Central Electricity Regulatory Commission (Sharing of Inter State Transmission Charges and Losses) Regulations, 2010

UNION OF INDIA
India

Central Electricity Regulatory Commission (Sharing of Inter State Transmission Charges and Losses) Regulations, 2010

Rule CENTRAL-ELECTRICITY-REGULATORY-COMMISSION-SHARING-OF-I of 2010

- Published on 15 June 2010
- Commenced on 15 June 2010
- [This is the version of this document from 15 June 2010.]
- [Note: The original publication document is not available and this content could not be verified.]

Central Electricity Regulatory Commission (Sharing of Inter State Transmission Charges and Losses) Regulations, 2010Published vide Notification No. L-1/44/2010-CERC, dated 15.6.2010Last Updated 30th April, 2019No.L-1/44/2010-CERC. - In exercise of the powers conferred under section 178 read with Part V of the Electricity Act, 2003 (36 of 2003), and all other powers enabling it in this behalf, and after previous publication, the Central Electricity Regulatory Commission hereby makes the following regulations:

Chapter 1
Preliminary

1. Short title, extent and commencement.

(1)These regulations may be called the Central Electricity Regulatory Commission (Sharing of Inter State Transmission Charges and Losses) Regulations, 2010.(2)These regulations shall apply to all Designated ISTS Customers, Inter State Transmission Licensees, NLDC, RLDC, SLDCs, and RPCs.(3)These regulations shall come into force from 1.1.2011, and unless reviewed earlier or extended by the Commission, shall remain in force for a period of 5 years from the date of commencement specified above.

2. Definitions.

(1)In these Regulations, unless the context otherwise requires,:-(a)"Act" means the Electricity Act, 2003 (36 of 2003);(b)['Application Period' means the period of application of the charges determined as per these regulations and shall be of 3 (three) months duration i.e. April to June, July to September, October to December, and January to March in a financial year: [Substituted by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (w.e.f. 15.6.2010).]Provided that in exceptional circumstances, the Commission may extend or curtail the duration of the application period for the reasons to be recorded in writing.](c)['Approved Injection' means the injection in MW computed by the Implementing Agency for each Application Period on the basis of maximum injection made during the corresponding Application Periods of last three (3) years and validated by the Validation Committee for the DICs at the ex-bus of the generators or any other injection point of the DICs into the ISTS, and taking into account the generation data submitted by the DICs incorporating total injection into the grid: [Substituted by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (w.e.f. 15.6.2010).]Provided that the overload capability of a generating unit shall not be used for calculating the approved injection:Provided further that where long term access (LTA) has been granted by the CTU, the LTA quantum, and where long term access has not been granted by the CTU, the installed capacity of the generating unit excluding the auxiliary power consumption, shall be considered for the purpose of computation of approved injection.](d)"Approved Additional Medium Term Injection" means the additional injection, as per the Medium Term Open Access approved by CTU after submission of data to NLDC by the Designated ISTS Customer over and above the Approved Injection for the Designated ISTS Customer for each representative block of months, [***] [Omitted 'peak and off-peak scenarios' by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (w.e.f. 15.6.2010).] at the ex-bus of the generator or any other injection point of the Designated ISTS Customer into the ISTS;(e)"Approved Short Term Injection" means the injection, as per the Short Term Open Access approved by RLDC / NLDC such injection including all injections cleared on the power exchange;(f)["Approved Withdrawal" means the withdrawal in MW computed by the Implementing Agency for each application period on the basis of the actual peak met during the corresponding application periods of last three (3) years and validated by the Validation Committee for any DIC in a control area after taking into account the aggregated withdrawal from all nodes to which DIC is connected and which affect the flow in the ISTS, and the anticipated maximum demand to be met as submitted by the DIC: [Substituted by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (w.e.f. 15.6.2010).]Provided that the overload capability of a generating unit in which the DIC has an allocation or with which the DIC has signed an agreement, shall not be used for calculating the approved withdrawal under long term access (LTA).](g)["Approved Additional Medium Term Withdrawal" means the additional withdrawal by a DIC as per the Medium Term Open Access approved by CTU after submission of data to the Implementing Agency by the concerned DIC.] [Substituted by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (w.e.f. 15.6.2010).](h)"Approved Short Term Withdrawal" means withdrawal, as per the Short Term Open Access approved by RLDC/NLDC and where such Withdrawal includes all withdrawals cleared on the power exchange;(i)"Basic Network" shall mean the power system of the country at voltage levels 132 kV and above and 110 kV where generators are connected, HVDC transmission network and all Generator and loads connected to it;(j)"Bulk Power Transmission Agreement (BPTA)" means the agreements between the ISTS licensees and the Designated ISTS Customers of the ISTS under the pre-existing arrangements for ISTS development and operations;(k)"Deemed Inter State Transmission System (Deemed ISTS)" means such transmission system which has regulatory approval of the Commission as being used for interstate transmission of power and qualified as ISTS for the purpose of these Regulations unless otherwise specified;(l)["Designated ISTS Customer or DIC" means the user of any segment(s) or element(s) of the ISTS and shall include generator, State Transmission Utility, State Electricity Board or load serving entity including Bulk Consumer and any other entity or person directly connected to the ISTS and shall further include any intra-State entity who has obtained Medium Term Open Access or Long Term Access to ISTS.] [Substituted by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (w.e.f. 15.6.2010).][(l-i) 'HVDC Charge' means the transmission charges shared for use of HVDC transmission systems as provided under Regulation 11 of these regulations.] [Inserted by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (w.e.f. 15.6.2010).](m)"Hybrid Methodology" shall mean the hybrid of the Marginal Participation Method and the Average Participation method detailed in Chapter-3 of these regulations and in Annexure - I hereto.(n)"Implementing Agency (IA)" shall mean the agency designated by the Commission to undertake the estimation of allocation of transmission charges and transmission losses at various nodes/zones for the Application Period along with other functions as per [Chapter-4, Chapter-5, Chapter-6, Chapter-7 and Chapter-8] of these regulations;(o)"Loss Allocation Factor" of a bus measures the losses attributed to that node and shall be computed as explained in the Annexure - I of these regulations.[(o-ii) "Merchant Power Plant" means a generating station or unit thereof whose tariff either for the whole capacity or for the part capacity is not determined under section 62 or section 63 of the Act and which sells electricity in the open market corresponding to such capacity and the term merchant capacity? shall be construed accordingly.] [Inserted by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (w.e.f. 15.6.2010).](p)"Monthly Transmission Charge" means the transmission charges (inclusive of incentives) payable for each calendar month as given in the Terms and Conditions of Tariff Regulations in force;(q)"Node" shall mean a sub-station or a switchyard of a generator;(r)"Point of Connection (PoC) Charging Method" shall mean the methodology of computation of sharing of ISTS charges and losses amongst Designated ISTS Customers, which depends on the location of the node in the grid and is calculated in accordance with Regulation 7(1(q)) and 7(1(s)) of chapter 4 of these regulations;(s)"Point of Connection (PoC) transmission charges" are the nodal / zonal charges determined using the Point of Connection charging method.(t)"Participation Factor" of a node in any transmission line means the percentage usage of that line by a node, whether a generator node or a demand node as explained in Annexure - I of these regulations.[(t-i) 'Reliability Support Charge' means the Charge for reliability benefits which accrue to the DICs by virtue of operating in an integrated grid. [Inserted by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (w.e.f. 15.6.2010).](t-ii) 'Reliability Support Charges Sharing Methodology' means the mechanism for determination and sharing of Reliability Support Charges as specified in sub-clause (q) of clause (1) of Regulation 7 of these Regulations and para 2.8.1.b. of Annexure-I.](tiii)[] [Renumbered '(ti)' by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (w.e.f. 15.6.2010).] 'Target Region' means the region to which a generator proposes to sell power after obtaining Long-term Access from the CTU and for which beneficiaries in the said region have not been identified.(u)"Transmission Service Agreement" (TSA) shall mean the agreement to be entered into between the Designated ISTS Customer(s) and ISTS Licensee(s) in terms of Chapter 6;[(u-i) 'Validation Committee' means the committee appointed by the Commission comprising officers from the Commission, the

Implementing Agency, each of the RPCs, CTU, CEA, STUs for the purpose of discharging various functions vested under these regulations, and the meetings of the committee shall be chaired by a nominee of the Commission.] [Substituted by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (w.e.f. 15.6.2010).][***] [Deleted 'sub-clause v,w,x' by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (w.e.f. 15.6.2010).]Explanation. - Uniform shall mean that such percentage loss is applied uniformly to all Designated ISTS Customers in a region irrespective of their location in the grid.(y)["Yearly Transmission Charge (YTC)" means the Annual Transmission Charges for the existing and new transmission assets of the transmission licensees and deemed ISTS Licensees including non-ISTS lines certified by Regional Power Committees for carrying inter-State power, determined by the Appropriate Commission under section 62 of the Act or adopted by the Appropriate Commission under section 63 of the Act or as otherwise provided in these Regulations] [Substituted by Notification No. L-1/44/2010-CERC, dated 24.11.2011 (w.e.f. 15.6.2010).].[Provided that in case of non-ISTS lines, the asset-wise tariff determined by the respective State Commissions or approved by the Central Commission based on the approved Annual Revenue Requirement of STU, shall be used:Provided further that transmission charges received by the STU under these regulations shall be adjusted in the Annual Revenue Requirement of the concerned STU approved by the respective State Commission.] [Inserted by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (w.e.f. 15.6.2010).](2)Words and expressions used in these Regulations and not defined herein but defined in the Act or regulations made by the Commission, shall have the meanings assigned to them respectively in the Act, and regulations made by the Commission from time to time.

Chapter 2
Scope of The Regulations

3.

Yearly Transmission Charges, revenue requirement on account of foreign exchange rate variation, changes in interest rates etc. as approved by the Commission and Losses shall be shared amongst the following categories of Designated ISTS Customers who use the ISTS:-(a)[Generating Stations (i) which are regional entities as defined in the Indian Electricity Grid Code (IEGC) or (ii) are having LTA or MTOA to ISTS and are connected either to STU or ISTS or both.] [Substituted by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (w.e.f. 15.6.2010).](b)[State Electricity Boards/State Transmission Utilities connected with ISTS or designated agency in the State (on behalf of distribution companies, generators and other bulk customers connected to the transmission system owned by the SEB/STU/ intra-State transmission licensee);] [Substituted by Notification No. L-1/44/2010-CERC, dated 24.11.2011 (w.e.f. 15.6.2010).](c)Any bulk consumer directly connected with the ISTS, and(d)Any designated entity representing a physically connected entity as per clauses (a), (b) and (c) above.

Chapter 3
Principles And Mechanism For Sharing of Ists Charges and Losses

4. Principles for sharing ISTS charges and losses.

(1)Based on the Yearly Transmission Charges of ISTS Transmission Licensees and transmission losses in the ISTS network, the Implementing Agency shall compute the Point of Connection charges and Loss Allocation Factors for all DICs:-(a)Using load-flow based methods; and(b)based on the Point of Connection Charging method.(2)A detailed explanation of the Hybrid methodology to be applied for sharing the ISTS charges and losses amongst the Designated ISTS Customers is set out in Annexure - I to these regulations, which may be reviewed by the Commission from time to time either upon an application by any interested party or otherwise .

5. Mechanism to share ISTS transmission charges.

(1)The sharing of ISTS transmission charges between Designated ISTS Customers shall be computed for an Application Period and shall be determined in advance and shall be subject to periodic true-up as specified subsequently in these regulations;(2)The sharing of ISTS transmission charges shall be based on the technical and commercial information provided by various Designated ISTS Customers, ISTS Transmission Licensees, and any other relevant entity, including the NLDC, RLDCs and SLDCs to the Implementing Agency.Provided that in the event of such information not being available within the stipulated timeframe or to the level of detail required, the Commission may authorise the Implementing Agency to obtain such information from alternative sources as per the procedure as may be approved by the Commission in this behalf.(3)The mechanism for sharing of ISTS charges shall ensure that:-(a)The Yearly Transmission Charge of the ISTS Licensees are fully and exactly recovered; and(b)Any adjustment towards Yearly Transmission Charge on account of change in commissioning schedule of elements of the power system and change in factors constituting the transmission charge, approved by the Commission, e.g., FERV, Changes in interest rates shall be fully and exactly recovered etc., as specified subsequently in these regulations.(4)The Point of Connection transmission charges shall be computed in terms of Rupees per MegaWatt per month. The amount to be recovered from any Designated ISTS Customer towards ISTS charges shall be computed on a monthly basis as per these regulations. The Point of Connection transmission charges for short term open access transactions shall be in terms of [Paisa/unit] [Substituted 'Rupees per MegaWatt per hour' by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (w.e.f. 15.6.2010).] and shall be applicable for the duration of short term open access approved by the RLDC/NLDC.(5)The Implementing Agency may, after seeking approval of the Commission, conduct studies from time to time to refine the mechanism for sharing of transmission charges and losses as detailed in Annexure - I to these Regulations.

6. Mechanism of sharing of ISTS losses.

(1)The schedule of electricity of Designated ISTS Customers shall be adjusted to account for energy losses in the transmission system as estimated by the Regional Load Despatch Centre and the State Load Despatch Centre concerned. These shall be applied in accordance with the detailed procedure to be prepared by NLDC within 30 days of the notification of these regulations. The losses shall be apportioned based on the loss allocation factors determined using the Hybrid methodology.(2)The sharing of ISTS losses shall be computed based on the information provided by various Designated

ISTS Customers, ISTS Licensees, and any other relevant entity, including the NLDC, RLDCs and SLDCs and submitted to the Implementing Agency.Provided that in the event of such information not being available within the stipulated timeframe or to the level of detail required, the Commission may authorise the Implementing Agency to obtain such information from alternate sources as may be approved for use by the Commission.(3)The applicable transmission losses for the ISTS shall be declared in advance and shall not be revised retrospectively.(4)The Implementing Agency may, after seeking approval of the Commission, conduct studies from time to time to refine the ISTS loss allocation methods.

Chapter 4
Processes For Sharing of Transmission Charges and Losses

7. Process to determine Point of Connection Transmission Charges and Losses allocations.

(1)The process to determine the allocation of transmission charges and losses shall be as under, and as per timelines set out subsequently in Chapter 7 of these regulations:(a)The Implementing Agency shall collect the Basic Network data pertaining to the network elements and the generation and load at the various network nodes from all concerned entities including Designated ISTS Customers, transmission licensees, NLDC, RLDCs, SLDCs, RPCs;(aa)[No transmission charges and losses for the use of ISTS network shall be payable for the generation based on solar and wind power resources for a period of 25 years from the date of commercial operation of such generation projects if they fulfill the following conditions: [Added by Notification No. L-1/44/2010-CERC, dated 27.3.2019 (w.e.f. 15.6.2010).](i)Such generation capacity has been awarded through competitive bidding process in accordance with the guidelines issued by the Central Government;(ii)Such generation capacity has been declared under commercial operation between 13.2.2018 till 31.3.2022;(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.](b)The Basic Network shall not contain any electricity system, electrical plant or line below 132 kV except where generators are connected to the grid at 110 kV. Power flow into a lower voltage system from the voltage levels indicated in the definition of the Basic Network shall be considered as load at that sub-station. Power flow from a lower voltage system into the electricity systems at the voltage levels shall be considered as generation at that sub-station;(c)The dedicated transmission lines constructed, owned and operated by the ISTS Licensees shall be considered to be a part of the Basic Network. Dedicated lines constructed, owned and operated by the generator shall not be considered Page 8 of 42 as a part of the Basic Network. In the latter case, the generator will be deemed to be connected directly to the ISTS;(d)[Nodal generation information shall be based on the forecast data provided by the DICs. Such forecast data shall incorporate estimate of total maximum injection into the grid, considering the injection under long term access, medium term open access and short term open access during an Application Period. The forecast data submitted by the DICs shall be vetted by the Implementing Agency based on historical maximum generation levels obtained from the NLDC/RLDCs/SLDCs. Any variation in the forecast generation shall be communicated to the concerned DIC by the Implementing Agency. [Substituted by Notification No.

L-1/44/2010-CERC, dated 1.4.2015 (w.e.f. 15.6.2010).]The forecast generation in respect of each DIC shall be normalized with respect to forecast All India Peak Demand met to create base case for load generation balance to arrive at the approved injection.Approved injection figures so arrived shall be validated by the Validation Committee based on the injection data submitted by the DICs. In case data submitted by any DIC is different from the data computed on the basis of last three years' actual data, requisite justification by the concerned DIC shall be submitted for considering its data.The generating station for which three years' data are not available, forecast shall be prepared based on available data and the data submitted by the concerned generating station. In case no data is submitted by the generating station, estimated injection as prepared by the Implementing Agency shall be considered as approved injection.In case of DICs which are injecting into the grid for the first time, approved injection based on norms formulated by the Validation Committee for generation based on different types of stations shall be considered.All withdrawal DICs shall also submit estimated maximum generation from their own generating stations during the Application Period to the Implementing Agency to prepare the Base Case for load generation balance. The data as validated by the Validation Committee shall be final.Mis-declaration by a DIC beyond +/- 20% for two consecutive quarters shall be treated as gaming. Unless reasonably explained by the concerned DIC, the Implementing Agency shall report the matter to the Commission for appropriate directions.](e)[Forecast demand data shall be submitted by the DICs for each node or a group of nodes in a zone, identified by the Implementing Agency under these regulations. The forecast demand data shall incorporate estimate of maximum withdrawal. The forecast demand data submitted by DICs shall be vetted by the Implementing Agency based on historical demand met of each DIC during the periods corresponding to the Application Period. Any variation in the forecast demand shall be communicated by the Implementing Agency to the concerned DIC. [Substituted by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (w.e.f. 15.6.2010).]In case data submitted by a DIC is different from the data forecast on the basis of last three years actual data, requisite justification shall be submitted by the concerned DIC for considering its data. The data as validated by the Validation Committee shall be final.Mis-declaration by a DIC beyond +/- 20% for two consecutive quarters shall be treated as gaming. Unless reasonably explained by the concerned DIC, the Implementing Agency shall report the matter to the Commission for appropriate directions.](f)Implementing Agency shall prepare detailed procedures and formats for collection of the generation and demand data from each Designated ISTS Customer and the data pertaining to the Basic Network within 30 days of the notification of these regulations;(g)[In the event of difference of opinion between any DIC and the Implementing Agency with regard to the revised generation and demand data so obtained, the Validation Committee shall take final decision after considering the point of view of the concerned DIC and the Implementing Agency.] [Substituted by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (w.e.f. 15.6.2010).](h)The Implementing Agency shall run AC load flows using the Basic Network, nodal generation and nodal demand. To ensure Load Generation balance, adjustment may be required to be made on the vetted generation and demand data.(i)[Basic Network along with the converged load flow results for the injection and withdrawal data as per sub-clauses (d) and (e) of clause (1) of this Regulation shall be validated by the Validation Committee. The Basic Network, nodal generation, nodal demand and the load flow results for each Application Period shall be validated by the Validation Committee not later than 15 days prior to the commencement of each Application Period. The approved Basic Network, nodal generation, nodal demand along with the load flow results shall be made available on the websites of the Commission and the Implementing Agency immediately after its approval by the Validation Committee. [Substituted by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (w.e.f. 15.6.2010).]Provided that non-submission of data in time for computation of transmission charges shall be treated as non-compliance of the regulations and action as considered appropriate shall be taken by the Commission after giving an opportunity of hearing to the defaulting DIC.](j)Approved Basic Network, nodal generation and nodal demand data shall form the base for computation of Marginal Participation factors and loss allocation factors.(k)[Consequent to development of load flows on the Basic Network, the Hybrid Methodology shall be applied by the Implementing Agency on the Basic Network to determine the transmission charges and loss allocation factors attributable to each node in the power system.] [Substituted by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (w.e.f. 15.6.2010).](l)[Overall charges to be shared among the nodes shall be computed based on the Yearly Transmission Charges apportioned to each of the lines of the ISTS Licensees. The Yearly Transmission Charges, computed for the assets for each voltage level and conductor configuration shall be provided by the respective ISTS transmission licensees. The ISTS Licensees, deemed ISTS Licensees and owners of the non-ISTS Lines certified by the Regional Power Committees shall give the total Yearly Transmission Charges of their transmission assets, whose charges are to be recovered through the PoC mechanism in the application period along with circuit kilometers at each voltage level and for each conductor configuration. The total Yearly Transmission Charges shall be apportioned for each voltage level and conductor configuration based on the ratio of the indicative cost levels furnished by CTU at the beginning of each year or application period and approved by the Commission: [Substituted by Notification No. L-1/44/2010-CERC, dated 24.11.2011 (w.e.f. 15.6.2010).][Provided further that there shall be nine slab rates for PoC charges. The slab rates shall be computed by the Implementing Agency based on the methodology given in Annexure-I to these regulations. The slab rates shall be approved by the Commission for each Application Period. The number of slabs shall be reviewed by the Commission after two years.]][***] [Deleted 'sub-clause (m)' by Notification No. L-1/44/2010-CERC, dated 24.11.2011 (w.e.f. 15.6.2010).](n)[For the computation of transmission charges at each node as per Hybrid Methodology, cost of ISTS transmission licensees whose lines feature on the Basic Network shall be considered: [Substituted by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (w.e.f. 15.6.2010).]Provided that in case of STU lines which are physically inter-State lines and whose tariff is approved by the Commission, such tariff shall be considered for computation of PoC chages:Provided further that in case of non-ISTS lines (lines owned by STUs but being used for carrying inter-State power as certified by respective RPCs), the asset-wise tariff as approved by the respective State Commission shall be considered. Where asset-wise tariff is not available, the tariff as computed by the Commission based on the ARR of the STUs (as approved by respective State Commissions) by adopting the methodology similar to the methodology used for ISTS transmission licensees shall be considered. The transmission charges received by the concerned STU on this account shall be adjusted in its approved Annual Revenue Requirement.](o)[The participation factors, and the Point of Connection nodal and zonal rates thus determined, shall be computed for each Application Period. Detailed methodology for preparing the Base Case shall be in accordance with the methodology given in Annexure-I to these regulations. [Substituted by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (w.e.f. 15.6.2010).]Provided that the load flow studies shall be carried out by the Implementing Agency for each Application Period.](p)In order to give proper signals towards transmission charges based on distance and direction, the transmission charge per circuit kilometre shall have to be made uniform for each voltage level and conductor configuration. For this purpose, total transmission charges to be recovered for all lines of a given voltage level and conductor configuration shall be divided by the total circuit kilometre for that voltage level and line configuration in order to arrive at the average transmission charge per circuit kilometre for that voltage level and conductor configuration. [***] [Deleted 'Such charges shall then be attributed to peak and other than peak periods of each season based on the hours constituting these periods.' by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (w.e.f. 15.6.2010).] The total transmission charge for each line shall be recovered in proportion to the participation factors as detailed in Annexure - I to these Regulations. The process shall thereby ensure that the total charges for the lines are fully recovered;(q)[The recovery of the Yearly Transmission Charges (YTC) of the ISTS network shall be based on the Hybrid Methodology (PoC charge), Reliability Support Charge and HVDC Charge. Ten percent (10%) of the Yearly Transmission Charges shall be recovered through Reliability Support Charge Sharing methodology. The Commission may review the weightage accorded to Reliability Support Charge whenever deemed necessary. The Reliability support charge rates shall be determined separately and shall not be mixed with zonal PoC rates. The Reliability Support Charge shall be payable by the DICs in proportion to their Approved Withdrawal. In case of Injection DIC shaving Long Term Access to target region, Reliability Support Charges shall also be payable in proportion to their Approved Injection.] [Substituted by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (w.e.f. 15.6.2010).](r)The loss allocation factors shall be computed for each season using the Hybrid method as explained in Annexure - I to these regulations. The loss allocation factors shall be applied to the total losses, computed as per the procedures developed by the NLDC under these regulations, to attribute losses to each Designated ISTS Customer .(s)[The losses shall be apportioned to the DICs by suitably adjusting their scheduled MWs. The extent of adjustment shall be on the basis of losses apportioned to each DIC based on the Hybrid Methodology. The Detailed Procedure for application of losses to various DICs shall be modified by NLDC with the approval of the Commission. [Substituted by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (w.e.f. 15.6.2010).]Provided that there shall be nine slabs for calculation of transmission losses which shall be expressed in terms of percentage. There shall be 4 steps above the average loss and 4 steps below the average loss with a slab size of 0.25% subject to minimum loss of Zero percent. The slabs may be reviewed by the Commission after two years.](t)The Implementing Agency shall aggregate the charges for geographically and electrically contiguous nodes on the ISTS to create zones, in order to arrive at uniform zonal charge in Rs / MW / month. Implementing Agency shall create zones for generation and demand. Such zoning shall be governed by the following considerations:(i)Zones shall contain relevant nodes whose costs (as determined from the output from the Hybrid method) are within the same range.(ii)The nodes within zones shall be combined in a manner such that they are geographically and electrically proximate. The demand zones shall normally be the state control areas except in the case of North Eastern States, which are considered as a single demand zone. Generation zones are formed by combining the generators connected to the ISTS.(iii)The same zone can act as a generation zone as well as a demand zone for the purpose of calculation of Generation and demand zonal charges respectively. Even as it is preferable to have similar zones for generation and demand, this shall be pursued only when practical, and other conditions for zoning are met(iv)Transmission charges for thermal power generators either directly connected with ISTS or through pooling stations that are designed to handle generation capacity of more than 1500 MW for inter-state transfer shall be determined as charges at these specific nodes (such nodes would be considered as separate generation zones) and not clubbed with other generator nodes in the area.(v)Transmission charges for hydro power generators either directly connected with ISTS or through pooling stations that are designed to handle generation capacity of more than 500 MW for inter-state transfer shall be determined as charges at these specific nodes (such nodes would be considered as separate generation zones) and not clubbed with other generator nodes in the area.(iv)[Any inter-State Generating Station connected to the 400 kV inter-State Transmission System (including those connected to both 400 kV ISTS and STU) shall be treated as a separate zone and shall not be clubbed with other generator nodes in the area, for the purpose of calculation of PoC injection rate: [Substituted by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (w.e.f. 15.6.2010).]Provided that in case of a merchant power plant in a State connected to 400 kV inter-State Transmission System, with zero LTA or part LTA, injection considered in the Base Case or LTA, whichever is higher, shall be considered to arrive at the PoC injection rate.](vii)[In case an ISGS is connected only to STU network and the shares of the beneficiaries of the said station are being delivered through the STU network, such a line of the STU network shall be considered as an ISTS for the purpose of these regulations.] [Substituted by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (w.e.f. 15.6.2010).](u)No transmission charges for the use of ISTS network shall be charged to solar based generation. This shall be applicable for the useful life of the projects commissioned in next three years.(v)No transmission losses for the use of ISTS network shall be attributed to solar based generation. This shall be applicable for the useful life of the projects commissioned in next three years.[Provided that the above provision shall also be applicable for the useful life of the projects commissioned during the period 1.7.2014 to 30.6.2017.] [Added by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (w.e.f. 15.6.2010).](y)[No transmission charges and losses for the use of ISTS network shall be payable for the capacity of the generation projects based on solar resources for a period of 25 years from the date of commercial operation of the such generation projects if they fulfill the following conditions: [Added by Notification No. L-1/44/2010-CERC, dated 14.12.2017 (w.e.f. 15.6.2010).](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]; 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.(z)No transmission charges and losses for the use of ISTS network shall be payable for the generation based on wind power resources for a period of 25 years from the date of commercial operation of such generation 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 30.9.2016 till [12.2.2018] [Substituted '31.12.2019' by Notification No. L-1/44/2010-CERC, dated 27.3.2019 (w.e.f. 15.6.2010).]; and(iii)Power Purchase Agreement(s) have been executed for sale of such generation capacity to the Distribution Companies for compliance of their renewable purchase obligations.](2)Detailed methodological aspects are set out in Annexure - I to these regulations. The Commission may modify or update the above processes from time to time based on the emergent needs for determining the Point of Connection transmission charges and allocation of losses.

8. Determination of specific transmission charges applicable for a Designated ISTS Customer.

(1)Based on the Yearly Transmission Charges determined by the Commission, the Implementing Agency shall determine the charges applicable to each Designated ISTS Customer for use of the ISTS to the extent of the Approved Withdrawal or Approved Injection in the ISTS. Each Designated ISTS Customer shall ensure that the forecast data of demand and injection for each season is furnished to the Implementing Agency as per the timelines described in these regulations [***] [Deleted 'for both peak and other than peak conditions' by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (15.6.2010).] as specified in Chapter 7 of these regulations;(2)In the event of a Designated ISTS Customer failing to provide its requisition for demand or injection for an Application Period, the last demand or injection forecast supplied by the Designated ISTS Customer and as adjusted by the Implementing Agency for Load Flow Analysis shall be deemed to be Approved Withdrawal or Approved Injection, as the case may be, for the Application Period;(3)The transmission charges for any month shall be determined as per Regulation 11 of these Regulations;(4)In case the metered MWs (ex-bus) of a power station or the aggregate demand of a Designated ISTS Customer exceeds, in any time block,(a)In case of generators: The Approved Injection + Approved Additional Medium Term Injection + Approved Short Term Injection or;(b)In case of demand customers: The Approved Withdrawal + Approved Additional Medium Term Withdrawal + Approved Short Term Demand,Then for first 20% deviation in any time block, the Designated ISTS Customer shall be required to pay transmission charges for excess generation or demand at the same rate and beyond this limit, the Designated ISTS Customer shall be required to pay additional transmission charges which shall be 25% above the zonal Point of Connection charges determined for zone where the Designated ISTS Customer is physically located. Such additional charges shall not be charged to the generators in case of rescheduling of the planned maintenance program which is beyond the control of the generator and certified to be so by the appropriate RPC. Further, any payment on account of additional charges for deviation by the generator shall not be charged to its long term customer and shall be payable by the generator;(5)[Where the Approved Withdrawal or Approved Injection in case of a DIC is not materializing either partly or fully for any reason whatsoever, the concerned DIC shall be obliged to pay the transmission charges allocated under these regulations:Provided that in case the commissioning of a generating station or unit thereof is delayed, the generator shall be liable to pay Withdrawal Charges corresponding to its Long term Access from the date the Long Term Access granted by CTU becomes effective. The Withdrawal Charges shall be at the average withdrawal rate of the target region:Provided further that where the operationalization of LTA is contingent upon commissioning of several transmission lines or elements and only some of the transmission lines or elements have been declared commercial, the generator shall pay the transmission charges for LTA operationalised corresponding to the transmission system commissioned:Provided also that where the construction of dedicated transmission line has been taken up by the CTU or the transmission licensee, the transmission charges for such dedicated transmission line shall be payable by the generator as provided in the Regulation 8 (8) of the Connectivity Regulations:[Provided also that a generating station drawing start-up power or injecting infirm power before commencement of LTA shall be liable to pay the withdrawal or injection charges corresponding to the actual injection of infirm power or withdrawal start-up power during a month (concerned month) and the amount received on account of such payments shall be reimbursed to the DICs in the month following the month of billing, in proportion to the billing of the DICs during the concerned month.] [Substituted by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (15.6.2010).]Provided also that CTU shall maintain a separate account for the above amount received in a quarter and deduct the same from the transmission charges of ISTS considered in PoC calculation for the next application period.](6)[For Long Term Transmission Customers availing power supply from inter-State generating stations, the charges attributable to such generation for long term supply shall be calculated directly at drawal nodes as per methodology given in the Annexure-I. Such mechanism shall be effective only after commercial operation of the generator. Till then it shall be the responsibility of the generator to pay transmission charges.] [Substituted by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (15.6.2010).](7)[DIC with LTA to target region whose POC rate has not been determined for the quarter, shall be billed at Average PoC rate of the target region.] [Added by Notification No. L-1/44/2010-CERC, dated 14.12.2017 (w.e.f. 15.6.2010).]

9. Differentiation among various categories of transmission Designated ISTS Customers.

(1)There shall be no differentiation in Point of Connection charges between the long term, medium term and short term Designated ISTS Customers of the transmission system.

Chapter 5
Accounting, Billing and Collection of Charges

10. Accounting of charges.

(1)Monthly Transmission Accounts applicable for various Designated ISTS Customers in each region shall be prepared by the respective RPC on the basis of:(a)Approved Withdrawal / Injection (MW) [***] [Deleted 'for peak and other than peak hours' by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (15.6.2010).] to be received from Implementing Agency,(b)Zonal Point of Connection charge (Rs / MW / month) to be received from Implementing Agency(c)Approved Additional Medium Term Withdrawal / Injection (MW) to be received from RLDC / NLDC,(d)Processed meter reading from all SEMs for computation of deviations from the sum of the Approved Withdrawal / Injection, Approved Additional Medium Term Withdrawal / Injection and Approved Short Term Withdrawal / Injection (MW) and time blocks for which such deviation is recorded. This data shall be received from RLDCs,RPC shall, based on Regulation 11.1(a), 11.1(b) and11.1(c), issue Regional Transmission Accounts on the 1st working day of the month for the previous month, to all Designated ISTS Customer s, CTU and other ISTS Transmission Licensees and display the same on its web site.RPC shall, based on Regulation 11.1(d), issue Regional Transmission Deviation Accounts by 15th of every month for the previous month to all Designated ISTS Customer s, CTU and other ISTS Transmission Licensees and display the same on the website of the respective RPCs.

11. Billing.

(1)The CTU shall be responsible for raising the transmission bills, collection and disbursement of transmission charges to ISTS transmission licensees. Any expenses incurred by CTU on account of this function shall be reimbursed as part of Yearly Transmission Charge;(2)The bill for the use of the ISTS shall be raised by the CTU on the concerned Designated ISTS Customers. The SEB/STU may recover the transmission charges for the use of the ISTS from the distribution companies, generators and bulk customers connected to the transmission system owned by the SEB/STU/intrastate transmission licensee in a manner approved by the Appropriate Commission.(3)The billing for ISTS charges for all Designated ISTS Customers shall be on the basis of Rs./MW/Month, and shall be raised by the CTU in three parts.(4)[The first part of the bill shall recover charges for use of the transmission assets of the ISTS Licensees based on the Point of Connection methodology. This part of the bill shall be computed in three sub-parts as under:

1. Point of Connection transmission charge towards LTA/MTOA. - For Generators having LTA to target region:

[PoC transmission rate of generation zone in Rs / MW / month] x[(Approved Injection)]For Demand:[PoC transmission rate for demand zone in Rs /MW /month] x[(Approved Withdrawal)]

2. Reliability Support Charge. - For Generators having LTA to target region:

[Reliability Support Rate in Rs /MW /month] x[(Approved Injection)]For Demand:[Reliability support r ate in Rs /MW /month] x[(Approved Withdrawal)]

3. HVDC charge. - (i) 10% of Monthly Transmission Charges (MTC) of HVDC transmission system shall form part of Reliability Support Charges and the balance shall be billed as detailed below:

Transmission charges for HVDC system created to supply power to specific regions shall be borne by DICs of such regions. The HVDC Charge shall be payable by DICs of the Region in proportion to their Approved Withdrawal. In case of Injection DICs having Long Term Access to target region, it shall also be payable in proportion to their Approved Injection.For Generators having LTA to target region:[HVDC Charge for Region in Rs/month] x [Approved Injection] / [Total Approved Withdrawal of the Withdrawal DIC and Approved Injection of the Generator having LTA to target Region]For Demand:[HVDC Charge for Region in Rs/month] x [Approved Withdrawal] / [Total Approved Withdrawal of the Withdrawal DIC and Approved Injection of the Generator having LTA to target Region](ii)HVDC Charge shall also be applicable for additional MTOA. Over/under recovery of HVDC charges shall be adjusted in the third part of bill in a manner as provided in Regulation 11(6) of these Regulations.(iii)Where transmission charges for any HVDC system are to be partly borne by a DIC (injecting DIC or withdrawal DIC, as the case may be) under a PPA or any other arrangement, transmission charges in proportion to the share of capacity in accordance with the PPA or other arrangement shall be borne by such DIC and the charges for balance capacity shall be borne by the remaining DICs by scaling up of MTC of the AC system included in the PoC. Such HVDC shall not be considered under (i) above.This first part of the bill shall be raised based on the Point of Connection rates, Reliability Support rate, HVDC Charge, Approved Withdrawal and Approved Injection for each DIC, provided by the Implementing Agency on the next working day of uploading of the Regional Transmission Accounts by the respective Regional Power Committees on their websites in each month for the previous month and determined prior to the commencement of the application period:Provided that the list of transmission assets along with the approved transmission charges for which billing has been done shall be enclosed with the first part of the bill:Provided further that the charges for the DICs having long term access without beneficiaries shall comprise the Injection POC Charges, Reliability Support Charges and HVDC Charges.] [Substituted by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (15.6.2010).](5)[The second part of the bill shall be raised to recover charges for Additional Approved Medium Term Open Access which shall be computed as follows:For Demand:[PoC Transmission rates for demand zone in Rs /MW /month] x[(Approved Additional Medium Term Withdrawal)]The second part of the bill shall be raised on the DICs alongwith the first part of the bill:Provided that the revenue collected from the approved additional Medium-term injection, which has not been considered in the Approved Injection/Approved Withdrawal, shall be reimbursed to the DICs having Long-term Access in the following month, in proportion to the monthly billing of the respective month:[Provided further that the quantum of Medium Term open access to any region availed during a month by a DIC having long term access to a target region without identified beneficiaries shall be adjusted against the long-term access of such DIC limited to granted quantum of long term access:] [Substituted by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (15.6.2010).]Provided also that a generator who has been granted Long-term Access to a target region shall be required to pay PoC injection charge for the remaining quantum after offsetting the quantum of Medium-term Open Access:Provided also that where a generator is liable to pay withdrawal charges for the specified quantum as per the terms of any MTOA contract, then injection charges for same quantum of power shall be offset against LTA granted.]The second part of the bill shall be raised on the Designated ISTS Customer s along with the first part of the bill.(6)[The third part of the bill shall be used to adjust any variations in FERV, Incentive, rescheduling of commissioning of transmission assets, arrears due to any revision Order etc. as allowed by the Commission for any ISTS Transmission Licensee. Total amount to be recovered or reimbursed on account of such under-recovery or over-recovery shall be billed by the CTU to each DIC in proportion of its average Approved Injection or Approved Withdrawal Charges over the relevant PoC application period. This part of the bill shall be raised on first working day of September, December, March and June for the previous PoC application period.] [Substituted by Notification No. L-1/44/2010-CERC, dated 14.12.2017 (w.e.f. 15.6.2010).](7)Deviations shall be billed separately by the CTU. This bill shall charge the Designated ISTS Customers for deviations from the sum of the Approved Withdrawal, Approved Additional Medium Term Withdrawal and Approved Short Term Withdrawal (MW) or Approved Injection, Approved Additional Medium Term Injection and Approved Short Term Injection (MW). This part of the bill shall be computed as:For Generators:In case Average MW injected during time block of positive deviation is greater the sum of Approved Injection, Approved Additional Medium Term Injection and Approved Short Term Injection, then for the first 20% deviation, transmission charges shall be at the zonal Point of Connection charges for the generation zone.For deviation beyond 20%, the additional transmission charges shall be 1.25 times the zonal

Point of Connection charges for the generation zone.In case a generator instead of injecting, withdraws from the grid, the additional transmission charges shall be computed as

1. [25× PoC Transmission Charge for the demand zone in Rs /MW / time block]×

[(Average MW Withdrawal during time blocks of such negative deviation)]For Demand:In case Average MW withdrawal during time block of positive deviation is greater the sum of Approved Withdrawal, Approved Additional Medium Term Withdrawal and Approved Short Term Withdrawal, then for the first 20% deviation, transmission charges shall be at the zonal Point of Connection charges for the demand zone.For deviation beyond 20%, the additional transmission charges shall be 1.25 times the zonal Point of Connection charges for the demand zone.In case a withdrawing DIC becomes a net injector the additional transmission charges shall be computed as[(Average MW Injected during time blocks of such negative deviation)]

1. [25× PoC Transmission Charge for the generation zone in Rs /MW / time block]×

[This bill shall be raised by the CTU within 3 (three) working days of the issuance of the Regional Transmission Deviation Account by the RPCs:Provided that the agency of the State responsible for the intimation of deviation on account of Unscheduled Interchange energy shall be the agency responsible for the intimation of deviation on account of the transmission usage to the respective RPCs, for inclusion of the same in their Regional Transmission Deviation Account (RTDA):Provided further that the revenue collected against the Bill for Deviation from DICs in the synchronously connected grid shall be reimbursed to the DICs in the same synchronously connected grid having Long-term Access, in the following month, in proportion to the monthly billing of the respective month.] [Substituted by Notification No. L-1/44/2010-CERC, dated 24.11.2011 (w.e.f. 15.6.2010).][***] [Deleted '(8) Revenue from Approved Additional Medium term open access that was not considered in the Approved Injection / Approved Withdrawal shall be used for truing up the Yearly Transmission Charge for the next financial year' by Notification No. L-1/44/2010-CERC, dated 24.11.2011 (w.e.f. 15.6.2010).].(9)The governance of the Short Term Open Access Transactions shall be as per the Central Electricity Regulatory Commission (Open Access in inter-State Transmission) Regulations, 2008 and as amended by the Commission from time to time with the exception that the Transmission Charges for Short Term Open Access Transactions shall be the Zonal Point of Connection charges as determined by these regulations.[Provided that the DICs which were granted LTA to a target region and are paying injection charges for Long Term Access, the injection PoC Charges and Demand PoC Charges paid for Short Term Open Access to any region shall be adjusted in the following month against the monthly injection PoC Charges for Approved injection:Provided further that a generator, who has been granted Long-term Access to a target region, shall be required to pay PoC injection charge for the Approved injection for the remaining quantum after offsetting the charges for Medium-term Open Access, and Short-term open access:Provided also that the injection PoC charge/Withdrawal PoC charges for Short-term open access given to a DIC shall be offset against the corresponding injection PoC charges or Withdrawal

PoC charges to be paid by the DICs for Approved injection/Approved withdrawal corresponding to Net withdrawal (load minus own injection) considered in base case:Provided also that for withdrawal DIC, this adjustment is given only for STOA transaction by DIC and not applicable to other intra-State entity embedded in State and engaged in STOA:Provided also that this adjustment shall also be allowed for collective transactions. Generators who are granted LTA to a target region shall be given adjustment corresponding to injection charges and withdrawal DICs shall be given adjustment corresponding to withdrawal charges:Provided also that this adjustment shall not be allowed for collective transactions and bilateral transactions carried out by any trading licensee, who has a portfolio of generators in a State for which LTA was obtained to a target region.] [Substituted by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (15.6.2010).](10)[The offset for STOA for a DIC paying charges under LTA shall be as follows:(a)If a DIC, having LTA to a target region without identified beneficiaries and paying injection charges for Long Term Access, avails Short Term Open Access to any region:(i)The charges for the quantum of Short Term Open Access shall be adjusted in the following month against the charges for Long Term Access of such DIC limited to the granted quantum of Long Term Access.(ii)This offset shall be limited to the extent of the quantum for which DIC has paid transmission charges towards long term access.(b)The quantum of power for which a DIC is granted STOA shall be offset against the Approved withdrawal for which Withdrawal PoC charges are paid by the concerned DIC. This offset shall be limited to difference between Approved Withdrawal and Net withdrawal (load minus own injection) considered in base case, if Approved withdrawal is less than the Net Withdrawal:(c)For Withdrawal DIC, this adjustment shall be given only for STOA transaction by DIC, and shall not be applicable to intra-State entities embedded in State network and availing STOA:(d)The adjustment for STOA availed by a DIC having LTA to target region without identified beneficiaries shall also be applicable in case of collective transactions undertaken by concerned DIC. In such cases, Injection DICs shall be given adjustment corresponding to injection charges and withdrawal DICs shall be given adjustment corresponding to withdrawal charges:(e)The adjustment of STOA against LTA shall not be applicable for collective transactions and bilateral transactions undertaken by a trading licensee, who has a portfolio of generators in a State for which LTA was obtained by the trading licensee to a target region.]

12. Collection.

(1)The CTU shall collect charges on account of the first part of the bill as computed in accordance with Regulation 11(4) of these Regulations on behalf of the ISTS service providers and thereafter redistribute the same to Transmission Licensees in the ISTS in proportion to their respective Monthly Transmission Charges;(2)The CTU shall collect charges on account of the second part of the bill as computed in accordance with Regulation 11(5) of these Regulations and thereafter distribute the same to Transmission Licensees in the ISTS in proportion to their respective Monthly Transmission Charges. This amount along with the interest thereon shall be adjusted in the Yearly Transmission Charge (to be used for the computation of Point of Connection charges) of the respective transmission licensee for the next financial year;(3)The CTU shall collect charges on account of the third part of the bill as computed in accordance with Regulation 11(6) of the section on Billing of these Regulations and thereafter transfer the same to respective ISTS Transmission Licensees for whom this adjustment bill is required;(4)The CTU shall collect charges on account of the fourth part of the bill as computed in accordance with Regulation 11(7) of these Regulations and thereafter distribute the same to Transmission Licensees in the ISTS in proportion to their respective Monthly Transmission Charges. This amount along with the interest thereon shall be adjusted in the Yearly Transmission Charge (to be used for the computation of Point of Connection charges) of the respective transmission licensee for the next financial year;(5)The payment by various Designated ISTS Customer s and disbursement to various ISTS Licensees and the owners of Deemed Inter State Transmission System shall be executed through RTGS.(6)Every Designated ISTS Customer shall ensure that the charges payable by them are fully discharged within the time-frame specified in the Transmission Service Agreement or the amended Bulk Power Transmission Agreements. Disputes, if any shall be resolved as per the provisions of the Transmission Service Agreement or the amended Bulk Power Transmission Agreement s as specified in Chapter 6 of these regulations.(7)Delayed payment in a month by any Designated ISTS Customer shall result is prorata reduction in the payouts to all the ISTS Licensees and other non-ISTS Licensees whose assets have been certified as being used for interstate transmission by the RPCs.(8)Designated ISTS Customers shall provide payment security as determined through detailed procedures developed by the CTU. The level of such payment security shall be related to the Approved Withdrawal or Approved Injection.(9)CTU shall prepare a detailed procedure for Billing, Collection and Disbursement and present the same to the Commission for approval within 30 days of the notification of these regulations.

Chapter 6
Commercial Agreements

13. Transmission Service Agreement (TSA).

(1)The Designated ISTS Customers and the CTU shall enter into new transmission services agreement or modify the existing Bulk Power Transmission Agreements to incorporate the new tariff and related conditions. Such agreement shall govern the provision of transmission services and charging for the same and shall be called the Transmission Service Agreement (TSA) and shall, inter-alia, provide for:-(a)Detailed commercial and administrative provisions relating to sharing of ISTS charges and losses based on principles derived from these regulations;(b)Provisions on metering, accounting, billing and recovery of charges for the ISTS from the constituents;(c)Procedures for declaration and approval of contracted capacity at each node or an aggregation of nodes in the ISTS for each Designated ISTS Customer;(d)Detailed procedures and provisions for connection by the Designated ISTS Customer s at the inter-connection points, including the processes for requisitioning new inter-connection capacity on the ISTS;(e)Procedures and provisions for treatment of over or under injections by the Designated ISTS Customers;(f)Procedures and provisions for treatment of the delay in injection / withdrawal by Designated ISTS Customers;(g)Treatment of the delay in commissioning of transmission lines;(h)Payment security mechanisms;(i)Default and its consequences;(j)Dispute resolution mechanisms;(k)Term of the agreement and the termination provisions;(l)Force Majeure Conditions; and(m)Any other matter that is relevant for the Point of Connection transmission charge and loss allocation mechanism.(2)Within 30 days of notification of these regulations, the CTU shall publish the draft Model Transmission Service Agreement on its website and invite public comments on the same.(3)The CTU shall, after duly considering the public comments, submit the draft Model Transmission Service Agreement to the Commission for its approval within 60 days of the notification of these regulations.(4)The final version of the Model Transmission Service Agreement, as approved by the Commission, shall be notified and used as the base transmission service agreement by the ISTS Licensees.(5)The notified Model Transmission Service Agreement shall be the default transmission agreement and shall mandatorily apply to all Designated ISTS Customers.(6)The Transmission Service Agreement may have separate provisions for long term, medium term and short term access to the ISTS.(7)Signing of the Transmission Service agreement shall not be a pre-condition for construction of new network elements by the CTU and Transmission Licensees, provided that such network construction is undertaken after due approval of the Commission.(8)The Transmission Service Agreement may have aspects that are amended from time to time by the signatories without the entire agreement being replaced or being rendered infructuous. Such aspects may include the contracted capacity, commercial terms, and reliability requirements, if any. Change of such terms shall be guided by the technical configuration and capabilities of the power system.(9)The CTU shall enter into a separate Revenue sharing agreement with other ISTS transmission licensees to disburse monthly transmission charges among various transmission licensees. The impact of any delayed payment / non-payment by any Designated ISTS Customer shall be shared pro-rata in proportion of their Yearly Transmission Charge by all the transmission licensees including the CTU. The CTU shall submit the Revenue Sharing Agreement within 30 days of the notification of these regulations for approval by the Commission.

14. Amendment of existing contracts.

(1)All existing users of the ISTS and the Transmission Licensees shall ensure that their existing contracts are realigned to these regulations within a period of 60 days from the date of notification of the Transmission Service Agreement insofar as the elements related to determination of Point of Connection transmission charges, allocation of losses, billing and collection, provision of information, and any other matter that requires amendment or realignment consequent to these regulations.

15. Transition Period/Mechanism.

(1)The Commission shall notify detailed procedures as proposed by the Implementing Agency, NLDC and the CTU to be followed under these regulations, along with corresponding timelines, as far as possible within 3 (three) months from the notification of these regulations. Such Procedures shall include:-(a)Procedures for provision of information by Designated ISTS Customers and other constituents as prepared by Implementing Agency and approved by the Commission;(b)Procedures to be followed by the Implementing Agency for computation of charges as prepared by Implementing Agency and approved by the Commission;(c)Procedures for sharing of losses according to the methodology set out in these Regulations as prepared by NLDC and approved by the Commission;(d)Procedures for Billing and collection of charges by the CTU on behalf of the Transmission Licensees and redistribution of the same (including amounts over or under collected) as prepared by the CTU and approved by the Commission; and(e)Payment and payment security related procedures as prepared by the CTU and approved by the Commission.(2)The Implementing

Agency shall ensure smooth transition to the new mechanism and shall take necessary steps to disseminate information and build capacity among the Designated ISTS Customer s and the ISTS Licensees.

Chapter 7
Information Procedures

16. Provision of information by Designated ISTS Customers and other constituents.

(1)On or before [At least 45 days prior to the beginning of the application period] [Replaced 'the end of the fourth week of November in each Financial Year' by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (w.e.f. 15.6.2010).], each Designated ISTS Customer whose network forms a part of the Basic Network, ISTS licensee and owners of Deemed Inter State transmission systems whose charges are to be recovered from Designated ISTS Customers, shall supply the Implementing Agency with Basic Network details, Yearly Transmission Charge computations, and any other information required by the Implementing Agency to compute the Page transmission charges for allocation and apportionment as detailed in the Procedures for provision of information by Designated ISTS Customers and other constituents prepared by NLDC consequent to these Regulations.(2)On or before [At least 45 days prior to the beginning of the application period] [Replaced 'the end of the fourth week of November in each Financial Year' by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (w.e.f. 15.6.2010).], each Designated ISTS Customer shall supply the Implementing Agency with its demand or injection forecast for each season of the following Financial Year to enable the Implementing Agency to use such demand and injection forecast as the basis for calculation of the transmission charge and loss allocators for the period.Provided that, if necessary, the information may be sought by the Implementing Agency at times other than those indicated in regulation 16 (1) and 16 (2).(3)Data to be submitted by CTU, owners of Deemed Inter State transmission systems and Designated ISTS Customer s whose assets are used in the Basic Network:(a)In the first year of implementation: the entire network data including that used for load flow analysis in the formats prescribed by the Implementing Agency , line-wise / network element-wise Yearly Transmission Charge ;(b)In the subsequent years: data and dates of commissioning of any new transmission asset in the [next Application Period] [Replaced 'next financial year' by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (w.e.f. 15.6.2010).] and their Yearly Transmission Charge approved by the Commission / provisional Yearly Transmission Charge , based on Commission norms in case such Yearly Transmission Charge is not approved by the Commission.(4)Data to be submitted by Designated ISTS Customers connected to ISTS:(a)[MW and MVAR Data for injection or drawal at various nodes or a group of nodes shall be submitted for maximum injection/maximum withdrawal for each application period. Such data shall include the power tied in long term contracts and approved medium term open access agreements.] [Substituted by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (w.e.f. 15.6.2010).][***] [Deleted '(b) In case any of the above fall on a Weekend/Public Holiday, the data shall be submitted for working days immediately after the dates indicated' by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (w.e.f. 15.6.2010).].(5)In the first year of the implementation of these regulations, the

Designated ISTS Customers and Transmission Licensees shall submit the Injection / Demand data, network data and Yearly Transmission Charge data to the implementing agency not later than 60 days of the notification of these regulations in formats provided by Implementing Agency ;(6)In case, large changes in the Point of Connection charges are foreseen on account of the network or its usage undergoing substantial change, the Implementing Agency may file a petition before the Commission, and undertake the revised computations only upon issuance of the Commission's orders in this regard;

17. [Information to be published by the Implementing Agency. [Substituted by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (w.e.f. 15.6.2010).]

(1)The information to be provided by the Implementing Agency consequent to the computations undertaken shall include:(a)Approved Basic Network Data and Assumptions, if any;(b)Zonal and nodal transmission charges for the ensuing Application Period;(c)Zonal and nodal transmission losses data for the ensuing Application Period;(d)Schedule of charges payable by each constituent for the ensuing Application Period;(e)YTC detail (Information submitted by the transmission licensees covered under these Regulation and computation by Implementing Agency);(f)Zone wise details of PoC Charges to enable each DIC to see details of transmission lines it is using and whose transmission charges it is sharing;(g)LTA /MTOA and their commencement schedule.]

Chapter 8
Implementation Arrangements

18. Implementing Agency.

(1)Based on the Yearly Transmission Charge, the allocation of the ISTS Charges and Losses shall be allocated by an entity authorised by the Commission for the purpose and shall be designated as the Implementing Agency.Provided that for the first two years of the notification of these regulations the NLDC shall be the Implementing Agency.(2)The Implementing Agency shall submit, for approval of the Commission, a detailed procedure along with the data formats for obtaining data from Designated ISTS Customers, ISTS Licensees and non-ISTS Licensees whose assets have been certified by RPCs as being used for inter-state transmission, within 30 days of notification of these regulations for the Implementation of the Point of Connection method, guidelines for which have been detailed in the Annexure - I to these regulations.(3)The Implementing Agency shall determine the allocation and sharing of transmission charges and losses for each financial year, which may be differentiated on a seasonal basis.(4)The Implementing Agency shall be reimbursed the expenses incurred for the computation of transmission charges (for the purpose of allocation and apportionment thereof) as per Yearly Transmission Charges approved by the Commission. The software for the implementation of transmission tariffs shall be audited by the Commission before it is commissioned, and thereafter before any changes are made to the software or implementation methodology. The Software shall be made available to Implementing Agency by the Commission;

Chapter 9
Miscellaneous

19. Savings and Repeal.

(1)Save as otherwise provided in these regulations, Regulation 33 of the Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2009, Regulation 16(1) and 16(2) of the Central Electricity Regulatory Commission (Open Access in inter-State Transmission) Regulations, 2008 are hereby repealed.(2)Not withstanding 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.

20. Power to Relax.

(1)The Commission may, for reasons to be recorded in writing, relax any of the provisions of these regulations on its own motion or on an application made before it by an interested person.

21. Power to Remove Difficulties.

(1)If any difficulty arises in giving effect to any of the provisions of these Regulations, the Commission, may by general or special order, direct the Implementing Agency, NLDC, CTU, RLDC, RPC, ISTS Licensees and Designated ISTS Customers, to take suitable action, not being inconsistent with the provisions of the Act, which appears to the Commission to be necessary or expedient for the purpose of removing the difficulties.(2)The Implementing Agency, NLDC, CTU, RLDC, RPC, ISTS Licensees and Designated ISTS Customers may make an application to the Commission and seek suitable orders to remove any difficulties that may arise in implementation of these Regulations.(3)Notwithstanding Sub-Regulations (1) and (2), if any difficulty arises in giving effect to the provisions of these Regulations, the Commission may, by general or specific order, make such provisions not inconsistent with the provisions of the Act, as may appear to be necessary for removing the difficulty.AnnexureI. Philosophy of Point of Connection Based Transmission Pricing Mechanism and Selection of the Hybrid MethodEfficient pricing of a commodity or service needs to reflect the marginal cost of utilization of the underlying resources that are used in the provision of that commodity or service. The 'operational' term here is 'utilization'. The pricing mechanism must therefore be able to capture the utilization, and charge for the resources being utilized.Utilization of the network is generally determined in terms of either average utilization or marginal utilization of the transmission assets. Pricing of transmission services based on average or marginal utilization of the network branches is known as Average Participation or Marginal Participation method respectively. These two methods have been compared and contrasted in detail in the literature. These methods are discussed in detail below.1.1Marginal Participation Method. - Any usage based methodology tries to identify how much of the power that flows through each of the lines in the system is due to the existence of a certain network user, in order to charge it according to the adopted measure of utilization. To do so, the marginal participation method analyzes how the flows in the grid are modified when minor changes are introduced in the production or consumption of agent i. For each of the considered scenarios (for each season) the procedure can be considered as follows:a. Marginal Participation sensitivities Aij are obtained that represent how the flow in line j changes when the injection in bus i is increased by 1 MW. The increase in 1 MW has to be compensated by a corresponding increase in load or generation at some other bus or buses - called the slack bus(es).b. Total participations for each agent are calculated as a product of its net injection by its marginal participation. If net injection is considered positive for generators and negative for demands, the total participation of any agent i in line j is Aij(generationi - demandi).c. The cost of each line is allocated pro-rata to the different agents according to their total participation in the corresponding line.1.2Average Participation Method. - The method of average participation works as follows:

1. For every individual generator i, a number of physical paths are constructed, starting at the node where the producer injects the power into the grid, following through the lines as the power moves through the network, and finally reaching several of the loads in the system.

2. Similar calculations are also performed for the demands, tracing upstream the energy consumed by a certain user, from the demand bus until some generators are reached. One such physical path is constructed for every producer and for every demand.

3. In order to create such physical paths, a basic criterion is adopted: A rule allocates responsibility for the costs of actual flows on various lines from sources to sinks according to a simple allocation rule, in which inflows are distributed proportionally between the outflows. The main attractions of tracing are that the rule has some theoretical backing based and does not require the choice of a slack node. The drawbacks of tracing are first that aggregation of users can lead to counterintuitive results: if generation and load or different nodes are aggregated, then they are exposed to different tariffs. Second, the choice of the allocation rule is decisive but apparently arbitrary. An illustrative example of the proportional allocation mechanism is demonstrated in Fig.3 below.

Fig. 3: Average Participation MethodThe average participation method calculates the participation of agent i by tracking the influence in the network of a transit between node i and several ending nodes that result from the rules that conform the algorithm. In the example above, based on flow in the outgoing lines, the injection of 40MW (through the red line) is allocated to the outgoing lines in the proportion of the transfers from the two outgoing lines. Thus the outgoing line that transfers 30 MW (i.e, 30% of the total transfer out of the bus) is allocated 30% of the 40 MW injection from the red line, i.e., 12 MW. Similar allocations are made for the other flows as well.1.3Reasons for

Adoption of the Hybrid Method. - The Marginal Participation method (with slight modifications to the above generic framework) has been implemented in various countries including United Kingdom, Norway (for transmission losses), Brazil, Columbia etc. There is however little international experience in the use of the Average Participation Method. Further in the Indian context the Hybrid Method - where the slack buses are selected by using the Average Participation Method and the burden of transmission charges or losses on each node is computed using the Marginal Participation Method was found appropriate because:• The nodal transmission access charges in the AP method have a higher variance. A compared to the range of transmission access charges in the Hybrid method (Rs 2.98 - 17.75 lakh / MW), the range in the AP method (Rs. 2.79 - 53.61 lakh / MW) is much higher.• Further, since Hybrid method takes into account all the incidental flows - which is the reality of interconnected transmission networks - the Hybrid Method captures network utilization much better than the AP method, which simply traces the path of power from the origin to the sink(s) or vice-versa. Because of the ability of the Hybrid method to consider incidental flows, the method captures network 'utilization' better than AP method - which is one of the objectives of the NEP.To illustrate the above point further, consider the following network and the flows indicated therein:Under Average Participation Method, tracing from generator at Node-A would lead to the consideration of utilization of Line 2 for load 2 and Line 2 and Line 6 for load 1. However, it can be seen from the above network diagram, that keeping the generation at Node B constant, an increase in generation at Node A is expected to lead to an increase in flow in Line 4, Line 5 and Line 3 (Flow in Line 1 will be from Node B to Node A, as in the base case, but with an increase in generation at Node A, the magnitude of flow will reduce). While the AP Method captures utilization of Line 2 and Line 6, it fails to consider the impact of generation at Node A on Line 4, Line 5 and Line 3. Application of the AP method, in this case, would lead to very low nodal charges at Node A and high Nodal Charges at Node B and hence an inaccurate estimation of line utilization. Application of the MP method, on the other hand, would capture utilization better by attributing some percentage of utilization of Line 3, Line 4 and Line 5 to Node A.Hybrid Method - a combination of the Average Participation and the Marginal Participation Method, while considering the absorption of power generated at Node A by Load 1 and Load 2 only (as determined using AP method), considers the utilization of Line 3, Line 4 and Line 5 also, as opposed to the consideration of only Line 2 and Line 6, as in the pure AP method.• The criticism of the MP method that the results are dependent on the choice of the slack bus is obviated because of the revised method of selection of slack buses which is based on the AP method.

2. Pricing Mechanism Under Selected Framework. - As discussed in the previous sections, based on the review of the international experience, the literature and the Indian system, the Hybrid method - a hybrid of the Marginal and Average Participation Methods has been found to be most appropriate. The details of the hybrid method are discussed in sections below. Following steps shall be followed in the implementation of the Hybrid Methodology:

1. Data Acquisition

2. Computation of Load Flows on the Basic Network

3. Network Reduction

4. Identification of Slack Node(s)

5. Hybrid Methodology for the determination of transmission charges

6. Hybrid Methodology for the determination of transmission losses

7. Determination of Sharing of YTC and Losses

8. Creation of Zones

2.1Data Acquisition: Inputs to the Model. - The transmission pricing model requires a set of inputs representative of [maximum injection/maximum withdrawal] [Substituted 'peak and other than peak conditions' by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (w.e.f. 15.6.2010).] in each of the blocks of months as required by the Central Electricity Regulatory Commission (Sharing of Inter State Transmission Charges and Losses) Regulations, 2010 on the transmission system:• Nodal generation information• Nodal demand information• Transmission circuits between these nodes and their electrical characteristics required for load flow analysis, the associated lengths of these transmission lines and its capacity, Yearly Transmission Charges (YTC) of each line• Identification of a reference node (s)

2. [1.1 Nodal Generation and Demand Information

Data Required for Annual process of determination of transmission charges based on Hybrid Methodology. - The DICs will provide forecast injection/withdrawal 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. "Typical" injection/withdrawal data based on maximum injection/withdrawal as defined in these regulations shall be provided to the Implementing Agency by the DICs for each of the application period.DICs shall also provide injection and withdrawal data for the corresponding quarter of last three years. The data provided by the DICs shall be as per the formats prepared by the IA and duly approved by the Commission under the relevant provisions of these Regulations.Information provided by the DICs shall be vetted by the Implementing Agency as per the provisions of the Regulations and Detailed procedure notified by Implementing Agency.Methodology for calculation of forecasted maximum generation/withdrawal of DICs for vetting by Implementing AgencyFor Demand data. - The projected maximum withdrawal figures provided by DICs will be vetted by Implementing Agency based on the following:a. Monthly peak demand met for each State/UT in the last 3 years for the period corresponding to the Application Period shall be considered.b. The average of monthly peak demand met for each State/UT in each of the last 3 years for the period corresponding to the Application Period shall be calculated.c. The average peak demand met for each State/UT for the Application Period shall be projected based on last 3 years average of monthly peak demand met figures.d. Similarly All India peak demand met in last 3 years shall be averaged for the period corresponding to the Application Period. This shall be projected for the ensuing Application Period. The projected peak demand of each State/UT thus arrived shall be normalized with the projected All-India peak demand met of the Application Period under consideration for the current year.For Generation Data:a. The projected maximum injection figures provided by DICs shall be vetted by the Implementing Agency based on average of monthly maximum injection in the last 3 years (based on actual metered data available from RLDCs) for the period corresponding to Application Period projected for the ensuing Application Period. Similarly maximum injection data (for last 3 years as well as projected for the ensuing quarter) for generators embedded within the State system shall be provided by respective SLDC. In case data is not provided by SLDC to the Implementing Agency, the maximum injection of the concerned State shall be taken as the difference between peak met and withdrawal from ISTS based on actual metered data (for the time block corresponding to the block in which peak met occurred).b. If sum of projected generation in the grid is more than sum of projected demand, the generation may be proportionately reduced to match sum of withdrawal data. If sum of projected generation in the grid is less than sum of projected demand, the demand may be proportionately reduced to match sum of generation.c. The peak demand met figures in respect of each State/UT and All India peak met shall be taken from the final/revised monthly power supply position published by CEA.d. The Implementing Agency shall finalize the data duly maintaining Load Generation balance.e. If the Validation Committee encounters any difficulty for validation of Approved Injection or Approved Withdrawal or any other data on account of non availability or partial availability of any information from the DICs, the Validation Committee may adopt such method as may be considered necessary consistent with the objectives of these regulations.f. The data as validated/adopted by the Validation Committee shall be final.]2.1.2Network Data. - CTU, owners of deemed ISTS transmission systems and the DICs whose assets are being considered in the Basic Network shall supply the Network Data for the existing network, in the format desired by the IA. The network data of the proposed network shall be supplied by the CTU. The requirement below has been given in the illustrative PTI format. The data shall inter-alia include:(a)Bus DataI - Bus number

1. - Load bus

2. - Generator or plant bus

3. - Swing bus

4. - Isolated bus

GL - Shunt conductance, MW at 1.0 per unit voltageBL - Shunt susceptance, MVAR at 1.0 per unit voltage. (- = reactor)IA - Area numberVM - Voltage magnitude, per unitBASKV - Base voltage, KVZONE - Zone(b)Generator dataI - Bus numberID - Machine identifierPG - MW outputQG - MVAR outputQT - Max MVARQB - Min MVARVS - Voltage set pointIREG - Remote controlled bus index (must be type 1), zero to control own voltage, and must be zero for gen at swing busMBASE - Total MVA base of this machine (or machines)ZR, ZX - Machine impedance, pu on MBASERT, XT - Step up transformer impedance, p.u. on MBASEGTAP - Step up transformer off nominal turns ratioSTAT - Machine status, 1 in service, 0 out of serviceRMPCT - Percent of total VARS required to hold voltage at bus IREG to come from bus I -for remote buses controlled by several generatorsPT - Max MWPB - Min MW(c)Branch DataI - From bus numberJ - To bus numberCKT - Circuit identifier (two character)R - Resistance, per unitX - Reactance, per unitB - Total line charging, per unitRATEA - MVA rating ARATEB, RATEC - Higher MVA ratingsRATIO - Transformer off nominal turns ratioANGLE - Transformer phase shift angleGI, BI - Line shunt complex admittance for shunt at from end (I) bus, pu.GJ, BJ - Line shunt complex admittance for shunt at to end (J) bus, pu.ST - Initial branch status, 1 - in service, 0 - out of service(d)Transformer Adjustment DataI - From bus numberJ - To bus numberCKT - Circuit numberICONT - Number of bus to control. If different from I or J, sign of ICONT determines control. Positive sign, close to impedance (untapped) bus of transformer. Negative sign, opposite.RMA - Upper limit of turns ratio or phase shiftRMI - Lower limit of turns ratio or phase shiftVMA - Upper limit of controlled volts, MW or MVARVMI - Lower limit of controlled volts, MW or MVARSTEP - Turns ratio step incrementTABLE - Zero, or number of a transformer impedance correction table 1-5(e)Area Interchange DataI - Area number (1-100)ISW - Area interchange slack bus numberPDES - Desired net interchange, MW + = out.PTOL - Area interchange tolerance, MWARNAM - Area name, 8 characters, enclosed in single quotes.(f)DC Line DataEach DC line has three consecutive recordsI,MDC,RDC,SETVL,VSCHD,VCMOD,RCOMP,DELTI,METERIPR,NBR,ALFMAX,ALFMN,RCR,XCR - DC Line numberMDC - Control mode 0 - blocked 1 - power 2 - currentRDC - Resistance, ohmsSETVL - Current or power demandVSCHD - Scheduled compunded DC voltage, KVVCMOD - Mode switch DC voltage, KV, switch to current control mode below thisRCOMP - Compounding resistance, ohmsDELTI - Current margin, per unit of desired currentMETER - Metered end code, R - rectifier I - InverterIPR - Rectifier converter bus numberNBR - Number of birdges is series rectifierALFMAX - Maximum rectifier firing angle, degreesALFMN - Minimum rectifier firing angle, degreesRCR - Rectifier commutating transformer resistance, per bridge, ohmsXCR - Rectifier commutating transformer reactance, per bridge, ohmsEBASR - Rectifier primary base AC volts, KVTRR - Rectifier transformer ratioTAPR - Rectifier tap settingTPMXR - Maximum rectifier tap settingTPMNR - Minimum rectifier tap settingTSTPR - Rectifier tap stepThird record contains inverter quantities corresponding to rectifier quantities above.(g)Switch Shunt DataI - Bus numberMODSW - Mode 0 - fixed 1 - discrete 2 - continuousVSWHI - Desired voltage upper limit, per unitVSWLO - Desired voltage lower limit, per unitSWREM - Number of remote bus to control. 0 to control own bus.VDES - Desired voltage setpoint, per unitBINIT - Initial switched shunt admittance, MVAR at 1.0 per unit voltsN1 - Number of steps for block 1, first 0 is end of blocksB1 - Admittance increment of block 1 in MVAR at 1.0 per unit volts.N2, B2, etc, as N1, B1The line-wise YTC of the entire network shall be provided by the Transmission Licensees. In case a line is likely to be commissioned during a financial year, the data of the same, along with the earliest COD will be provided to the Implementing Agency by the CTU.For the determination of the transmission charges based on Hybrid Methodology applicable in the next financial year, all the above data shall be provided to the IA as per the timelines specified by IA.(g)[Overall charges to be allocated among nodes shall be computed by adopting the YTC of transmission assets of the ISTS licensees, deemed ISTS licensees and owners of the non-ISTS lines which have been certified by the respective Regional Power Committees (RPC) for carrying inter-State power. The Yearly Transmission Charge, computed for assets at each voltage level and conductor configuration in accordance with the provisions of these regulations shall be calculated for each ISTS transmission licensee based on indicative cost level provided by the Central Transmission Utility for different voltage levels and conductor configuration. The YTC for the RPC certified non-ISTS lines which carry inter-State power shall be approved by the Appropriate Commission. [Substituted by Notification No. L-1/44/2010-CERC, dated 24.11.2011 (w.e.f. 15.6.2010).]In case the tariff for the RPC certified non-ISTS lines have not been specified by the Appropriate Commission, the average YTC as computed for the relevant voltage level and conductor configuration shall be used.The non-ISTS lines certified by the RPCs as on 15.06.2010 shall continue to be treated as RPC certified non-ISTS lines carrying inter-State power. The YTC of such RPC certified non-ISTS lines shall remain the same and be governed by the same principle as it existed as on 15.6.2010.For certifying non-ISTS lines for carrying inter-State power, which were not approved by the RPCs on the date of notification of the Principal Regulations, this shall be determined through the process of load flow studies. The results of the load flow studies, on an annual average basis, should show these lines carrying more than 50% of the total power carried by it to be inter-State power. This shall be vetted by the NLDC in consultation with the respective RLDC on the proposal made by the respective RPC, through a common methodology to be adopted by the NLDC. The YTC for such RPC certified non-ISTS lines which carry inter-State power, shall be approved by the Appropriate Commission.The recovery of the YTC of the transmission assets expected to be commissioned in the Application Period shall be incorporated by the Implementing Agency on the basis of the approved tariff including provisionally approved tariff:Provided that the disbursement to the owners of new RPC certified non-ISTS lines shall be done after the tariff is approved by the Appropriate Commission.] [Substituted by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (w.e.f. 15.6.2010).]

2. [1.3 [Substituted by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (w.e.f. 15.6.2010).] The line-wise YTC of the entire network shall be provided by the Transmission Licensees. In case a line is likely to be commissioned during the Application Period, the data in respect of the same, along with the anticipated COD will be provided by the CTU/ Transmission Licensee to the Implementing Agency.

For the determination of the transmission charges based on Hybrid Methodology applicable in the next Application Period, all the above data shall be provided to the Implementing Agency as per the timelines specified by the Implementing Agency.Overall charges to be allocated among nodes shall be computed by adopting the YTC of transmission assets of the ISTS licensees, deemed ISTS licensees and owners of the non-ISTS lines which have been certified by the respective Regional Power Committee (RPC) for carrying inter-State power. The Yearly Transmission Charge, computed for assets at each voltage level and conductor configuration in accordance with the provisions of these regulations shall be calculated for each ISTS transmission licensee based on indicative cost provided by the Central Transmission Utility for different voltage levels and conductor configuration. The YTC for the RPC certified non-ISTS lines which carry inter-State power shall be approved by the Appropriate Commission.In case line-wise tariff for the RPC certified non-ISTS lines has not been specified by the Appropriate Commission, the tariff as computed for the relevant voltage level and conductor configuration shall be used. The methodology for computation of tariff of individual asset shall be similar to the methodology adopted for the ISTS transmission licensees and shall be based on ARR of the STU as approved by the respective State Commission.Certification of non-ISTS lines carrying inter-State power, which were not approved by the RPCs on the date of notification of the Central Electricity Regulatory Commission (Sharing of Transmission Charges and Losses) Regulations, 2009, shall be done on the basis of load flow studies. For this purpose, STU shall put up proposal to the respective RPC Secretariat for approval. RPC Secretariat, in consultation with RLDC, using WebNet Software would examine the proposal. The results of the load flow studies and participation factor indicating flow of Inter State power on these lines shall be used to compute the percentage of usage of these lines as inter State transmission. The software in the considered scenario will give percentage of usage of these lines by home State and other than home State. For testing the usage, tariff of similar ISTS line may be used. The tariff of the line will also be allocated by software to the home State and other than home State. Based on percentage usage of ISTS in base case, RPC will approve whether the particular State line is being used as ISTS or not. Concerned STU will submit asset-wise tariff. If asset wise tariff is not available, STU will file petition before the Commission for approval of tariff of such lines. The tariff in respect of these lines shall be computed based on Approved ARR and it shall be allocated to lines of different voltage levels and configurations on the basis of methodology which is being done for ISTS lines.] [Added by Notification No. L-1/44/2010-CERC, dated 14.12.2017 (w.e.f. 15.6.2010).]

2. [2 Computation of Load Flows on the Basic Network. [Substituted by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (w.e.f. 15.6.2010).] - The Implementing Agency shall run AC load flow on the Basic Network using the technical data obtained from the DICs, SLDCs, RLDCs and NLDC. The real power generation at the generator nodes in the Basic Network shall be based on maximum injection of the generators connected directly to the ISTS or the injection submitted by the DICs, where such nodes are embedded in the networks of the DIC. The demand at the load nodes shall be based on the maximum demand met of the DICs. In the case of an STU / SEB, the total injection at all the generator nodes owned by the STU/SEB shall be equal to the aggregate of injection of the entities connected in the state network. Similarly, the withdrawal at all the nodes owned by the SEB/STU shall be equal to withdrawal of all the entities connected in the SEB / STU network.

In the process of convergence of the Load Flow on the Basic Network, the IA may require to make certain adjustments in the load/generation at various buses to ensure load generation balance. Such load flow analysis shall be performed for all the network conditions as required by the Regulations in force. The entire process of formation of the Basic Network and convergence to load flows shall be validated by the Validation Committee.]

2. [3 [Deleted by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (w.e.f. 15.6.2010).] ***]

2.3 Computation: Reduction of the Indian Grid.- The determination of transmission charges based on Hybrid Methodology is required to be limited to the network owned, operated and maintained by the ISTS Licensees and those transmission licensees / SEBs whose assets have been certified by RPC as being used for interstate transmission. "Neat" truncation of the grid at the interface of the state and the central sector boundaries is not possible because all the assets of PGCIL are not interconnected by their own assets. Preparation of a cogent network therefore requires consideration of state owned lines also. One of the methods of network reduction, viz., network truncation is explained below. However IA may adopt alternative network reduction tools that find smaller but equivalent representations of large networks after due approval of the Commission.Most of the assets of PGCIL are operated at 400 kV. For the year 2008-09, PGCIL had Rupees 221 Crores (excluding NER) to be recovered from 220 kV assets of the total YTC of Rupees 4959.43 Crores. Most of the 220 kV assets in India are owned by the state utilities. It was, therefore, deemed appropriate by the CEA that the network be truncated at 400 kV level because it would involve minimal use of the state owned lines. The voltage level for the purposes of network truncation may be revised in the subsequent years by the IA after approval by the Commission.The complete Network shall be truncated at 400 kV level by the Implementing Agency following the following guidelines:1. The IA shall run AC Load Flow on the two grids - NEW Grid and SR Grid separately till these grids are synchronously integrated.2. Based on the load flow analysis on the Basic Network, for each 400 kV node (and 132 kV in the NER grid) in the NEW grid (except NER, where the network shall be truncated at 132 kV) and SR grid, the IA shall determine the net power flowing out of each node and power flowing into each node from the power system at lower voltage levels connected to this node, to compute the total injection and / or total withdrawal at each node from the lower voltage power system. a. All injection from the lower voltage system into 400 kV (in the case of NEW grid except NER and SR grid) and 132 kV in the case of NER grid shall be treated as a generator and vice-versa in the case of net withdrawal, the system below each node shall be replaced by a net demand.3. The network thus modified will have assets at 400 kV (and upto 132 kV assets in NER) and higher voltages with revised generation and load buses.4. A truncated network for each grid condition for each season shall be obtained based on the above guidelines.5. The Implementing Agency shall execute AC load flow on the truncated network and the truncation shall be accepted only when the (1) Slack bus generation, (2) Voltage angles at generation and demand buses closely match with the AC load flow on the full network.6. The network considered for NER region will however have all the assets from 765 kV to 132 kV.The truncated network so obtained shall be used for the implementation of the Marginal Participation methodology of transmission pricing.

2.4Identification of the Slack Nodes: Using Average Participation Method. - Rationale for Hybridization of the Marginal Participation and the Average Participation MethodsDue to the Kirchoff's laws, any 1 MW increase in generation (or load) at node i has to be compensated by a corresponding increase in load (or generation) at some other node or nodes. Thus the calculation of how much an injection (or withdrawal) at a certain bus affects the flows in the network depends on the choice of the node (s) that responds.Different choices are possible for this 'slack bus' (the responding node in power systems terminology). In cases of countries like Argentina or Chile, the 'slack node' is near the major load centre. For larger networks, distributed slack nodes can be considered - where the demand (generation) at all / pre-selected nodes responds pro-rata to 1 MW increment in generation (load). For the purposes of the computations in the Indian context distributed slack nodes have been considered. The selection of slack buses influences the final results prominently and therefore is a decision which must not be made arbitrarily.The method considered here is a hybrid of the marginal and the average participation methods, and is sympathetic with the concerns of those who, in the defense of the interests of their states argue that demand in each state must first be met by the generation within the state and that the mismatches between the state generation and demand will result in export or import flows.Truncation at the 400 kV level also allows relation of local generation and local demand and obtains a source (or a sink) for the net imports (or exports). In other words, state generators below 400 kV are primarily linked with state demand and only net imports or exports are linked with external nodes. The external slack bus (es) for each node shall be found as follows:a. 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 generator (or from generator to load), a set of generators (or loads) (including those outside the state) and their contribution to the load (generator) is determined for each load (generator) bus.b. Using the above choice of slack buses for each generator and load bus, marginal participation of each generator and load in each transmission line is computed.2.5Computation: Hybrid Method for the Determination of Transmission Charges. - Any usage based methodology attempts to identify how much of power that flows through each of the lines in the system is due to the existence of a certain network user, in order to charge it according to the adopted measure of utilization. To do so, the Hybrid Method analyzes how the flows in the grid are modified when minor changes are introduced in the production (or consumption) of agent i, and it assumes that the relationship of the flow through line j with the behaviour of the agent i can be considered to be linear. For each of the considered blocks of months and [***] [Deleted 'peak and other than peak condition' by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (w.e.f. 15.6.2010).], the procedure can be described as follows:

1. Marginal participation sensitivities are obtained that represents how much the flow through each network branch j increases when the injection/ withdrawal in a bus is increased by 1 MW. Flow variation in each network branch j incurred by 1 MW injection / withdrawal at each bus is computed for each scenario, e.

2. Due to the Kirchoff's laws, any 1 MW increase in generation (or load) at node i has to be compensated by a corresponding increase in load (or generation) at some other node or nodes (after adjusting for incremental system losses). Thus the calculation of how much an injection (or withdrawal) at a certain bus affects the flows in the network depends on the decision of which is the node that responds, and the answer that is

demanded from the method is heavily conditioned by an assumption that it needs as an input. The methodology used for the selection of the distributed slack buses is explained above.

3. Once the flow variation in each line incurred by each agent and [***] [Deleted 'for every scenario' by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (w.e.f. 15.6.2010).] is obtained, it is possible to compute a seasonal usage index for each network user. This index is computed according to equation given below. It can be seen that only positive increments in the direction of the power flow in the base case are considered. This implies that increments which reduce burden on lines are neither given any credit nor charged for use of the system. This is essentially because of practical reasons where it could be difficult to pay grid connected entities for being connected to the grid. Further, there could be times (with strictly positive chance) when these entities need to use certain network branches along the direction of the main flow, though such times may not be the times which coincide with [maximum injection/ maximum withdrawal] [Substituted 'typical seasonal system peak and other than peak periods' by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (w.e.f. 15.6.2010).] considered in the load flow studies. This is also a standard international practice followed in countries where such pricing mechanisms are used.

The [***] [Deleted 'seasonal' by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (w.e.f. 15.6.2010).] index (for each block of months) is computed as:Ue,i,l = (| F le i | - | F le |).Pie.| F le i | - | F le | > 0,Sign (F le i) is same as Sign (F le)Where,Ueil is the [***] [Deleted 'seasonal' by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (w.e.f. 15.6.2010).] usage index in line l due to injection / withdrawal at node iFle is the flow in line l under scenario e under base caseFi le is the flow in line l under scenario e due to injection / withdrawal of 1 MW at nodePie is power dispatch / demand at bus i under scenario e under base case

4. The revenue requirement of each line is allocated pro-rata to the different agents according to their total participation in the corresponding line.

Cost Allocatedeil=| Ueil□Ueil| ×| C1

iWhere,Cl is the Transmission Charge of the line - computed by attributing the Yearly Transmission Charge for the ISTS licensee to each line owned by it and to the block of month under consideration

| Ueil□Ueil| ×| is the marginal participation factor

iThe above mechanism is also commonly referred to as the "Point tariff" and has been considered by the CERC in the past as a potential alternative to the regional postage stamp method.2.6Computation: Hybrid Method for the Sharing of Transmission Losses. - 1. In the application of the Marginal Participation Method for the allocation of transmission losses to various nodes in the system, the change in losses in the system (above the base case) because of a incremental injection / withdrawal at each node are computed. The change in overall system losses per unit of injection / withdrawal at each node is termed as the Marginal Loss Factor for that node. The marginal loss factor shall be based on the following formula:

| | Marginal Loss Factori=| □System Losses□Power generation / load at Node i| ki|

2. The selection of the slack buses for absorption (supply) of the incremental injection (withdrawal) is done as per the methodology discussed above.

3. The marginal loss factors are multiplied by the generation / demand at these nodes under base case, i.e.

K i× P ig for generation nodesK j× Pdj for demand nodesPi g is base case generation at node iWhere,Pi d is base case demand at node j

4. Loss Allocation Factor for generation and demand nodes are computed by:

| ki× Pig□ki× Pig+ □kj× Pjd| for generation node i and
i j
| kj× Pjd□ki× Pig+ □kj× Pjd| for demand node j
i j

5. The Loss Allocators computed above are multiplied by the total system losses to allocate losses to each node in the system.

2.7Computation: Determination of Sharing of Ytc and Transmission Losses. - The simulations will be carried out by the IA by using a software duly approved by the CERC.The following steps shall be followed:

1. [Converged AC Load Flow data for the all India Grid shall be used directly for the implementation of the Hybrid Methodology. [Substituted by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (w.e.f. 15.6.2010).]

2. Treatment of HVDC: Flow on 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. Since the HVDC systems were specifically set up for transfer of bulk power to specific Region, the DICs of the Region shall share the cost of HVDC systems. HVDC

system also helps in controlling voltages and power flow in inter-regional lines and some benefits accrue to all DICs by virtue of HVDC system. Accordingly, 10 % of the MTC of these systems be recovered through Reliability Support Charges. The balance amount shall be payable by Withdrawal DICs of the Region in proportion to their Approved Withdrawal. In case of Injection DICs having Long Term Access to target region, it shall be payable in proportion to their Approved Injection.

Where transmission charges for any HVDC system line are to be partly borne by a DIC (injecting DIC or withdrawal DIC, as the case may be) under a PPA or any other arrangement, transmission charges in proportion to the share of capacity in accordance with PPA or other arrangement shall be borne by such DIC and the charges for balance capacity shall be borne by the remaining DICs by scaling up of YTC of the AC system included in the PoC.]

3. Using AC load flow, marginal participation factors shall be computed for determination of transmission system utilization due to marginal injection / withdrawal at each generator / demand node.

4. YTC for each line shall be based on the line-wise YTC provided by the Transmission Licensees. Average per km YTC for each voltage level (and line configuration viz., 400 KV D/C twin Moose, 400 kV Quad Moose, 400 kV Quad Bersimis etc.) of the transmission licensee lines shall be applied to the 765 kV, 400 kV, 220 kV and 132 kV lines considered in the network.

5. [Hybrid Methodology shall be applied to Application Period. [Substituted by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (w.e.f. 15.6.2010).]

6. Annual Average YTC of each line will then be attributed to maximum injection/maximum withdrawal.]

7. The annual average YTC (of each period in each season) of each line is attributed to the total change in flow in each line. Therefore the YTC is allocated to each agent in proportion of the change in the flow in network branch affected by that agent.

8. Transmission charges based on Hybrid Methodology in Rs/MW/Month and Rs/MW/hr at each node in each block of months will be computed.

9. Loss Allocators shall also be computed along with the above simulations and as discussed above.

10. Total losses shall be computed, as per the present methodology, viz.,

The total net drawal by each utility is subtracted from the sum of net injection of Inter-State Generating Stations (ISGS) and the inter-regional injections to arrive at the losses in MWh.All loss computations are on a weekly basis from the Special Energy Meters (SEMs) installed at all inter-utility exchange points in the region. A week for the purpose of accounting is from 0000 hours of Monday to 2400 hours of the following Sunday.

11. Using the loss allocators, the losses shall be allocated to each node, as per the detailed procedure to be developed by NLDC under these Regulations.

12. [There shall be slabs for the percentage transmission losses in the All India grid till such period the Commission may consider appropriate.] [Substituted by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (w.e.f. 15.6.2010).]

2.8Creation of Zones and Determination of Zonal Charges and Losses. - The proposed mechanism is based on a locational point charge (Rs/MW/month) of [Paisa/unit] [Substituted '(Rs/MW/hr)' by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (w.e.f. 15.6.2010).] for each grid connected entity, which entitles it to access the entire network. In practice it is indeed cumbersome from an implementation perspective in view of the large size of the Indian power system. In some instances it may be inappropriate to apply the pricing at each node in the network since certain local peculiarities could distort pricing signals. Hence a logical basis for aggregating the charges in a region into zones is necessary. The principles of zoning of such charges are articulated in the Regulations.2.8.1Determination of Locational Charges in Generation Zones. - [The transmission access rates shall be determined for each generation zone by computing the weighted average of nodal access charges at each generation node in this zone.The weighted average transmission access rate for nodes in a zone is the zonal transmission access [rate] based on Hybrid Methodology for generation, e.g. in a Zone - ZZ, the following three nodes were considered in one zone: PP, AA and KK.ZZ - zone computation in a particular scenario:

Node	Transmission Charges (`/Month)	Approved Injection/ Withdrawal* (MW)	Zonal Transmission Rate (`/MW/Month)
PP	45,00,000	250	70000
AA	50,00,000		
KK	80,00,000		
ZZ - ZONE	1,75,00,000	250	

*Approved Injection/ Approved withdrawal (MW) shall be the Long-term Access plus Medium Term Open Access i.e. Zonal PoC Charge computed considering maximum injection /maximum withdrawal shall be divided by LTA + MTOA to arrive at PoC Rate. The PoC rates shall be further grouped under slabs in accordance with sub-clause (l) of clause (1) of Regulation 7.]

2. [8.1.a. Methodology for calculation of PoC rates and billing of POC charges [Added by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (w.e.f. 15.6.2010).]

(i)PoC rates for billing towards LTA/MTOA shall be calculated only on Withdrawal nodes (as Withdrawal charges) and for generators who have Long Term Access to target region (as injection charges) corresponding to untied power. PoC rates shall not be calculated for ISGS with identified long term customers/ beneficiaries with whom PPA have been signed.Example for billing a Generator who have LTA to target region:Suppose a Generator "A" has LTA of 900 MW to target region (WR-500 MW, NR-400 MW).He ties up 150 MW of power with U.P through PPA. "A" shall be billed for 500+250 =750 MW as its LTA to target region.(ii)If any generator has contractual liability to pay the Withdrawal Charges of drawee entity, then drawee DIC shall inform CTU and bill shall be raised by the CTU to generator directly. In such a case, only withdrawal charges shall be payable by generator for corresponding quantum of power.(iii)For balance injection i.e. difference between Approved Injection and Quantum of withdrawal, generator shall pay Injection Charges only.(iv)For the purpose of STOA, collective transactions and computation of transmission deviation charges, POC injection rate / withdrawal rate for all DICs shall be determined separately and shall be declared in paise/kWh(v)The injection and withdrawal rates in paise/kWh as at (iv) above shall be computed before transferring injection charges of ISGS having long term customers on withdrawal DICs.2.8.1.b. Methodology for calculation of Slab Rates(i)The PoC rates shall be arrived at by dividing the quantum of charges allocated to each zone by its LTA+MTOA.(ii)The PoC rates so arrived shall be adjusted based on average rate and one sigma deviation on either side. The difference between maximum rate and minimum rate so arrived shall be divided by eight to determine width of each slab. The POC rates for all entities shall be placed in appropriate slab, minimizing the distance from slab rate as per its adjusted rate calculated after accounting for standard deviation. The rates may be scaled up/down as required.(iii)For the purpose of STOA, collective transactions and computation of transmission deviation charges, there shall be separate slabs for injection and withdrawal rates.2.8.1.c. Methodology for calculation of Reliability Support Charge Rate and billing of Reliability Support Charges(i)Reliability Support Charges shall be 10% of the Monthly Transmission Charges.The Reliability Support Charge Rate, in `/MW/month shall be as under:[10% of the Monthly Transmission Charges of ISTS]/[Total Approved Withdrawal of the Withdrawal DICs and Approved Injection of the Generators having LTA to target region]Reliability Support Charge for Withdrawal DIC shall be obtained by multiplying the above rate (in `/MW/month) by Approved Withdrawal. For Generator with Long term Access to target region shall be obtained by multiplying these charges by Approved Injection.The above rate shall also apply for additional MTOA.(ii)Over/under recovery shall be adjusted in the transmission charges of ISTS in the third part of bill in a manner as provided in Regulation 11(6) of these Regulations.(iii)These charges shall also be applicable to STOA/collective transactions. The offset shall also be given in the manner as provided in Regulation 11 (9) of these Regulations.]2.8.2Determination of Locational

Charges in Demand Zones. - While multiple generation zones shall be considered in a state, for each state there shall be a single demand zone. This is essentially because, the interface of the CTU network with the State is usually at either 400 kV or 220 kV nodes which are generally owned by the state transmission utilities. The transmission bills by the CTU are generally raised on the STU or the SEBs where state utilities have not been unbundled. While the nodal charges for access by demand customers will be made available to the State Utilities, the manner of application within the state would be left to the state utilities. This may change when the states implement a 'Point of Connection' based transmission pricing mechanism.Transmission access charges for demand zones are computed in a manner similar to the transmission access charges for generation zones.2.8.3Determination of Losses in Generation Zones. - The loss allocators, computed at the nodal level are indicative of the percentage of losses to be allocated to each node. The total system losses shall be computed as per the existing methodology.The detailed procedure for determination of losses using the loss allocation factors shall be prepared by the NLDC within 30 days of the notification of these Regulations.2.8.4Determination of Losses in Demand Zones. - The loss allocators, computed at the nodal level are indicative of the percentage of losses to be allocated to each node. The total system losses shall be computed as per the existing methodology. The detailed procedure for allocation of losses shall be prepared by NLDC within 30 days of the notification of these regulations.[Substituted by Notification No. L-1/44/2010-CERC, dated 1.4.2015 (w.e.f. 15.6.2010).]