DICs in the region and RPC may issue certificate, if any, only after detailed discussion and comments from DICs.

33.2.3 NTPC has suggested that the words 'generating station' may be replaced with the words 'generating station including generating stations for which LTA Agreement has been entered by its long-term customers'.

33.2.4 NEEPCO has suggested that in case liability of payment of transmission charges lies on the beneficiaries, Regulation 11(6) may be modified to include Long Term Customers (who have signed the LTA Agreement) for operationalization of part LTA. Under such circumstances, CTU may operationalize the part LTA based on availability of transmission system on request made by CGS for scheduling of power. This will avoid bottling up power of CGS where beneficiaries are long term customers.

33.2.5 TANGEDCO has suggested that the proviso may be deleted that states that – *'as if an associated Transmission system is developed for power evacuation from a generating station and only when some of the elements of the ATS have achieved COD, the transmission charges are to borne by the Generator and not included in Regulations 5 to 8'*.

33.2.6 Sembcorp has suggested that following proviso may be added before proviso of 11(6):

> *'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 early operationalization of Long Term Access. However in case of delay in achieving such revised COD by the generating station, the generating station shall not be subject to payment of any transmission charges till the commissioning of balance transmission elements.'*

33.3 Analysis and Decision

33.3.1 The capital cost of transmission system is a small percentage of the capital cost of a generation project. Therefore, where transmission system is delayed, a transmission licensee cannot fully compensate for the generation loss of a generation project in terms of the revenue loss based on the tariff in the PPAs or IDC, IEDC of generating station or fixed charges.

33.3.2 Regional Power Committee (RPC) as provided under the Act comprises of distribution licensees apart from CEA, CTU, POSOCO, generating stations and STUs. Further, it is the function of RPC as per Grid Code to agree on matters concerning stability and smooth operation of the integrated grid. Therefore, RPC is the appropriate forum to certify as to whether the transmission line is being used for improving the performance, safety and security of the grid. In cases where LTA is applied by a generating station on behalf of beneficiaries and beneficiaries sign the LTA Agreement, part LTA operationalization may be sought by generating station in case generating unit(s) has been declared under commercial operation.

33.3.3 If a generating station seeks part operationalization of LTA, it shall be liable to pay transmission charges as per the Regulations including untied LTA, if any.

## 34. Clause (7) of Draft Regulation 11

34.1 The draft Regulation provided as under:

> *"(7) 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 ."*

34.2 Comments have been received from APP, Tata Power, WIPPA, Azure Power, Hero Future, FICCI, DANS Energy, NHPC, NTPC, NEEPCO, NLC, MSEDCL, NTPC, KSK Mahanadi, RUVNL, APP, ACME Solar, ATL and APP.

34.2.1 APP, Tata Power and WIPPA have suggested considering generation loss of developer due to unavailability of transmission system and that the concerned transmission licensee(s) should compensate revenue loss based on the tariff in the PPAs. Azure Power, Hero Future and FICCI have also suggested that the generator should be compensated for the generation losses due to non-commissioning of transmission elements.

34.2.2 DANS Energy has suggested that till alternate arrangement is made, transmission licensee should pay to the generating station, the loss of revenue and IDC & IEDC for the period of delay in providing transmission access.

34.2.3 NHPC has suggested that declaration of COD of generating stations and associated transmission system needs to be managed through appropriate implementation agreement. Due to remote location of hydro plant, alternate arrangement is generally not practically feasible. Further, hydro generating stations incur loss of AFC (capacity charges + energy charges) for the duration of delay in COD of transmission system and the same is not commensurate with the compensation in terms of transmission charges. Hence, generating company should also be able to recover its full AFC for the duration of this delay. NLC has suggested that generating companies should be compensated with AFC rather than the transmission charge in case of delay.

34.2.4 NTPC and NEEPCO have suggested that compensation may be fixed at certain percentage of fixed charges payable by the transmission licensee to the generator in case of delay in COD of transmission system and the same percentage of transmission charges payable by generator to the transmission licensee in case of delay in COD of generating station.

34.2.5 MSEDCL has suggested that if operationalization of any long term access is delayed due to COD of associated transmission lines, the fixed charge burden of generating unit/ station (if any claimed by generator under deemed availability) should be borne by concerned transmission licensee responsible for delay unless such delay is beyond control of the said owner. WBSEDCL has suggested that Central Transmission Utility ought to compensate the generating station for all the revenue losses, on account of, interest, RoE, depreciation etc. for delay in evacuation of power so that cost is not passed on to the beneficiaries/ DISCOMs.

34.2.6 NTPC has suggested that the words 'in case of scheduling of such power shall be on long term basis' may be inserted after Regulation 11(7) before proviso.

34.2.7 KSK Mahanadi has suggested that alternate arrangement is only for short notices and requires huge investment by the generating stations. Hence, capital expenditure of the alternate arrangement shall be at the cost of the transmission licensee.

34.2.8 RUVNL has suggested to define that any additional charges borne by the transmission licensee(s) on account of penalty due to delayed COD, should not be passed on to the Distribution Licensee. Further, if CTU makes alternate arrangement through STU network, then either CTU or the generating station should be required to pay transmission charges proportionate to the LTA.

34.2.9 APP and ACME Solar have suggested that additional clause may be added as under:

> *'in case of any delay in commissioning of evacuation system by CTU then generating stations shall be entitled to refund of Bank Guarantees submitted if any. Any such delay was not factored in by generator while quoting the tariff. BG comes with a cost and delay has added cost. Therefore, generator must be protected from this additional cost which is not due to its fault.'*

34.2.10 ATL and L&T IDPL have suggested that the responsibilities and liabilities of transmission licensees and the generating stations are defined in the TSA and PPA respectively and, therefore, in case of any delay, treatment should be as per the provisions of TSA/PPA. There should be no liability on transmission licensee or the generating station beyond what is specified and agreed in the TSA/PPA else liability would mount and it will become impossible to get these projects financed. Therefore, in case of delay in CoD of any of the assets, the tariff for other assets should be borne by the beneficiaries, through the pool account.

34.2.11 L&T IDPL has suggested that it is understood that the concerned transmission licensee should make alternate arrangement for dispatch of power in consultation with Central Transmission Utility at the cost of the transmission licensee. Practically, it would be very difficult for a transmission licensee to make alternate arrangements for dispatch of power as it may not own the other asset and it would be difficult to convince the CTU i.e. PGCIL that is the largest transmission licensee. It may even lead to conflict of interest.

34.2.12 APP, during the public hearing, has suggested that alternative arrangement may be made in consultation with gencos and should not be unilateral.

34.3 Analysis and Decision

34.3.1 Generally, the capital cost of the transmission system is a small percentage of the capital cost of a generation project. Therefore, where transmission system is delayed, a transmission licensee cannot fully compensate for the generation loss of a generation project in terms of the revenue loss based on the tariff in the PPAs or IDC, IEDC of generating station or fixed charges. This clause is in line with the provisions of Tariff Regulations 2019 notified on 7.3.2019.

34.3.2 Dealing with bank Guarantee is not the subject matter of this regulation.

34.3.3 In case of alternate arrangement, scheduling of power on long term basis would depend on whether LTA has been operationalized by CTU with such system. Moreover, dealing with issue of LTA is beyond the scope of these regulations.

34.3.4 Treatment of any charges paid by generating station for delay is beyond the scope of these regulations.

34.3.5 In case a transmission system is delayed and the other transmission system is ready but prevented from being put to use due to delayed transmission system, the transmission charges for such system which is ready, cannot be left without any compensation. Further, such compensation cannot be charged to other DICs, who are denied the benefit of using the transmission system for delay by another transmission licensee.

34.3.6 The Regulations provide that alternate arrangement shall be at the cost of transmission licensee. For making alternate arrangement for dispatch of power, the transmission licensee shall consult CTU. Needless to state, any alternate arrangement by the transmission licensee shall be allowed only with proper system studies, so that grid security is not compromised.

**35. Clause (8) of Draft Regulation 11**

35.1 The draft Regulation provided as under:

*"(8) Where construction of dedicated transmission line has been taken up by the Central Transmission Utility as part of coordinated transmission planning and is constructed by an inter-State transmission licensee, the Yearly Transmission Charges for such dedicated transmission line shall be payable by the generating station in proportion to the Connectivity granted and for which Long Term Access is not operational. Such transmission charges shall be payable to the inter-state transmission licensee who has constructed such dedicated line."*

35.2 Comments have been received from GETCL, ATL, L&T IDPL, BYPL, MSEDCL, KSEBL, KSK Mahanadi, NTPC and MBPMPL.

35.2.1 GETCL has suggested that the losses of such lines shall also be on account of the generators/ users who seek connectivity on dedicated lines. The losses should not be pooled to other ISTS users.

35.2.2 ATL and L&T IDPL have submitted that duties of a generating company to construct dedicated transmission lines as per Draft 2019 Sharing Regulations is in conflict with the duties spelt out under Section 10 of Electricity Act, 2003.

35.2.3 BYPL and MSEDCL have suggested that YTC of dedicated transmission line from generating station to pooling station of transmission licensee should be borne by the concerned generator only and the same should not be included in the POC pool since it is responsibility of generator to construct dedicated line as per Regulation 8(8) of the 2009 Connectivity Regulations.

35.2.4 KSEBL has suggested that since LTA is not operational for such portion, the transmission charges of such portion may not be loaded on the DICs. It has suggested that the following may also be added in the proposed Regulation:

> *'The transmission charges of these dedicated lines may not be included in the transmission charges under Regulation 5 to 9'.*

35.2.5 KSK Mahanadi has suggested that no change is required in this Regulation. However, it has suggested that one clause requires to be added as under:

> *'The transmission charges for the dedicated transmission line taken up by CTU as a part of coordinated transmission planning and is constructed by ISTS licensee shall be calculated separately and be borne either by the Generator (untied capacities) or by the Generator beneficiaries (with tied up capacities).'*

35.2.6 NTPC has commented that liability of payment of transmission charges for dedicated line by the generator should be restricted only up to the commercial operation of the generating unit as non-operationalization of long term access is beyond the control of generator.

35.2.7 MBPMPL has suggested that this Regulation should not be made applicable for the existing generating stations and should be only for those generating stations for which construction of dedicated transmission line is yet to be taken up by the ISTS licensee(s). If the Commission decides to impose such charges on the existing generating Stations, then the Regulation 11(8) should be made applicable for only those existing generating stations, where the operational quantum of LTA plus MTOA is less than 50% of the quantum of Connectivity. It has also suggested that if any MTOA is operational, the same should also be accounted for.

35.3 Analysis and Decision

35.3.1 Booking of losses for dedicated transmission lines depends on metering point which is beyond the scope of these Regulations. As per present provisions, losses get into the account of the generator as the metering and billing is done at the remote end of dedicated transmission line of the generator when it is constructed by generator.

35.3.2 The clause covers dedicated transmission lines already constructed or are being constructed by CTU. However, construction of any new dedicated transmission lines shall be dealt with provisions of the 2009 Connectivity Regulations which provides that generating station shall be responsible for construction of the dedicated transmission line.

35.3.3 In case of dedicated transmission lines, for the LTA quantum which is operational, charges shall be included under Regulation 5 to 8 of 2020 Sharing Regulations. However, for the quantum for which LTA is not operational, proportionate charges shall be billed to the generating station.

35.3.4 Regarding considering dedicated transmission lines under Regulations 5 to 8 of 2020 Sharing Regulations on commercial operation of generating station, the Commission observes that there may be cases where either generating station which has achieved COD, has not obtained any LTA or has relinquished LTA. The charges for dedicated transmission lines in such cases cannot be loaded on to other DICs. Further, in case LTA is not operationalized due to non-availability of transmission system of a transmission licensee and no alternate arrangement is made by such a licensee, such licensee is liable to pay charges as specified in the Regulations.

35.3.5 A generating station enters into a separate Agreement with CTU for construction and payment of charges for dedicated transmission line. It is the liability of generating station to pay such charges for the quantum for which LTA is not operationalized. Transmission charges of dedicated transmission line proportionate to the quantum of LTA not operational qua the quantum of Connectivity shall not be included under Regulations 5 to 8 of the 2020 Sharing Regulations.

*Illustration*

A generating station has sought Connectivity for 1,400 MW and CTU has constructed the dedicated transmission line accordingly. If the generator has LTA for 500 MW which is operational, the generator shall pay proportionate transmission charges for the dedicated transmission line corresponding to 900 MW.

## 36. Clause (9) of Draft Regulation 11

36.1 The draft Regulation provided as under:

*"(9) 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."*

36.2 Comments have been received from APP, Tata Power, Mytrah Energy, WIPPA, Azure Power, KSK Mahanadi, MSEDCL, NLC and SRPC.

36.2.1 APP, Tata Power, Mytrah Energy and WIPPA have suggested that transmission deviation charges for drawing start-up power should be exempted for wind and solar projects covered under the special cases under clause 11(1).

36.2.2 Azure Power has suggested that the concept of start-up power is for the thermal power generating stations and should not be used for solar power generating stations. The solar power generating stations use auxiliary power which should be netted out from power exported and not billed as import power.

36.2.3 KSK Mahanadi has submitted that this clause is not very clear. Quantum (generation station capacities, LTA grant or on start power quantum) on which

Yearly Transmission Charges is to be levied, may be specified clearly. Secondly, the time period from start-up power drawl to COD would be less than a year, but yearly transmission charges is equivalent to 12 months' time period. Thirdly, associated transmission system has many lines and substations and its capacity is more than drawl of start power capacity and, therefore, its YTC would be very high.

36.2.4 MSEDCL has suggested that the transmission charges recovered from such generator should be paid only to DICs in the State in which such generator is located instead of all DICs of country since only the DICs within the State are paying transmission charges for network developed.

36.2.5 NLC has submitted that the Regulation mentions only the drawal of start-up power and does not mention anything about transmission charges for infirm power injection. At present transmission deviation charges are levied for infirm power injection. It has requested that no transmission charges for infirm power injection may be levied on the generators.

36.2.6 SRPC has suggested that it should be clarified as to whether RE drawl (before/ after COD) is exempted from this transmission deviation charges or notand whether RE drawal/ injection before and after COD has to be shown in RTDA or not.

36.3 Analysis and Decision

36.3.1 The draft Regulation has been modified as Regulation 13(6) and Regulation 13(10) in the 2020 Sharing Regulations as follows:

*"(6) If any transmission element(s) of the Associated Transmission System is required by the generating station prior to COD of the Associated Transmission System, the Yearly Transmission Charges for such transmission element(s) shall be payable by the generating station from the COD of the said transmission element(s) of the Associated Transmission System till the generating station achieves COD.*

*…….*

*(10) Generating stations drawing start-up power from ISTS shall pay transmission charges at the rate of Transmission Deviation Rate for the State in which they are located:*

*Provided that the amount so received in a billing month, shall be reimbursed to the DICs in proportion to their share in the first bill in the following billing month."*

36.3.2 For drawl of start-up power, generator shall be liable to pay transmission deviation charges @TDR. Provisions of Regulations are clear regarding applicability of transmission deviation charges.

36.3.3 Waiver of transmission charges for use of transmission system is available for the eligible generation projects covered under Regulation 13(1), after such projects are declared under commercial operation. Any other use of transmission system, such as for drawl of start-up power shall be billed as per the general provisions for all the generators. Further, any transmission deviation beyond LTA+MTOA+STOA shall also be payable by such generating stations.

36.3.4 Transmission deviation charges recovered from generating stations for start-up power shall be reimbursed to the DICs in proportion to their share in the first bill. Such generating stations connected to the ISTS shall be utilising the entire ISTS network, and hence it may not be appropriate to reimburse to the State in which the generation station is located.

36.3.5 Yearly Transmission Charges is the tariff approved by the Commission in respect of the transmission system. In case such charges are to be levied for only part of a year, prorate charges are to be calculated accordingly.

**37. Clause (10) of Draft Regulation 11**

37.1 The draft Regulation provided as under:

*"(10) 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."*

37.2 Comments have been received from HPPTCL, RPG Trading, Torrent Power and JSW.

37.2.1 HPPTCL has suggested that applicability of inter-State or intra-State or both transmission charges and losses should be determined on the basis of actual flow of power and not as per the draft regulation as the same will result in loading of STU lines and loss accounting may get affected.

37.2.2 RPG trading has suggested that the clause needs further elaboration. In fact, the 2009 Connectivity Regulation must address this issue first. The proposed regulation should also bring in clarity for connectivity and applicability of transmission charges and losses (central and State level) of those generating stations which are presently connected to both ISTS and STU. Such clarity can bring in flexibility of selling untied capacity from these projects by getting themselves connected to ISTS and STU simultaneously (subject to technical constraints) so that untied capacity from one unit can be sold at minimum transmission charges through the State or Central transmission system based on nature of contract (inter-State/ intra-State). Thus, this provision can bring in benefits to these generating companies in terms of competitiveness for having connectivity to both central and State system.

37.2.3 Torrent power has suggested that Transmission Deviation Charges should be applicable only in case the total injection is higher than the scheduled injection. There should be no Transmission Deviation Charges for a generator connected to both ISTS and InSTS for injection of power within its LTA+MTOA since generator does not have any control over power flow through any network. In case of inadequate State network, power flow may take place through ISTS.

37.2.4 JSW has suggested to clarify that for cases where SLDC carries out scheduling, whether STU charges and losses shall be applicable to schedules on ISTS. Since CTU has information about installed capacity of the generating station and capacity (MW) for which connectivity is sought from ISTS, while granting connectivity, CTU should ensure that adequate State system is available or shall be made available. It has further sought clarification in case of a generating station that is connected to State through inadequate capacity, and the power envisaged to be flowing through the State network actually flows into ISTS. It has suggested that in such cases, LTA Customer should not be liable for ISTS transmission charges and losses.

37.3 Analysis and Decision

37.3.1 Detailed rationale has been provided for introduction of this Clause in the Explanatory Memorandum to the Draft 2019 Sharing Regulations under the section *"ISTS charges for generators connected to both ISTS and STU".* Before the liability towards ISTS charges and losses is determined, CTU shall ensure that adequate State system is available for drawl of power by the State.

37.3.2 The draft Regulation has been modified as Regulation 13(11) of 2020 Sharing Regulations as follows:

*"(11) Where a generating station is connected to both ISTS and intra-State transmission system, only ISTS charges and losses shall be applicable on the quantum of Long Term Access and Medium Term Open Access corresponding to capacity connected to ISTS."*

37.3.3 A generating station, if connected to STU and CTU system or both, shall be scheduled by either RLDC or SLDC. The actual injection for such generating station shall be the sum of injection at ISTS and intra-State points. However, transmission deviation charges shall be calculated on actual injection in CTU system in excess of LTA+MTOA+STOA on CTU system.

**38. Clause (11) of Draft Regulation 11**

38.1 The draft Regulation provided as under:

*"(11) 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."*

38.2 Comments have been received from GMR, APP, Mytrah Energy, Tata Power, WIPPA, KSEBL, L&T IDPL, NTPC, WBSEDCL, Sembcorp and Azure Power.

38.2.1 GMR has welcomed the proposition. GMR has suggested that as per the Explanatory Memorandum, 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. Such change in the regulations is appreciated as it will lead to cost reflective transmission tariff. However, the Commission may put across clear terms & conditions for commissioning of transmission lines and systems.

38.2.2 APP, Mytrah Energy, Tata Power and WIPPA have suggested that in line with MoP order regarding waiver of transmission charges and losses for wind and solar projects, there should not be any levy of transmission charges for delay in COD of wind and solar projects although 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 in terms of clause (2) of Regulation 5 of the Tariff Regulations, 2019 or proviso (ii) to clause (3) of Regulation 4 of the Tariff Regulations, 2014.

38.2.3 KSEBL has suggested that following may be added:

*'The transmission charges of such lines may not be included under the transmission charges under Regulations 5 to 9.'*

38.2.4 L&T IDPL has suggested that delay in commissioning of transmission project can also be on account of uncontrollable force majeure (FM) events. In case of delay due to FM, the other party needs to be paid its dues. Therefore, the proposed Regulation is not good in law and should be removed. In all such cases, the payment to party who has completed its obligations should be made from pool account.

38.2.5 Sterlite during the public hearing has suggested that tariff should be realized from common pool if transmission licensee has performed its obligation.

38.2.6 NTPC has suggested that liability of generator should be restricted corresponding to the generating units which have not been declared under commercial operation. Transmission charges for the capacity which has achieved commercial operation should be recovered through the sharing mechanism. Accordingly, it has suggested that following should be added after paragraph 1 of the Regulation:

*'Corresponding to capacity of generating station or unit(s) thereof which have not achieved COD'.*

38.2.7 WBSEDCL has suggested to clarify that costs for any delay pursuant to the said Regulation should not be passed on or borne by the beneficiaries or DISCOMs.

38.2.8 Sembcorp has suggested that in case part of the transmission system required for operationalization of LTA is not ready, then the generator should not be penalized.

38.2.9 Azure Power has suggested that following should be added after Regulation 11(11):

*'These charges should apply from the SCOD of generating station or COD of the transmission station, whichever is later. If the COD of the Transmission system is later than the COD of the generating plant, then the transmission licensee has to pay.'*

38.3 Analysis and Decision

38.3.1 The draft Regulation has been modified as Regulation 13(12) in the 2020 Sharing Regulations as follows:

*"In case of a transmission system where COD has been approved in terms of proviso (ii) of Clause (3) of Regulation 4 of the Tariff Regulations, 2014 or Clause (2) of Regulation 5 of the Tariff Regulations, 2019 or where deemed COD has been declared in terms of Transmission Service Agreement under Tariff based Competitive Bidding, the Yearly Transmission Charges for the transmission system shall be:*

*(a) paid by the inter-State transmission licensee whose transmission system is delayed till its transmission system achieves COD, or*

*(b) paid by the generating company whose generating station or unit(s) thereof is delayed, till the generating station or unit thereof, achieves COD, or*

*(c) shared in the manner as decided by the Commission on case to case basis, where more than one inter-State transmission licensee is involved or both transmission system and generating station are delayed."*

38.3.2 COD of transmission system shall be governed as per provisions of the Grid Code. The transmission charges of system covered under Regulation 13(12) shall not be included in computations under Regulations 5 to 8 i.e. will not be shared by all DICs.

38.3.3 All charges for the transmission system covered under Regulations 5 to 8 are being paid by drawee DICs or injecting DICs with untied LTA. In case a particular system is not put to use, it cannot be included under the pool of charges of Regulations 5 to 8 and the transmission licensee or generating company whose transmission system or generating station or unit thereof is delayed should pay the transmission charges of the transmission system till the generating station or unit thereof or the transmission system achieves COD. This shall encourage coordinated effort between the generating station, transmission licensee and owner of downstream system so that assets are utilised once commissioned.

38.3.4 Liability under this clause arises due to delay of upstream and downstream system thereby preventing use of assets. If generating station commissions the terminating bay at switchyard along with station transformer and draws power through such transmission system, it shall not be governed by this Clause and shall be governed in terms of other Clauses (3), (4), (5) or (6) of Regulation 13 of the 2020 Sharing Regulations.

38.3.5 RE projects which are covered under the provision of waiver of transmission charges and losses, cannot be excluded from liability of payment of YTC in case they are delayed, as the transmission system which have been planned for them, has achieved COD and needs to be serviced. .

38.3.6 Regarding linking payment of transmission charges to SCOD of generating station, the Commission observes that a generating station seeks Connectivity or LTA through inter-State transmission system from a particular date which may be the SCOD of the generating station or any other date prior to or after the said SCOD. In case COD of such a generating station gets delayed, this Clause provides that the liability for such transmission system shall be governed in terms of Connectivity or LTA sought by generator, as the case may be and not SCOD.

38.3.7 Tariff determination is not a subject matter of these Regulations.

**39. Clause (12) of Draft Regulation 11**

39.1 The draft Regulation provided as under:

*"(12) 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."*

39.2 Comments have been received from ATL, L&T IDPL, HPPTCL, SRPC, TANGEDCO, GUVNL and APPCC.

39.2.1 SRPC has suggested that a new proviso may be added as under:

'*Incentive for Intra-state lines will be considered by CTU based on the Availability certificate issued by respective SLDC within a month, else no incentive will be considered. RPCs to follow 50% criteria for certification of Intra-state lines as ISTS lines.*
*RPC shall certify the Non-ISTS lines with the above criteria for a year based on the base case furnished by NLDC for the peak ISTS drawal for the previous year*.'

39.2.2 SRPC has also suggested that certification of intra-State lines needs to be carried out by respective SLDCs. No post facto inclusion of intra-State lines should be allowed. If a region is following 50% criteria while other regions are following 10% criteria, more lines of 10% criteria would be included in AC-UBC and other regions would be burdened with additional usage component. Therefore, uniform criterion need to be specified by the Commission.

39.2.3 ATL and L&T IDPL have suggested that for any intra-State transmission system, tariff is being determined by the respective SERCs. Proposed regulation is published by the CERC while the powers are conferred with SERCs under the Act.

Some SERCs are not determining tariff transmission line-wise, e.g. Uttarakhand Electricity Regulatory Commission determined the tariff on overall basis and not at the transmission line level.

39.2.4 HPPTCL has strongly objected to the proposal to discontinue the certification of the inter-State lines as part of ISTS. HPPTCL is constructing a number of power plants whose power will go outside the State of HP and these projects have been designed considering them as part of inter-State transmission system. Hence, any proposal discounting certification by RPC will have negative impact on cash flow of hydro-rich States.

39.2.5 KPTCL has suggested that it is not clear whether intra-State lines will be considered as ISTS in the future. Hence, clarity is required as to whether the existing natural ISTS lines and non-ISTS lines of STU will be certified as ISTS as per the proposed Regulations for future period.

39.2.6 TANGEDCO has suggested that the proviso may be deleted. An intra-State transmission system already certified by the respective Regional Power Committees being used for inter-State transmission of electricity should continue to be covered under these Regulations, as the assets are to be continuously used for transmission of ISTS power. Removal of such intra-State lines (deemed ISTS) from AC-UBC of transmission charges will hamper the evacuation/ conveyance of ISTS connected RE power.

39.2.7 GUVNL has suggested that when the flow of inter-State power through intra-State network is more than 50% in spite of having adequate inter-State transmission capacity, it is reducing the utilisation of such intra-State lines for flow of intra-State power even after bearing the transmission charges for such asset by the State. Therefore, it is imperative that when the flow of inter-State power through intra-State network is more than 50% as certified by respective Regional Power Committee, the same needs to be included for the purpose of sharing of charges under the Regulation, else the State will end up paying the charge of such intra-State lines without adequate utilisation by the State.

39.2.8 APPCC has suggested that the tariff for deemed ISTS lines (intra-State lines carrying inter-State power as certified by the concerned RPC based on a criteria) is to be determined by the concerned SERC. The criterion for qualifying a particular InSTS line is to be specified by the CERC itself in the present

Regulation. At least 33.33% of inter-State power flow in transmission lines should be necessary for it to be considered as ISTS.

39.3 Analysis and Decision

39.3.1 The rationale for the proposed Clause was provided in the Explanatory Memorandum issued along with the Draft 2019 Sharing Regulations. Such intra-State systems that have already been certified by RPC as being used for inter-State use and for which tariff has already been approved by the Commission shall be covered under these Regulations.

39.3.2 Approval of tariff for intra-State system is done by SERCs. However, in circumstances where an intra-State system is used for inter-State flow of power, its tariff is required to be approved by CERC, if such system is to be considered for recovery of transmission charges under the 2020 Sharing Regulations.

**40. Clause (1) of Draft Regulation 12**

40.1 The draft Regulation provided as under:

*"(1) Implementing Agency shall notify total transmission charges payable by the DICs for the Billing month in terms of Rs. per MW for each State by dividing total transmission charges payable by the State by its quantum of Long Term Access and Medium Term Open Access."*

40.2 Comments have been received from JSW and MB Power.

40.2.1 JSW has suggested that the Regulation may be suitably modified so as to incorporate that the notification of total transmission charges payable by the DICs for billing month should be on website of the Implementing Agency for access in public domain.

40.2.2 MB Power has suggested that as per the 2010 Sharing Regulations, node-wise/ State-wise monthly transmission charges and losses were duly approved and notified by the Commission on quarterly basis, wherein the Commission undertakes a comprehensive prudence check in consultation with various agencies and stakeholders before approving and publishing such transmission rates and losses. As such, these bear a testimony of the Commission, hardly leaving any scope of litigations with respect to monthly transmission charges invoices raised by PGCIL. However, billing mechanism envisaged under the Draft 2019 Sharing Regulations would do away with the existing practice of approval of the Commission as regards transmission rates and losses. In absence of such prudence check and approval by the Commission, there may be an exponential increase in litigations. As such, it is imperative that a periodic regulatory prudence check and approval mechanism should continue in all the times to come.

40.3 Analysis and Decision

40.3.1 The draft Regulation has been modified as Regulation 14(1) as follows:

*"The Implementing Agency shall publish transmission charges payable by drawee DICs and injecting DICs with untied LTA for the billing month in Rupee terms."*

40.3.2 Regulation 25 of the 2020 Sharing Regulations provides for the Information to be published by Implementing Agency which includes transmission charges payable by each constituent for the billing month along with component-wise break-up as provided in sub-clause (i). The transmission charges under the 2010 Sharing Regulations were calculated based on projected data, whereas the same shall be calculated on the basis of actual data under the 2020 Sharing Regulations. Therefore, the need of any prudence check by the Commission is not envisaged. In case of any dispute, stakeholders can always approach the Commission.

**41. Clauses (2) and (3) of Draft Regulation 12**

41.1 The draft Regulation provided as under:

*"(2) Regional Transmission Accounts for the DICs shall be prepared by the respective Regional Power Committee Secretariat on the basis of:*

*(a) Transmission charges for Long Term Access or Medium Term Open Access to be received from the Implementing Agency;*

*(b) DIC-wise transmission charges for the Billing month, in Rs.per MW, to be received from Implementing Agency; and*

*(c) Meter reading to be received from RLDCs, from all Special Energy Meters for computation of deviations from the sum of the Long Term Access and Medium Term Open Access for every time block.*

*(3) Regional Power Committees Secretariat shall issue Regional Transmission Accounts and Regional Transmission Deviation Accounts for the Billing month within 3 days of communication of data by the Implementing Agency and receipt of meter reading data from RLDCs to all DICs, Central Transmission Utility and inter-State Transmission Licensees and also display the same on its web site."*

41.2 Comments have been received from SRPC.

SRPC has suggested to remove words "*Regional Transmission Deviation Accounts"* from draft Regulation 12(2)(c) stating that it may require around 15 days to prepare RTDA by RPCs as other weekly and energy accounts are also to be prepared.

41.3 Analysis and Decision**:**

41.3.1 The timeline of issuance of accounts by RPC shall be as per Regulation 14(5) of the 2020 Sharing Regulations. RTA and RTDA should be issued together for the stakeholders to have clarity on charges and adjustment of RTDA charges in subsequent month.

## 42. Clause (5) of Draft Regulation 12

42.1 The draft Regulation provided as under:

*"(5) Timelines for preparation of base case, notification of transmission charges, issue of Regional Transmission Accounts and raising bills shall be as under:*

a) *Base case for the Billing month shall be prepared by the Implementing Agency by 15th day of the month following the Billing month.*

b) *Payable transmission charges shall be notified by the Implementing Agency by 25th day of the month following the Billing month.*

c) *Based on the notified allocation of charges by the Implementing Agency, Regional Power Committee Secretariat shall issue Regional Transmission Accounts by the end of the month following the Billing month.*

d) *Central Transmission Utility shall raise bills on DICs based on Regional Transmission Accounts in first week of the second month following the Billing month."*

42.2 Comments have been received from APP, FICCI, Tata Power, Sembcorp, DNHPDCL, GRIDCO and MSEDCL.

42.2.1 APP, FICCI and Tata Power have suggested that as per current practice, the usual recovery cycle of the transmission licensee's monthly bills varies from 52 to 60 days as against receivables of 45 days in Interest on Working Capital for transmission projects built under section 62 of the Act as per Tariff Regulations issued by the Commission. However, as per the proposed cycle, the usual recovery cycle of the transmission licensee's monthly bills will increase to 75 - 80 days i.e. an increase of 15-20 days. In such case, the Tariff Regulations will require to be amended to provide additional Interest on Working Capital for such additional period. Also, for transmission projects built/ bid out under section 63 of the Act, they should be allowed benefits under change in law to compensate for such additional no of days.

42.2.2 Sembcorp, with regard to the short-term power procurement bids, suggested that the generators under the existing 2010 Sharing Regulations consider the applicable ISTS charges which are determined in advance for next quarter. Such charges to a large extent reflect the actual charges levied on the generator for using ISTS network for actual supply of power. However, in the Draft 2019 Sharing Regulations, the Commission will issue the ISTS charges only after the end of the month and the applicable charge would not be known to the generators even for the next month. Further, it is expected that because of charge determination being shifted to actual load flow study, the variation in charges will be high on the month to month basis. This would unnecessarily increase the risk for generators for participating in short-term bids. Hence, it has requested to make corresponding amendments in the Standard Bidding Documents to align such uncontrollable change in transmission charges as pass through to the procurer or beneficiaries as “change in transmission charge”.

42.2.3 DNHPDCL has suggested that since the transmission charges will be calculated post-facto, trading and open access would be adversely affected as unexpected increase in transmission charges can make some trades non-profitable and risky especially to traders and Discoms.

42.2.4 TPTCL has also requested that for STOA injection charges (In Rs/MWh) at generator node and drawl charges (In Rs/MWh) at buyer node should be published in advance preferably one quarter ahead.

42.2.5 CII and IEX have suggested that Open Access consumers buying through DAM (day ahead market), need to know charges payable ex-ante the bidding and NoC issued by SLDC may contain all information. This helps consumers bid on the DAM, keeping in view, all charges payable including ISTS charges.

42.2.6 DNHPDCL has suggested that for short term open access (STOA), injection POC charges and withdrawal POC charges have to be determined in paise/KWH and rate should be available at least 3 months in advance (STOA is up to three months, one month at a time). To support efficient financial base for STOA, the present method may be continued. Further, open access customers (STOA and MTOA) need not have to participate in socialising/ subsidising over-built capacities as usage of transmission is for limited period and there is no certainty to get the requisite quantum of corridors for their transactions and also low priority given to them especially regarding curtailment, renewal aspects.

42.2.7 GRIDCO has suggested that Base Case, payable transmission charges as indicated under Regulation 12(5)(a) & (b) should be uploaded on NLDC website. In case of bills on DICs based on Regional Transmission Accounts as indicated under Regulation 12(5)(d), Central Transmission Utility needs to update such bills in the BCD portal with intimation to DICs.

42.2.8 MSEDCL has suggested that after preparation of Base Case for the billing month, IA should inform all DICs for verification, for which two days should be given to DIC. The Base Case network should be made available on IA website, where all PoC calculation related data should be stored. After incorporating required correction informed by DICs (if any), IA should run load flow study.

42.3 Analysis and Decision**:**

42.3.1 Some stakeholders have submitted that the recovery cycle of the transmission charges under the 2020 Sharing Regulations is about 75-80 days which is more than the recovery cycle provided in the Tariff Regulations in case of projects covered under Section 62 of the Act or the recovery cycle provided in the Transmission Service Agreements in case of projects covered under Section 63 of the Act. These stakeholders have sought compensation for such additional period of billing cycle through additional interest on working capital by amending the Tariff Regulations for projects under Section 62 of the Act and considering them under Change in Law provision of TSA in case of projects under Section 63 of the Act. The Commission is of the view that the recovery cycle provided in the Tariff Regulations or TSAs are designed for billing and collection of transmission charges by the transmission licensees directly from the beneficiaries in terms of the order of the Commission (for projects under Section 62 of the Act) or the Transmission Service Agreements (for projects under Section 63 of the Act), as the case may be. The sharing of transmission charges and losses are being governed by the 2010 Sharing Regulations since 1.7.2011 and after the 2020 Sharing Regulations are notified, sharing shall be governed by provisions of the 2020 Sharing Regulations. Under the 2010 Sharing Regulations as well as the 2020 Sharing Regulations, the billing, collection and disbursement of transmission charges are being undertaken by CTU on behalf of the transmission licensees. In other words, the transmission licensees get disbursement of their transmission charges without having to put in efforts for billing and collection for the same since the process is facilitated through CTU on behalf of the transmission licensees. It is pertinent to mention that the process of centralised billing, collection and disbursement by CTU involves additional time over and above those specified in the Tariff Regulations or TSAs and accordingly, the timeline for processing of the bills for transmission charges has been fixed in clause (5) of Regulation 12 of the 2020 Sharing Regulations. The Commission is of the view that the additional recovery time under the 2020 Sharing Regulations is attributable to the various processes involved as specified in the 2020 Sharing Regulations and since the ultimate objective is to ensure timely payment of transmission charges to the transmission licensees, there is no rationale to compensate the transmission licensees for the additional recovery time under the 2020 Sharing Regulations over and above the time specified in the Tariff Regulations or Transmission Service Agreement.

42.3.2 As per Regulation 11(2) of the 2020 Sharing Regulations, transmission charges for Short Term Open Access (along with other applicable charges) shall be payable by generating stations and embedded entities located in the State, as per the last published Short Term Open Access Rate for the State.

42.3.3 Basic Network shall be based on data received from DICs. Further, the Regulation already provides for publishing such information as basic network, load generation data, load flow results on the website of Implementing Agency transparently.

**43. Sub- Clause (c) of Clause (2) of Draft Regulation 13 and Clause (3) of Draft Regulation 13**

43.1 The draft Regulation provided as under:

*"(c) The Third Bill shall be raised for each month as follows:*

*i. This shall comprise of bill for transmission deviation and shall be billed along with the First Bill by the Central Transmission Utility.*

*ii. In case aggregate metered ex-bus MW injection or the aggregate metered MW drawal of a DIC, in any time block exceeds the sum of Long Term Access and Medium Term Open Access, the concerned DIC shall be charged for such deviations @ Transmission Deviation Rate as determined below.*

*iii. Transmission Deviation Rate shall be calculated as follows:*

*a. Transmission Deviation Rate for a State shall be charged at 1.20 X (transmission charges of the State for the Billing month)/ (quantum of Long*

*Term Access plus Medium Term Open Access of the State for the Billing month)*

*b. Transmission Deviation Rate for generating stations and bulk consumers shall be charged @Transmission Deviation Rate for the State where the generating station or bulk consumer is located.*

*iv. For hydro-generating stations, the transmission deviation shall be calculated after considering overload capacity of 10% over quantum of Long Term Access and Medium Term Open Access.*

*v. Transmission deviation charges shall be borne by the concerned DIC only. ;*

*vi. The agency(ies) of the State responsible for intimating deviations under the Central Electricity Regulatory Commission (Deviation Settlement Mechanism and related matters) Regulations, 2014 as amended from time to time, shall also be the agency responsible for intimating transmission deviation to the respective Regional Power Committee Secretariat for preparation of Regional Transmission Deviation Account.*

*vii. The charges for transmission deviations shall be calculated for a State as a whole. The charges for transmission deviation for an embedded intra-State entity shall be as determined in accordance with the regulations or orders of the respective State Commission.*

*(3) No transmission Charges shall be levied for Inter-State transmission system in respect of Short Term Open Access transactions."*

43.2 Comments have been received from HPPTCL, IEX, CII, Adani Mundra, MSEDCL, KPTCL, Torrent Power, TANGEDCO, RUVNL, APPCC, APP, Sembcorp, KSEBL, NTPC, SRPC, MB Power, BYPL, BRPL, FICCI, HPPTCL, TPDDL, IEX, GRIDCO, TPTCL, APP, L&T IDPL, DNHPDCL, MSEDCL, Tata Power and CPPA

43.2.1 HPPTCL has suggested that levying transmission deviation charges on States for variation in actual drawal vis-a-vis sum of LTA plus MTOA despite paying for reliability charge corresponding to peak drawal, is not correct. No transmission deviation charges should be applicable to State as transmission assets pricing do include the reliability margin.

43.2.2 IEX and CII have suggested that Regulation 13(2)(c)(ii) and Regulation 13(2)(c)(vii) are contradictory as one provides for DIC-wise transmission deviation charges while other provides for State-wise transmission deviation charges.

43.2.3 Adani Mundra, Torrent Power, APPCC, APP and Sembcorp in reference to 13(2)(c)(ii) & (iii) have suggested that while determining the TDR, it is also necessary to consider the approved Short Term and Collective Transactions.

43.2.4 MSEDCL has suggested that the transmission deviation of State should be computed based on difference between metered drawal and sum of LTA, MTOA and STOA.

43.2.5 KSEBL has suggested that penalizing a scheduled open access transaction (STOA) is not legal, particularly when the transmission asset is only 35% utilized and short term transactions aid in utilizing the under-utilized transmission asset.

43.2.6 KPTCL, Torrent Power, TANGEDCO and RUVNL have requested to allow 20% margin beyond the sum of Long Term Access and Medium Term Open Access. KPTCL has suggested that transmission deviation beyond this margin should be considered for deviation charges to accommodate variation in RE generation.

43.2.7 APPCC, APP and Sembcorp have suggested that TDR applicable for STOA (over and above untied LTA capacity) are already proposed to be 20% more than LTA charges and further linking it with the charges applicable to the State in which it is located, may in many cases put additional burden on ISTS generator.

43.2.8 KSEBL has requested that transmission deviation rate may be made same as transmission charges instead of penalizing at 1.20 times.

43.2.9 APPCC has suggested specifying transmission deviation rate as 1.10 times the transmission charges of the State for the billing month.

43.2.10 NTPC has suggested that in case a generator is to provide primary frequency response/ RGMO/ FGMO, it has to ramp up its generation up to 5% of its current generation or up to 105% of normative capacity. So, in such cases, it should be exempted from any transmission deviation charge liability. Further, the generator should not be required to pay the transmission charges for drawing power when under reserve shut down (RSD) or due to scheduled maintenance as both are beyond the control of generator. The drawl of power under scheduled maintenance was exempted earlier also.

43.2.11 MSEDCL and SRPC have suggested to remove overload capacity of 10% allowed to hydro stations. It has stated that by making such provision, hydro generator is allowed to schedule power over and above its LTA and MTOA and is simply a case of over-injection into grid. This is violation of DSM Regulations.

43.2.12 MB Power has stated that it is unclear as to how the part capacity of a generator for which LTA has been availed by its buyer (State Discom) shall be treated with respect to computation and levy of transmission deviation charges i.e. whether this LTA capacity shall be treated as LTA capacity of generator or aggregate LTA capacity of the State (i.e. the host state of buyer Discom) for the purpose for computation and levy of transmission deviation charges.

43.2.13 MSEDCL has suggested that the transmission deviation charges of generators should be borne by generators only and should not be recovered from its contracted buyer.

43.2.14 APP has suggested that in Regulation 13(2)(c)(ii) provides for computation of transmission charges/ transmission deviation charges, on block-wise basis instead of monthly average schedule basis. Due to coal shortage, outage of generating plant or unviable short term market rates, generators may not be able to sell full target region LTA quantum under MTOA/ STOA/ Collective transaction, in each time block. Thus, they may incur additional cost for such shortage even after selling higher quantum in some time blocks under MTOA/ STOA/ Collective transaction as compared to LTA quantum for target region. Hence, it is requested to keep the same provision of monthly average supply calculation for target region customers instead of time block wise calculation.

43.2.15 BYPL, BRPL, FICCI, Adani Mundra. and CII have suggested that in Regulation 13(2)(c)(iii), the treatment of transmission deviation charges collected from DIC or generator is not explained.

43.2.16 KSEBL suggested that the transmission deviation charges collected by CTU may be reimbursed to DICs as in the 2010 Sharing Regulations.

43.2.17 BSPHCL, during public hearing, has suggested that money collected from TDR may be used to reduce the YTC.

43.2.18 CII and FICCI have suggested that the recovery of TDR will result in excess recovery above YTC and it cannot be used to reimburse to DICs or to reduce the transmission charges for the following month, since it would lose its penal nature and mean cross-subsidization amongst the DICs. There would be situations when the MTC/ YTC is not fully recovered, leading to a shortfall in the pool. In such scenarios, without extinguishing the liability on the defaulting DICs, the TDR charges should be added to the pool to ensure complete recovery of transmission charges. Any excess TDR remaining in the pool should be routed to the PSDF fund after the outstanding liability on the defaulting DIC is paid.

43.2.19 In reference to Regulation 13(2)(c)(vii), HPPTCL has suggested that the Commission may specify some mechanism which can be implemented to recover impact from the embedded consumers till the time State Regulations are in place as a stop gap arrangement. The charges should be such that the impact on the State is revenue neutral. It has further suggested that embedded consumers having no LTA or MTOA should necessarily pay TDR irrespective of whether State overdraws or not. The present provision is tantamount to free access to such IPPs and disincentivises signing of LTAs which is not desirable for proper grid management.

43.2.20 KSEBL has suggested that exempting transmission charges for short term open access transaction is not in accordance with the provisions of section 38(2)(d) of the Act. If transmission charges are not levied from short term open access consumers including embedded intra-State entities of the State, it will lead to increase in transmission charge of other DICs, and this increase is loaded on the ordinary consumers of the State. Accordingly, it has suggested that transmission deviation rate applicable for the State should be payable by intra-State embedded customers who avail inter-State STOA.

43.2.21 TPDDL has commented that it welcomes the proposal towards restricting the overall drawal of a DIC within the pre-specified LTOA+MTOA quantum availed by them and overall commercial discipline. However, administration of short term transactions by certain open access consumers/ deemed licensees would become difficult as they are without any LTOA and hence, they will not be billed any transmission charges as per new regime. Scheduling of power under short term by deemed licensees/ open access consumers would result into transmission deviation charges for the utilities in which they are embedded. This may lead to consequential penalty and transmission charges beyond the usage by utilities. To overcome these issues, it has requested to put in place an appropriate mechanism under which embedded consumers are liable to pay transmission charges corresponding to their ISTS usage and any transmission deviation charges being levied upon the concerned distribution licensees on account of fault of such embedded (temporary ISTS customers) may be addressed.

43.2.22 CII has suggested that the approach of ‘leaving the determination of charges for embedded entities open ended’ shall add to the uncertainties of the open access consumers who are embedded in the State network. This will further create difficulties for the embedded entities to avail open access which is already under a lot of strain. Unless specified in these Regulations, the SERCs may follow different approaches to determine the charges to be levied from respective embedded entities. The Commission may consider specifying the broad principles in these Regulations.

43.2.23 CII and IEX have suggested that inter-State transmission charges proposed to be borne by the DIC in terms of Rs/MW/Month should be proportionately recovered from the embedded open access consumers in Rs/MWh i.e. depending on the duration for which these consumers are going to avail the open access. Under no circumstances, these charges should be levied in terms of Rs/MW/Month as this will increase overall transmission charges payable for the embedded consumers and will make open access unviable. There should be a provision of returning (socializing) additional transmission charges collected by States to embedded consumers in case of over-recovery of charges from consumers through fixed demand charges and or additional surcharge.

43.2.24 IEX during the public hearing has suggested that the Draft 2019 Sharing Regulations has not specified the mechanism of allocation of ISTS charges incurred by the DICs to the intra-State embedded entities. This would bring additional challenges to the open access consumers particularly related to additional surcharge and cross subsidy surcharges. Besides that, the States may follow different approaches that may further fragment the market.

43.2.25 GUVNL has suggested that in the absence of a mechanism for recovery of transmission charges from embedded customer is tantamount to providing Short Term Open Access to the embedded customer at the cost and risk of the State DIC. Further, devising an appropriate mechanism by the State to recover the charges from embedded entities would also be difficult considering the computation of AC-UBC and transmission deviation account as per the proposed mechanism.

43.2.26 Torrent Power has suggested that in order to avoid cross-subsidization of charges payable by the entity responsible for deviation, the transmission deviation charges paid by the State may be divided amongst the embedded entities and State based on actual charges paid by the State. Therefore, there should not be any upfront recovery of these charges.

43.2.27 GRIDCO has suggested that when the State is well within its LTA limit, but the leftover cushion of transmission capacity is used by intra-State entities to avail their requirement through STOA, there is no transmission deviation by the State. However, under such circumstances, the State will pay the total bill to the billing agency, but the embedded entity/ entities get a free ride on the State's cushion.

43.2.28 RPG Trading has suggested that the Commission may clarify the scenario wherein a generator under-injects or a procurer under-draws from the schedule in a short term transaction which is in excess of LTA+MTOA to avoid paying transmission deviation rate. This seems likely since the TDR is applicable on actual generation/ drawl, but not on scheduled generation/ drawl and the entities may under-inject or under-draw deliberately by paying DSM charges. It has suggested that TDR should be made applicable on aggregate scheduled ex-bus MW injection or the aggregate scheduled MW drawl of DIC.

43.2.29 TPTCL has suggested that at present, the short-term open Access charges comprises of STU chares (of injecting State), injection POC charges, drawl POC charges, STU charges (of drawee State) and operating charges. As per the 2019 Draft Sharing Regulations, it seems that all the aforesaid charges shall not be applicable under STOA transaction. However, it requires clarity as whether only injection and drawl POC charges are not applicable or other charges like STU charges (if applicable) and operating charges continue to be part of STOA charges.

43.2.30 APP has suggested that there are certain short-term and medium-term PPAs where the obligation of securing such open access and payment of transmission charges thereof vests with the buyer. In such a scenario, despite the generator selling the untied LTA capacity under medium-term and/or short-term transactions, it will still be saddled with obligation of payment of transmission charges of such untied LTA capacity and the benefit of the same would accrue to buyer, who is otherwise obliged to pay for these transmission charges under such short-term and/or medium-term PPAs. It has requested that the existing off-setting mechanism whereby the MTOA and STOA charges are offset against target region LTA charges (for untied capacity) should be continued.

43.2.31 CII and L&T IDPL have suggested that the proposed regulation gives contradictory treatment to long term, medium term and short term open access transaction. Under such situation, DICs will be discouraged to take long term/

medium term access. Such regulation would create a lot of discrimination for usage of different types of open access transactions.

43.2.32 DNHPDCL has suggested that free transmission (no charges) to STOA is not desirable. The income that can be earned through STOA would progressively increase and pay for the margins and excess capacities built-in rather than seeking subsidies/ socialising among the long term access holders. In fact, STOA customers have to use the margins/ excess capacity only.

43.2.33 GETCL has suggested that waiver of STOA charges instigates private DISCOMs/ OA consumers to avail more STOA. They may not come up with LTA to meet their demand and would tend to depend more on STOA. It may increase burden on long-term customer of ISTS. Hence, the transmission charges for STOA customers should be equal to LTA.

43.2.34 GRIDCO has suggested that no charges for STOA will be an encouragement to use of STOA route as a free ride rather than paying for long term commitment in term of LTA/MTOA for power requirement and would in turn inhibit planned development of transmission capacity for future. More importantly, it will lead to huge transmission deviation by DICs/State because of intra-State embedded customers enhanced inclination to meet power requirement through STOA.

43.2.35 RUVNL has also suggested levying STOA charges.

43.2.36 WBSEDCL has suggested that the existing offsetting mechanism should be continued.

43.2.37 MSEDCL has suggested that ISTS user scheduling power under STOA (either bilateral/ collective) should be charged for both POC losses and PoC charges. The PoC charges for use of ISTS under STOA and collective transaction should be more than LTA as recommended by Task force on PoC. As proposed by the Commission in draft 5$^{th}$ amendment to the 2009 Connectivity Regulations, PoC charges for STOA should be 1.35 times that for LTA.

43.2.38 TANGEDCO has suggested that transmission charges should be levied in respect of STOA @ 1.40 X (transmission charges of the State for the Billing month).

43.2.39 Torrent Power has also suggested that STOA charges should be continued.

43.2.40 APPCC has suggested that non-levying of any kind of transmission charges for short-term open access transactions is incorrect and unreasonable.

43.2.41 SRPC has suggested that STOA charges could be specified. If they are not specified, the STOA/ collective products may have advantage over LTA/MTOA products and it may distort the power market.

43.2.42 IEX has suggested that this is a good initiative from the market perspective. It will give flexibility to the utilities for procuring power through different medium i.e. long medium or short term (within the limit of LTA and MTOA) without getting influenced by the associated transmission charges. The utilities will be able to optimize its power procurement cost by procuring power purely based on the cost of electricity rather than considering the impact of transmission charges. The planning for transmission system will also improve as going forward, the utilities will become more meticulous in utilizing their transmission infrastructure and seeking LTA. Proposed Regulation will simplify the accounting and settlement procedure and any uncertainties associated with offsetting of short term PoC charges in subsequent months. This is also expected to reduce the electricity prices for DISCOMs eventually benefiting the end consumers.

43.2.43 Tata Power has suggested that the existing mechanism used to help LTA beneficiaries to reduce their costs to certain extent. In the proposed mechanism, the LTOA beneficiaries would not have any option to realize that benefit. As STOA transaction becomes more economical, it would encourage DISCOMs to approach the short term market for sourcing power rather than securing long term and medium term contracts, which in turn is likely to cause a sudden increase in market prices.

43.2.44 CPPA has suggested that there is no provision which addresses a situation wherein an LTA customer, after the LTA is operationalized in a particular target region, is utilizing MTOA for the said region. Regulation 15B of the 2009 Connectivity Regulations completely obviated the need to schedule power under MTOA, when LTA for the same region is granted. It is, perhaps, for this reason that the Draft 2019 Sharing Regulations do not provide for setting/ netting off MTOA charges with LTA charges for the same target region. CPPA has further submitted that the omission of the provision for setting/ netting off MTOA charges with LTA charges in the same target region, gives an impression that such setting off is not a commercial principle anymore. It has requested to address the issue by providing a provision for setting off/ netting off MTOA charges with LTA in the same target region.

43.2.45 TPTCL during the public hearing has suggested that merchant generator has no LTA or has only part LTA. In such cases, transmission deviation rate should not be applicable. On month to month basis, e-bidding can be conducted for determination of short-term prices and, therefore, there is no need of levying 20% transmission charges for STOA. Further, in case of Collective Transactions, clarity is needed as regards price discovery i.e. on generator ex-bus integration with CTU or on buyer's State periphery (currently, it is on regional periphery). Clarity is also required as regards losses since earlier it was losses on regional basis whereas now there is proposal to have single ISTS drawl loss.

43.3 Analysis and Decision**:**

43.3.1 The proposed Clauses of Draft Regulation 13 has been modified as Regulations 11 and 12 of the 2020 Sharing Regulations as follows:

*"11. Transmission charges for Short Term Open Access*

*(1) Short Term Open Access Rate (in paise/kWh) shall be published for each billing month by the Implementing Agency which shall be calculated State-wise as under: Transmission charges of the State for the billing month (in rupees) / (7200 X the quantum, in MW, of Long Term Access plus Medium Term Open Access of the State for the corresponding billing period).*

*(2) Transmission charges for Short Term Open Access shall be payable by generating stations and embedded entities located in the State, as per the last published Short Term Open Access Rate for the State, along with other charges or fees as per Open Access Regulations, 2008 and the Transmission Deviation charges, if any, as per these regulations.*

*(3) Transmission charges for Short Term Open Access paid by an embedded intra-State entity during a month shall be reimbursed in the following billing month to the State in which such entity is located.*

*(4) Transmission charges for Short Term Open Access, paid by a DIC with untied LTA shall be offset against the transmission charges payable by the said DIC for untied LTA in the following billing month.*

*(5) No transmission charges for Short Term Open Access for inter-State transmission system, shall be payable by a distribution licensee which has Long Term Access or Medium Term Open Access or both, or by a trading licensee acting on behalf of such distribution licensee: Provided that other charges or fees as per Open Access Regulations, 2008 and the Transmission Deviation charges, if any, as per these regulations shall be payable.*

*(6) Transmission charges for Short Term Open Access collected in a billing month, after adjustment as per Clauses (3) and (4) of this Regulation, shall be reimbursed to the DICs in proportion to their share in the first bill in the following billing month.*

***12.Transmission Deviation***

*(1) Transmission Deviation, in MW, shall be computed as under:*

(a) *For a generating station, net metered ex-bus injection, in a time block in excess of the sum of Long Term Access, Medium Term Open Access and Short Term Open Access:*

*Provided that for a hydro-generating station, overload capacity of 10% during peak season shall be taken into account.*

(b) *For a State net metered ex-bus injection or net metered drawal, in a time block, in excess of the sum of Long Term Access and Medium Term Open Access.*

(c) *For any drawee DIC, which is a regional entity other than distribution licensees, net metered drawal in a time block in excess of the sum of Long Term Access, Medium Term Open Access and Short Term Open Access.*

*(2) Transmission Deviation Rate in Rs./MW, for a State or any other DIC located in the State, for a time block during a billing month shall be computed as under:*

*1.05 X (transmission charges of the State for the billing month in Rs.)/ (quantum in MW of Long Term Access plus Medium Term Open Access of the State for the corresponding billing period X 2880)*

*(3) The Transmission Deviation charges shall be recovered through the third bill and shall be reimbursed to the DICs in proportion to their share in the first bill in the following billing month."*

43.3.2 LTA is the basic input for planning the transmission system while MTOA is granted on margins. As such, drawl by a utility should correspond to LTA+MTOA. Accordingly, the transmission deviation rates are applicable for drawl of power beyond LTA+MTOA.

43.3.3 With regards to the suggestion that no deviation charges should be levied on State since States are paying for reliability charge corresponding to peak drawl, the Commission observes that only a portion of the transmission charges are paid for under the AC-UBC component, which corresponds to the peak block. Most of other components of transmission charges are based on LTA+MTOA. If transmission deviation charges are not levied, a DIC which has not sought LTA or MTOA corresponding to its drawl requirement, can draw power more than the open access taken and will be liable to pay charges only up to its LTA+MTOA. However, it will not be fair for States who have sought LTA+MTOA commensurate with their drawl requirements. Also, charges recovered under transmission deviation are being reimbursed to all DICs in proportion to their first bills.

43.3.4 For STOA sought by a distribution licensee, no transmission charges shall be collected towards such STOA as per Regulation 11(5) of the 2020 Sharing Regulations. However, in case the actual drawl or injection exceeds its LTA+MTOA, a State shall be liable for transmission deviation charges as per Regulation 12 of the 2020 Sharing Regulations.

43.3.5 Charges towards transmission deviation for generators shall be borne by generators only.

43.3.6 Transmission deviation rate has been fixed at 1.05 times the rate for LTA+MTOA, keeping in view the suggestions of the stakeholders. Transmission deviation rate in Rs./MW for a time block has been specified as *"1.05 X (transmission charges of the State for the billing month in Rs.)/ (quantum in MW of Long Term Access plus Medium Term Open Access of the State for the corresponding billing period X 2880)".*

43.3.7 An entity which has not obtained adequate LTA or MTOA and uses the system over and above its LTA or MTOA, does not pay for such system on a regular basis, while other DICs bear charges for such system. Hence, charges for utilising the system over and above LTA+MTOA has been kept marginally higher.

43.3.8 TDR is linked to transmission charges for the State to have a uniform criteria and rate for all entities located in a State.

43.3.9 Primary response (through RGMO or FGMO) provided by generators may be available only for a few seconds or minutes, while time block is of 15 minutes. Also, segregating deviation on account of providing primary response and otherwise may not always be possible.

43.3.10 Regarding hydro generating stations' overload capacity of 10%, the Regulation has been modified to include that such exemption/ consideration shall be applicable only during high inflow period.

43.3.11 The Grid Code provides that there shall be no restriction of schedule during high inflow period to avoid spillage and hence once scheduling is allowed for such capacity, the same shall not be considered under transmission deviation. However, any scheduling beyond 100% would be under some mode of open access which shall be governed as per provisions of the 2009 Connectivity Regulations and Open Access Regulations,2008.

43.3.12 For LTA and MTOA obtained with identified buyer and seller, such LTA and MTOA shall be considered for both buyer and seller while calculating their respective transmission deviations.

*Illustration*

If a State ’A’ has obtained LTA for procurement of power from a generating station “G1” for 500 MW. Suppose “G1” injects 550 MW in a particular block and ‘G1’ has not obtained any access for such additional injection beyond 500 MW, then transmission deviation for “G1” shall be 50 (= 550 minus 500) MW for that time block. However, as regards the State ’A’, its transmission deviation would be considered taking into account all LTA or MTOA with various generators. Suppose in above example, apart from LTA of 500 MW by State “A” for procurement of power from “G1”, another State ‘B’ has obtained STOA for procurement of power from “G1” for 40 MW. If “G1” injects 550 MW in a particular time block, then transmission deviation for “G1” for that time block shall now be 10 (= 550 minus 500 minus 40) MW.

43.3.13 Transmission deviation is calculated for each time block so that open access sought by entities are close to their injection/ drawl requirement for every time block. Considering monthly average of transmission deviation will mask the very purpose of levying the transmission deviation charges. DSM charges under CERC (Deviation Settlement Mechanism and related matters) Regulations, 2014 are also levied block-wise since it represents the true picture of deviations.

43.3.14 Transmission deviation charges shall not be used for compensating cases of under-recovery since charges should be recovered from entity to whom they are billed and not from any other entity.

43.3.15 Regulation 11(2) and 11(3) of the 2020 Sharing Regulations provide that embedded entities shall be liable to pay STOA charges. An embedded entity avails STOA on the transmission system being paid by the State under LTA+MTOA. Any deviation from LTA+MTOA due to drawl or injection by an embedded entity is also billed to the State. Hence, the Regulations provide for reimbursement of charges paid for availing STOA by embedded entities within State to the State.

43.3.16 Transmission deviation charges shall be levied on actual injection or drawl exceeding LTA+MTOA+STOA and has no bearing with respect to schedule, whereas DSM charges are energy charges which are levied for deviation beyond schedule.

43.3.17 Regulation 11(5) of the 2020 Sharing Regulations clearly provide that other charges such as STU charges, operating charges etc. shall be applicable as per CERC (Open Access in inter-State Transmission) Regulations, 2008.

43.3.18 The Regulations provide that offset against STOA charges for the untied LTA is available only if the generator applies for STOA and makes payment towards STOA. This is provided to ensure that generator does not pay twice for transmission for the same quantum of power. In case a buyer is making payment towards such STOA, generator is not entitled to receive offset for same. In case power under MTOA is tied up by such generator, for which buyer is making payment, such capacity shall be considered as tied while calculating the untied LTA capacity. Offset for STOA charges shall be as per Regulation 11 of the 2020 Sharing Regulations that provides as follows:

> *"Transmission charges for STOA, paid by a DIC with untied LTA shall be offset against the transmission charges payable by the said DIC for untied LTA in the following billing month."*

43.3.19 The rates under each type of open access is kept the same. However, for a distribution licensee which has LTA/MTOA, if it obtains STOA which is within its LTA+MTOA, it would not be levied charges for such STOA, but deviations from LTA+MTOA will be billed under transmission deviations. On the other hand, generating stations shall be liable to pay STOA charges as per the specified rates if they avail STOA and they shall be eligible for offset of such charges against untied LTA capacity.

43.3.20 STOA charges paid by embedded entities for availing STOA shall be given to the State in which such embedded entity is located.

43.3.21 A few illustrations are provided below for clarity:

*Illustration-I*

Suppose a State 'K' is raised first bill for Rs. 300 crores by CTU in a billing month, say March 2021. If it has LTA plus MTOA of 8,000 MW for the corresponding billing period i.e. January 2021 (billing month of March 2021 corresponds to billing period of January 2021), STOA rate for 'K' in March 2021 shall be calculated as $(300 \times 10^7)/(7200 \times 8000)$ paise/kWh= 52.1 paise/kWh

*Illustration-II*

(a) Suppose a distribution licensee in a State has LTA of 5,000 MW, and sum of schedules by the distribution licensee under LTA is 3,000 MW; sum of STOA availed by the distribution licensee is 1,000 MW; and schedule under collective transactions in power exchanges is 1,200 MW. As per Regulation 11(5) of the 2020 Sharing Regulations, the distribution licensee is not liable to pay any transmission charges for inter-state transmission system towards STOA while scheduling 1000 MW + 1200 MW under short term or collective transactions. However, the transmission deviation charges shall be payable as follows:

- If the inter-State drawl by the State is up to 5000 MW in a time block (i.e. within its LTA plus MTOA), it shall not be levied any transmission deviation charges. However, if the drawl is more than 5000 MW, say, 5100 MW in a time block, it shall pay transmission deviation charges for 100 (= 5100 minus 5000) MW @TDR.
- Though the schedule is for 5200 MW, the transmission deviation charges shall be calculated on actual drawl and not on schedule.

(b) Suppose the above distribution licensee with LTA of 5,000 MW sells power at the State boundary i.e. takes injection schedule under STOA or collective transactions in power exchange. It being a distribution licensee shall not be liable to pay any charges for inter-State transmission system towards STOA while availing such injection schedules as per Regulation 11(5) of the 2020 Sharing Regulations. If the actual inter-State drawl or injection by the State is up to 5,000 MW in a time block, it shall not be levied any transmission deviation charges. However, if it injects, say, 5100 MW in a time block, it shall pay transmission deviation charges for 100 MW @TDR. Thus, within LTA of 5,000 MW, the distribution licensee may sell or buy power under STOA including collective transactions in power exchange without any additional liability towards inter-State transmission charges up to the quantum of such LTA.

*Illustration-III*

(a) Suppose a generating station (located in State ‘C’) with installed capacity of 1,200 MW has LTA of 1,000 MW and long-term PPA for 500 MW. Thus, it has untied LTA of 500 (= 1000 minus 500) MW. The transmission charges corresponding to 500 MW of long-term PPA shall be determined at drawl end. If the generating station obtains 300 MW under STOA, it shall be liable to pay STOA charges @ STOA rate of ‘C’ that shall be calculated as specified in Regulation 11(1) and Regulation 11(2), which shall be offset against its untied LTA as per Regulation 11(4) of the 2020 Sharing Regulations.

(b) Suppose the above generating station obtains STOA from its injection point in the State ‘C’ to another State ‘D’ under short term bilateral transaction. In such case also, it shall be liable to pay STOA charges @ STOA rate of State ‘C’ (where the generating station is located) as calculated as per Regulation 11(1). STOA charges paid by the generating station shall be offset against its untied LTA as per Regulation 11(4) of the 2020 Sharing Regulations.

(c) If the above generating station sells power in power exchange, it shall still be liable to pay STOA charges @ STOA rate of State ‘C’ that shall be calculated as per Regulation 11(1). STOA charges paid by the generating station shall be offset against its untied LTA as per Regulation 11(4) of the 2020 Sharing Regulations.

(d) Suppose for the above generating station located in State ‘C’, a trader obtains STOA or trades under collective transactions in the power exchanges on behalf of generator. In such a case, the trader shall be liable to pay STOA charges @ STOA rate of ‘C’ as calculated as per Regulation 11(1) and as specified in Regulation 11(2) and STOA charges paid by it shall be offset against untied LTA of the generating station as provided in Regulation 11(4).

*Illustration-IV*

Suppose a generating station with installed capacity of 1000 MW has LTA of 500 MW, STOA of 200 MW and it injects 800 MW, it shall pay for transmission deviation @TDR for 100 (= 800 minus 500 minus 200) MW. Transmission deviation is payable on actual injection and not on schedule.

*Illustration-V*

(a) Suppose a generating station, located in a State ‘G’, with installed capacity of 1,000 MW has no LTA or MTOA. It applies and obtains STOA for sale of power to a distribution licensee in State ‘D’ for 500 MW, it shall pay transmission charges

@ STOA rate of ‘G’ for 500 MW as calculated as per Regulation 11(1). If it injects 600 MW, it shall, in addition, pay transmission deviation charges @TDR for 100 MW.

(b) Suppose generating station ‘G’ sells power to a distribution licensee in State ‘D’ under short term bilateral contract for 500 MW and such distribution licensee applies for STOA. Then the generating station shall not be liable to pay charges for such STOA. However, if the generating station injects 600 MW, it shall pay for transmission deviation @TDR for 100 (= 600 minus 500) MW since there is STOA for only 500 MW obtained by its buyer.

*Illustration-VI*

(a) A generating station, say ‘G’ located in the State ‘K’, has LTA of 2,000 MW and firm PPA with the beneficiaries of the State ‘K’ and another State ‘T’ for 1,000 MW each. Suppose ‘G’ has got day-ahead schedule for only 1,500 MW from its beneficiaries for a particular day and thus has an un-requisitioned surplus of 500 (= 2000 minus 1500) MW. If ’G’ sells 250 MW in the power exchange, it shall be liable to pay STOA charges @ STOA rate of the State ‘K’ (where it is located) that shall be calculated as per Regulation 11(1) and as specified in Regulation 11(2). The transmission charges collected under such STOA paid by ’G’ shall be reimbursed to the DICs in proportion to their share in the first bill in the following billing month.

*Illustration-VII*

(a) Suppose a generating station has a PPA with a distribution licensee in a State for 500 MW and the distribution licensee (buyer) obtains LTA for procurement of power from the generating station to buyer’s periphery. Suppose, on a given day, the buyer schedules only 300 MW from such generating station and at the same time, the generating station obtains STOA for 200 MW. If generating station injects 500 MW, no deviation charges shall be levied on such generating station.

*Illustration VIII - Embedded customers and embedded generating station*

(a) Suppose a State ‘K’ has embedded consumer (intra-State entity) which does not have any LTA or MTOA. If it schedules power under collective transactions over power exchanges, the charges towards ISTS for availing STOA shall be @ STOA rate of ‘K’ that shall be calculated as per Regulation 11(1) and as specified in Regulation 11(2). The charges paid by the embedded customer towards this STOA transaction shall be reimbursed in the form of adjustment to ‘K’ under first bill.

(b) Suppose in the above example, the State ‘K’ has embedded generating station (intra-State entity) instead of embedded consumer which does not have any LTA or MTOA. If it schedules power under collective transactions over power exchanges, the charges towards ISTS for availing STOA shall be @ STOA rate of ‘K’ that shall be calculated as per Regulation 11(1) and as specified in Regulation 11(2). The charges paid by the embedded generating station towards this STOA transaction shall be reimbursed in the form of adjustment to ‘K’ under first bill.

(c) Suppose an embedded generating station ‘G1’ in the State ‘K’ sells power to an embedded consumer ‘C’ in the State ‘U’ and ‘G1’ obtains STOA for scheduling of such sale. The charges towards ISTS for availing STOA by ‘G1’ shall be @ STOA rate of ‘K’ that shall be calculated as per Regulation 11(1) and as specified in Regulation 11(2). No transmission charges towards ISTS shall be payable by ‘C’ for such STOA transaction. The charges paid by ‘G1’ towards this STOA transaction shall be reimbursed in the form of adjustment to ‘K’ under first bill.

**44. Clause (3) of Draft Regulation 13**

44.1 The draft Regulation provided as under:

*“(3) No transmission Charges shall be levied for Inter-State transmission system in respect of Short Term Open Access transactions.”*

44.2 Comments have been received from TPTCL, APP, CII, L&T IDPL, DNHPDCL, MSEDCL, TANGEDCO, Torrent Power, SRPC, IEX, Tata Power, CPPA and TPTCL.

44.2.1 TPTCL has suggested that at present, the short-term open Access charges comprises of STU chares (of injecting State), injection POC charges, drawl POC charges, STU charges (of drawee State) and operating charges. As per the 2019 Draft Sharing Regulations, it seems that all the aforesaid charges shall not be applicable under STOA transaction. However, it requires clarity as whether only injection and drawl POC charges are not applicable or other charges like STU charges (if applicable) and operating charges continue to be part of STOA charges.

44.2.2 APP has suggested that there are certain short-term and medium-term PPAs where the obligation of securing such open access and payment of transmission charges thereof vests with the buyer. In such a scenario, despite the generator selling the untied LTA capacity under medium-term and/or short-term transactions, it will still be saddled with obligation of payment of transmission charges of such untied LTA capacity and the benefit of the same would accrue to buyer, who is otherwise obliged to pay for these transmission charges under such short-term and/or medium-term PPAs. It has requested that the existing off-setting mechanism whereby the MTOA and STOA charges are offset against target region LTA charges (for untied capacity) should be continued.

44.2.3 CII and L&T IDPL have suggested that the proposed regulation gives contradictory treatment to long term, medium term and short term open access transaction. Under such situation, DICs will be discouraged to take long term/ medium term access. Such regulation would create a lot of discrimination for usage of different types of open access transactions.

44.2.4 DNHPDCL has suggested that free transmission (no charges) to STOA is not desirable. The income that can be earned through STOA would progressively increase and pay for the margins and excess capacities built-in rather than seeking subsidies/ socialising among the long term access holders. In fact, STOA customers have to use the margins/ excess capacity only.

44.2.5 GETCL has suggested that waiver of STOA charges instigates private DISCOMs/ OA consumers to avail more STOA. They may not come up with LTA to meet their demand and would tend to depend more on STOA. It may increase burden on long-term customer of ISTS. Hence, the transmission charges for STOA customers should be equal to LTA.

44.2.6 GRIDCO has suggested that no charges for STOA will be an encouragement to use of STOA route as a free ride rather than paying for long term commitment in term of LTA/MTOA for power requirement and would in turn inhibit planned development of transmission capacity for future. More importantly, it will lead to huge transmission deviation by DICs/State because of enhanced inclination of intra-State embedded customers to meet power requirement through STOA.

44.2.7 RUVNL has also suggested levying STOA charges.

44.2.8 WBSEDCL has suggested that the existing offsetting mechanism should be continued.

44.2.9 MSEDCL has suggested that ISTS user scheduling power under STOA (either bilateral/ collective) should be charged for both POC losses and PoC charges. The PoC charges for use of ISTS under STOA and collective transaction should be more than LTA as recommended by Task force on PoC. As proposed by the Commission in draft 5$^{th}$ amendment to the 2009 Connectivity Regulations, PoC charges for STOA should be 1.35 times that for LTA.

44.2.10 TANGEDCO has suggested that transmission charges should be levied in respect of STOA @ 1.40 X (transmission charges of the State for the Billing month).

44.2.11 Torrent Power has also suggested that STOA charges should be continued.

44.2.12 APPCC has suggested that non-levying of any kind of transmission charges for short-term open access transactions is incorrect and unreasonable.

44.2.13 SRPC has suggested that STOA charges could be specified. If they are not specified, the STOA/ collective products may have advantage over LTA/MTOA products and it may distort the power market.

44.2.14 IEX has suggested that this is a good initiative from the market perspective. It will give flexibility to the utilities for procuring power through different medium i.e. long, medium or short term (within the limit of LTA and MTOA) without getting influenced by the associated transmission charges. The utilities will be able to optimize its power procurement cost by procuring power purely based on the cost of electricity rather than considering the impact of transmission charges. The planning for transmission system will also improve as going forward, the utilities will become more meticulous in utilizing their transmission infrastructure and seeking LTA. Proposed Regulation will simplify the accounting and settlement procedure and any uncertainties associated with offsetting of short term PoC charges in subsequent months. This is also expected to reduce the electricity prices for DISCOMs eventually benefiting the end consumers.

44.2.15 Tata Power has suggested that the existing mechanism used to help LTA beneficiaries to reduce their costs to certain extent. In the proposed mechanism, the LTOA beneficiaries would not have any option to realize that benefit. As STOA transaction becomes more economical, it would encourage DISCOMs to approach the short term market for sourcing power rather than securing long term and medium term contracts, which in turn is likely to cause a sudden increase in market prices.

44.2.16 CPPA has suggested that there is no provision which addresses a situation wherein an LTA customer, after the LTA is operationalized in a particular target region, is utilizing MTOA for the said region. Regulation 15B of the 2009 Connectivity Regulations completely obviated the need to schedule power under MTOA, when LTA for the same region is granted. It is, perhaps, for this reason that the Draft 2019 Sharing Regulations do not provide for setting/ netting off MTOA charges with LTA charges for the same target region. CPPA has further submitted that the omission of the provision for setting/ netting off MTOA charges with LTA charges in the same target region, gives an impression that such setting off is not a commercial principle anymore. It has requested to address the issue by providing a provision for setting off/ netting off MTOA charges with LTA in the same target region.

44.2.17 TPTCL during the public hearing has suggested that merchant generator has no LTA or has only part LTA. In such cases, transmission deviation rate should not be applicable. On month to month basis, e-bidding can be conducted for determination of short-term prices and, therefore, there is no need of levying 20% transmission charges for STOA. Further, in case of Collective Transactions, clarity is needed as regards price discovery i.e. on generator ex-bus integrated with CTU or on buyer's State periphery (currently, it is on regional periphery). TPCTL has sought clarity as regards losses since earlier it was losses on regional basis whereas now there is proposal to have single ISTS drawl loss.

## 44.3 Analysis and Decision

44.3.1 The draft Regulation has been modified as Clauses (5) and (6) of Regulation 11 of the 2020 Sharing Regulations as follows:

"*(5) No transmission charges for Short Term Open Access for inter-State transmission system, shall be payable by a distribution licensee which has Long Term Access or Medium Term Open Access or both, or by a trading licensee acting on behalf of such distribution licensee:*

*Provided that other charges or fees as per Open Access Regulations, 2008 and the Transmission Deviation charges, if any, as per these regulations shall be payable.*

*(6)Transmission charges for Short Term Open Access collected in a billing month, after adjustment as per Clauses (3) and (4) of this Regulation, shall be reimbursed to the DICs in proportion to their share in the first bill in the following billing month.”*

44.3.2 The proposed clause refers only to ISTS charges payable for STOA and other charges such as STU charges, operating charges etc. shall be applicable as per CERC (Open Access in inter-State Transmission) Regulations, 2008. To bring clarity, the same has been included under Regulation 11(5) of the 2020 Sharing Regulations.

44.3.3 Where STOA and MTOA is applied for and paid by a buyer, the generator would not get any offset of transmission charges against its untied LTA capacity. Offset against STOA charges for the untied LTA will be available only if the generator applies for STOA and makes payment towards STOA. This is provided to ensure that generator does not pay twice for transmission for the same quantum of power. In case a buyer is making payment towards such STOA, generator is not entitled to receive offset for same. In case power under MTOA is tied up by such generator, for which buyer is making payment, such capacity shall be considered as tied while calculating the untied LTA capacity. Offset for STOA charges shall be as per Regulation 11 of the 2020 Sharing Regulations that provides as follows:

*“Transmission charges for STOA, paid by a DIC with untied LTA shall be offset against the transmission charges payable by the said DIC for untied LTA in the following billing month.”*

44.3.4 The rates under each type of open access is kept the same. However, for a distribution licensee which has LTA/MTOA, if it obtains STOA which is within its LTA+MTOA, it would not be levied charges for such STOA, but any deviations from LTA+MTOA will be billed under transmission deviations. On the other hand, generating stations shall be liable to pay STOA charges as per the specified rates if they avail STOA and they shall be eligible for offset of such charges against untied LTA capacity.

44.3.5 STOA charges paid by embedded entities for availing STOA, shall be given to the State in which such embedded entity is located.

44.3.6 STOA rate has been kept the same as that for LTA.

## 45. Clause (4) of Draft Regulation 13

45.1 The draft Regulation provided as under:

*“(4) Central Transmission Utility shall be responsible for raising the bilateral bills for transmission systems covered under Regulation 11of these regulations.”*

45.2 Comments have been received from CII, FICCI, SRPC, BRPL, BYPL and Sterlite.

45.2.1 CII and FICCI have suggested that recovery of these bilateral bills too should be routed through CTU. In case the generator fails to pay the bilateral bills or becomes insolvent, since the project has been commissioned as per the TSA, the LTTCs should pay the transmission charges due in line with clause 6.2.2 of the TSA.

45.2.2 SRPC has suggested to add following before Regulation 13(4):

> *'Details of bilateral billing will be furnished by CTU through implementing agency to RPCs for it to be included in RTA'.*

45.2.3 BRPL and BYPL have stated that the word 'Bilateral Bills' has not been defined.

45.2.4 Sterlite, during the public hearing, has suggested that some clarity is required as regards raising of bills by CTU, modality of collection against the bills and treatment in case bills are not paid. It has suggested that CTU should initiate legal proceeding for bills remaining unpaid and that the transmission licensee should be paid from PoC pool.

45.3 Analysis and Decision

45.3.1 Regarding recovery of bills through CTU, Regulation 20(2) of the 2020 Sharing Regulations provides as follows:

> *"Transmission charges collected by the Central Transmission Utility for transmission systems covered under Clauses (3), (6), (8), (9) and (12) of Regulation 13 and not covered under Regulations 5 to 8 of these regulations shall be disbursed directly to the concerned inter-State transmission licensee or the generating company, as the case may be."*

45.3.2 Details of billing under Regulation 20(2) shall be covered under Regional Transmission Accounts issued by RPC.

45.3.3 In the 2020 Sharing Regulations, the word "Bilateral Billing" has been removed.

45.3.4 If bills raised by CTU remain unpaid by an entity, the same cannot be paid from the pool since amount of bill not paid by an entity cannot be levied on other entities. Situation of non-payment of bills is covered under Regulation 21 of the 2020 Sharing Regulations under "Consequences of non-payment of dues by a DIC".

**46. Draft Regulations 14 and 15**

46.1 The draft Regulations provided as under:

***"14. Due date***

*Due date in relation to any Bill shall mean the forty fifth (45th) day from the date on which such Bill is raised by the Central Transmission Utility.*

***15. Rebate and Late Payment Surcharge***

*The rebate and late payment surcharge shall be governed in accordance with the Tariff Regulations, 2019 or the Tariff Regulations for subsequent period to be notified by the Commission, as the case may be."*

46.2 Comments have been received from CII, ICCI, ATL and L&T IDPL.

46.2.1 CII and FICCI have suggested that as per prevailing Billing, Collection and Disbursement Procedure under the 2010 Sharing Regulations, Due date in relation to any bill is the thirtieth (30th) day from the date of raising the bills. Further, as per the TSA, the due date is defined as 30th day after the date on which any invoice is received. Hence, to maintain consistency, the due date should be considered as 30th day from the date on which bill is raised.

46.2.2 CII, ATL and L&T IDPL have suggested that in order to bring discipline in the payment by the DISCOMs, LPS rate of 1.5% per month may be retained. Further, Tariff Regulations do not specify the priority of apportionment of payment as regards late payment surcharge (LPS), past dues, current dues etc. This encourages DISCOMs to delay the payments as the LPS remains static. Consequently, transmission licensee has to incur higher working capital. CII has suggested that interest should also be charged on LPS as DISCOMs typically delay payment.

46.3 Analysis and Decision

46.3.1 The Commission observes that due date for billing of transmission assets under Tariff Regulations, 2019 is 45 days whereas that for assets covered under tariff based competitive bidding is 30 days. Similarly, late payment surcharge under the Tariff Regulations, 2019 is 1.5% beyond 45 days whereas the same is 1.25% beyond 30 days. Further, recovery of charges under TSA consequent upon tariff based competitive bidding is directly from LTTCs. However, the recovery of ISTS transmission charges is currently being done under the 2010 Sharing Regulations for the transmission assets covered under the Tariff Regulations, 2019 as well as transmission assets that have entered into TSA. As billing and recovery is being done through a common mechanism by a common agency, namely the CTU, the Commission is of the view that uniformity is needed in terms and conditions of recovery of transmission charges including due date, rebate and late payment surcharge. The 2020 Sharing Regulations provides as follows:

*"16. Due Date*
*Notwithstanding any provision to the contrary in the applicable Tariff Regulations or Transmission Service Agreement under tariff based competitive bidding, due date in relation to any bill raised by the Central Transmission Utility under these regulations shall mean the forty fifth (45th) day from the date of presentation of such bill.*

*17. Rebate*
*Notwithstanding any provision to the contrary in the applicable Tariff Regulations or Transmission Service Agreement under tariff based competitive bidding, rebate on payment of bills shall be governed as under:*

*(a) A rebate of 1.50% shall be allowed for payment of bills within a period of 5 days of presentation of bills. Explanation: In case of computation of '5 days', the number of days shall be counted consecutively without considering any holiday. However, in case the last day or 5$^{th}$ day is an official holiday, the 5$^{th}$ day for the purpose of rebate shall be construed as the immediate succeeding working day.*

*(b) A rebate of 1% shall be allowed where payments are made on any day after 5 days and within a period of 30 days of presentation of bills.*

*18. Late Payment Surcharge*
*Notwithstanding any provision to the contrary in the applicable Tariff Regulations or Transmission Service Agreement under tariff based competitive bidding, in case the payment of any bill for charges payable under these regulations is delayed by a DIC, beyond the due date, a late payment surcharge at the rate of 1.50% per month shall be payable by the concerned DIC."*

46.3.2 Based on the suggestions of stakeholders to provide priority of apportionment of payment among LPS, past dues, current dues, the same has been included as Regulation 20(6) in 2020 Sharing Regulations:

*"The charges collected shall be first adjusted towards late payment surcharge on the outstanding transmission charges and thereafter towards outstanding transmission charges, starting from the longest overdue bill."*

## 47. Clause (1) of Draft Regulation 16

47.1 The draft Regulation provided as under:

*"(1) Not later than 1 (one) month prior to the date of operationalization of Long Term Access or Medium Term Open Access, as the case may be, each DIC shall, through a scheduled bank, open an irrevocable, unconditional and revolving Letter of Credit or any other acceptable payment security mechanism in favour of the Central Transmission Utility, to be made operative from a date prior to the Due Date of its First Bill and shall be renewed annually."*

47.2 Comments have been received from ACME Solar, Mytrah Energy, APP, WIPPA, FICCI, Tata Power, Hero Future and Renew Power.

47.2.1 ACME Solar, Renew Power, Mytrah Energy, APP, WIPPA, Hero Future, FICCI and Tata Power have submitted that wind/ solar project under waiver scheme should be exempted from LC and suggested to add a suitable provision regarding waiver of LC for such RE projects.

47.2.2 Hero Future and FICCI have suggested that the LC condition should not be made applicable for the period from LTA operationalization to actual SCOD of wind/ solar projects if the delay is due to any reasons not attributable to wind and solar generators.

47.3 Analysis and Decision

Amount for which LC is to be provided depends on the average amount of the first bill for a year, as per Regulation 19 of the 2020 Sharing Regulations. Projects covered under Regulation 13(1) of the 2020 Sharing Regulations are not liable to open LC for the capacity for which transmission charges and losses are waived off. However, such dispensation would be available only after such waiver becomes effective i.e. after COD of the project.

**48. Clause (2) of Draft Regulation 16**

48.1 The draft Regulation provided as under:

*"(2) The Letter of Credit shall have a term of 12 (twelve) months and shall be for an amount equal to 1.05 (one point zero five) times the average amount of the First Bill for a year, where tripartite agreement for securitization on account of arrears against the transmission charges with the Government of India exist.*
*Provided that where such tripartite agreement does not exist, the DIC shall open the Letter of Credit for an amount equal to 2.10 (two point one times) the average amount of First Bill for a year."*

48.2 Comments have been received from MBPMPL, ATL, L&T IDPL, BRPL, BYPL, HPPTCL, MSEDCL, HVPN, Torrent Power and CII.

48.2.1 MBPMPL has suggested that Regulation 16(2) may be modified in line with Regulation 11(3) to state that within 30 days of finalisation of the Regulations, PGCIL shall return the already opened Letter of Credit to respective generators/ sellers and seek new Letter of Credit from the buyers/ beneficiaries for such LTA and/or MTOA granted to generators/ sellers and tied to PPAs for supply of power to their buyers/ beneficiaries.

48.2.2 ATL, L&T IDPL and CII have suggested that ideally the Letter of Credit is to be produced before initiation of billing cycle. Hence, there is no point in linking Letter of Credit to first bill. Therefore, they have requested to calculate the Letter of credit on the basis of approved Yearly Transmission Charges and have suggested the following amendment:

> *'The Letter of Credit shall have a term of 12 (twelve) months and shall be for an amount equal to 1.05 (one point zero five) times the amount of 1/12th of the Approved Yearly Transmission Charges, where tripartite agreement for securitization on account of arrears against the transmission charges with the Government of India exist.'*

48.2.3 BRPL and BYPL have suggested that the commercial terms such as Letters of Credit is typically a negotiated document between parties. It is, therefore, not necessary for binding the parties to commercial terms by way of Regulations. Further Letter of Credit for an amount of 2.10 (two point one) times the average amount of first bill for a year, is excessive and usurious. LC may be 1.05 times the average annual first bill for both types of DICs i.e. those who have tripartite agreement with GoI for securitization on account of arrears against transmission charges and for those who do not.

48.2.4 HPPTCL has suggested that there is no rationale of having 2.10 times the average bill in case of absence of any agreement and, therefore, the proviso should be deleted as 1.05 times LC is more than sufficient to provide revenue security.

48.2.5 MSEDCL has suggested that the amount of LC for State-owned DISCOMs should also be equal to 1.05 times average amount of the first bill for a year.

48.2.6 HVPN has suggested that the LC for State-owned DISCOMs shall not be levied.

48.2.7 Torrent Power has suggested that LC should be equal for all DISCOMs. The amount of LC should be equal to 1.05 times average amount of the first bill for a year for all the DISCOMs irrespective of any tripartite agreement.

48.3 Analysis and Decision

48.3.1 Regarding LC already furnished by the generators who are granted LTA and have entered into PPA, CTU shall take appropriate action in accordance with provisions of the 2020 Sharing Regulations.

48.3.2 The amount of LC will vary for each DIC on the basis of its billing and cannot be uniform for all the DICs.

48.3.3 Provisions of BCD Procedure under the 2010 Sharing Regulations provides that the amount of LC shall be 1.05 times or 2.10 times of first bill depending on availability of Tripartite Agreement. This provision has been retained in the 2020 Sharing Regulations to ensure appropriate payment security mechanism.

## 49. Clause (7) of Draft Regulation 16

49.1 The draft Regulation provided as under:

*"(7) If a DIC fails to pay any bill or part thereof on or before the Due Date, the Central Transmission Utility may encash the Letter of Credit, and, for amount of the bill or part thereof that is overdue plus Late Payment Surcharge, if applicable, by presenting to the scheduled bank issuing the Letter of Credit, the following documents:*

*(a) a copy of the Bill, which has remained unpaid or partially paid by such DIC; and*

*(b) a certificate from the Central Transmission Utility to the effect that the Bill at item (a) above, or specified part thereof, is in accordance with these Regulations and that it has remained unpaid or partially paid beyond the Due Date; and*

*(c) Calculations of applicable Late Payment Surcharge, if any.*

*Provided that the failure on the part of the Central Transmission Utility to present the documents for encashment of the Letter of Credit shall not attract any Late Payment Surcharge, for the duration of such failure on part of the Central Transmission Utility, on the DIC."*

49.2 Comments have been received from ATL, BYPL, BRPL, CII, L&T IDPL, FICCI and Torrent Power.

49.2.1 ATL, L&T IDPL, FICCI and CII have suggested that proviso to the proposed regulations emphasizes that any failure or delay in presenting the document to Banker for encashment of LC shall not attract any LPS on DIC. They have submitted that since transmission licensee would suffer delays in realization from encashment of LCs, any delay due to presentation of documents to bank should be to the account of DICs or CTU and that transmission licensee should be eligible for LPS on such delays.

49.2.2 BYPL and BRPL have suggested that a proviso may be added that the existing agreements or arrangements or PPAs shall continue to hold good and accordingly all terms and conditions of payment security mechanism as had been agreed to by the parties, inter se, in the said agreement or otherwise would be saved and not disturbed.

49.2.3 Torrent Power has suggested that Late Payment Surcharge starts from due date. If LC is to be encashed compulsorily on due date, then there is no question of LPS. Therefore, proposed provision may be reviewed.

49.3 Analysis and Decision

49.3.1 Proviso to the draft Regulation has been deleted.

49.3.2 Inter-State transmission charges shall be governed as per provisions of the 2020 Sharing Regulations notwithstanding anything to the contrary provided in Agreements.

49.3.3 In case CTU decides to encash the LC to recover the amount due and the outstanding is cleared, there shall be no LPS. However, in case CTU does not encash the LC, LPS shall be applicable beyond due date.

**50. Clause (3) of Draft Regulation 17**

50.1 The draft Regulation provided as under:

*"(3) The Central Transmission Utility shall collect transmission charges on account of the Third Bill raised in accordance with sub-clause (c) of clause (2) of Regulation 13 of these regulations and the transmission charges collected shall be reimbursed to the DICs, in the following month, in proportion to the First Bill of the respective month."*

50.2 Comments have been received from MSEDCL and CII.

50.2.1 MSEDCL has suggested that the transmission deviation charges should not be reimbursed to generator from whom transmission charges have been collected for usage of network for drawal of start-up power or injection before COD.

50.2.2 CII has suggested that as there is no mention on the timelines for disbursement of transmission charges by the CTU. The Commission may include the same provision as in the BCD Procedure for Disbursement of transmission charges.

50.3 Analysis and Decision

50.3.1 Charges collected under transmission deviation shall be reimbursed to the DICs, in proportion to their first bill in the following billing month. The generators not covered under first bill, shall not be reimbursed any charges collected under transmission deviation.

50.3.2 The timeline for disbursement of transmission charges shall be as per Detailed Procedure to be issued by CTU.

**51. Clause (5) of Draft Regulation 17**

51.1 The draft Regulation provided as under:

*"(5) If payment against any bill raised by Central Transmission Utility under this Regulation is outstanding, the Central Transmission Utility may undertake Regulation of Power Supply on behalf of inter-State Transmission Licensees under the provisions of the Central Electricity Regulatory Commission (Regulation of Power Supply) Regulations, 2010 as amended from time to time and any subsequent enactment thereof."*

51.2 Comments have been received from FICCI, MSEDCL and CII.

51.2.1 MSEDCL has suggested that since there is provision of encashment of LC as payment security mechanism, provision of regulation of power supply should be used only if LC is not fully recovering dues and DIC is not paying even after being informed about the same by CTU.

51.2.2 FICCI and CII have suggested that number of days from due date should be specified for CTU to invoke provisions of regulation of power supply.

51.3 Analysis and Decision

51.3.1 Regulation of power supply shall be invoked only in case of failure on the part of any DIC to maintain the payment security mechanism for the required amount or failure on the part of a DIC to make payment, in full, against the bills by the due date. CTU shall take recourse to regulation of power supply in accordance with provisions of CERC (Regulation of Power Supply) Regulations, 2010.

**52. Clause (6) of Draft Regulation 17**

52.1 The draft Regulation provided as under:

*"(6) Delayed payment in a month by any DIC shall result in pro-rata reduction in disbursement to the inter-State Transmission Licensees and intra-state licensees whose assets are included in Yearly transmission Charges."*

52.2 Comments have been received from KPTCL and TANGEDCO.

52.2.1 KPTCL has suggested that in the proposed Regulation assets of intra-State licensees are also included in YTC. However, the Regulation does not indicate elsewhere, how the intra-State assets are considered for YTC.

52.2.2 TANGEDCO has suggested that a new sub clause (7) should be created as:

*'Relinquishment Charges: The relinquishment charges to be collected from the entities relinquishing part or full of their LTA quantum shall form part of the RTA. The same shall be reduced in YTC and the amount shall be directly collected from the relinquishing entity."*

52.3 Analysis and Decision

52.3.1 Intra-State assets are covered under definition of Yearly Transmission Charges and Regulation 13(13) of the 2020 Sharing Regulations which provides that "*An intra-State transmission system for which tariff is approved by the Commission shall be included for sharing of transmission charges of DICs in accordance with Regulations 5 to 8 of these regulations, only for the period for which such tariff has been approved."*

52.3.2 Relinquishment charge is not the subject matter of this regulation.

**53. Clause (1) of Draft Regulation 18**

53.1 The draft Regulation provided as under:

*"(1) The occurrence and continuation of the following events shall constitute a DIC Event of Default:*

*(a) A DIC fails to comply with the prevailing regulations including the provisions of the Central Electricity Regulatory Commission (Indian Electricity Grid Code) Regulations, 2010 as amended from time to time including any subsequent re-enactment thereof or is in material breach of these Regulations and such material breach is not rectified by the said DIC within 60 (sixty) days of receipt of notice in this regard from the concerned inter-State Transmission Licensee or the Central Transmission Utility; or*

*(b) DIC fails to make payments against bills raised by the Central Transmission Utility under these Regulations within 60 days beyond Due Date."*

53.2 Comments have been received from MSEDCL and ACME Solar.

53.2.1 MSEDCL has suggested that as far as non-compliance of any provision of this Regulation, the Implementing Agency should report to Commission who should take action for non-compliance. In case of the Grid Code, the compliance is covered under Regulation 1.5. It has suggested that no changes should be made to this provision of the Grid Code. Hence, it has suggested that only cause (b) should be taken as an event of default.

53.2.2 ACME Solar has suggested to insert following provision:

***"Event of Default of Transmission Licensee:***

*Transmission licensee failed to initiate construction of the required evacuation infrastructure even after 30 days from when it was required to initiate.*

*Transmission licensee failed to achieve monthly progress of work for continuous three months period.*

*This will ensure accountability of system developer and timely completion of evacuation infrastructure*

***Procedure in case of Transmission licensee event of Default:***

*(i) DIC shall be entitled to terminate all agreements with licensee without any liability.*

*(ii) DIC shall be indemnified for any kind of loss by CTU.*

*(iii) Developers must be allowed to exit from the agreement or get compensated on its own discretion if any such event of default occurs."*

53.3 Analysis and Decision

53.3.1 Regulations have been modified to provide for consequences for non-payment of dues at Regulation 21 of the 2020 Sharing Regulations as follows:

***"21. Consequences of non-payment of dues by a DIC***

*Failure on the part of a DIC to make payment, in full, against the bills by the due date under these regulations shall make such DIC liable for action for any or combination of the* *following, by the Central Transmission Utility, on behalf of inter-State transmission licensee(s):*

*(a) regulation of power supply in accordance with the Power Supply Regulations 2010;*

*(b) denial of Short term Open Access by RLDC or NLDC in accordance with the Open Access Regulations, 2008;*

*(c) suspension or termination of Long Term Access or Medium Term Open Access in accordance with Connectivity Regulations, 2009."*

53.3.2 Any action required for suspension or termination of Long Term Access or Medium Term Open Access shall be in accordance with the provisions of the 2009 Connectivity Regulations.

53.3.3 Liabilities of a transmission licensee in case of delay are covered under Regulation 13(8) of the 2020 Sharing Regulations.

## 54. Clause (2), (3), (4) and (5) of Draft Regulation 18

54.1 The draft Regulations provided as under:

*"(2) Upon the occurrence and continuance of a DIC Event of Default, the Central Transmission Utility may serve notice on the concerned DIC, specifying the circumstances giving rise to such Notice.*

*(3) Following the issue of such notice by the DIC, the concerned DIC shall take steps to remedy the default within 60 (sixty) days of issue of such notice.*

*(4) After the expiry of 60 (sixty) days from the date of issue of notice, unless the circumstances giving rise to such notice as mentioned in clause (1) of this regulation shall have ceased to exist or have been remedied, the concerned DIC shall cease to be a DIC under these Regulations and the Central Transmission Utility shall issue a Termination Notice of 30 (thirty) days to this effect with a copy to the Commission and the Implementing Agency.*

*Provided that in case of termination as DIC of an entity on account of DIC"s event of default, the Long Term Access or Medium Term Open Access or both of such entity shall be cancelled. Such cancellation shall be treated as relinquishment of Long Term Access or Medium Term Open Access in terms of 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 said entity shall pay the relinquishment charges accordingly.*

*(5) Upon termination of the status of DIC, the entity shall not be eligible for interchange of power under any form of open access unless such entity remedies the default and makes payment of all outstanding charges including relinquishment charges."*

54.2 Comments have been received from FICCI, ATL, CII and MBPMPL.

54.2.1 FICCI, ATL and CII have suggested that as per the draft regulations, 45 days is the due date from the date CTU has raised the bill. Failure to make payments against bills raised by CTU within 60 days beyond Due Date is construed as an Event of Default. In such case, the CTU shall serve notice on the concerned DIC, and the concerned DIC shall take steps to remedy the default within 60 days of issue of such notice. After the expiry of 60 days from the date of issue of notice, the concerned DIC shall cease to be a DIC under these Regulations and CTU shall issue a Termination Notice of 30 days to this effect with a copy to the Commission. This indicates that the total time available for a DIC to remedy the default is 150 days (60+60+30) from the due date of the bill and 195 days (45+60+60+30) days from the date of issuance of the bill. It has submitted that 195 days for remedying the default is unreasonably long. The cash flows would be impacted leading to increase in working capital requirement for the transmission licensee, which would manifest in increase in the tariffs. The timelines should be modified such that time available to a DIC is 90 days from date of billing.

54.2.2 MBPMPL has suggested that Regulation(s) 18(4) and 18(5) may be suitably modified in line with Regulation 11(3) to clarify in case of event of default by buyers/ beneficiaries with respect to the LTA and/or MTOA granted to generators/ sellers and tied to PPAs for supply of power to their buyers/ beneficiaries, the LTA and/or MTOA so terminated and cancelled shall be on the account of such buyers/ beneficiaries and only such buyers/ beneficiaries shall be liable to pay relinquishment charges, without having any incidence/ bearing whatsoever of the same on the original generators/ sellers to whom such LTA and/or MTOA was granted and such generators/ sellers shall continue to interchange power without any restrictions/ curtailments.

54.3 Analysis and Decision

54.3.1 The clause related to event of default and its consequences, such as notice and termination of access shall be dealt in accordance with the 2009 Connectivity Regulations and has been deleted from the instant Regulations.

**55. Regulation 19**

55.1 The draft Regulation provided as under:

*"(1) The Implementing Agency shall ensure smooth transition to the mechanism under these regulations.*

*(2) From the date these Regulations come into force, the first month's bill shall be raised in the third month as per the timeline specified in these Regulations. Bills for the previous two months i.e. first and second month, shall be based on earlier mechanism under the Central Electricity Regulatory Commission (Sharing of Inter-State Transmission Charges and Losses) Regulations, 2010."*

55.2 Comments have been received from GRIDCO.

55.2.1 GRIDCO has suggested that the smooth transition should include providing necessary software, knowledge and detailed procedure of calculation etc. by IA, which needs to be disseminated to DICs in every region.

55.3 Analysis and Decision

55.3.1 Implementing Agency (IA) shall publish the detailed procedures and formats for collection of data and information from various agencies and entities for implementation of the provisions of these regulations after stakeholder consultation. Software shall be made available for purchase to any DIC from software developer. Workshops may be conducted by IA to disseminate knowledge and procedure to DICs.

**56. Clause (1) of Draft Regulation 20**

56.1 The draft Regulation provided as under:

*"(1) Implementing Agency shall notify detailed procedures and formats for collection of generation and demand data from each DIC, data pertaining to the Basic Network and for calculation of transmission charges within 90 (ninety) days of the notification of these Regulations and post it on its website."*

56.2 Comments have been received from APP, Renew Power, GRIDCO, Tata Power, JSW and MBPMPL.

56.2.1 APP, Renew Power, MBPMPL, GRIDCO, JSW and Tata Power have suggested that the stakeholders should be given opportunity to offer comments on the Detailed Procedure to be formulated by Implementation Agency.

56.2.2 MBPMPL and GRIDCO have suggested that the Detailed Procedures to be formulated by IA should be notified only after approval of the Commission.

56.3 Analysis and Decision

56.3.1 Detailed Procedures shall be finalised after stakeholder consultation and the same has been provided in Regulation 23(1) of the 2020 Sharing Regulations.

**57. Clause (2) of Draft Regulation 20**

57.1 The draft Regulation provided as under:

*“(2) The software for the implementation of these regulations shall be audited or cause to be audited by the Commission before it is put to use, and thereafter from time to time as may be decided by the Commission.”*

57.2 Comments have been received from KPTCL, MSEDCL, TPDDL, BYPL, HVPN and Sembcorp.

57.2.1 KPTCL, Sembcorp, MSEDCL, BYPL, BRPL, TPDDL and HVPN have suggested that DICs should have access to the software and there is need to include demonstration training of the software to DICs.

57.3 Analysis and Decision

57.3.1 DICs may approach Implementing Agency for necessary clarifications and training.

**58. Clause (3) of Draft Regulation 20**

58.1 The draft Regulation provided as under:

*“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.”*

58.2 Comments have been received from GRIDCO.

58.2.1 GRIDCO has submitted that the list of untied LTA capacity (generator-wise) needs to be updated every month by CTU/NLDC which is considered for calculation of transmission charge of DICs.

58.3 Analysis and Decision

58.3.1 Regulation 25(1)(g) of the 2020 Sharing Regulations provides that IA shall put details of LTA and MTOA of each DIC for the billing period on its website.

**59. Clause (2) of Draft Regulation 21**

59.1 The draft Regulation provided as under:

*“(2) Implementing Agency shall notify, on its website, the peak block for the Billing Month on first day of the following month.”*

59.2 Comments have been received from APPCC.

59.2.1 APPCC has suggested adding proviso stating that all the States need to submit the details of intra-State generation injections/ drawls as may be required by the Implementing Agency, for the Peak block subject to scrutiny by RLDCs/RPCs.

59.3 Analysis and Decision

59.3.1 As per the Regulations, DICs shall submit data for peak block of the billing period and IA may verify the details from RLDCs, if required.

**60. Clause (3) of Draft Regulation 21**

60.1 The draft Regulation provided as under:

*"(3) On or before 7 (seven) days after start of Billing Month, Central Transmission Utility shall submit indicative cost for each voltage level and conductor configuration for transmission lines to the Implementing Agency."*

60.2 Comments have been received from SRPC.

60.2.1 SRPC has suggested that Regulation 21(3) may be modified as under:

*"On or before 7 (seven) days after start of Billing Month, Central Transmission Utility shall submit indicative cost for each voltage level and conductor configuration for transmission lines LTA/MTOA details and bilateral billing details to the Implementing Agency."*

60.2.2 SRPC has also stated that LTA/MTOA details need to be communicated by CTU.

60.3 Analysis and Decision

60.3.1 Regulation 24 (3) of the 2020 Sharing Regulations provides as follows:

*"Within 7 (seven) days after end of the billing period, the Central Transmission Utility shall submit indicative cost for transmission lines for each conductor configuration at each voltage level to the Implementing Agency."*

60.3.2 LTA and MTOA details shall be provided by CTU to Implementing Agency along with above said details.

**61. Clause (4) of Draft Regulation 21**

61.1 The draft Regulation provided as under:

*"(4) On or before 7(seven) days after end of Billing Month, DICs shall submit following data:*
*(a) MW and MVAR Data for injection or drawal at various nodes or a group of nodes for peak block for each Billing Month.*
*(b) Quantum of power tied up through PPAs for interchange of power under long term access or approved medium term open access."*

61.2 Comments have been received from HPPTCL, TPDDL, MSEDCL, Tstransco, GRIDCO and SECI.

61.2.1 HPPTCL has suggested to specify whether the data to be reported is SEM data or any other reference data so that consistency is maintained by all the States.

61.2.2 TPDDL has suggested to clarify as to which agency will submit the data, i.e. DISCOMs/State utilities or the State Load Dispatch Centres? Further, if the data is to be provided in any specific format, the same may be made available to all the DICs for timely compliance. GRIDCO has suggested that rather than generalising the overall data requirement, it would be better for a detail segregation of data requirement from individual entity/ stakeholders.

61.2.3 MSEDCL has suggested that the timeline for submission of data should be 10 days. The responsibility of data of node-wise actual generation and demand should be given to respective SLDCs.

61.2.4 Tstransco has suggested that 30 days is required for preparing the data for onward submission to Implementing Agency (IA) as ABT mechanism is not implemented in many States.

61.2.5 GRIDCO has suggested that given time limit of 7 days would be difficult on part of DICs to process data of various ISTS connected nodes for peak block for each Billing Month if peak block happens to be in any block on the last day of the billing month. It has suggested that the time limit for DIC to submit MW and MVAR Data for injection or drawal nodes may be increased to 15 days.

61.2.6 SECI has suggested that DICs would most likely submit the required data within stipulated time period unless there is some uncontrollable reason. It has requested to exempt a DIC for such charges for delay in case it is able to prove that the delay in submission resulted due to reason beyond its control.

61.3 Analysis and Decision

61.3.1 Implementing Agency shall publish the detailed procedures and formats for collection of data and information from various agencies and entities for implementation of the provisions of these regulations after stakeholder consultation. DICs shall provide Information as per the detailed procedure stipulated by the Implementing Agency.

61.3.2 The exercise of data collection, preparation of Base Case, calculation of charges, issuance of RPC accounts has to be completed within a month so that billing is not delayed. Hence, relaxation on timeline for providing data cannot be agreed to.

**62. Clause (6) of Draft Regulation 21**

62.1 The draft Regulation provided as under:

*"If a DIC does not provide the required data, including injection or drawal data for intra-State points within stipulated time period, it shall be levied an additional transmission charge @ 1% of the transmission charges under the First Bill for the month."*

62.2 Comments have been received from GRIDCO, APP, Sembcorp, Tata Power, FICCI, BRPL, BYPL, MSEDCL, HPPTCL, GETCL, RUVNL, WBSEDCL, JITPL, Tstransco and SRPC.

62.2.1 APP, Sembcorp, Tata Power and FICCI have suggested that there does not seem to be any major/ substantial reason for delaying or avoiding such data submission. Hence, in most of the cases, there would be some substantial reason/ hurdle beyond the control of DIC for not submitting such data. However, onus to prove that the matter was beyond its own control should be on the DIC.

62.2.2 BRPL and BYPL have suggested removing additional transmission charge at the rate of 1% of transmission charges.

62.2.3 HPPTCL has suggested that no penal provision should be in place. Delay may be due to practical difficulty that a utility may face in getting these data as the same are not readily available and the process will take time to streamline.

62.2.4 GETCL has suggested to remove the clause as the SLDC/ STUs of respective State provides data in validation committee.

62.2.5 RUVNL has suggested not levying any penalty in case of genuine reasons of delay at the end of DICs.

62.2.6 WBSEDCL has suggested that the provision ought to be deleted since all the data/ information related with LTA/MTOA/STOA and actual injection/ withdrawal are available with the Central Transmission Utility as well as with POSOCO. Hence, the Implementing Agency may utilise the information available for computation of transmission charges.

62.2.7 JITPL, during public hearing, also suggested that there should not be additional 1% charges on non-submission of data.

62.2.8 Tstransco has suggested removing any such penalty in case of genuine reasons of delay at the end of DICs.

62.2.9 MSEDCL has suggested that in case concerned SLDC fails to submit information in stipulated timeframe for consecutive three billing month, SLDC may be penalised instead of DIC, as actual data of EHV substation level is available with SLDC and not with DISCOMs.

62.2.10 SRPC has suggested that utilization/ settlement of 1% needs to be specified to avoid any ambiguity.

62.3 Analysis and Decision

62.3.1 Providing accurate data is the responsibility of all the DICs and providing this in a timely manner will facilitate calculation of charges representative of peak block. There is no provision of levying additional charges in case of delay in providing data in the 2020 Sharing Regulations. However, DICs should endeavour to provide correct data within the stipulated time.

**63. Clause (1) of Draft Regulation 22**

63.1 The draft Regulation provided as under:

*"(1) The information to be made available, on its website, by the Implementing Agency shall include:*

*(a) The Basic Network, generation at nodes and drawal at nodes considered for the base case and the load flow results for each Billing Month, on its website, immediately after its finalization;*

*(b) Assumptions, if any;*

*(c) Details of transformers, transmission system for renewables, list of elements considered under Regional Component and corresponding transmission charge considered for the Billing Month;*

*(d) Schedule of transmission charges payable by each constituent for the Billing month with Component-wise break-up;*

*(e) Yearly Transmission Charges as submitted by the transmission licensees covered under this Regulation and computation by Implementing Agency;*

*(f) Zone-wise details of transmission charges with details of transmission lines being used by each DIC and consequent transmission charges being borne by each DIC under AC-UBC component;*

*(g) Details of Long Term Access and Medium Term Open Access for the Billing Month;*

*(h) New transmission lines or transmission systems added during the Billing Month*

*(i) Detailed calculations of indicative cost for arriving at the average cost in respect of each transmission line;"*

63.2 Comments have been received from SRPC, MSEDCL, WIPPA, KSEBL and FICCI.

63.2.1 SRPC has suggested that Regulation 22(1)(c) may be replaced as under:

*'Details of transformers, transmission system for renewables, list of elements considered under National Component, Regional Component and corresponding transmission charge considered for the Billing Month, bilateral billing details.'*

63.2.2 SRPC has suggested to add two new provisions in Regulation 21(1) as 21(1)(j) and 21(1)(k) as under:

*'j. Modified line wise YTC taken for the charge computation.*

*k. AC-BC component charge details.'*

63.2.3 MSEDCL has suggested that details of components used for National Component, Regional Component, Transformers Component, AC-Usage Based Component along with its transmission cost considered in billing should be displayed.

63.2.4 WIPPA has suggested that DIC-wise details of components needs to be describe at Regulations 4 to 8. This will give crystallized picture as to how DIC is charged and in what proportion for each component.

63.2.5 KSEBL has suggested that the following may also be included under the information to be published by the Implementing Agency:

*(i)* *Power System Study case file of the peak block considered for arriving at the transmission charges.*
*(ii)* *Transmission asset considered for National Component, Regional Component, Transformer Component and AC charges*
*(iii)* *New generating stations added during the billing month*
*(iv)* *Details of Transmission deviation block wise*
*(v)* *State generation*
*(vi)* *State Transformer component*
*(vii)* *Regional nodes considered.*
*(viii)* *Loss study details*
(ix) *Transmission charge computation details*

63.2.6 FICCI has suggested that for providing transparency in the information availability and to avoid asymmetry in the information, CTU should provide the details of information used for computation of charges on its website, the details of LTA and MTOA should be updated on monthly basis.

63.3 Analysis and Decision

63.3.1 The elements covered under National Component and details of bilateral billing shall be covered under the information to be provided by IA under Regulation 25 of the 2020 Sharing Regulations.

63.3.2 Any requirement of additional data may be included by IA in its procedure and a DIC can always seek such data from IA.

**64. Clause (4) of Draft Regulation 22**

64.1 The draft Regulation provided as under:

*"(4) Implementing Agency shall provide sensitive data to the DICs with access control."*

64.2 Comments have been received from GRIDCO.

64.2.1 GRIDCO has suggested that the data transparency and accessibility by DICs should be such that data retrieval methods should help DICs in further analysis and systematically decipher the transmission charge components/ calculation part/ statements without ambiguity and with due traceability.

64.3 Analysis and Decision

64.3.1 The data to be published on the website by IA shall be published in editable “Microsoft Excel” format and with interactive “query”.

**65. Draft Regulation 23**

65.1 The draft Regulation provided as under:

*“(1) Save as otherwise provided in these regulations, Central Electricity Regulatory Commission (Sharing of inter-state transmission charges and losses) Regulations, 2010, as amended from time to time, is hereby repealed.*

*(2) Notwithstanding such repeal anything done or any action taken or purported to have been done or taken under the repealed regulations shall be deemed to have been done or taken under these regulations.”*

65.2 Comments have been received from CII.

65.2.1 CII has suggested that status of TSA, RSA and BCD Procedure in light of these regulations may be clarified in the regulations itself. Further, the order dated 29.04.2011 approving the TSA, RSA and BCD procedure, connected TSA (as per Standard Bidding Document) and the Model TSA (under the 2010 Sharing Regulations), whereby it was clearly stated in the Recital D of the Model TSA that:

*‘D. The development of an ISTS Scheme including any scheme which is under construction would continue to be governed in accordance with the Indemnification Agreement or Bulk Power Transmission Agreement or Transmission Service Agreement or any such agreement, as entered into between the concerned ISTS Licensee and the concerned DIC (s)( erstwhile beneficiary) to the extent relevant to the development construction and commissioning of the elements referred therein till such time the said element is for commercial operation and actually brought into the operations, post which the terms and conditions of this TSA would come into force.*

65.2.2 It needs to be clarified in these Regulations that the commercial operations shall be as per these Regulations.

65.3 Analysis and Decision

65.3.1 With regards to prevailing Transmission Service Agreement, Revenue Sharing Agreement and Billing Collection and Disbursement Procedure, the Explanatory Memorandum to the Draft 2019 Sharing Regulations had clarified the position as under:

*“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”*

65.3.2 The 2020 Sharing Regulations do not provide for model TSA or model RSA. Regulation 23(3) of the 2020 Sharing Regulations provides as follows:

*“(3) The Central Transmission Utility, in discharge of its functions under these regulations, may make such procedure as may be necessary, which is not inconsistent with these regulations or any other regulations of the Commission.”*

65.3.3 As noted in the Explanatory Memorandum, relevant features of TSA, RSA and BCD Procedure have been included in the Regulations itself. 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 the 2020 Sharing Regulations as and when it becomes effective.

**66. Clause 5.3 of Annexure-I**

66.1 The draft Regulation provided as under:

*“5.3 The DICs will provide actual injection/drawal information {MW and MVAR (or an assumption about the power factor to be used)} at all the nodes or a group of nodes in a*

*zone (identified a-priori by the Implementing Agency (IA)) in the Network. The data provided by the DICs shall be as per the formats prepared by the IA. All drawal DICs shall also submit the generation from their own generating stations for the peak block during the Billing month to the Implementing Agency to prepare the Base Case for load generation balance."*

66.2 Comments have been received from SRPC.

66.2.1 SRPC has suggested that the treatment of transmission lines/ elements in open condition in the peak block Base Case may be mentioned.

66.3 Analysis and Decision

The calculations of transmission charge shall be on actual data of load and generation. The transmission lines, including lines which are temporarily out of service shall be included in the Base Case.

**67. Clause 5.8 of Annexure-I**

67.1 The draft Regulation provided as under:

*"5.8 The dedicated transmission lines constructed, owned and operated by the ISTS Licensees shall be considered to be a part of the Basic Network. However, dedicated lines constructed, owned and operated by the Generating Station shall not be considered as a part of the Basic Network and the Generating Station will be deemed to be connected directly to the ISTS for the purpose of modelling basic network;"*

67.2 Comments have been received from HVPN.

67.2.1 HVPN has suggested that 1495 MW capacity of Mundra-Mohindergarh HVDC transmission line should not be part of Basic network.

67.3 Analysis and Decision

67.3.1 Mundra-Mohindergarh HVDC transmission line has been declared as a part of ISTS vide previous Orders of the Commission. However, the charges forcapacity corresponding to 1495 MW is to be paid by M/s Adani Mundra Limited or its successor company.

**68. Clause 5.9 of Annexure-I**

68.1 The draft Regulation provided as under:

*"5.9 The transmission system covered under clause (2) of Regulation 5 and clause (4) of Regulation 11 shall be considered at "zero cost" in the line wise transmission charges and modified line wise transmission charges at clause (3) and clause (6) of Regulation 9."*

68.2 Comments have been received from KSEBL, WBSEDCL and GRIDCO.

68.2.1 KSEBL has suggested that proposal of assigning ‘zero cost’ to transmission systems developed for RE will double benefit the DICs using such transmission lines as submitted below:

i. The cost of transmission system developed for RE is socialized and so the DIC is benefitted by not paying the entire transmission charges of the transmission systems developed for RE.

ii. Over and above this, due to existence of actual power flow in these lines, the power flow in the other lines of the DIC taken for computing AC-UBC is reduced, which leads to reduced usage based charges for the DIC

68.2.2 WBSEDCL has commented that the provision ought to be modified to the extent of inclusion of the National Component to the Regional Component for the purposes of considering the concerned transmission system to be at ‘Zero Cost’ under AC-UBC.

68.2.3 GRIDCO has suggested that exclusion of LTA/MTOA for RE projects and zero cost of transmission system build for RE evacuation will definitely skew the transmission charge and load flow pattern of other DICs since most RE evacuation is planned at 400 kV or 765 kV level. Hence, necessary provision may be made to avoid such skewed effect. Month wise Long Term Access or Medium Term Open Access for projects covered under clause (1) of Regulation 11 need to be uploaded in the CTU/ NLDC website so as to maintain transparency and avoid information asymmetry.

68.3 Analysis and Decision

68.3.1 The rationale for considering “zero cost” for referred transmission systems was provided in Explanatory Memorandum to the Draft 2019 Sharing Regulations as follows:

*“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 interstate 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."*

68.3.2 Only a portion of transmission charges are on usage basis under AC-UBC component. In view of the detailed reasoning given in the Explanatory Memorandum as quoted above, the transmission lines covered under Clause (2) of Regulation 5 shall be considered at zero cost under AC-UBC. The operationalization of such "zero cost" shall be effected by considering "zero circuit kms" while calculating transmission line-wise transmission charges and transmission line-wise usage-based transmission charges. Annexure-I of the notified Regulations provides as follows:

*"5.10.1 The transmission lines covered under Clause (2) of Regulation 5 shall be considered with "zero circuit kms"*

68.3.3 Month-wise Long Term Access or Medium Term Open Access for projects covered under clause 13(1) of the 2020 sharing Regulations shall be uploaded on the website of CTU and NLDC.

## 69. Clause 5.11 of Annexure-I

69.1 The draft Regulation provided as under:

*"5.11 The transmission charge per circuit kilometer for a transmission line for each voltage level and conductor configuration shall be made uniform. The methodology followed shall be as follows:*

*5.11.1. Central Transmission Utility shall provide indicative cost level per circuit kilometer for a transmission line for each voltage level and conductor configuration.*

*5.11.2 Total Circuit kms for transmission lines for each voltage level and conductor* *configuration shall be allocated uniform charges as per ratio methodology in illustrative example.*

*An Illustrative Example is given below for transmission lines:*

*--------"*

69.2 Comments have been received from JSW, NTPC, WBSEDCL and GRIDCO.

69.2.1 JSW has suggested to provide more clarity on the illustration/ example provided since following points are not clarified:

- Why only 400 kV D/C Quad Moose is considered as reference to calculate the ratio in first table.
- The total circuit kilometer is not matching between second and third tables.
- Why again 400 kV D/C Quad Moose line is considered as based for working out uniform rate per circuit kilometer for each voltage level and conductor configuration and rates for other lines are calculated accordingly.

69.2.2 JSW has suggested to share an editable version of the illustrative example for better understanding.

69.2.3 WBSEDCL has suggested that the transmission charge per circuit kilometer for a transmission line of each voltage level and conductor configuration for a particular region may be made uniform to avoid any additional burden of transmission charges of one region being borne by another region in line with the National Electricity Policy and the Act.

69.2.4 GRIDCO has suggested a simpler method for computation of average cost of conductors. In the table below, the indicative cost and ckt-km has been taken from CTU data. A base value is determined considering the 400 kV D/C Quad moose as reference. Basing on this reference value, the apparent ckt-km of all other conductor configuration is determined. Then the MTC value is apportioned among each conductor configuration to get the verage cost.

**Computation of Average MTC**

| **Indicative Cost Levels for 1st Quarter of 2016-17 (As Provided by CTU)** | | | | | | **Average Cost (Rs per ckm)** | |
|---|---|---|---|---|---|---|---|
| **Type of conductor** | **Indicative Cost (Rs Lakh)** | **Cost/ Circuit (Rs Lakh)** | **Base Value** | **Ckt-km** | Ckt-km as per Base Value | Total MTC to be recovered through PoC | Avg. Cost (Rs/Ckm) |
| | **a** | **B** | **c= b/90** | **D** | e= c*d | F | g = f *e/ |

| Indicative Cost Levels for 1st Quarter of 2016-17 (As Provided by CTU) | | | | | | Average Cost (Rs per ckm) | |
|---|---|---|---|---|---|---|---|
| | | | | | | | Total ckt-km |
| **765 kV D/C** | 332 | 166 | 1.84 | 9,687 | 17,867 | **15,75,04,11,038** | 2,61,323 |
| **765 kV S/C** | 133 | 133 | 1.48 | 13,790 | 20,379 | | 2,09,373 |
| **400 kV D/C Quad Moose** | 180 | 90 | 1.00 | 16,296 | 16,296 | | 1,41,681 |
| **400 kV D/C Twin Moose** | 104 | 52 | 0.58 | 60,122 | 34,737 | | 81,860 |
| **400 kV S/C Twin Moose** | 71 | 71 | 0.79 | 17,946 | 14,157 | | 1,11,771 |
| **220 kV D/C** | 41 | 20.5 | 0.23 | 10,696 | 2,436 | | 32,272 |
| **220 kV S/C** | 23 | 23 | 0.26 | 2,188 | 559 | | 36,207 |
| **132 kV D/C** | 27 | 13.5 | 0.15 | 926 | 139 | | 21,252 |
| **132 kV S/C** | 18 | 18 | 0.20 | 1,853 | 371 | | 28,336 |
| **400 kV D/C Triple Snowbird** | 150 | 75 | 0.83 | 5,072 | 4,227 | | 1,18,068 |
| Total Ckt-km as per Base Value = | | | | | 1,11,168 | | |

69.3 Analysis and Decision

69.3.1 400 kV Quad Moose has been used as base. Irrespective of which type is considered as base, the results are identical. The calculations have been further simplified based on suggestions of GRIDCO.

69.3.2 The transmission charge per circuit kilometre for a transmission line of each voltage level and conductor configuration have been made uniform across all India.

**70. Clause 5.13 of Annexure-I**

70.1 The draft Regulation provided as under:

> *"5.13 In the process of convergence of the Load Flow on the Basic Network, the IA may require to make certain minor adjustments in the load/generation at various buses to ensure load generation balance."*

70.2 Comments have been received from SRPC.

70.2.1 SRPC has suggested to add following after clause 5.13:

> *"and ISTS drawal of the DICs (as close as possible)".*

70.2.2 SRPC has suggested that as computations are done for the peak ISTS drawal block, so endeavour should be to ensure that ISTS drawal of each DIC corresponds to peak ISTS drawal block.

70.3 Analysis and Decision

70.3.1 Only minor adjustment can be made by IA to ensure load generation balance.

**71. Clause 5.15 of Annexure-I**

71.1 The draft Regulation provided as under:

> *"5.15 The external slack bus (es) for each node shall be found as follows:*
>
> *5.15.1 For every node in a particular scenario, Average Participation method will be applied to each generation / load located in the state under consideration. Tracing from load to Generating Station (or from Generating Station to load), a set of Generating Stations (or loads) (including those outside the state) and their contribution to the load (Generating Station) is determined for each load (Generating Station) bus.*
>
> *5.15.2 Using the above choice of slack buses for each Generating Station and load bus, marginal participation of each Generating Station and load in each transmission line is computed."*

71.2 Comments have been received from RUVNL.

71.2.1 RUVNL has suggested that the proposed regulation identifies slack nodes using Average Participation (AP) Method. However, while finalizing the 3rd amendment of the 2010 Sharing Regulations, it was discussed to implement Min-Max Fairness Method for selection of Slack Bus. Min-Max Fairness Policy tries for equity in POC tariffs to the extent possible without violating the laws of physics in calculating the extent of use by providing favourable economic slack bus for high POC tariff entities. Min-Max Fairness Method guarantees best possible choice of economic slack bus to reduce regrets. Moreover, Average Participation Method fails in case of loop flows, while Min-Max Fairness Method will avoid the problem of loop flows.

71.3 Analysis and Decision

71.3.1 Min-max method was deliberated and was not found suitable at the time of framing of the 2010 Sharing Regulations. The same has also been discussed in the Bakshi Committee Report, which concluded as follows:

*(i) Fallacies of the proposed Min-Max method: The proposed min-max method has following shortcomings :*

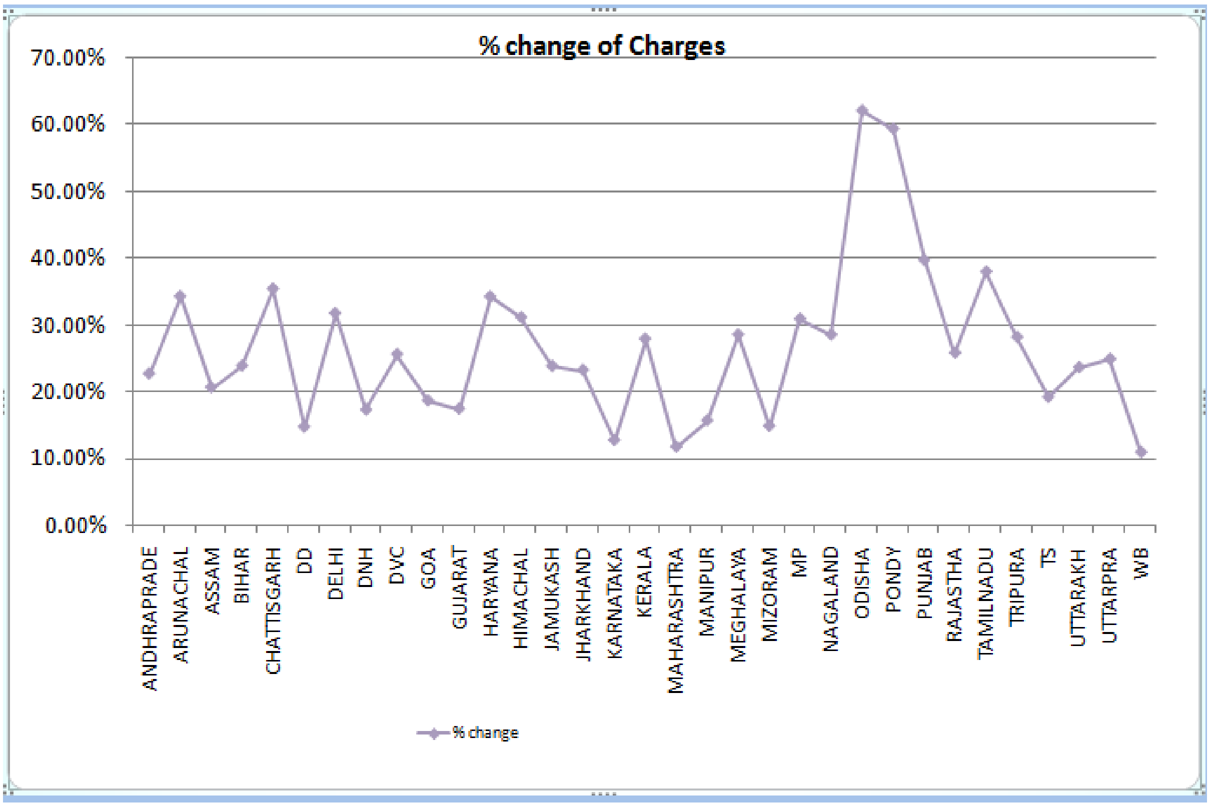
*(a) Economic efficiency: It was stated that allocation rule should provide efficient siting signals and that min-max method will achieve it. The results of the proposed min-max method shows that the results are completely against siting signals. The charges of States like Chattisgarh which are generation rich are high whereas charges for states like Rajasthan are low which loses siting signal. Since ISTS drawal of Rajasthan is high, it requires more ISTS. Hence the proposed method loses economic efficiency.*

*(b) Fairness: The principle of fairness is that an entity should not get undue advantage over others. But min-max method fails on this criteria also. Firstly min-max method exactly gives advantage to such person who is using more ISTS at the cost of a person who is using less ISTS and allocates same rate to both such entities. Such an allocation is highly unfair which has no basis. It will also be very difficult to justify the reasons of increase of charges to such entity that their charges have increased because it was desired to reduce charges of other entity. This will be completely against Tariff Policy and principles of natural justice.*

*(c) Transparency: The proposed min-max method is completely opaque as to the allocation of charges since it tries iteratively to search such a slack bus so that the charges of an entity who is heavy user of ISTS is reduced at the cost of an entity which uses less ISTS.*

*(d) Simplicity: The proposed min-max method is very complex and non-justifiable. The proposed methodology to determine usage of line and scale up the charges for unused portion for each line is again a very complicated and disputable proposition.*

*(e) Stability: It was argued that the proposed min-max method is stable in terms of rates which have been determined by making everybody's rate same through min-max method. The same has been compared with POC rates which are determined only on usage principle, by dividing charges attributable by LTA (which is contractual ISTS drawal). It is observed that transmission charges attributable to each entity varies over the 4 quarters even in proposed min-max method. A comparative chart of the charges attributable over the 4 quarters is indicated below:*




*(f) It is observed that that if principles of Tariff policy are to be adhered to the charges cannot be stable because ISTS drawal of states are varying over quarters and Quarterly transmission charges are increasing @4% every quarter.*

*(g) It is noted that proposed min-max methodology is based on cross subsidisation between DICs which cross subsidises high ISTS users at the cost of low ISTS users. Electricity Act 2003 provides that cross subsidies should be progressively reduced. The method proposes to increase the cross subsidy would be against the intent and objective of the Act*

(h) *Slack bus in transmission pricing mechanism (based on Load flow study) predominates the outcome of the results. There is no unique way for identification of slack bus. The present methodology based on tracing actually captures the distance of various groups of generators from a load point based on the power flow in the base case. This methodology is adopted to capture the distance of generation from load center. Hence Average participation factor helps in computation of transmission charges based on distance. Whereas Max – Min based selection of slack bus is based on minimum regret which is not the intent of tariff policy. Hence the method is not accepted.*

71.3.2 Accordingly, the min-max method has not been accepted.

**72. Clause 5.20 of Annexure-I**

72.1 The draft Regulation provided as under:

*"5.20 For generating stations having no Long term access or medium term access, the transmission charges attributable to such generators shall be calculated as injection charges (as for generators with LTA to target region with untied capacity) under AC-UBC*

*Component. The charges of other DICs on whom AC-UBC charges have been computed shall be scaled up to the extent of charges attributable to such generators."*

72.2 Comments have been received from APP, KSEBL, TPTCL and GRIDCO.

72.2.1 APP has suggested that it is not clear how this transmission charges sharing mechanism would be implemented if the injection by a generator during the peak block is nil or if there is a substantial variation in the actual injection pattern of the generator over a month vis-à-vis the injection by this generator during the peak block. The injection pattern of any generator is dynamic in nature on account of various uncontrollable factors (like scheduling by buyer, grid conditions, load pattern and seasonal variations etc.) and as such injection during a particular block (i.e. the defined peak block) can in no way be a true determinant of transmission charges sharing mechanism envisaged in the Draft 2019 Sharing Regulations.

72.2.2 KSEBL has stated that there is no clarity in the proposed clause. As per the proposed Regulations, if transmission charges are payable by generating stations availing STOA over and above LTA (target region or otherwise) or MTOA, it is accounted as transmission deviation rates. In that case, there is no requirement for including the same as AC-UBC and scaling up the charges of other DICs due to this.

72.2.3 TPTCL has suggested that it seems that the generators having no LTA/MTOA are merchant generators and transmission charges attributable to such generators shall be calculated using usage-based methodology (AC-UBC) only and all other charges like National Component, Regional Component, Transformers Component or AC-Balance Component shall not be applicable to such generators.

72.2.4 GRIDCO has suggested that allocating merchant generator cost by adding proportionately to all entities based on their base cost share is not just and fair. It will distort the other DICs transmission charges. Merchant generators should be allocated charges based on generation at time of all-India peak for the month for PoC component.

72.3 Analysis and Decision

72.3.1 Generation and load vary in every time block. The Commission has considered peak block as the block which shall be used as representative block to allocate charges under AC-UBC. Since the calculations are based on actual data, the actual generation can only be considered, irrespective of quantum of generation.

72.3.2 Clause 5.20 of the Annexure-I to Draft 2019 Sharing Regulations has been deleted considering the suggestions.

**73. Section E of Annexure-I**

73.1 The draft Regulation provided as under:

**"(E) COMPUTATION: DETERMINATION OF SHARING OF TRANSMISSION CHARGES**

*5.17 The following steps shall be followed:*
*--------"*

73.2 Comments have been received from HVPN.

73.2.1 HVPN has suggested that the 2010 Sharing Regulations mentions the treatment of HVDC lines as under: "*Treatment of HVDC: Flow of HVDC systems is regulated by power order and remains constant for marginal change in load or generation. Hence marginal participation (MP) of HVDC systems is zero*". This results in increase of PoC charges of Haryana as Haryana is receiving power from M/s Adani through a dedicated HVDC Mundra- Mohindergarh HVDC transmission line. Under Marginal Participation method, an increase in 1 MW of load in Haryana has to be compensated by a corresponding increase in generation at the slack buses at Mundra end, but as stated above, HVDC line doesn't respond in the marginal participation. Hence, power flows through alternate AC transmission lines which results in increase in the PoC charges for the State of Haryana. However, the Draft 2019 Sharing Regulations are silent about treatment of HVDC transmission line.

73.3 Analysis and Decision

73.3.1 Marginal participation of HVDC system is zero since its flow is regulated by power order. The Statement of Reasons for the 3rd amendment to the 2010 Sharing Regulations had clearly recognised this, when it was noted that *"As tariff of HVDC links cannot be allocated with marginal participation method, a separate treatment is unavoidable."* The treatment of HVDC system is provided for in the Regulations under NC-HVDC and RC components.

| sd/- | sd/- | sd/- |
|---|---|---|
| **(Arun Goyal)** | **(I.S.Jha)** | **(P.K.Pujari)** |
| **Member** | **Member** | **Chairperson** |

**Appendix-I**

**List of stakeholders/individuals who submitted written comments**

| S No. | Name of Stakeholder | Short form used in this Document |
|---|---|---|
| 1 | ACME Solar Holdings Limited | ACME Solar |
| 2 | Adani Power Mundra Ltd | Adani Mundra |
| 3 | Adani Transmission Ltd | ATL |
| 4 | Assam Electricity Regulatory Commission | AERC |
| 5 | Assam Power Distribution Company Ltd | APDCL |
| 6 | Association of Power Producers | APP |
| 7 | Andhra Pradesh Power Coordination Committee | APPCC |
| 8 | Azure Power India Pvt. Ltd | Azure Power |
| 9 | BSES Rajdhani Power Ltd | BRPL |
| 10 | BSES Yamuna Power Ltd | BYPL |
| 11 | Confederation of Indian Industry | CII |
| 12 | Captive Power Producers Association | CPPA |
| 13 | Dans Energy Pvt Ltd | Dans Energy |
| 14 | DB Power Ltd | DB Power |
| 15 | DNH Power Distribution Corporation Ltd | DNHPDCL |
| 16 | Federation of Indian Chambers of Commerce and Industry | FICCI |
| 17 | Gati Infrastructure Pvt. Ltd. | Gati Infrastructure |
| 18 | Gujrat Energy Transmission Corporation Limited | GETCL |
| 19 | GMR | GMR |
| 20 | Greenko Energies Pvt Ltd | Greenko |
| 21 | GRIDCO Limited | Gridco |
| 22 | Gujarat Urja Vikas Nigam Ltd | GUVNL |
| 23 | Hero Future Energies Ltd | Hero Future |
| 24 | Himachal Pradesh State Electricity Board Limited | HPSEBL |
| 25 | H.P. Power Transmission Corporation Ltd | HPTCL |
| 26 | Haryana Vidyut Prasaran Nigam Ltd | HVPN |
| 27 | Indian Captive Power Producers Association | ICCPA |
| 28 | Indian Energy Exchange | IEX |
| 29 | Jindal India Thermal Power Ltd | JITPL |
| 30 | JSW Energy Ltd | JSW |
| 31 | Kerala State Electricity Regulatory Commission | KSERC |
| 32 | Karnataka Power Transmission corporation Ltd. | KPTCL |
| 33 | Kerala State Electricity Board Ltd | KSEBL |
| 34 | KSK Mahanadi Power Company Ltd | KSK Mahanadi |
| 35 | L&T IDPL | L&T IDPL |
| 36 | Maharashtra State Electricity Distribution Co. Ltd | MSEDCL |
| 37 | MB Power (Madhya Pradesh) Ltd | MB Power |
| 38 | Ministry of New & Renewable Energy | MNRE |

| S No. | Name of Stakeholder | Short form used in this Document |
|---|---|---|
| 39 | M.P. Power Management Company Ltd | MPPMCL |
| 40 | Mytrah Energy India Pvt Ltd | Mytrah Energy |
| 41 | North Eastern Electric Power Corporation Ltd | NEEPCO |
| 42 | NHPC Ltd | NHPC |
| 43 | NLC India Ltd | NLC |
| 44 | National Solar Energy Federation of India | NSEFI |
| 45 | NTPC Ltd | NTPC |
| 46 | O2 Power | O2 Power |
| 47 | Power Company of Karnataka Ltd | PCKL |
| 48 | Punjab State Power Corporation Ltd. | PSPCL |
| 49 | PTC India Ltd | PTC |
| 50 | Power Exchange India Ltd | PXIL |
| 51 | Rajasthan Urja Vikas Nigam Ltd. | RUVNL |
| 52 | ReNew Power Ltd. | Renew Power |
| 53 | RPG Power Trading Company Ltd. | RPG Trading |
| 54 | Solar Energy Corporation of India Ltd | SECI |
| 55 | SembCorp Energy India Ltd | Sembcorp |
| 56 | Sprng Energy Pvt. Ltd | Sprng Energy |
| 57 | Southern Regional Power Committee | SRPC |
| 58 | Statkraft India Pvt. Ltd | Statkraft |
| 59 | Sterlite Power transmission Ltd | Sterlite |
| 60 | Tamilnadu Generation and Distribution Corporation Ltd. | TANGEDCO |
| 61 | Tata Power Company Ltd | Tata Power |
| 62 | Tamilnadu Electricity Regulatory Commission | TNERC |
| 63 | Torrent Power Ltd | Torrent Power |
| 64 | Tata Power Delhi Distribution Ltd | TPDDL |
| 65 | Tata Power Trading company Ltd | TPTCL |
| 66 | Transmission Corporation of Telengana Ltd. | Tstransco |
| 67 | West Bengal State Electricity Distribution Company Ltd. | WBSEDCL |
| 68 | Wind independent Power Producers Association | WIPPA |

**Appendix-II**

**List of stakeholders/individuals who made oral submissions/power point presentation during the public hearing**

| S No. | Name of Stakeholders | Short Form used in this Document | Presentation /Oral Submission |
|---|---|---|---|
| 1 | Association of Power Producers | APP | Oral Submission |
| 2 | Azure Power India Pvt. Ltd | Azure Power | Oral Submission |
| 3 | Bihar State Power Holding Company Ltd | BSPHCL | Oral Submission |
| 4 | Continuum wind Energy Ltd | Continuum wind | Oral Submission |
| 5 | Captive Power Producers Association / Indian Captive Power Produces Association | CPPA/ ICPPA | Oral Submission |
| 6 | Gridco Ltd | Gridco | Oral Submission |
| 7 | Indian Energy Exchange | IEX | Presentation |
| 8 | Jindal Power Ltd | JPL | Oral Submission |
| 9 | Kreate Energy | Kreate Energy | Oral Submission |
| 10 | Kerala State Electricity Board Ltd | KSEBL | Presentation |
| 11 | L&T IDPL | L&T IDPL | Oral Submission |
| 12 | Mytrah Energy India Pvt Ltd. | Mytrah Energy | Presentation |
| 13 | NHPC Ltd | NHPC | Presentation |
| 14 | NTPC Ltd | NTPC | Presentation |
| 15 | Sterlite Power Transmission Ltd | Sterlite | Oral Submission |
| 16 | Tamilnadu Generation and Distribution Corporation Ltd. | TANGEDCO | Presentation |
| 17 | Tata Power Trading company Ltd | TPTCL | Oral Submission |
| 18 | West Bengal State Electricity Distribution Company Ltd. | WBSEDCL | Oral Submission |