CENTRAL ELECTRICITY REGULATORY COMMISSION

NEW DELHI

Coram:**Shri Gireesh B. Pradhan, Chairperson**
Shri A.K.Singhal, Member
Shri A. S. Bakshi, Member

File No. L-1/44/2010/CERC

Date: 26th October 2015

In the matter of

Central Electricity Regulatory Commission (Sharing of Inter State Transmission Charges and Losses) (Third Amendment) Regulations, 2015

Statement of Reasons

1. **Introduction:**

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

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

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

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

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

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

(e) the principles rewarding efficiency in performance;

(f) Multiyear tariff principles;

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

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

(i) the National Electricity Policy and tariff policy:”

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

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

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

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

1.4 The above statutory provisions and policy guidelines enjoin upon the Central Commission to develop and implement a national transmission tariff framework sensitive to distance and directions and quantum of flow.

1.5 In compliance with the said mandate, the Commission had notified the Central Electricity Regulatory Commission (Sharing of Inter-state Transmission Charges and Losses) Regulations, 2010 (hereinafter referred to as Sharing Regulations) on 16.06.2010. Two amendments to the Sharing Regulations were notified in the official Gazette on 25.11.2011 and 29.03.2012. The Sharing Regulations, which came into force with effect from 1.7.2011, provided that the transitory mechanism like Uniform Charges is to be reviewed after two years of implementation. In addition, certain issues had come to fore since implementation of these Regulations, which needed to be considered. These included the issues agitated by stakeholders in various fora like Central Advisory Committee (CAC) and in the writ petitions before the High Courts. Major issues which drew attention of the Commission were the need for harmonization of principles of sharing of transmission charges with the principles of transmission planning, levy of transmission charges based on usage close to maximum actual usage rather than average usage, adjustment of STOA charges against the transmission charges already paid in proportion to the maximum injection/drawal, reliability support to DICs or Designated ISTS Customers by virtue of operating in an integrated grid, sharing of transmission charges for HVDC systems, treatment of delay in commissioning of generating stations etc. Providing a framework which is conducive for proper projection of usage of transmission system with commensurate sharing of transmission charges was also an important underlying consideration.

1.6 The Commission has followed a detailed process of stakeholders' and public consultation while finalizing the third amendment to Sharing Regulations. The draft amendment seeking comments/suggestions/observations from the stakeholders/public at large was hosted on the Commission's website along with an Explanatory Memorandum on 7.2.2014. Comments were received from 27 stakeholders, organizations, and individuals, etc., which included State Power utilities, Central Electricity Authority (CEA), Central Transmission Utility (CTU), Power System Operation Corporation (POSOCO), Inter-state transmission licensees, generating companies in central sector and private sector, including associations. Thereafter, the Commission conducted public hearing on 12.6.2014. Nine (09) organizations/individuals including POSOCO, CTU, generating companies, associations and individuals made oral submissions and /or presentations during the public hearing. List of stakeholders/individuals who submitted written comments and who made oral submissions/power point presentation during the public hearing along with detailed comments is given at ***Appendix-I & Appendix-II*** respectively. After due considerations of the comments/suggestions/objections received and detailed discussions with the statutory authorities like Central Electricity Authority and Central Transmission Utilities as well as National Load Despatch Centre which has been assigned the role and responsibility of Implementing Agency under the Sharing Regulations, the Commission has finalized and notified the Third Amendment to the Sharing Regulations. The Statement of Reasons seeks to discuss in detail the rationale behind the various provisions included in the Third Amendment to Sharing Regulations.

1.7 At the outset, the Commission intends to mention that in many countries, the mechanism for sharing of transmission charges is in an evolving stage. Many permutations and combinations of different methods like postage stamp based on Peak MW or Energy, Point of connection charges and congestion based nodal transmission charges are being used. A comprehensive survey is available in a study by PJM which can be accessed at http://www.pjm.com/~/media/documents/reports/20100310-transmission-allocation-cost-web.ashx. The countries like UK, Brazil and New Zealand which adopted transmission charge sharing mechanism based on usage or point of connection charge methods are also continuously reviewing the methodology either to address the concern of stakeholders or to test whether the methodology is achieving intended objectives. In New Zealand Transmission Price Advisory Group (TPAG) constituted by New Zealand Electricity Authority is discussing and modifying this mechanism since the last seven years. Similarly in UK, OFGEM reviewed its transmission pricing mechanism Transmission Network Use of System (TNUoS) under a project called “Project Transmit" from September 2010 to May2012. Thus, sharing of transmission charges methodology depends on development stage of power market and transmission infrastructure in the country. Further, emergence of Renewable Generation sources also creates need for review of transmission sharing mechanism. Also the objective of synergizing the transmission planning and transmission sharing mechanism is required to achieve agreement to build new transmission assets. The feedback from stakeholders is the most important input for framing a robust transmission sharing mechanism and this need to be continuously and periodically reviewed to address the concerns of planners, system operators and users of the transmission system.

1.8 The broad features of the Third Amendment to Sharing Regulations can be capitulated as under:

(a) Sharing of transmission charges commensurate with usage close to maximum actual usage by way of (i) calculation of charges on only withdrawal nodes and for generators with LTA to target region,(ii) shift from average (energy based) base case to maximum injection/drawal based base case, (iii) removal of uniform charge, (iv) spreading number of slabs from three to nine, (v) elimination of truncation of network, and (vi) off set of transmission charges commensurate to STOA transactions in any region.

(b) The concept of reliability support charge has been introduced in view of the fact that DICs getting benefits which accrue to them by virtue of operating in an integrated grid. The Commission has for the present taken a decision to allocate 10% charges as Reliability Support Charges. However the Commission would like to have a better picture in this regard and hence has directed POSOCO to prepare a base paper in consultation with CEA and CTU on quantification of reliability benefit in a large inter-connected grid such as ours including market risk mitigation based on international experience.

(c) A separate treatment for sharing of charges of HVDC systems, being a different type of transmission asset, is unavoidable as with the marginal participation method, HVDC cost cannot be allocated. Various methods for sharing of transmission charges of HVDC systems, namely With and Without method, uniform distribution of the charges among all the DICs and sharing by withdrawing DICs of regions for whom such HVDC systems were set up, were considered and it was concluded that the charges for HVDC systems shall now be borne by the withdrawing DICs of region(s) for whom the asset has been created. In the event of better projection and appreciation of benefit of HVDC systems in due course, keeping in view evolving methodologies worldwide, the Commission may consider the proposal for review of sharing of transmission charges of HVDC system. NLDC may in consultation with CEA, CTU, IITs and international consultants submit a technical report for various solutions for allocation of cost for HVDC system in India supported by adequate calculations.

(d) Introduction of nine slab rates in place of three slab rates to approximate the transmission charge liability of a DIC to its actual usage.

1.9 The Commission also intends to clarify for the information of all concerned the reasons for the variation in the slab rates for transmission charges and losses payable prior to and post implementation of Third Amendment to the Sharing Regulations. The reasons for variation are broadly as under:

(a) POC charges towards LTA/MTOA were determined as 'POC injection charges' and 'POC withdrawal charges' separately and both these charges were being paid by (i) Withdrawal DICs and (ii) the generators with LTA to target region without identified beneficiaries. Post Third Amendment, the PoC injection charges have been merged into PoC withdrawal charges in respect of withdrawal DICs and in respect of the generator with LTA to target region without identified beneficiaries, withdrawal charges have been merged with injection charges.

(b) There is change in slab rates on account of replacement of 3 slabs by 9 slabs for computation of PoC rates and losses.

(c) Consideration of full network in place of truncated network. The charges for states which are drawing power through network below 400 kV i.e. at 220 kV or 110 kV may get affected due to no truncation of network.

(d) Consideration of maximum injection/ withdrawal as compared to average injection/withdrawal considered earlier.

(e) There are additions of new transmission assets to ISTS thereby increasing the overall transmission charges to be included in the Yearly Transmission Charges.

2. Consideration of the views of the stakeholders and analysis and findings of the Commission on important issues:

The Commission has considered the comments/suggestions of the stakeholders received on the draft regulations, views of the participants in the public hearing as well as their written submissions received during and after the public hearing. The regulations have been finalized after detailed deliberations and due consideration to the comments/suggestions. The amendments proposed in the draft regulations, deliberation on the comments/suggestions offered by the stakeholders, statutory bodies and individuals, etc., on the proposed amendments and the reasons for decisions of the Commission are given in the succeeding paragraphs. While an attempt has been made to consider all the comments/suggestions received, the names of all the stakeholders may not appear in the deliberations. However, the comments of all the stakeholders are enclosed as ***Appendix-I and II.***

3. **<u>Sub-clause (b) of clause (1) of Regulation 2</u>**

3.1 Sub-clause (b) of clause (I) of Regulation 2 of the Principal Regulations was proposed to be substituted as under:

*"**(b) Application Period** means the period for application of the transmission charges determined in accordance with these regulations and shall ordinarily be 12 (twelve) months coinciding with the Financial Year, which shall be further divided into four quarters of three months each and each quarter shall be an application period for computation of PoC charges."*

3.2 Comments have been received from APP, NTPC Ltd., AD Hydro Power Limited and Shri Ravinder.

3.2.1 NTPC has suggested that definition of Application Period should be unique and both quarter of a financial year and a financial year should not be defined as Application Period.

3.2.2 APP has suggested to assume peak scenario on monthly basis.

3.2.3 AD Hydro has suggested to use block of two months as Application Period.

3.2.4 Shri Ravinder has stated that making application period as one year is neither practical nor desirable.

3.3 We have considered the submissions of the stakeholders. PoC Charges are currently computed on quarterly basis. The draft amendment was proposed to clarify the scope of 'application period' for computation of PoC Charges.

3.3.1 With regard to APP's suggestions that for each month peak injection or drawal will be different, it is clarified that any load flow study is a sample or representative scenario of forecasted or expected load generation balance. As the purpose of the load flow study in present case is allocation of transmission charges, it can only be done at fixed intervals for representative scenarios. APP's proposal to make Application Period as one month would require twelve computations per year. In view of long process involved in data collection, data validation and tariff determination of expected transmission assets, it may not be possible to do this exercise on monthly basis. Since it is only a representative scenario of load or injection of all DICs varying over the year, it is expected to capture seasonal variation with fair degree of accuracy. The difference between actual and forecasted scenarios for many DICs get evened out over a period of time and method/periodicity by design does not give advantage or disadvantage to any DIC. To capture monthly, daily and 15 minute block wise variation in injection and drawal is neither practical nor desirable. However as average of maximum injection or maximum withdrawal is being taken to prepare base case, it addresses the concern of APP to large extent.

3.3.2 AD Hydro's suggestion to do this exercise on bi-monthly basis is also not feasible for similar reasons. The micro view of one particular type of generation cannot form basis of periodicity. In this regard it may be noted that while planning of transmission system is being done on three season basis, already by doing computation four times in a year, variation in usage of transmission system is captured more closely. Practical difficulties in increasing the periodicity are already explained. Shri Ravinder, former Member (Power Systems), CEA has supported quarterly computation of PoC Charges.

3.2.3 There may be exceptional circumstances when the computation for one particular application period may get delayed due to some exigency, which may require curtailment or extension of that application period. A proviso has been added to take care of such situations.

3.2.4 Accordingly the definition of Application period has been modified as under:

*"(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:*

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."

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

4.1 Sub-clause (c) along with Proviso of clause (1) of Regulation 2 of the Principal Regulations was proposed to be substituted as under:

*"(c) **'Approved Injection'** means the maximum injection in MW computed based on injection during corresponding application period of last year validated by Implementing Agency (IA) for the Designated ISTS Customer for each application period, during peak period at the ex-bus of the generator or any other injection point of the Designated ISTS Customer into the ISTS, and determined on the basis of generation data submitted by the Designated ISTS Customers incorporating total injection into the grid."*

4.2 Comments have been received from POSOCO, CEA, CTU, Thermal Powertech, Lanco Kondapalli, NTPC Ltd., AD Hydro Power Limited and Torrent Power Ltd.

4.3 POSOCO has objected to the proposed amendment on the ground that since DICs are to be billed for this amount, this amount has to be considered as sacrosanct and should not be subject to any dispute. POSOCO has suggested that Approved Injection should be based on installed capacity less auxiliary consumption or LTA, whichever is higher for regional entities and LTA/MTOA quantum for intra-State entities. POSOCO has pointed out a few possibilities in regard to outage of a generator, and commissioning of new lines/generators.

4.4 CEA has agreed that transmission users should pay as per their maximum usage of transmission system or LTA/MTOA, whichever is higher.

4.5 CTU has advocated billing on the basis of LTA and has raised concerns regarding billing of generators who have not commissioned any unit.

4.6 Thermal Powertech has supported the calculation of approved injection/ approved drawal on peak injection/drawal drawal in view of it being reflective of actual usage.

4.7 Lanco has stated that approved injection should be based on actual injection without considering LTA figure.

4.8 NTPC has stated that Schedule Generation for its generating stations is dependent on schedules given by the beneficiaries and it has no say in the matter. Hence requirement of submission of injection data by NTPC should be dispensed with.

4.9 AD Hydro has raised concern that RoR/hydro plants, which are able to inject maximum during summer/monsoon period i.e. June to September would have to pay high transmission charges for the entire quarter of April-June because of high generation during the month of June. Similarly, RoR/hydel plants would have to pay high transmission charges even during lean months as they are generally able to provide peak power due to pondage facility.

4.10 Torrent Power has welcomed the proposed amendment stating that it is very much necessary to make transmission charges reflective of maximum injection/ peak withdrawal. This would ensure payment of transmission charges for the utilization of assets. It has further requested to allow DICs to send quarterly forecast of the injection and withdrawal along with proper justification which can be vetted by the Implementing Agency and revision in such forecast may be allowed with proper justification.

4.11 We have considered the submissions of the stakeholders. The detailed analysis of proposed calculation of transmission charges based on peak injection as compared to average injection was provided in the Explanatory Memorandum to the draft Regulation. We have decided that for making transmission charges reflective of its usage, charges should be attributed to users based on maximum injection/drawal.

4.12 The word 'Peak' might be creating confusion in the mind of stakeholders since Individual maximum withdrawal (non-coincidental peak) may occur at a time which is different from the time when System Peak (coincidental peak) occurs and also duration and timing of peak injection/withdrawal for different Regions would be different. It is therefore clarified that to capture transmission usage of each DIC, the usage corresponding to maximum injection or maximum withdrawal is intended to be captured. The methodology has been finalized based on methodology suggested by CEA and it captures individual usage corresponding to maximum injection and withdrawal, scaled by All India Peak Met.POSOCO, during presentation, raised the issue of coincidental or non-coincidental peak. In other countries, transmission charges are allocated based on coincidental peak but the peak is taken as corresponding to one peak value (1 – CP), average of three peaks (3 –CP) or average of 12 peaks (12-CP). In Maharashtra transmission charges are recovered based on Average of 12 months Non–Coincidental peak and Coincidental Peak value as quoted below:

"64.2 Base Transmission Capacity Rights

64.2.1 The Commission shall approve yearly 'Base Transmission Capacity Rights' as average of Co-incident Peak Demand and Non-Coincident Peak Demand for TSUs as projected for 12 monthly period of each year (t) of the Control Period, representing the "Capacity Utilisation' of Intra-State transmission system and accordingly determine yearly 'Base Transmission Tariff' for the same."

To address the concern of stakeholders that Peak, being one off value, is not appropriate, average of maximum injection / withdrawal during application months has been taken.

4.13 The base case shall be prepared based on average of maximum injection /maximum withdrawal. The injection/withdrawal data to be considered in base case shall be submitted by DICs and the same shall be vetted by IA and validated by the Validation Committee.

4.14 Regarding POSOCO's comments in regard to possibilities of outage of a generator, commissioning of new lines/generators, it is underlined that in Sharing Regulations, participatory role is assigned to all DICs wherein instead of a single central entity or Agency like Implementing Agency declaring DIC's Approved Injection or Approved Withdrawal, DICs are given opportunity to declare their Approved Injection or Approved Withdrawal. The concept of self-declaration is the underlying theme of Sharing Regulations. In the present procedure of computation of PoC Charges, DICs are required to give their injection and withdrawal themselves. This is validated in a representative Validation Committee in a transparent manner. All stakeholders are given opportunity and in case of any difference in forecasted figures, by providing satisfactory justification, the figure agreed by Validation Committee is taken into consideration for computation. There are multiple ways and data available to check veracity of forecast and the difference between forecasted and actual values becomes visible in next quarter. With so many entities affecting load generation, no single entity can influence the result, in this cooperative exercise, in a way which is advantageous to it. Sufficient check and balance in form of transmission deviation charges is available wherein the entity which under-declares needs to pay higher transmission charges. The procedural issues, if any, may be resolved upfront in the Validation Committee. The larger objective of payment of transmission charges based on actual usage needs to be given more weightage than procedural difficulties. The method of computation of peak injection/peak withdrawal has been suggested in the Regulations which should provide clarity in regard to calculation of peak and avoidance of possible gaming.

4.15 All the observations of POSOCO have been taken care of as outlined hereunder:

(i) As average of maximum injection/withdrawal for the months corresponding to Application Period for past three years would be taken for determination of projected peak injection, anyone off incident of no injection gets discounted. Further, application period data is being sought from injecting DIC.

(ii) No fixed peak hour is proposed to be declared, rather average of maximum injection at any time during the period corresponding Application Period would be considered.

(iii) For new units, Validation Committee has fixed certain % of generation during the initial period depending on type of station. If generator itself does not give Injection figure, the same corresponding to norms may be considered.

(iv) In Validation Committee based on input from injecting DICs, RLDCs and RPCs, an estimate of injection can be made and the value can be published ex-ante.

4.16 With regard to billing based on Approved Injection, our observations are as under:

(i) In the Explanatory Memorandum to Draft Regulations it was brought out that billing should be on the basis of maximum injection or maximum withdrawal as most of the DICs are injecting into or drawing from the ISTS more than their LTAs. It was explained that PoC rates in Rs/MW/Month get distorted while dividing by LTA but it was found to have a merit in the sense that the PoC charges can be said to be free of dispute. As the LTA corresponds to transmission capacity contracted for availing power as per allocation, or LTA/MTOA granted, this figure is known ex-ante. It has, therefore, been reconsidered and it has been decided to use LTA/MTOA figures for billing.

(ii) The base case shall be developed considering maximum injection/maximum withdrawal and charges shall be allocated to each node/zone. The total YTC shall be recovered considering the charges as allocated to nodes. The rate of PoC charges shall be determined by dividing these charges by the LTA+ MTOA. CEA's suggestions have also been taken care of since DICs shall be billed for their LTA/MTOA and shall be liable for transmission deviation charges for any usage beyond their (LTA+ MTOA+ Approved STOA).

(iii) Though the PoC charges in Rupees are computed as per usage i.e. the load of Withdrawal DIC which affects flow in inter-State transmission line (load having marginal participation in particular line), while computing POC rates in Rs./MW/month, PoC charges are divided by LTA + MTOA. While billing, the PoC rates are multiplied by LTA/ MTOA, thereby resulting in recovery of same POC charges in Rupees Though division by LTA+MTOA affects PoC rate, this problem is unavoidable, but it does not affect the total PoC Charges to be paid by a DIC.

(iv) To understand, let us consider a base-case based on either average or peak withdrawal of a state, the load-connected at all nodes of the State as 10,000 MW (say). This results in flow in intra-State lines and ISTS lines. As tariff of only inter-State lines is to be considered, only the base case flow and subsequent change in inter-State i.e. marginal flow (MF) is considered and multiplied with tariff of inter-State lines to compute PoC charges.

(v) If 10,000 MW load is used for billing, there will be a misconception that all 10,000 MW load is on inter-State lines, which is actually not so. In fact this is the load which affects flow in ISTS. At initial level this load is served by State lines at lower voltage and then it is reflected on ISTS.

(vi) If any DIC is raised bill for 10000 MW, the DIC may not understand and may rather presume that it is being charged even for state line flows, and object. However, as only YTC of inter-State lines is considered, DIC is not being charged for intra-state lines. So, the ISTS usage corresponding to this load is to be recovered through LTA+MTOA. Thus, in total PoC charges, actual usage of ISTS is captured; LTA+MTOA is only used to compute the PoC rate. The loss of locational signal of POC rate through this method is inevitable, but as it does not change the total transmission charge payable except for minor changes due to slab which may be positive or negative.

(vii). While measuring actual flow, only the withdrawal from ISTS is considered and in a particular time block, it is equal to LTA+MTOA+Approved STOA and deviation from schedule. So by billing at LTA+MTOA, collecting charges for STOA and transmission deviation charges, total usage of ISTS is captured.

(viii) In so far as the generators are concerned, mostly their injection considered in the base case operation is either equal to or more than LTA. They have requested that actual injection be considered. Their request is based on the fact that in initial period of operation, they may not have injection equal to LTA. As charges are computed on actual usage, the charges will reflect actual usage only. After division of these charges by LTA and then again multiplying the same with LTA would not put any extra burden on them for unutilized capacity of LTA.

4.17 We do not agree with NTPC's suggestions for dispensing with requirement of submission of injection data by NTPC. We have decided to use peak injection/withdrawal for base case and LTA+MTOA for billing. The transmission charges for generators with long term PPAs are being levied directly on beneficiaries but generators should provide actual data for last 3 years and provide projected generation for the ensuing quarter. Generators are in best position to indicate their peak injection keeping in view their maintenance schedule, availability of coal, water, etc. Generators like NTPC should also declare their proposed peak injection for the ensuing quarter so that the base case considered is representative of actual conditions. Hence NTPC’s comments that requirement of submission of generation data by NTPC may be dispensed with is not accepted.

4.18 CTU’s comments regarding a generating station which has not commissioned any unit has been dealt with separately in Regulation 8(5) at para 32 of this SOR.

4.19 We disagree with AD Hydro to bill hydro plants on MWh basis since transmission system is planned on the basis of capacity to be evacuated/ transmitted. Further, in so far as comment that load factor of less than 50% shall also attract high charges due to peaking facility, it needs to be appreciated that peak injection for such cases shall be reflective of its usage commensurate with its planning. We have specified the methodology for calculation of peak injection/withdrawal which provides that average of months of an application period shall be projected and the same shall be scaled as per All India peak case. The data shall also be validated by Validation Committee on the basis of data submitted by stakeholders. Stakeholders may provide their data accordingly. Any usage above approved injection shall be charged as per Regulations.

4.20 Regarding Torrent Power's submission of quarterly data and its revision, we have already provided that forecast data need to be submitted by DICs for each application period which shall be vetted by IA. The data shall be discussed and finalized in Validation Committee meeting.

4.20 **In view of the foregoing, the proviso has been retained and the Regulation 2 (1) (c) has been amended as under:**

"(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.*

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."

4.21 It is clarified that Approved Injection under Regulation 2(1) (c) shall have two dimensions as detailed below:

4.21.1 For the purpose of injection to be considered under base case under Regulation 7(1) (d).

The Approved Injection shall be 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.

4.21.2 For the purpose of billing under Regulation 11

Approved injection shall be considered as LTA/ MTOA for a DIC under the provisos quoted below and as indicated under Table provided at Para 2.8.1 of Annexure–I of the Principal Regulations

"*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"

5 <u>Sub-clause (d) along with Proviso of clause (1) of Regulation 2</u>

The words 'peak and off-peak scenarios' have been deleted at various points in the Regulations. This is keeping in view the fact that a single scenario is being contemplated for the base case which is peak scenario. The rationale for considering the case corresponding to maximum injection and maximum withdrawal has been provided at Regulation 7 (1) (d).

6 <u>Sub-clause (f) of clause (1) of Regulation 2</u>

6.1 Sub-clause (f) along with Proviso of clause (1) of Regulation 2 of the Principal Regulations was proposed to be substituted as under:

"(f) 'Approved Withdrawal' *means the simultaneous Peak withdrawal in MW based on actual peak during corresponding application period of last year validated by Implementing Agency for any Designated ISTS Customer in a control area aggregated from all nodes of ISTS to which Designated ISTS Customer is connected for each representative block of months and peak scenarios at the interface point with ISTS, and where the Approved Withdrawal shall be determined on the demand data submitted by Designated ISTS Customers. Provided that in case data submitted by DIC is different from data computed on the basis of last year actual data, suitable justification by the DIC is required to be submitted for considering the data. Provided further that any mis-declaration by DICs would be liable for Deviation charges.*

6.2 Comments have been received from CEA, DVC, POSOCO, Lanco Kondapalli, CTU, GRIDCO Ltd and Torrent Power Ltd.

6.3 CEA has agreed that transmission users should pay as per their maximum usage of transmission system or LTA/MTOA, whichever is higher.

6.4 DVC has stated that due to difficulty in projecting maximum drawal, deviation beyond peak drawal may be suitably provided.

6.5 POSOCO has commented that approved withdrawal should be based on LTA quantum which is sacrosanct**.**

Lanco has stated that approved withdrawal should be matching with approved injection.

6.6 CTU has suggested to clarify peak as per actual peak during corresponding application period of last year and demand data submitted by DIC.

6.7 GRIDCO has stated that it has never exceeded drawal as compared to its LTA and the data shown in Explanatory Memorandum to draft Regulations is not correct.

6.8 Torrent Power has welcomed the proposed amendment stating that it is very much necessary to make transmission charges reflective of maximum injection/ peak withdrawal. This would ensure payment of transmission charges for the utilization of assets. It has further requested to allow DICs to send quarterly forecast of the injection and withdrawal along with proper justification which can be vetted by the Implementing Agency and revision in such forecast may be allowed with proper justification.

6.9 We have considered the suggestions of stakeholders. With regard to DVC's comments it is clarified that the approved withdrawal of any DIC shall be considered incorporating sum of its long term and medium term open access. Further, any deviation upto 20% beyond approved withdrawal shall be allowed at the POC rate as per the existing Regulations, beyond which additional charges are levied.

6.10 We have considered suggestion of POSOCO and Lanco and accordingly, billing shall be done on Approved Withdrawal which shall be based on Long Term Access and Medium Term Open Access.

6.11 We have taken note of the suggestions of CTU and have specified the methodology for calculation of Approved Withdrawal for base case considering demand data as submitted by DICs which shall be vetted in the light of past data and duly validated by the Validation Committee.

6.12 Regarding GRIDCO's contention of its maximum drawal data, it is clarified that peak demand met was obtained from CEA website. Further it is provided in in the Regulations that DICs shall project their withdrawal data and submit to IA. This issue has also been discussed in detail at Para 17 and Para 18 of this SOR.

6.13 Regarding Torrent Power's submission of quarterly data and its revision, we have already provided that forecast data need to be submitted by DIC for each Application Period which shall be vetted by IA. The data shall be discussed and finalized in Validation Committee meeting.

6.14 **In view of the foregoing, the Regulation 2 (1) (f) has been amended as:**

*"(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.*

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)."

7 Sub-clause (g) of clause (1) of Regulations 2

7.1 Sub-clause (g) of clause (1) of Regulations 2 has been amended to remove 'peak and off-peak scenarios'. The same shall be calculated for each Application Period and hence 'for each representative block of months' has been deleted. Further, Approved Additional Medium Term Withdrawal for all purposes shall be considered on the principles as defined for Approved Withdrawal.

7.2In view of the foregoing**,** the Regulation has been amended as:

*"(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."*

8 Sub-clause (l) of clause (1) of Regulations 2

8.1 Sub-clause (l) of clause (1) of Regulations 2 of the Principal Regulations was proposed to be substituted as under:

"(l) Designated ISTS Customers (DICs) *means the users of any segments/elements of the ISTS and shall include all generators, state transmission utilities, SEBs or load serving entities directly connected to the ISTS including Bulk Customer and any other entity/person. The intra-State* *entities connected to STU, but using inter-State transmission system shall also be considered as DICs for their injection payment liabilities and withdrawal payment liability should be of the concerned STU. The payment liability for their injection be settled with concerned STU who may make interim arrangement for collection of the same from the concerned intra-State entity*.

8.2 Comments have been received from CTU, APP, WBSETCL, AD Hydro Power Limited and Steel Authority of India Limited.

8.3 CTU has suggested that payment of POC charges by STU shall create uncertainty in the revenue realization.

8.4 APP has stated that in case STU is made responsible to bear the liability of injection and withdrawal charges for intra-state entities it should have full authority to recover same from the concerned intra-state entity.

8.5 WBSETCL has suggested that STUs are formed basically to maintain intra-State Network and are in no way related to ISTS payment mechanism.

8.6 AD Hydro has also objected to collection of charges attributable to intra-state entities towards inter-state usage by STU.

8.7 SAIL has suggested that captive generators and captive consumers who have constructed their own dedicated lines and not using any intra or inter-State transmission systems, should not be considered as DIC.

8.8 We have considered the suggestions of the stakeholders. Modalities of payment security mechanism (opening LC, etc.) by involving STUs will increase complications. As the tariff of STU is under purview of SERCs, we are not inclined towards shifting of payment liability of the intra-State entities for use of inter-State transmission system to STU. Hence we have made intra-State entities who have obtained Medium Term Open Access or Long Term Access to ISTS, a DIC with liability for associated payment resting with the concerned DIC.

The issue of payment securitization raised by CTU is already covered under these regulations as well as CERC (Regulations of Power Supply) Regulations, 2010

8.9 In regard to suggestion of SAIL to exclude CPPs with dedicated line not using ISTS from the definition of DIC, we would like to clarify that the definition of DIC has been firmed up after due deliberations.

8.10 The intended objective of proposed amendment to include usage of ISTS by intra state generator is achieved by revised methodology of computation of transmission charges for withdrawal nodes.

8.11 In view of the foregoing, Regulation 2 (1) (l) (except the provisos) have been amended as :

*"(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."*

9.**<u>Sub-clause (l-i) of clause (1) of Regulation 2</u>**:

9.1 The definition for 'HVDC Charges' has been added for clarification as sub-clause (l-i) of clause (1) of Regulation 2.

9.2 The definition has been added as:

*"(l-i) '**HVDC Charge'** means the transmission charges shared for use of HVDC transmission systems as provided under Regulation 11 of these regulations."*

10. **<u>Sub-clause (o) of clause (1) of Regulation 2</u>**

The definition for 'Merchant Power Plant ' has been added for clarity as sub-clause (o-ii) of clause (1) of Regulation 2. The definition has been added as:

*"(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."*

11. **<u>Sub-clause (t-i), (t-ii) of clause (1) of Regulation 2</u>**

11.1 The definition of 'Reliability Support Charges' and Reliability Support Charges Sharing Methodology' has been added for clarification as sub-clause (t-i) and (t-ii) of clause (1) of Regulation 2 of the Principal Regulations.

11.2 The definition has been added as under:

"(t-i) '**Reliability Support Charge'** means the Charge for reliability benefits which accrue to the DICs by virtue of operating in an integrated grid.

(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.c. of Annexure-I."

11.3 The above has been introduced in light of deletion of Uniform Charges and the same has been explained in para-13 of SoR.

12. **<u>Sub-clause (u) of clause (1) of Regulation 2</u>**

12.1 The definition for Validation Committee has been added for clarity as sub-clause (u-i) of clause (1) of Regulation 2.

12.2 The definition has been added as:

*"(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."*

12.3 Accordingly sub-clause (g) of clause (1) of Regulation 7 has been amended

13. **<u>Sub-clause (v) and (w) of clause (1) of Regulation 2</u>**

13.1 Sub-clause (v) and (w) of clause (1) of Regulation 2 of the Principal Regulations , defining Uniform Charge and Uniform Charge Sharing Mechanism were proposed to be deleted.

13.2 Comments have been received from GRIDCO, Bihar State Power (Holding) Company Limited (BSPCL), Thermal Power Tech, SN Power, POSOCO, POWERGRID and CEA.

13.3 GRIDCO has welcomed the deletion of uniform charges and suggested that it should be made effective from 1.7.2011.

13.4 BSPCL has stated that some inter-regional transmission schemes supply surplus power from NER and ER to beneficiaries outside ER and as such are beneficial for other regions and for the States within the region having surplus power to export. Hence, the above said transmission schemes in no manner provide any benefit to Bihar but as per extant PoC methodology, Bihar has to pay transmission charges for above said assets without using those facilities.

13.5 Thermal Power Tech Limited and SN Power have supported the proposal. SN Power has suggested to consider a market based system with auctioning/trading of transmission capacity along with pricing based on actual usage.

13.6 POSOCO has stated that though review of uniform charge has been specified in the principal regulations, it could have been reduced to 25% instead of removing it altogether. Removal of uniform charge and slab rates would lead to a situation, where, a number of entities would have 'NIL' injection / withdrawal charge and some other would have very high charge. Similar would be the case with transmission losses. All the entities are availing reliability support of the grid, be it generator or load serving entity. Further, the concept of General Network Access (GNA) is under discussion, and need of uniform charge may be seen in this context also. POSOCO has suggested that uniform charge may be reduced to 25% and it may be renamed as "Reliability Charge."

13.7 During the public hearing, POWERGRID also welcomed the removal of Uniform charges and stated that proposed amendment addresses concerns of the different stakeholders and transmission charges allocation being aligned with the planning.

13.8 CEA has supported the proposal for deletion of uniform charge.

13.9 We have considered these comments. We do not agree with the suggestion of GRIDCO that the uniform charge should be deleted from 1.7.2011. Sharing Regulations came into force with effect from 1.7.2011 and the Regulations explicitly contained a provision that uniform charge will form 50% of PoC charge and the scheme will be reviewed after two years. The Commission undertook the exercise of reviewing the uniform charge through the Third Amendment and after stakeholders' consultations decided to do away with uniform charge. The Third Amendment was proposed to come into effect from the date of its publication in the Gazette. While notifying the Third Amendment, it was provided that the regulations would come into effect from 1.5.2015. Accordingly, the Third Amendment has come into effect from 1.5.2015. The suggestion of GRIDCO to retrospectively amend the regulations is not possible for two reasons. Firstly, regulations made in exercise of the powers of delegated legislations have to be given effect prospectively. Secondly, the transmission charges collected from the DICs have already been disbursed to the CTU and inter-State transmission licensees and STUs where applicable. If the allocation of liabilities for transmission charges among the DICs are allowed to be revised retrospectively, it will lead to reopening of the entire PoC mechanism from 1.7.2011. Since the DICs and the inter-State transmission licensees have settled their affairs based on the applicable regulations in vogue from 1.7.2011 till 30.4.2015, it is in nobody's interest to unsettle the settled position. Therefore, both from legal and commercial points of view, the suggestion of GRIDCO for retrospective operation of Sharing Regulations with effect from 1.7.2014 cannot be accepted.

13.10 With respect to comments of BSPCL, we are of the view that PoC charges capture the distance, direction and quantum of flow and every DIC has the liability to pay the transmission charges for the system it uses. The issue raised by BSPCL that it shouldnot be burdened with the charges for the transmission lines constructed for power transfer from NER to NR without any benefit to BSPCL, it is clarified that the concerns of BSPCL have been addressed by removing the uniform charges as a component of POC charges. If these lines are of such nature that they directly transfer power from NER to NR with no connection with ER system, it will not burden Bihar. If these are interconnected with ER and Bihar is using the same, its charges will be shared by Bihar to the extent of usage. It may also replace power from farther station(s) and may actually benefit Bihar. Keeping in view increasing Peak Demand Met trends of Bihar from 1000 MW to more than 2100 MW in last five years, these assets may prove beneficial to Bihar. To avail benefit, it is required that Bihar improves its intra-state transmission network and more connections are made with ISTS. This will also help in reducing transmission losses, which will in turn result in important gain through higher net scheduled energy.

13.11 The suggestion of SN Power regarding auctioning of transmission capacity was not proposed in the draft regulations and thus has not been considered.

13.12 POSOCO has opined that uniform charges may be renamed as Reliability Charges since all the entities, be it generator or load serving entity, are availing reliability support of the grid.

13.13 We would like to deal with the issue of uniform charges starting with the views sent by Prof. Ignacio J. Pérez-Arriaga of Massachusetts Institute of Technology (MIT) to FERC. Prof. Arriaga is an eminent researcher in the field and has published many papers on the transmission pricing mechanism based on load flow studies. The average participation and marginal participation method used in CERC Regulations is based on his research. In his submission to FERC, Prof. Arriaga mentioned following principle:

"**<u>Cost Allocation Principle</u>**:

Beneficiary Pays First and foremost, all principled costs allocation schemes should be founded on the principle of beneficiary pays or its dual, cost causality."

13.14 So the starting principle of transmission allocation process is either the one who caused the creation of the asset should pay and also to avoid any free rider(s), anyone who is benefiting from the same should pay. While transmission planning is done for 5 years horizon, the life of assets is more than 35 years. During the life of the project, its benefit to different users changes and it is assumed that power flow in a snap shot or a scenario captures this benefit, power flow based methodologies are used to allocate transmission cost i.e. sharing of transmission charges. However, no cost should be allocated without assessing the benefits.

13.15 Further in Illinois Commerce Commission v. FERC, the U.S. Court of Appeals for the Seventh Circuit heard a challenge to FERC's approval of a cost allocation proposal for certain new transmission facilities in the PJM Interconnection. Two state utility commissions in Midwestern states protested a FERC-approved allocation of transmission costs for the PJM interconnection that required pro rata contributions from all utilities in the region; that is, the utilities in the PJM region would increase their rates by a uniform amount sufficient to cover the cost of the new facilities. According to the court, FERC's rationale for this pro rata increase was that (1) some of the PJM members entered into similar pro rata cost sharing agreements in the past and would like to continue to allocate costs in that manner; (2) the burden of determining which parties would benefit from the new transmission (and to what degree they would benefit) would be onerous and would likely result in litigation; and (3) that every member of the PJM Interconnection would benefit from the new transmission facilities because the reliability of the entire network would improve. The court held that the FERC-approved pro rata rate increase for recovery of transmission costs was not supported by substantial evidence. The court quickly dispatched FERC's two arguments in favor of the reasonableness of the pro rata rates. According to the court, the fact that previous arrangements among the PJM members had pro rata cost sharing arrangements in the past carried no weight. The court rejected FERC's argument regarding the difficulty of measuring benefits and the likelihood of litigation, because of an absence of evidence of the relative difficulty of assessing the benefits. The court did not dismiss the possibility of such a finding, noting that feasibility concerns can play a role in rate determinations. However, in this instance, the court found that FERC had not offered sufficient explanation for this factor and the role it played in the rate decision. The court spent more time addressing FERC's third line of reasoning: that the new transmission facilities would benefit every PJM member, and therefore, the costs should be allocated among all of them. As the court acknowledged, even though the purpose of the new facilities was to satisfy demand for eastern customers in the PJM system, the entire PJM system would benefit from greater reliability as a result. However, the court found that it was possible that such secondary benefits could be minor in relation to the costs to customers not in the eastern region expected to benefit directly from the new transmission capacity, and that FERC had not provided any information by which these benefits could be assessed. According to the court, if FERC cannot quantify the benefits to the mid-western utilities from new 500 kV lines in the East, but it has an articulable and plausible reason to believe that the benefits are at least roughly commensurate with those utilities' share of the total electricity sales in PJM's region, then the Commission can approve PJM's proposed pricing scheme on that basis. But it cannot use the presumption to avoid the duty of "comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party." The impact of this decision on cost allocation going forward is not entirely clear. On the one hand, as several observers have noted, the case appears to create a new obligation for FERC to reconsider and potentially discard pro rata allocation of transmission costs. However, the ruling seems to be directed more at FERC's procedural failure to justify the ratemaking than a substantive failure in the application of the law. The court repeatedly mentioned that FERC's arguments in favor of the pro rata allocation were dismissed not because such a cost allocation method was unreasonable on its face, but rather because FERC had failed to demonstrate the reasonableness of the rates. Perhaps the most significant restriction on FERC articulated by the Seventh Circuit is that FERC must show reason to believe that the benefits received by the parties are "at least roughly commensurate" with the pro rata cost allocation.

13.16 FERC does not propose interconnection-wide cost allocation as a regional allocation method for transmission facilities. The regions will define benefits, and FERC considers at least three primary areas for benefits will be considered—**reliability, economics and public policy**. Order No. 1000 states that there will be no cost allocation where there is no benefit:

13.17 Those that receive no benefit from new transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated any of the costs of those facilities. That is, a utility or other entity that receives no benefit from transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated any of the costs of those facilities.

13.18 FERC also believes this Final Rule will protect transmission customers from free riders, that is, those who receive benefits without paying for them. Order No. 1000 addresses the “free rider” issue by invoking cost-causation principles:

“In Order No. 890, the Commission recognized that the cost causation principle provide that costs should be allocated to those who cause them to be incurred and those that otherwise benefit from them”.

13.19 MIT in its study Future of the Electric Grid further deliberated this:

Principle-1. Costs should be allocated in proportion to benefits.

This is the most fundamental principle. Each beneficiary’s share of a project’s costs should be as close as practical to its share of the project’s total benefits. In principle, beneficiaries are any network users who see a change in their expected expenditures or profits as a result of the project, taking into account the value of increased reliability and any other benefits. This so-called “beneficiary-pays” principle has been widely accepted in the U.S. and abroad. It stands at the core of FERC Order No. 1000, which in 585(1) states, “The cost of transmission facilities must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits.” We see no principled reason not to take this one step further: the allocation of costs should be exactly proportional to those estimates if the planning process has produced a set of estimates of expected benefits. This stronger language would avoid an interpretation permitting cost allocations that depart materially from the pattern of estimated benefits.

A transmission project is economically justified if its benefits exceed its costs. By reducing or eliminating price differences, however, a transmission project could impose losses on generators in previously high-price areas or on load in previously low-price areas. In addition, these projects can affect the economic value of any existing transmission rights and contracts (see Box 4.2), and some entities might suffer losses because of environmental harm. Regulators can cut through this tangle of effects by approving any project with positive net benefits, even if it imposes losses on some entities. They should disapprove projects with gross benefits for some that exceed costs but with negative net benefits overall. This means turning down some projects for which those who receive benefits would be willing to cover the costs.

Dividing a project's costs among network users in proportion to their benefits is generally perceived as equitable. And if a project's benefits exceed costs, all beneficiaries will be better off and less likely to oppose progress on the project. Conversely, if a project's costs exceed its benefits, it will be impossible to allocate costs in such a way as to make all entities better off. Thus adopting the beneficiary-pays principle helps with decisions about what should be built, as well as determining who should pay for what is built. Fairness is important, but support of consistent incentives for investments is the key reason for embracing this principle. Of course, failure to recognize all beneficiaries—the generators, in particular—could cause a beneficial project not be built because not enough of the benefits have been captured to cover the costs.

An inferior but commonly used alternative to the beneficiary-pays principle is the socialization of cost, which spreads it uniformly throughout a region. Socialization eliminates locational signals, reducing the system's ability to promote investment in the best locations. For instance, all else equal, socialization would always favor the best wind or solar resources, regardless of their location and impact on transmission costs. Additionally, spreading costs too widely may reduce cost discipline and eliminate the incentive to consider economic alternatives to transmission expansion. One solution might be to socialize the costs of the alternatives, too, but doing so would call for significant changes in decision-making in the electric system and put many important investment decisions into the hands of regulators. Finally, uniform region-wide cost recovery can provoke substantial public opposition to even highly beneficial new investments if some parties are forced to shoulder costs that significantly exceed the benefits they realize.

It is sometimes argued that cost socialization is a workable approximation when much uncertainty exists in the estimation of beneficiaries, or when the investment impacts several regions. However, this argument misleads. Great uncertainty about benefits and beneficiaries generally implies that expected benefits are widely distributed. The beneficiary-pays principle is still applicable, even though it might produce a cost allocation similar to direct socialization. But this would not be the same as abandoning the principle, nor would it produce the same result in the more common cases where significant uncertainty about some beneficiaries is accompanied by less uncertainty about others.

13.20 So in a developing country like India where transmission infrastructure needs to be built to fulfill aspirations of better life of people, a limited view of benefit that a particular line is built for a particular entity and it is not useful for my state or region cannot be taken. With changing development scenario, a line built for another entity, passing through a particular state may become useful for intervening state. Also with power flowing through displacement method, a new transmission line for a new generating station can replace power from generating station situated at longer distance. It can also bring power in the event of failure of state's own generating station. During the period of monsoon failure, the same transmission line can prevent hike in energy price in the region by bringing power from other region and in extreme contingency of grid disturbance it can help in early restoration of the grid. Thus the benefits are more than evacuation only; what is needed is to define them, quantify them, informing them in advance and passing the cost broadly commensurate with benefit.

13.21 Further, the stakeholders are aware that Commission sought stakeholders' comments on Transmission Planning, Open Access, through Staff paper in September, 2014. The transmission cost allocation is a complex, evolving process. The conceptual framework for common benefit needs to be evolved further and needs to defined and quantified.

13.22 To illustrate which type of benefits may occur due to transmission system development, extensive details are given in **transmission benefit quantification, cost allocation and cost recovery (2008): CERTS report for Public Interest Energy research (PIER) submitted to California Energy Commission, which are extracted hereunder:**

"*Types of Benefits*

The benefits from an economic transmission project can be grouped into:

- *Primary Benefits (Traditional Benefits).*
- *Strategic Benefits.*
- *Extreme Event Benefits.*

There are also secondary benefits from new projects. These include: economic development, tax base increase, use of right-of-way, and impact on infrastructure development. These secondary benefits are not addressed in this study.

Primary or traditional benefits can be defined as cost reduction, congestion reduction and expansion of access to regional markets to take advantage of load and resource diversity. Primary benefits improve network reliability and result in lower cost of energy and capacity adjusted for transmission losses.

Strategic benefits can include:

- *Access to new renewables resources to meet Renewable Portfolio Standard (RPS).*
- *Promote efficient market operation and market power mitigation.*
- *Promote fuel diversity.*
- *Provide emission reduction/environment benefits.*
- *Improve deliverability.*
- *Insurance against contingencies.*
- *Meet policy goals such as Renewable Portfolio Standard.*

These strategic benefits all contribute to lower cost electricity or risk for consumers, and if properly quantified, will show larger streams of benefits of transmission projects than what has traditionally been quantified.

The types of benefits of new transmission projects depend on whether the region is at the generation or exporting end or importing end of the transmission line. Benefits accruing to a region are a function of location with respect to a transmission line as follows:

- *Exporting Region Benefits*
  - *Regional economic development.*
  - *Increase tax base.*
  - *Reliability Improvement.*
  - *Expansion of generation resources.*
- *Importing Region Benefits*
  - *Import of lower cost energy and capacity.*
  - *Reliability improvement.*
  - *Strategic benefits:*
  - *Access to Renewables.*
  - *Fuel diversity.*
  - *Emission reduction.*
  - *Insurance against contingencies.*
  - *Increased deliverability.*
  - *Decrease Market Power.*
- *Exporting and Importing Region Benefits*
  - *Seasonal exchange.*
  - *Sales of surplus energy.*
  - *Reserve sharing.*
  - *Reliability improvement*

There are many uncertainties that impact the size of primary benefit and types of strategic benefits from a new project. These uncertainties include load forecast, fuel prices, development of new generation and retirement of existing power plants, regional prices for electricity, and environmental regulation. Production cost-simulation, scenario analysis, stochastic modeling, and other techniques have traditionally been utilized to estimate a base level of benefit and the sensitivity analysis to take into consideration future uncertainties. These models tend to come up with base case, sensitivity cases, and expected value of benefits.

Another category of benefits relates to extreme events. In recent years, the August 2003 Northeast Blackout and the California 2000–01 market dysfunction put a spotlight on the significant economic (billions of dollars) and societal impact of such extreme events. The challenge is that traditionally, there has been no attempt to quantify the benefit of mitigating extreme events or when it is done, an expected value approach is utilized which understates the societal value of mitigating these very low probability but very high impact events.

One of the research conclusions is that insurance against extreme events should be defined as an additional societal benefit for reducing exposure to extreme market volatility and multi region-wide blackouts due to multiple contingencies. While there is general consensus on the existence of these types of strategic benefits, they are not easily quantified or captured using traditional models. For example, policymakers anecdotally acknowledge the value of transmission projects as insurance against contingencies, but there is no definition or examples of quantification of such values.

The above category of benefits can be defined as Extreme Event Benefits and are in addition to the Primary and Strategic Benefits. The value of extreme event benefits can be put in context when some of recent power system experiences are examined. For example:

- *2001 California market dysfunction and volatility with a cost of $20-40 billion.*
- *2003 Northeast Blackout due to multiple contingencies with a cost of $5- 10 billion.*

Extreme Event Benefits can be defined as:

1. Reliability—which is based on improved network load carrying capacity and ability to reduce or mitigate impact of extreme events resulting from multiple contingencies (N-3, 4, 5, 6 events).

2. Market Volatility—which is based on the societal benefit of reduced vulnerability to extreme price volatility which could result from extreme system events, market dysfunction, or a combination of factors.

Society's willingness to buy protection against extreme events is well established in the insurance industry, for example hurricane insurance, life insurance, re-insurance against major losses. In each of these examples, there is a well established actuarial data base that allows valuation of such insurance. However, there is not a rich data base related to extreme events in the electric power industry because major blackouts and market dysfunctions are infrequent events. Hence, the research challenge is to come up with alternative approaches that address these benefits rather than dismiss them due to difficulty in quantifying them."

To summarize the above, it may be said that all connected users get benefits by the development of transmission systems.

13.23 In view of the foregoing discussions, the concept of common benefit of Reliability needs to be introduced in the mechanism for sharing of transmission charges. We agree with POSOCO that all the entities, be it a generator or load serving entity, are availing reliability support of the grid. We are of the view that any user who is connected to the Grid gets access to improved power quality, enhanced reliability and stabilized operation. The interconnected system (Electricity Grid as a whole) gives stability and provides inertia. Transmission system is a common carrier and every entity (whether an injecting or drawing utility) having connectivity to the transmission system avails its services.

13.24 An operating generator, when it gets connected to a larger system would get the advantage of better frequency control, better reactive power management and voltage control, quick availability of startup power supply in case of a blackout at the power station and so on as compared to a situation wherein it was operating in islanded mode. Similarly, Drawee Entities / Discoms also get benefitted by way of improved frequency and voltage profile, improved adequacy and reliability. The Drawee Entities can source their requirements for power from various generators either to get benefit of cheaper power or to avail supply/assistance during emergencies. The consumers in turn benefit by way of improvement in quality and quantity of supply. For instance, by installation of polymer insulators in place of porcelain insulators in the Northern Region, not only the reliability of Northern Region Grid has improved but also that of other inter connected regional grids in the country benefited, which would have otherwise been vulnerable due to tripping of a large number of transmission lines in NR during heavy fog conditions. Further there is an increasing use of Power Electronic Devices (PEDs) such as High Voltage Direct Current (HVDC) systems, Static Var Compensators (SVCs), STATCOMs, Thyristor Controlled Series Capacitor (TCSC) in the system. The controllability of these devices makes them helpful in case of an emergency in the power system. All players connected to the grid avail benefit of these devices through better grid security. Therefore, the DICs (generator or load serving entity) need to pay certain transmission charges.

13.25 We would like to make it clear that we had proposed dispensing with uniform charges on the premise that the basic philosophy of Sharing Regulations is that sharing of transmission charges needs to be related to quantum of flow and it would be just and appropriate to dispense with uniform charge which is based on LTA or deemed LTA based on allocation of power from Central Sector Generating Stations. However we find merit in considering a part of charges of ISTS as Reliability Support Charges in view of reliability benefits which accrue to users of Grid (DICs) by virtue of operating in an integrated grid. Hence irrespective of location of the user and quantum of payment of transmission charges based on the actual usage, every user needs to pay certain fixed charges corresponding to their Approved Injection or Approved Withdrawal, as the case may be.

13.26 Hence to start with we decide that 10 % of the yearly transmission charge for AC system is to be recovered through Reliability Support Charge. Similarly, 10% of the transmission charge for HVDC systems (including Back-to-Back system) except where the transmission charges for any HVDC system which are to be partly borne by a DIC under a PPA, shall be considered under Reliability Support Charge. The same may be revised as and when considered necessary by the Commission. These charges are to be paid by DICs as a part of transmission charges corresponding to their Approved Injection or Approved Withdrawl.

While Commission has for the present taken a decision to allocate 10% charges as Reliability Support Charges, the Commission would like to have a better picture in this regard. We therefore, direct POSOCO in consultation with CEA and CTU to prepare a base paper on quantification of reliability benefit in a large interconnected grid such as ours including market risk mitigation based on international experience and submit for consideration of the Commission.

13.27 Accordingly, the proposed Sub-clause (v) and (w) of clause (l) of Regulation 2 of the Principal Regulations defining Uniform Charge and Uniform Charge Sharing Mechanism have been deleted and following new clauses in Regulation 2 have been included:

“New definition under Sub-clause (t-I) and (t-II) of clause (1) of Regulation 2 of the Principal Regulations shall be added.

"(t-i) ‘**Reliability Support Charge’** means the Charge for reliability benefits which accrue to the DICs by virtue of operating in an integrated grid.

(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.c. of Annexure-I.”

13.28 In view of the above, consequential changes have been made by substituting sub-clause (q) of clause (1) of Regulation7 of the Sharing Regulations as under:

"(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."

13.29 In the Annexure-I following has been inserted.

"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 Rs/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 Rs/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."

13.30 Accordingly **Regulation** 11 (4) of the Principal Regulations has been modified. The same is provided at Para 34 of this SOR

13.31 HVDC system also helps in controlling voltages and power flow in interregional lines and certain benefits accrue to all DICs by virtue of HVDC. 10 % MTC of HVDC back to back systems shall be considered in Reliability Support Charges, For HVDC system of Talcher–Kolar, Rihand- Dadri and Balia-Bhiwadi, 10 % of their MTC shall be recovered through Reliability Support Charges.

13.32 Appropriate proviso in HVDC charges has been accordingly included.

13.33 Following example is provided for clarity:

Let the MTC of the ISTS including HVDC systems be Rs 1400Cr (except Mundra-Mohindergarh, as part of HVDC Mundra-Mohindergarh shall be included in PoC calculation, by scaling up of YTC, it would not be included in Reliability Support Charges.)

Let total of Approved Withdrawal of the Withdrawal DICs and Approved Injection of the Generators having LTA to Target Region be 1,40,000 MW.

The Reliability Support Charge (RSC) rate shall be:

(10 % of Rs 1400,00,00,000)/1,40,000 = Rs 10,000/MW/month

RSC rate shall be considered for deriving Reliability Support Charge in first part of bill.

Let for a withdrawal DIC, '**X**', if the Approved Withdrawal is 3500 MW in a month, its RSC would be = 10,000 X 3500 = Rs 350,00,000 for that month.

Similarly for a **Generator having LTA to target region**, '**Y**', if the Approved Injection is 400 MW in a month, its RSC would be = 10,000 X 400 = Rs 40,00,000 for that month.

For STOA purpose it would be Rs 10,000/7200= 1.39 paise / kWh
This amount i.e1.39 paisa/ kWh shall be added to the slab rate of STOA for obtaining the transmission charges under STOA.

14. **Sub-clause (x) of clause (1) of Regulation 2**

14.1 Sub-clause (x) of clause (1) of Regulation 2 of the Principal Regulations giving definition of 'Uniform Loss' was proposed to be deleted.

14.2 Comments have been received from POSOCO.

14.3 POSOCO has stated that though review of uniform charge has been specified in the principal regulations, it could have been reduced to 25% instead of removing it altogether. Removal of uniform charge and slab rates would lead to a situation, where, a number of entities would have 'NIL' injection / withdrawal charge and some other would have very high charge. Similar would be the case with losses.

14.4 We have considered suggestion of POSOCO. Total transmission charges can be segregated into transmission usage charge and transmission losses. If the relative distance between generating source and load is less, the losses are less. Thus, transmission losses are indicative of distance & direction sensitivity.

14.5 Although transmission losses are small and less attention is given to them as compared to transmission charges, it has more value in terms of energy as scheduling to the customer depends on losses. The uniform loss component has been removed so that benefit of distance & direction in form of less loss can be given.

14.6 In computation of PoC charges while there were certain assumptions in regard to tariff of individual assets, no major assumptions are there in technical parameters of lines. Also losses are a function of load and generation and only the proportions of loss to be attributed to various DICs are calculated through software which will then be applied on schedule based on past actual weekly losses. The concept of uniform losses was therefore not found reasonable.

14.7 In view of the foregoing, we have deleted sub-clause (x) of clause (1) of Regulation 2

15. **<u>Sub-clause (y) of clause (1) of Regulation 2</u>**

15.1 Following was proposed to be added at the end of Sub-clause (y) of clause (I) of Regulation 2 of the Principal Regulations:

"However in case of non-ISTS lines (lines owned by STU but being used for carrying ISTS power), the average YTC of similar lines of ISTS shall be used. For the computation for payment purpose, if the approved capital cost and tariff is available either from State Commission or Central Commission, tariff proportionate to actual usage shall be reimbursed. The payment to the concerned STU shall be adjusted in proportion to its approved Annual Revenue Requirement.

Provided that where separate line wise capital cost is not available, only the proportionate O&M charges in accordance with O&M norms of concerned State's Tariff Regulations shall be reimbursed to the concerned STU."

15.2 Comments have been received from BBMB, AD Hydro, GRIDCO, BSPCL, SAIL, POSOCO and CTU were received.

15.3 BBMB has suggested that the average YTC of the similar lines of ISTS, proportionate to the actual usage, may be reimbursed to concerned STU in place of O&M charges.

15.4 AD Hydro has raised the issue of Intra State settlement.

15.5 GRIDCO has proposed that actual line cost for the transmission lines whose tariffs are available should be considered instead of indicative cost.

15.6 BSPCL has suggested that transmission charges of the intra state transmission assets determined by the Appropriate Commission may be considered in place of O&M Charges so that STU should be able to recover cost and equity invested in the said transmission assets.

15.7 SAIL has suggested that in case of non-ISTS lines (Dedicated lines which are not used for carrying ISTS power), the yearly YTC shall not be used for computation purpose.

15.8 POSOCO suggested that that full tariff of non ISTS lines may be considered in the base case.

15.9 CTU has stated that in the present draft, there is relaxation granted for STUs lines used for ISTS power transfer by considering the YTC even without such tariff determination/adoption by the appropriate commission. CTU has suggested that YTC of ISTS lines may also be captured based on the principle of average YTC of similar ISTS transmission element whenever such situation arises.

15.10 We have considered comments of the stakeholders. The Sharing Regulations are for recovery of transmission charges of Inter-state Transmission System (ISTS). The YTC of transmission system approved by Appropriate Commission is considered in the PoC calculation.

15.11 In regard to suggestions of BBMB, we are of the view that the YTC of concerned STU lines, as approved by the Appropriate Commission or derived from the ARR approved by the State Commission shall be considered for inclusion in the PoC calculation.

15.12 The issue of Intra State settlement raised by AD Hydro is beyond the jurisdiction of this Commission and scope of these Regulations.

15.13 In regard to GRIDCO's suggestions, it is clarified that the purpose of using indicative cost to normalize tariff of all the transmission lines is to make transmission charge distance sensitive. As both old and new lines are providing same level of service if actual tariff is used, then transmission charge per km of old and new line will be different and the objective of distance sensitivity cannot be achieved.

15.14 The suggestion of SAIL in regard to non-inclusion of YTC of dedicated lines is in order; the cost of dedicated lines is not considered in computation of PoC charges.

15.15 We agree with the submission of BSPCL. The tariff as approved/ adopted by the Appropriate Commission shall be considered in the YTC of PoC computation.

15.16 We are in agreement with the suggestion of POSOCO in regard to tariff of non ISTS lines. The software will assign the usage of all lines whose tariff is considered in the WebNet software, to DICs automatically and if it is found that the line is being used by home State to a certain extent, the STU shall share the tariff of the line to that extent and the balance would be allocated to other DICs.

15.17 With respect to the submission of CTU in regard to relaxation granted for STUs lines used for ISTS power transfer by considering the YTC even without such tariff determination/adoption by the Appropriate Commission, and adopting the same methodology to CTU lines, it is clarified that YTC as approved by the Appropriate Commission shall only be considered in the PoC calculations.

15.18 The Commission in its order dated 18.3.2015 in Petition no. 213/TT/2013 has approved the methodology for consideration of tariff of transmission lines owned by STU (RRVPNL) but which are used to carry ISTS power. A uniform methodology for allocating Annual Revenue Requirement (ARR) approved by the State Electricity Regulatory Commission (SERC) to all the transmission lines of the State and deriving YTC for various configurations for the State owned Lines has been elaborated. YTC so derived in respect of STU lines being used for carrying ISTS power shall be included in the calculation of PoC Charges. Methodology for calculating YTC for the lines of STU as mentioned in aforementioned order is as follows:

i. Step-1: Consider Line lengths and ARR approved by the concerned SERC for the FY for which tariff is to be derived. For example for RRVPN for FY 2013-14, the ARR was Rs 200427 Lakh and the configuration of various lines was as under:

Line Type	Ckt km
+500kV HVDC	-
+800kV HVDC	-
765kV D/C	-
765kV S/C	426.00
400kV D/C	-
400kV D/C Quad. Moose	-
400 kV S/C	3974.75
220 kV D/C	-
220 kV S/C	12543.01
132 kV D/C	-
132 kV S/C	15166.76
66 kV	-

ARR approved by Hon'ble RERC	200427

ii. Step-2: Consider the indicative cost of ISTS lines. In the PoC calculation, indicative cost of 400 kV D/C Quad Moose transmission line has been taken as base indicative cost. The same has been considered here. As the indicative cost of STU lines are either not available or may vary from utility to utility, the indicative cost of lines of various configurations owned and operated by POWERGRID has been taken for computation purpose. Indicative cost of 400 kV D/C Quad Moose transmission line has been taken as base and indicative cost of lines with configurations other than 400 kV D/C Quad Moose have been made expressed with reference to indicative cost of 400 kV D/C Quad Moose. For instance for FY 2013-14:

Type	Cost (Rs. lakh)	Cost (Rs Lakh) /Circuit	Coefficient	Ratio w.r.t.
765 kV D/C	412.00	206(A)	a=D/A	0.56
765 kV S/C	179.80	179.80(B)	b=D/B	0.65
400 kV D/C Twin Moose	130.40	65.2(C)	c=D/C	1.78
400 kV D/C Quad Moose	232.60	116.3(D)	d=D/D	1.00
400 kV S/C Twin Moose	87.00	87.00(E)	e=D/E	1.34
220 kV D/C	61.40	30.7(F)	f=D/F	3.79
220 kV S/C	37.80	37.80(G)	g=D/F	3.08
132 kV D/C	48.40	24.2(H)	h=D/H	4.81
132 kV S/C	30.00	30.00(I)	i=D/I	3.88

iii. Step-3: Calculation of base line YTC of 400 kV D/C Quad moose line:- After getting ratio with respect to 400 kV D/C Quad Moose, YTC per ckt km 400 kV D/C Quad Moose transmission line has been calculated as under:

ARR for FY……….in Rs

YTC per ckt km =---
400 kV D/C
Quad Moose

(Length of 765 kV DC/**a**) + (Length of 765 kV SC/**b**) + (Length of 400 kV DC TM/**c**) + (Length of 400 kV DC QM /**d**) + (Length of 400 kV SC TM /**e**) + (Length of 220 kV DC /**f**) + (Length of 220 kV SC /**g**) + (Length of 132 kV DC /**h**) + (Length of 132 kV SC /**i**) *value of a, b, c, d, e, f, g, h, and i are as given above

DC- Double circuit, SC- Single circuit, QM- Quad Moose, TM- Twin Moose,

iv. Step-4: As per information (line length in ckt. km and ARR approved by RERC) for the 2013-14 and PoC cost data for the same year, YTC for the assets for FY 2013-14 has been calculated as under:

Total ARR approved by the RERC for FY 2013-14= **Rs. 20,04,27,00,000**

(In Rs)

S No	Asset	For entire system (Rajasthan)		
		Line Length (ckt. km)	YTC (Per ckt. km)	YTC
1	765 kV S/C	426	26,66,375.48	1,13,58,75,954
2	400 kV S/C	3,974.75	12,90,181.68	5,12,81,49,645
3	220 kV S/C	12,543.01	5,60,561.70	7,03,11,30,969
4	132 kV S/C	15,166.76	4,44,890.24	6,74,75,43,430
				20,04,27,00,000

15.19 The tariff approved by the Commission and applicable as on 31.3.2014 for the period starting from 1.4.2014 till approval of tariff by the Commission in accordance with Tariff Regulations for the period 2014- shall be considered provisionally for computation purpose.

15.20 The suggestion of BSPCL has been accepted by providing that in respect of non-ISTS lines, tariff based on ARR of STU shall be considered.

15.21 A question arises for consideration is whether to fix a minimum percentage figure to consider a STU line as an ISTS line or not. As per Electricity Act and Tariff Policy, all lines which are incidental to Inter-state flow of power are to be considered as ISTS. In a meshed transmission system, many intra-State transmission lines carry inter-State power and therefore become incidental to inter-State transmission system. However, as Electricity Grid is being operated in a cooperative manner, for a minor fraction of ISTS power, it is expected that STU would not insist on considering its line(s) to be inter-State as on the one hand it will receive payment for its own lines, on the other it has to pay for usage of other States' lines. If a STU puts up a proposal for considering its line as ISTS and it is found that it is being utilized to a large extent by its own drawee nodes, then it would be merely an academic exercise as major part of tariff would be allocated to home State only. So keeping in view the regulatory process involved in getting a line certified as carrying ISTS power, getting its tariff approved and then adjustment from STU's ARR, it is expected that this claim will be raised judiciously. An interesting situation happened during 2011 when in Eastern and Northern Regions, many lines were submitted to RPCs for approval as ISTS, Southern States realizing that they all are using each other State's line, decided that they will not put up any line for certification by RPC as ISTS. While Commission wants to consider legitimate claims but this must not result in making process too complex. The RPC may therefore uniformly decide a percentage below which (say 10%) such a line would not be considered as an ISTS. Further, it is intended that for assessment of a particular line being used for carrying inter-State power, technical knowhow and tools will be provided by Secretariat of RPCs and NLDC/ RLDCs shall provide all necessary support to States in this regard.

15.22 We have accordingly decided that the following provisos shall be inserted under sub-clause (y) of clause (1) of Regulation 2 of the Principal Regulations:

"*Provided that in case of non-ISTS lines, the asset wise tariff determined by the respective State Commission or approved by Central Commission based on the approved Annual Revenue Requirement of STU, shall be used.*

Provided further that the payment to the concerned STU under these regulations shall be adjusted in the Annual Revenue Requirement approved by the respective State Commission"

15.23 As both old and new lines give same transmission service, the proposal to give O&M charges only for very old lines is dropped.

15.24 The Yearly Transmission Charge shall be computed for assets of transmission licensees at each voltage level and conductor configuration in accordance with the provisions of these regulations based on indicative cost provided by the Central Transmission Utility for different voltage levels and conductor configuration. The tariff of the RPC certified non-ISTS lines which carry inter-State power shall be approved by the Appropriate Commission. The same shall also be included in the YTC to be recovered through PoC.

15.25 Accordingly Sub-clause (n) of clause (1) of Regulation-7 and Sub-paras under Para 2.1.3 of the Annexure-I of the Principal Regulations has been modified.

16. **<u>Sub-clause (b) of Regulation 3</u>**

16.1 In sub-clause (b) of Regulation 3 of Principal Regulations, the word 'generators' was proposed to be replaced with the words 'Generator connected with STU system and using ISTS'.

16.2 No comments have been received from stakeholders.

16.3 The amendment was proposed to include state embedded generators using ISTS to pay for usage of ISTS. We had explained vide the Explanatory Memorandum to draft regulations as under:

"Also many steps taken during implementation stage of PoC Regulations during June, 2010-June, 2011 stem from the fact that many generating stations are using ISTS but not paying for this because they have not taken LTA from CTU. Their non payment results in loading other DICs, so effectively they were free riders. If they had sought connectivity and LTA from State system, either STU should create sufficient transmission system for them or make arrangement that these state generators/state embedded generators also pay for ISTS."

16.4 The transmission charges shall now be calculated only for Withdrawal nodes and for generators who have LTA to target region. With this methodology, the transmission charges attributable due to generation from such embedded generators who have not sought LTA from CTU shall be recovered through the Withdrawal points. However, there are few generators who are connected both to ISTS and STU systems or only to STU system and are having LTA/MTOA to ISTS. Such generators shall also be covered under this Regulation.

16.5 In view of the foregoing, clause (a) of Regulation (3) has been amended as follows:

"(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."

17. **<u>Sub-clause (4) of Regulation 5</u>**

Short term Open Access Rates are published in "Paisa/unit". Hence the words *"Rupees per Mega Watt per hour"* shall be substituted with the words *"Paisa/unit".*

18. **<u>Sub-clause (d) of clause (1) of Regulation 7 and Sub-clause (e) of clause (1) of Regulation 7.</u>**

18.1 Sub-clause (d) of clause (1) of Regulation 7 of the Principal Regulations was proposed to be substituted as under:

"(d) Nodal generation information shall be based on the forecast provided by Designated ISTS Customers. Such forecast shall incorporate estimates of

Maximum total injection into the grid, considering the long term and medium term during application period peak conditions. The forecast submitted shall be cross-checked by Implementing Agency based on historical generation levels obtained from the NLDC/RLDCs/SLDCs under such peak conditions identified in advance by the NLDC. Any changes in the forecast generation shall be communicated to the appropriate Designated ISTS Customer by the Implementing Agency; if DICs request any change in forecasted injection, then detailed justification for this need to be submitted and confirmed in the Validation Committee."

18.2Sub-clause (e) of clause (1) of Regulation 7 of the Principal Regulations was proposed to be substituted as under:

"(e) Forecast demand data shall be submitted by the Designated ISTS Customers for each node or a group of nodes in a zone, identified by Implementing Agency under these regulations. The forecast demand data shall incorporate estimates of Maximum drawal and under peak conditions. The forecast submitted shall be cross-checked by the Implementing Agency based on historical demand of each Designated ISTS Customer for all the months during peak conditions identified by the NLDC. Any changes in the forecast demand shall be communicated to the appropriate Designated ISTS Customer by the Implementing Agency. The request for change in forecasted Demand, if any, shall be accompanied with detailed justification and the data as confirmed in the Validation Committee shall be final."

18.3Comments have been received from POSOCO,CEA, BSPCL,CTU, and SN Power.

18.4POSOCO has welcomed peak case over average case and has stated that method to arrive at injection/drawal to be considered in peak case may be clearly specified.

18.5CEA has also supported calculation of transmission charges on peak case and has suggested a methodology for preparation of peak case.

18.6BSPCL has stated that peak time drawal does not give true picture of their drawal as it may be one off condition during certain period of time which is excessively high but drawal is generally much less than that. BSPCL has suggested that separate charges be determined for peak and off peak conditions. BSPCL have raised an apprehension regarding high charges if the computation is based on maximum injection or withdrawal.

18.7CTU has stated that a new generator should submit its generation beforehand.

18.8SN Power has supported raising transmission charges based on peak injection and withdrawal, it has suggested that DICs should be given rights to trade their unused capacity to other users.

18.9We have considered objections /suggestions of the stakeholders. We had given detailed analysis of proposing billing on peak injection over average injection in the Explanatory Memorandum to proposed draft amendment which is quoted below:

"3.1 Manual on Transmission Planning Criteria issued by Central Electricity Authority in January, 2013 mentioned following criteria for planning of new transmission lines & substations.

"For planning of new transmission lines and substations, the peak load scenarios corresponding to summer, monsoon and winter seasons may be studied."

3.2 As the transmission planning is being done to take care of load generation balance during peak load scenario and computation based on average scenario is not capturing the usage correctly, it is proposed to allocate transmission charges also on the basis of peak injection and withdrawal.

3.3 Maximum Withdrawal vis-a-vis LTA by different DICs (States/UTs) is enclosed at Annexure -1 and Exhibit-I. A comparison of Peak injection vis-avis LTA considered for computation of PoC and by different injecting DICs is enclosed at Annexure-2 alongwith a graph of maximum injection vis-a-vis LTA for Northern Region generators at Exhibit-II. These indicate the extent of usage of inter- state transmission system by different DICs.

3.4 At present the computation of sharing of transmission charges is being done based on average usage which does not correctly reflect the usage of the transmission system. For example, the injection by Tehri HPS in Q2 (Peak Monsoon Period) is considered as 659 MW against its installed capacity of 1000 MW which is utilised in during peak periods up to its installed capacity. Similarly KarchamWanngtoo HPS generates 1200 MW continuously during peak monsoon period, however, in average scenario is generation of 969 MW from the plant is considered. As the transmission system is planned to evacuate installed capacity, transmission charges should reflect commensurate usage of transmission network. Based on CEA data for past period and consultation with the stakeholders in Validation Committee meeting, in each application period, the Peak Injection and Peak Demand is proposed to be forecasted for the ensuing application period and in the second meeting of Validation Committee for the ensuing application period, all DICs shall be informed their Approved Injection and Approved Withdrawal figures from ISTS as finalised after Load Flow studies. The Approved Injection figures shall also include injection from Intra-State entities within a DIC's control area, which is incidental on ISTS.

3.5 It is underlined that allocation of transmission charges among users either based on "average usage" or "peak usage" is basically a sharing mechanism of transmission charges. With large difference in peak and offpeak usage and considering the fact that transmission planning process is based on Peak scenario, it is proposed to allocate transmission charges based on peak usage."

18.10 Hence for making transmission charges reflective of its usage, charges should be attributed to users based on maximum injection/withdrawal. Accordingly the base case shall be prepared based on maximum injection /maximum withdrawal. The injection/ withdrawal data to be considered in base case shall be as submitted by DICs and as cross-checked and validated.

18.11 Regarding CTU's suggestions for the requirement of a new generator to submit its generation beforehand, it is stated that new generators are already required to submit these details as per Regulation 7(1)(e) and hence no change is required in the Regulations

18.12 Our observations in regard to suggestions of BSPCL are as under:

(1) It is not correct to assume that charges would increase if computation is done based on maximum withdrawal. Total transmission charges to be recovered are same and only the distribution of charge among DICs would change depending on their maximum drawal. It would also depend on drawal of a DIC with respect to drawal of other drawee DICs.

(2) Having taken peak based on peak met for the last 3 years during the period corresponding to Application Period and All India Peak Met (normalized with All India peak), the drawal no longer represents one-off situation in which State had drawn heavily due to certain local reasons. The State/UT- wise peak met figures being non-coincidental, the same will be normalized w.r.t peak met on all India basis. Further during peak periods drawal of few entities will be at their peak and the same in respect of few entities may be at their minimum. Similar is the case with off peak condition where drawal of few entities may be at their peak. Hence the approved injection/withdrawal considering average and scaled peak and not the actual peak shall be a representative figure rather than being an abnormal or non-representative figure.

(3) The concept of considering peak scenario instead of average scenario also gets supported by the fact that transmission planning is done considering peak scenario and not average scenario which was also stated in Explanatory Memorandum to Draft Regulations.

(4) For a test period Q2 2014-15, it was examined from All India Load curves that in the month of July, August & Sept, 2014, 56%,54% and 44% of the time, the load was above the average all India load considered for average case in the study. Thus it emerges that the charges in respect of the assets created to cater to peak drawal or injection do not reflect proper sharing of charges. Such assets are quite underutilized and marginal participation of any state/DICs using these assets comes very high, as base case flow is small and power flow change (delta p) due to 1MW additional drawal becomes large. Hence the costs for such assets are allocated to DICs which are using these assets marginally.

(5) Regarding request of BSPCL that computation should be done both for Peak and Off Peak time, it is clarified that in the Principal Regulations it was envisaged that separate computation will be done for Peak and Off Peak but during the implementation phase it was found difficult due to following reasons:

a. Due to regional diversity it was difficult to define" Peak hours" for all India Grid. Also Peaks of individual DICs were not coinciding with Regional Peaks.

b. For computation, separate node wise data for Peak and off Peak was not submitted by most of the DICs.

c. DICs were not giving firm figures for their drawal.

d. Also in sample cases done on assumption basis, there was wide difference in Peak and Off Peak, which was difficult to comprehend.

18.13 Keeping in view POSOCO's suggestions, we have specified the methodology for calculation of maximum injection / withdrawal for vetting by Implementing Agency at Para 2.1.1 of Annexure-I of the Principal Regulations.

18.14In view of the foregoing, sub-clause (d) of Clause (1) of Regulation 7 has been amended as:

“(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.

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."

18.15 In view of the foregoing, sub-clause (e) of Clause (1) of Regulation 7 has been amended as :

The Regulation has accordingly been amended as:

"(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.

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."

19. **<u>Sub-clause (g) of clause (1) of Regulation 7</u>**

19.1 The definition of Validation Committee has been added in definitions. Hence this clause has been substituted accordingly. The sub-clause (g) of clause (1) of Regulation 7 has been substituted as:

“(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.”

20. **Sub-clause (i) of clause (1) of Regulation 7**

20.1 Sub-clause (i) of clause (1) of Regulation 7 of the Principal Regulations was proposed to be substituted as under:

*“**(i)**Basic Network along with the converged load flow results for various grid conditions 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 this Committee not later than 45 days before beginning 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 NLDC immediately after its approval by the Validation Committee.”*

20.2 Comments have been received from CTU only.

20.3 CTU has suggested that "basic network along with the converged load-flow results for various grid conditions shall be validated by validation committee" to be replaced with “Basic network along with the converged load-flow results for injection and drawal data as per para 7.1 (d) and 7.1(e) shall be validated by validation committee.”

20.4 We have considered comments of stakeholders. We agree with suggestions of CTU. Since basic network shall be converged for only one peak scenario and not for various grid conditions, Regulation has been amended accordingly.

20.5 In view of the foregoing, sub-clause (i) of clause (1) of Regulation 7 has been amended as :

“(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.*

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."*

21. **<u>Sub-clause (k) of clause (1) of Regulation 7 and Para 2.3 of Annexure to the Principal Regulations</u>**

21.1 Sub-clause (k) of clause (1) of Regulation 7 of the Principal Regulations was proposed to be substituted as :

*"**(k)** Consequent to the development of the base load flows on the Basic Network, the Hybrid method 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 power system."*

21.2 Para 2.3 of Annexure to the Principal Regulations was proposed to be deleted.

21.3 Comments have been received from POSOCO, CEA, Prof . Soman & Prof. Som Shekhar of IIT Bombay and GRIDCO.

21.4 POSOCO has suggested that truncation be continued, since charges of most of the 132/220 kV lines are not to be recovered and that objective of Commission is being met even with truncation. POSOCO has also quoted SoR to the Sharing of inter-state charges and losses Regulations, 2010 whereby reasons for truncation were mentioned and has stated that rationale of consideration of full network as discussed in the Explanatory Memorandum of the 3rd amendment is contrary to reason-II stated below:

Reason- I: The ARR of ISTS Licensee owned assets at 220 kV and below (except NER) is less than Rs. 260 Crores out of the total ARR of Rs. 4959 Crore for 2008-09

Reason– II: Truncation helps relate local demands with local generation."

21.5 CEA has stated that such a network may be considered provided that each state generation is also perturbed and that cost of State transmission network is accounted for in computation of PoC charges. CEA has also suggested that cost of State transmission network should also be accounted for in computation of PoC charges and net charges payable by state may be arrived.

21.6 Prof. Soman and Prof. Som Shekhar of IIT Bombay have supported the amendment stating that truncation of network should be avoided while determining PoC tariffs.

21.7 GRIDCO has also supported the amendment stating that truncation of network to 400 kV level failed to take account of Odisha's STU networks.

21.8 We have considered suggestions of stakeholders.

21.9 We do not agree with POSOCO that rationale for consideration of full network as discussed in the Explanatory Memorandum of the 3rd Amendment is contrary to Reason-II ("*Truncation helps relate local demands with local generation"*) stated in Explanatory Memorandum of the 3rd Amendment. In our opinion, local generation needs to be related with local demand but should not be related to demand of other State(s) which are separate commercial entities. Hence the charges calculated for a particular State should be for loads for that State only. The Explanatory Memorandum to draft (third) amendment provided as follows:

"Due to truncation of network at 400 kV level, there are instances wherein effect of marginal participation of state's own generation (example Tenughat in Jharkhand) is not being captured. The power flow change due to change in 1 MW drawal by Bihar which may be supplied by Tenughat is now reflected as drawal from a Central Generating Station located far away and utilizing larger network of ISTS. Similar examples may be noted in other regions as well. This becomes more important in case of 220 kV transmission assets existing between two states and owned by STUs which are being used for transfer of ISGS power. Software for PoC computation is capable of running full network, so procedure for computation can be modified."

21.10 With regard to CEA's suggestions regarding perturbation of each node, it is clarified that the perturbation shall be done for all the nodes considered in the network. CEA's suggestion to consider all State lines requires tariff of all lines and then tariff of both inter-State and intra-State lines will be allocated by software. This will be like computation of transmission charges for all India network (ISTS plus transmission system of STU). Since net payment is to be made by DICs, exercise would become complex commercially and administratively. However, the cost of state transmission lines which have been considered as ISTS and YTC as approved by State Commission or Central Commission as available shall only be included for cost allocation under POC mechanism. The cost in respect of State lines which are entirely intra-State lines shall, under POC,be considered as zero cost. We have decided to do away with truncation since truncation of network leads to a network which is non-existent. While truncated network may be similar to basic network so far as the base flows are considered but when 1 MW perturbation is done, part of it can be supplied through state generation and state network and it may not come entirely through ISTS as prescribed in truncated network. Since electricity flows as per laws of Physics, any marginal change in load/generation for calculating marginal participation factor is captured wrongly with truncated network. Examples in this regard are detailed below:

i. Purnea (Bihar) is connected to Dalkhola (West Bengal) at 220kV level which is further connected to New Siliguri and Tala. Power may flow through the downstream 220kV network as well which has not been taken into account due to truncation. The consideration of the entire network may impact the charges levied on the node.

ii. Similarly, Biharshariff is connected to Tenughat at 220kV network. An increase in the demand on this node is reflected on the upstream 400kV and above network while that on the downstream 220kV and below is neglected. The consideration of the entire network may impact the charges levied on the node. Bihar's own transmission network can feed this power but due to truncation, this power only appears to be getting transmitted through ISTS.

iii. Purulia is connected to Waria at the 220kV level. Consideration of the entire network may have a subsequent impact on the nodal charges.

iv. Similarly lot of transaction's on 220 kV network happen from Karnataka to Kerala and Goa. Kerala draws power through 220kV lines connected to Karnataka which in turn draws power from ISTS. Hence the charges for Kerala's drawal are also captured in Karnataka's marginal flow due to truncation.

21.11. POSOCO during the discussions stated that if network is not truncated, losses for state transmission lines shall also be reflected in base case. We have decided to consider the entire network without truncation to capture correct usage of transmission lines by DICs. The intra-State transmission lines (which have not been considered as ISTS) shall be considered with zero cost in the Basic Network. Regarding losses for intra-state lines, the contention of POSOCO is not a point of concern since only Marginal Participation Factors are determined on Basic Network whereas the losses are allocated to various nodes as per actual inter-State regional system losses for last week. Hence DICs will not be charged for intra-State losses. The method computes percentage of sharing of losses by various DICs and since only ISTS losses computed through special energy meters data are to be allocated for scheduling, untruncated network would not result in allocation of state losses.

21.12. In view of the foregoing, sub-clause (k) of clause (1) of Regulation 7 shall be amended as under:

“(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.”

21.13. In view of the foregoing, Para 2.3 of Annexure to the Principal Regulations shall be deleted.

<u>22. Sub-clause (l) of clause (1) of Regulation 7</u>

22.1. The proviso under Sub-clause (l) of clause (1) of Regulation 7 of the Principal Regulations was proposed to be deleted.

22.2. Comments have been received from POSOCO, CEA, GRIDCO Ltd and Torrent Power Ltd.

22.3. POSOCO has opposed the deletion of slabs. POSOCO has proposed to keep 5 slabs and increasing them gradually to 7 or 9 keeping in view the assumptions made while calculating POC and that other cybernetics also follow slab rates e.g. metro rail ticket, bus fare, taxi fare, etc.

22.4. CEA has suggested to keep upper and lower cap rates to avoid excessively high and low rates. CEA has suggested that transformers are in fact branches having specific impedance and they must be treated in the same manner as the transmission lines. It has also suggested that instead of AC load flow method, DC load flow may be carried out for determining Marginal Participation factors for allocation of transmission charges.

22.5. GRIDCO and Torrent Power have supported removal of slab rates. Torrent Power has stated that existing slab system distorts the transmission charges.

22.6. Prof. Soman and Prof. Som Sekhar of IIT Bombay have suggested that min-max fair Marginal Participation approach improves equity and should be used instead mixing hybrid method with postage stamp method. They have also suggested use of DC load flow method.

22.7. We have considered suggestions of the POSOCO, CEA, GRIDCO, Torrent Power and IIT, Bombay.

22.8. Regulation 7(1) (l) of Sharing Regulations provides that the slab rates for Injection and Demand POC charges shall be rationalized in 2014-15 based on a review by the Commission as could be seen from the excerpts given below:

"*7(1) (l) Provided further that there shall be three slab rates for injection and demand PoC charges for the year upto 2013-14, after which the same shall be rationalized in the year 2014-15 based on a review by the Commission.".*

22.9. We had presented the impact of uniform charges and slab system in the Explanatory Memorandum to draft amendment and had observed that this adjustment is proving to be advantageous for the States who are drawing more than their LTA. Further it is also not conforming to the principle of sharing of transmission charges based on usage of the network. It is noted that the slab system also distorts the locational signal. We had proposed to dispense with the Slab Rate in draft amendment and make the DICs pay the Transmission Charges as per actual usage.

22.10. The objection of stakeholders in regard to slab was due to the fact that they were adversely affected due to wide variations in slab rates. Their objection was emanating from their apprehensions that their PoC rates increased due to slabs.

22.11. The slabs were provided in 2011for reducing the impact of new mechanism for sharing of transmission charges. As the methodology was to be implemented for the first time and it was a shift from Regional postage stamp method, for better understanding and administrative ease in implementation, based on a proposal from implementation committee in which DICs of all regions had representation, slab system was approved by the Commission.

22.12. In Regional postage stamp method, all DICs in a region were paying the same per MW rate for transmission system, which was calculated based on allocation in Central Sector Generating Stations. Also at that time, the differential in transmission charges among various regions were ranging from 2 to 8 paisa per kWh, slab system was designed keeping three slabs around average charges.

22.13. After three years of implementation it was found that the slab design is creating more resentment among DICs. The reason being that the PoC rates of DICs which are at the lower end of PoC rates are shifted upward at the first available lower slab of 'Average rate-Rs.15000.' This lowest slab was Rs. 70,000 initially (Year 2010-11) and now it is Rs 92,173 per MW per month (Q4/ 2014-15). So the PoC charges to be paid by these DICs are increasing. Also it benefits the States which are using ISTS to a large extent as their charges were pegged at 'Average rate + Rs15,000.' It means that for such DICs for whom actual PoC rates are high as per the software output, say Rs 2,00,000 to Rs 3,00,000 /MW per month were pegged at Rs 1,00,000 per MW/month for the Year 2010-11 and now pegged at Rs 1,22,173 per MW per month for Q4/ 2014-15.

22.14. Details of average PoC rates during last four years are given below:

PoC Rates

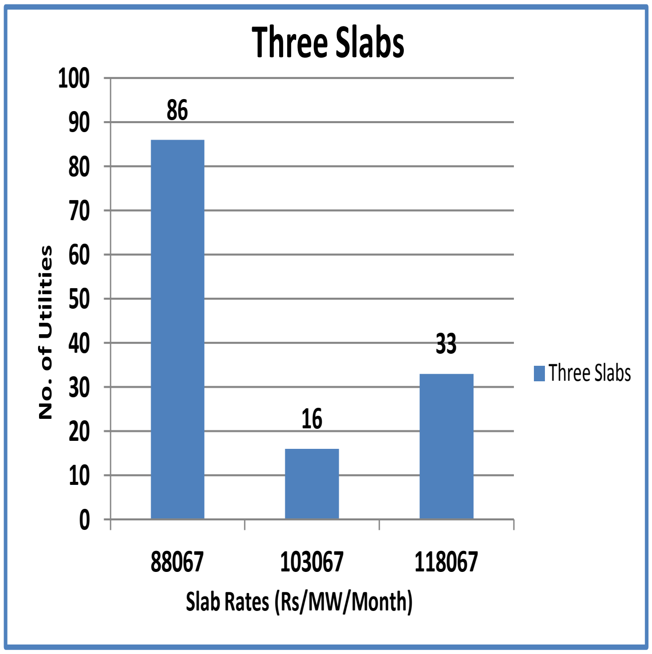
NEW Grid				
Time Period	**MTC (Rs. Cr)**	**LTA+MTOA (MW)**	**Rs/MW/Month**	**Paisa/Unit**
July 2011-March 2012	592	**72310**	**85000**	**12**
Apr-Sep 2012	773	86294	89542	13
Oct 2012-Mar 2013	933	98261	94966	14
Apr-June 2013	959	101615	94350	13
July-Sep 2013	975	104126	93684	13
Oct-Dec 2013	974	103189	94391	13
Jan-Mar 2014	1090	105585	103280	14

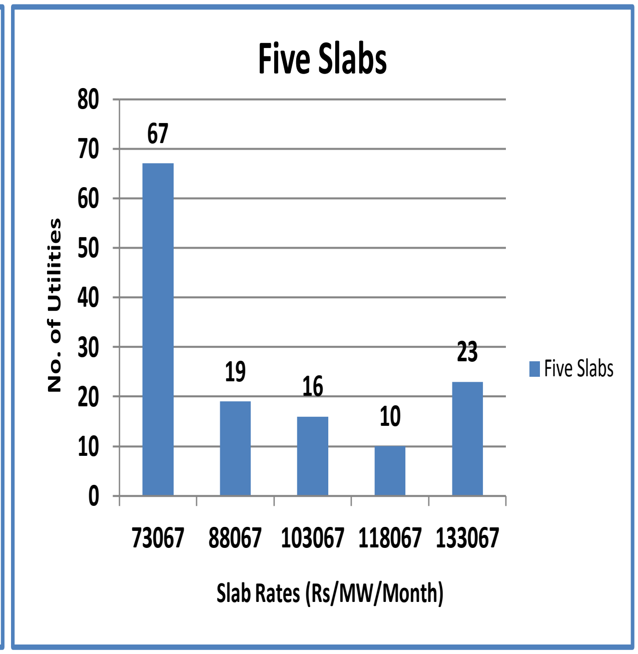
SR Grid				
Time Period	**MTC (Rs. Cr)**	**LTA+MTOA (MW)**	**Rs/MW/Month**	**Paisa/Unit**
July 2011-March 2012	133	**14028**	**95000**	**13**
Apr-Sep 2012	149	18659	79784	12
Oct 2012-Mar 2013	153	20482	74500	11
Apr-June 2013	164	21014	78219	11
July-Sep 2013	163	20623	79161	11
Oct-Dec 2013	164	18858	86819	12
Jan-Mar 2014	169	21158	80055	11

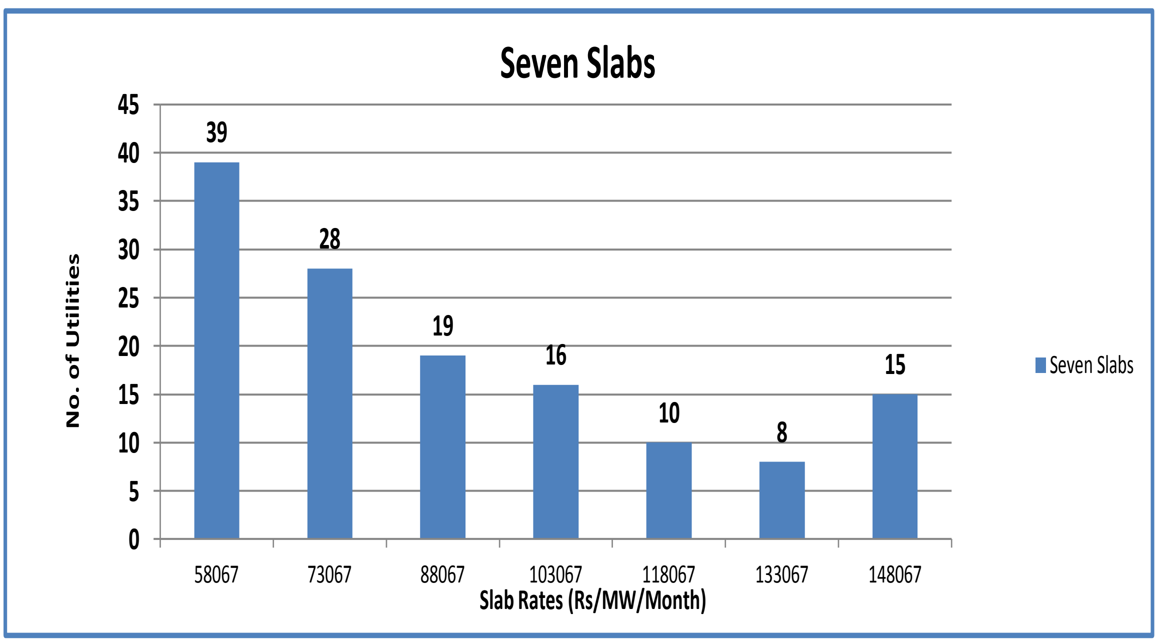
NATIONAL GRID				
Time Period	**MTC (Rs. Cr)**	**LTA+MTOA (MW)**	**Rs/MW/Month**	**Paisa/Unit**
Apr-June 2014	1294.52	130201	99425	13.81
July- Sep 2014	1367.77	133878	102165	14.19
Oct- Dec 2014	1400.16	135849	103067	14.31
Jan 2015-March 2015	1485	138560	107173	14.89

22.15. A comparison of different slabs structure (3-5-7) is given below. It indicates that that at lower end of the curve many entities are there. If less no of slabs are used, entities at the lower end of the curve are adversely affected and quantum of effect is large. As even in case of seven slabs there are many DICs(39) at the lowest rate. It was decided that nine slabs would be a better option so that impact of slabs can be minimized on DICs having PoC rates on lower end.

No. of utilities in different slabs







The differential in PoC rates needs to be understood in the context of transmission assets and their usage. If more transmission assets are created in a region and commensurate LTA or usage in MW is not materializing the PoC rates would increase. But it should not burden other entities in whose area no new assets are being built.

22.16. In last five years, more transmission assets have been created for NR and WR keeping in view target region estimates given by generators and projected load growth in these regions. In planning process all the DICs of these regions were aware that assets are being created. If power is not being procured under long term PPAs and LTAs are not adding into system, the rates may increase.

22.17. If design of slab rate is done around average rates and number of slabs is less, it will adversely affect the DICs at lower end of PoC rates. So to actually implement minimum regret principle it is necessary that slab design is reviewed. So a slab mechanism based on statistical and scientific method has been adopted.

The other two less significant reasons of retaining Slabs suggested by POSOCO are administrative ease in implementation and some approximations in computation of PoC rates.

22.18. So far as the approximations in computation are concerned, we find that some of these like clubbing of transmission line and transformer cost are inescapable. In Principal Regulations separate cost for these two was to be used but there also transformer cost was to be allocated to high and low voltage line in proportion of 2:1. Later, based on difficulties expressed by CTU like non availability of separate tariff, multiple type of configuration in different sub-stations, additional cost of bay equipment like CT, PT and Reactors, it was not found feasible and method of allocating all tariff to transmission lines depending on length and voltage was approved vide first amendment to Sharing Regulations.

22.19. The approximations in computation are applied to all nodes without any discrimination and they get evened out in four seasons and so no user is, by design, adversely affected by this. Approximation in computation should not be the reason to reduce confidence in computation and increasing and decreasing the PoC rates. The software for computation of transmission charges was got validated by a highly qualified and experienced committee comprising Prof Tukaram of IISc, Banglore and other experts from CEA, CTU and POSOCO.

22.20. Assumptions and approximations are part of computation of Usage based transmission sharing mechanism and in UK National Grid "Use of System Charging Methodology" even different voltage transmission lines are converted into single base of 400 kV by a factor called circuit expansion factor.

22.21. CEA has suggested that transformer should be included in computation as an element and its tariff can be taken based on Capital cost. This suggestion would be considered after doing some sample case studies and analysis of the results and its implication. Implementing Agency is advised do this exercise in consultation with IIT, Bombay and CEA.

22.22. We have also carefully examined the concept of Min Max Method explained by IIT Bombay, during the public hearing.

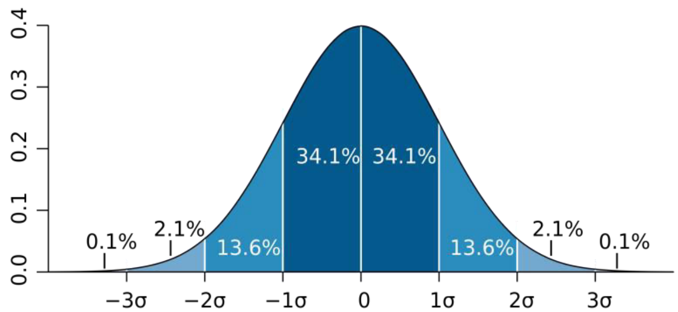
22.22.1 The proposed methodology is based on DC Load Flow method. The approach paper for Sharing of Transmission charges published by the Commission in 2009 had also proposed methodology based on DC Load Flow as it has certain advantage like simplicity and fastness in execution but after discussion with stakeholders in various workshops, it was decided to adopt AC Load Flow method. So the issue of DC Load Flow cannot be reopened without giving chance to other stakeholders to respond.

22.22.2 The Min Max method suggested by IIT Bombay, though is based on economic theory, yet it is difficult to implement, as it will change sensitivity to distance, direction and usage. This method reduces the differential of transmission rates of DICs, by selecting different set of participatory nodes (dispersed slack buses) for each node with the objective to reduce PoC rates at a particular node as compared to original computation based on average participation method. This may lead to results which are technically unexplainable to stakeholders. In present methodology, the major participatory nodes are nodes which are nearby nodes and same is easily explainable and can be understood. In Min Max method, the participatory node selection is based on iterative process, sometimes it selects dispersed slack bus which is too far or too remote from the withdrawal node /injecting node which is difficult to explain to the practicing engineers. Also min max method works on the nodal basis and is useful when transmission pricing or energy pricing is done on nodal basis (Locational Marginal Pricing). Sharing of transmission charges at present is based on aggregated PoC rates on Zonal basis after computing at nodal basis. Even if PoC rates of few nodes is decreased, it will simultaneously increase PoC rates of other nodes so the effect on overall Zonal charges cannot be predicted.

22.22.3 In view of these difficulties, it was decided that min max method although with its intended benefit of reducing diversity of PoC rates cannot be implemented.

22.23 While we had proposed a slabless system for specifying transmission charges, taking note of submissions of POSOCO in regard to assumptions we have decided to keep the slabs. Keeping in view suggestions of Torrent Power and GRIDCO and in order to increase satisfaction level of DICs, we have decided to introduce 9 slabs in this amendment which shall be reviewed after 2 years and considering suggestion of CEA that some maximum and minimum limits on PoC rate should be there, slab design has been formulated as given is succeeding paragraphs

22.24 The rates shall be obtained by dividing the charges allocated to each DIC as per Marginal Participation method by its LTA+MTOA considered for the quarter. We have considered a normal distribution curve as below:



22.25 Rates outside 1 sigma shall be considered as outliers. These rates shall be brought to 1 sigma level. The slab rates lying outside Mean minus 1 sigma shall be brought up to Mean minus 1 sigma and rates above Mean plus 1 sigma shall be brought down to Mean plus 1 sigma. In case distribution of data is such that sigma comes out to be more than mean and thereby resulting in Mean minus 1 sigma to be negative value, the data set shall successively exclude the highest rate while calculating mean and sigma till Mean minus 1 sigma becomes a positive value. In case of under-recovery or over-recovery, all the rates shall be scaled up or scaled down as the case may be. We have not considered 2 sigma levels which leaves out only 5% of data since number of DICs outside 2 sigma level will be very few and the intended rationalization of rates through slabs would not be achieved.

22.26 This method has advantage that slabs are not built around Average but after removing outliers on a statistical principle of sigma, the differential is divided into nine categories. So majority of DICs in 68.2% range are not affected except for some scaling up, which is required to recover total YTC recovery as outliers on the higher side have higher rate as well as quantum of usage.

22.27 It is interesting to see that these outlier PoC rates are higher because their usage is high but their LTA due to their long term purchases is low and when rate is calculated by dividing usage by LTA, their rates become high. These DICs are purchasing more power in Short term, so their usage is coming higher.

22.28 The methodology for determining slab rates has hence been decided and provided at para 2.8.1.b of Annexure-I to Principal Regulations as follows:

"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."*

22.30. In view of the foregoing, sub-clause (l) of clause (1) of Regulation 7 has been amended as:

"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."*

23 Sub-clause (n) of clause (1) of Regulation 7

23.1 It was proposed that Sub-clause (n) of clause (1) of Regulation 7 of the Principal Regulations shall be substituted as under:

"(n) For the computation of transmission charges at each node as per the Hybrid methodology requires cost to be adopted for ISTS transmission licensees whose lines feature on the Basic network. Provided that in case tariff is not available for any transmission line, average tariff as computed for POWERGRID transmission lines shall be used for computation purpose only. The actual tariff to be reimbursed to the licensee will be in accordance with the tariff order of the Appropriate Commission. In the event of line wise tariffs not being available, then tariff will be computed based on ARR using the methodology similar to 7(1)(l) adopted for ISTS transmission licensees. For the purpose of payments, the computed charges shall be adjusted proportionate to approved Revenue Requirement of the concerned STU."

23.2 We have already dealt with the issue under sub-clause (y) of clause (1) of Regulation 2 at Para 15 of SoR.

23.3 Accordingly, sub-clause (n) of clause (1) of Regulation 7 of the Principal Regulations, shall be substituted as under:

"(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:

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 charges:

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."

24. Sub-clause (o) of clause (1) of Regulation 7

24.1 It was proposed that Sub-clause (o) of clause (1) of Regulation 7 of the Principal Regulations was be substituted as under:

"(o) *The participation factors, and hence the Point of Connection nodal and zonal charges thus determined, shall be computed for each application period for peak. Four quarterly application period shall be (i) April to June, (ii) July to September, (iii) October to December, (iv) January to March. Peak hours shall be considered to be of four hours duration. However for the ex-ante computations, the Implementing Agency may specify the date in each application period for which Peak Scenario shall be computed. Normally it will be the mid date of each application period unless it is a holiday in that application period.*

Provided further that the load flow studies shall be carried out for each application period by Implementing Agency as and when the YTC is revised in accordance with proviso of sub-clause (l) of clause (l) of this regulation."

24.2 Comments have been received from APP, NTPC, CTU, BSPCL, AD Hydro and Shri Ravinder.

24.3 APP has suggested that peak hours be defined clearly in the Regulations.

24.4 NTPC has suggested that the RLDC/SLDC may consider the likely highest demand day and work out that day's injection for the purpose since considering injection on a particular day may give misleading data.

24.5 CTU has apprehended that choosing particular date for peak load condition may lead to DICs getting involved in gaming.CTU has also suggested that Proviso to the Regulation may be deleted.

24.6 BSPCL has suggested that Point of Connection nodal and zonal charges shall be computed for peak and off peak scenario for each application period.

24.7 AD Hydro has opposed the concept of peak injection/withdrawal and has stated that concept of considering peak injections or maximum drawal will only help the CTU/licensees in jacking up their revenue under the proposed mechanism and this will also increase the liability of RoR/Hydel generator towards sharing of the charges as compared to any other sources.

24.8 We have considered suggestions of the Stakeholders. Stakeholders have raised comments regarding ambiguities in defining peak hours and have suggested that likely highest demand day may be considered. We have considered the suggestions and have deleted the provision of peak hours. We shall be considering maximum injection/withdrawal based on historical maximum injection/ withdrawal forecast for the ensuing Application Period. The apprehension of gaming shall also be resolved through this methodology.

24.9 BSPCL's suggestion of considering peak and off peak scenario is not accepted. The rationale of considering maximum injection/ withdrawal has been detailed at para 18 of the SOR in Regulation 7 (1) (d) and 7(1)(e).

24.10 We donot agree with AD Hydro's objections. The YTC of transmission licensees shall have to be recovered fully irrespective of whether maximum injection is considered or average injection is considered. The revenue cannot be jacked by CTU under the methodology being provided for recovery of transmission charges under Sharing Regulations.

24.11 We have considered CTU's suggestion regarding proviso and proviso has been amended accordingly.

24.12 In view of the foregoing, sub-clause (o) of clause (1) of Regulation 7 has been amended as:

"(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 as given in ***Annexure-I*** *to these regulations.*

Provided that the load flow studies shall be carried out by the Implementing Agency for each Application Period."

25 Sub-clause (p) of clause (1) of Regulation 7

The concept of peak and other than peak periods has not been considered and there shall be only one maximum injection / withdrawal to be considered for the base case for an Application period. The rationale of considering maximum injection/ withdrawal has been detailed at Para 18 of the SOR in Regulation 7 (1) (d) and 7(1)(e).

26 <u>Sub-clause (q) of clause (1) of Regulation 7</u>

26.1 Sub-clause (q) of clause (I) of Regulation 7 of the Principal Regulations provided as under:

"As a part of the transition to the new Point of Connection based transmission pricing methodology, the recovery of the Yearly Transmission Charge of the ISTS network shall be based on both the Hybrid Method and the Uniform Charge Sharing Mechanism (postage stamp method) by giving appropriate weightage to both. The Commission shall decide the weightage based on the weightage to both. The Commission shall decide the weightage based on the impact of such transition on various Designated ISTS Customers. For the first two years, the zonal charges obtained using the Point of Connection method shall be adjusted such that 50% of the Yearly Transmission Charge of the ISTS Licensees is recovered through Hybrid methodology and the balance 50% of the Yearly Transmission Charge of the ISTS Licensees is recovered based on Uniform Charge Sharing Mechanism. After a period of two years from the implementation of these arrangements, the Commission may review the weightages accorded to the Hybrid methodology and the Uniform Charge Sharing Mechanism."

26.2 It was proposed that Sub-clause (q) of clause (I) of Regulation 7 of the Principal Regulations shall be deleted.

26.3 APP has supported the proposal to dispense with uniform charges and has suggested to use PoC mechanism. It has also suggested to present the real impact before final amendment is done. APP has further suggested that sudden shock of drastic changes may be avoided as was being considered in the earlier amendments.

26.4 In regard to APP's suggestion, we are of the view that uniform charges were introduced to avoid the tariff shock and now we have decided to do away with it. Reliability Support Charges have been introduced as explained in Para 13 of this SOR. Detailed methodologies for various charges have been explained in appropriate paras of the Statement of Reasons.

26.5 The PoC rates shall be determined based on Marginal Participation method. We have specifically provided that the Reliability Support Charge rates shall be determined separately and shall not be mixed with zonal PoC rates. Hence, there shall be separate PoC charges and separate Reliability Support charge rate.

26.6 Accordingly, sub-clause (q) of clause (1) of Regulation 7 of the Principal Regulations, shall be substituted as under:

"(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."

27 <u>Sub-clause (s) of clause (1) of Regulation 7</u>

27.1 It was proposed that Sub-clause (s) of clause (I) of Regulation 7 of the Principal Regulations be substituted as under:

"(s) The losses shall be attributed to the Designated ISTS Customers by suitably adjusting their scheduled MWs. The extent of adjustment shall be based on the losses attributed to each Designated ISTS Customer based on the Hybrid Method. The detailed procedure for application of losses to various Designated ISTS Customers shall be prepared by NLDC within 30 days of the notification of these regulations.

27.2 Comments have been received only from POSOCO. POSOCO has stated that slabs may be increased gradually to 5 or 7 keeping in view assumptions made while calculating losses and that with more and more entities getting connected to ISTS at 400 kV and above, loss administration with more than hundreds of rates would be prone to errors and may lead to disputes.

27.3 We have considered suggestions of POSOCO. We had proposed to dispense with slabs for calculation of losses since slab system distorts locational signal. However keeping in view POSOCO's suggestions, the Commission has decided to increase the number of slabs from present 3 slabs to 9 slabs. This shall be reviewed by Commission after two years. The slabs have been kept keeping in view loss administration with actual losses which need to be allocated to each DIC and assumptions made in basic network. The nine slabs in place of 3 slabs will allocate losses which will be more sensitive to distance, direction and quantum of flow as compared to 3 slab system.

27.4 As we have decided to keep 9 slabs for losses, there shall be 4 steps above the average and 4 steps below the average loss with a slab size of 0.25% subject to minimum loss of Zero percent.

27.5 In view of the foregoing, sub-clause (s) of clause (I) of Regulation 7 of the Principal Regulations has been amended as follows:

"(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."

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."

28 <u>Para (iv) under sub-clause (t) of clause (1) of Regulation 7</u>

28.1 The proviso under para (iv) under sub-clause (t) of clause (1) of Regulation 7 was proposed to be deleted.

28.2 No comments have been received from stakeholders.

28.3 The proviso under para (iv) under sub-clause (t) of clause (1) of Regulation 7 was proposed to be deleted keeping in view the methodology suggested vide the draft amendment whereby POC injection rate was to be determined using injection in base case only. However keeping in view Stakeholder's comments discussed at Regulation 2 (1) (b) and 2(1) (c), the POC transmission charges shall be divided by its LTA. The same is detailed at para 2.8.1 of Annexure-I of these Regulations. There are few generators who have part LTA or zero LTA and are using ISTS under STOA. For such generators, POC rate shall be determined by dividing POC charges with injection considered in the Base Case or LTA whichever is higher.

28.4 We have also brought generators who are connected to both STU and ISTS under the ambit of Regulation 3(a). Hence the same has been included in this regulation also.

28.5 Para (iv) under sub-clause (t) of clause (1) of Regulation 7 shall, therefore, be substituted as:

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

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

29 <u>Para (vii) under Sub-clause (t) of clause (1) of Regulation 7</u>

29.1 It was proposed that Para (vii) under sub-clause (t) of clause (1) of Regulation 7 of the Principal Regulations shall be substituted as under:

“7(t) (vii) In case an ISGS is connected only to STU network and the shares of beneficiaries of this station are being delivered through the STU network, such a line of STU shall be considered as an ISTS line.

If an ISGS is connected to both STU and ISTS, the injection corresponding to flow on ISTS shall only be considered for transmission charges. However, the application of losses shall depend on whether RLDC or SLDC is doing scheduling power for the same. In case scheduling is being done by RLDC, ISTS losses shall be applicable for those schedules.”

29.2 Comments have been received from APP, Adani Power Limited (APL), Thermal Power Tech Limited and Shri. Ravinder.

29.3 APP and APL have suggested that existing methodology of allocation of losses should be continued.

29.4 Thermal Power Tech has suggested that additional transmission charges should be levied on Home State if it is injecting more than its approved injection in ISTS network.

29.5 Shri Ravinder has stated that regulation needs a review. However, no further suggestion has been given by him.

29.6 We have considered the submissions and are of the view that after allocation of transmission charges for withdrawing entity, the concerns expressed by stakeholders would be addressed. To safeguard the interest if ISGSs, they will be charged corresponding to their LTAs with ISTS only. Hence, after allocation of transmission charges to withdrawing entities, the proposed Regulation was not found necessary. It is clarified that 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 line for the purpose of these regulations.

29.7 However Long Term Transmission Customer (LTTC) of ISGS connected to STU network shall continue to pay the transmission charges for the STU network as per the existing mechanism till tariff of such lines are determined by the State Commission or approved by this Commission as per methodology given in these Regulations.

29.8 Para (vii) under sub-clause (t) of clause (1) of Regulation 7 shall, therefore, be substituted as:

"(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."

30 <u>Sub-clause (u) of clause (1) of Regulation 7 and Sub-clause (v) of clause (1) of Regulation 7</u>

30.1 Following was proposed to be added at the end of Sub-clause (u) of clause (1) of Regulation 7 of the Principal Regulations 'i.e. between 1.7.2014 to 30.6.2017'.

30.2 Following was proposed to be added at the end of Sub-clause (v) of clause (1) of Regulation 7 of the Principal Regulations 'i.e. between 1.7.2014 to 30.6.2017'.

30.3 Comments were received from CEA ,Indian Wind Power Association (IWPA), Association of Power Producers (APP), Shri Ravinder, Indian Wind Energy Association (InEWA), Moser Baer Engineering and Construction Limited, SurajBari Windfarm Development Pvt. Ltd., Himachal Small Hydro Power Association(HSHPA)and Sandhya Hydro Power Projects Balargha Pvt. Ltd..

30.4 IWPA, APP, InEWA, Moser Baer Engineering and Construction Limited, SurajBari Windfarm Development Pvt. Ltd., HSHPA and Sandhya Hydro Power Projects balargha Pvt. Ltd have agreed for the same and requested that similar approach be extended for wind and other renewable based generation also. InWEA also suggested payment of transmission charges on Rs./unit basis

30.5 Sh. Ravinder does not agree that losses should not be applied to Solar and Wind power. He opines that this will increase the ISTS losses, once ultra mega solar plants come up. In his opinion there are different agencies to encourage renewable energy, it is not the job of transmission customers.

30.6 CEA has suggested that exemption from payment of transmission charges and losses may be allowed, provided no additional transmission system is required to be created because of solar generation.

30.7 We have considered comments on both the amendments. The suggestions received can be broadly summarized as under:

i. Allow exemption to Solar Generation from payment of transmission charges and losses for use of ISTS.

ii. Extend the similar exemption to wind and other RE generation or atleast make them pay transmission charges on per unit charges basis in place of per MW basis.

iii. Ultra Mega solar based plants will have adverse impact on transmission losses and should not be exempted from payment of transmission losses for use of ISTS.

iv. Exemption to Solar Generation from payment of transmission charges and transmission losses be allowed only if no additional transmission system is required to be created because of the solar generation.

30.8 The Commission is aware that the Government of India has embarked on an ambitious target of solar based generation capacity – the target announced being of the order of 1,00,000 MW by 2022. This is much more than the earlier target of adding 20,000 MW by 2022 under National Solar Mission (NSM). MNRE has also accordingly requested the Commission to support the initiative of the Government by exempting the solar generation from payment of transmission charges and losses upto 2017.The Commission has noted the request and is inclined to extend the benefit to solar based generation duly considering slow growth of solar based generation in the country so far, plans of Government of India and its impact on transmission charges and losses on other DICs.

30.9 We note that the cost of energy from solar based generation which was in the range of Rs. 14-15/kWh a few years ago has now come down to around Rs 7/ kWh under cost plus regime and in the range of Rs 5.50 - 6.50/kWh under competitive bidding. However, this is still higher than that from other sources of energy. As such, the Commission has decided to continue the support extended to solar generation, with due regard to the spirit of **section 61** of the Act which provides that

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

a.

.

.

h. the promotion of co-generation and generation of electricity from renewable sources of energy;"

30.10 The extracts of MNRE's **letter dated 12th December, 2014**, for **conveying sanction for setting up at least 25 solar parks,** are quoted here under:

a) *Transmission and evacuation of power from solar park Interconnection of each plant with pooling stations through 66KV /other suitable voltage underground or overhead cable will be the responsibility of the solar project developer.*
b) *The designated nodal agency will set up the pooling stations (with 400/220, 220/66 KV or as may be suitable switchyard and respective transformers) inside the solar park and will also draw transmission line(s) to transmit power to 220 KV/400 KV sub-station.*
c) *The responsibility* ***of setting up a sub-station nearby the solar park to take power from one or more pooling stations will lie with the central transmission utility (CTU) or the State transmission utility (STU),*** *after following necessary technical and commercial procedures as stipulated in the various regulations notified by the central/state Commission. If the state government is willing to buy substantial part of the power generated in the solar park, preference will be given to STU, which will ensure setting up of sub-station and development of necessary infrastructure for transmission of power from substation to load centres.*
d) *If the state is not willing to buy substantial power generated in the solar park, then CTU may be entrusted with the responsibility of setting up 400 KV sub-station right next to the solar park and its connectivity with the CTU. For setting up of this transmission & evacuation infrastructure, Power Grid may prepare a separate project to be funded from NCEF / external funds / Green Corridor project, if the cost is very high. The system would be planned in such a manner so that there is no wheeling charge applicable on solar power in accordance with the CERC Regulation or reduce the wheeling charges to affordable level.*
e) *To build this infrastructure using the highest possible standards, the whole solar power evacuation network scheme may be designed using latest technologies like SCADA, GIS, Bay controller, Online monitoring equipment for dissolved gas analysis, OPGW, PLCC etc.*

30.11 As the thrust being given by the Government of India for implementation of Project for setting up of 15,000 MW of Grid-connected Solar PV Power plants, we would like to assess impact of granting exemption from payment of transmission charges and transmission losses to solar generation on the existing DICs who would have to bear the same .*Considering four scenarios of installation of 3000 MW, 5000 MW, 8000 MW and 15000 MW of solar generation till 2016-17, which use the ISTS, impact on transmission charges is shown below:*

Monthly Transmission Charges (MTC) of ISTS during Q3 of 2014-15: Rs. 1400.16 crore

LTA/MTOA for Q3 of 2014-15 : 1,35,849 MW

The uniform charges during Q3 of 2014-15 is : Rs1,03,067/MW/month

n ISTS charges and losses

	Impact under various Scenarios of Solar capacity addition on ISTS	MTC	LTA +MTOA	Rate payable by other than SOLAR generators		Impact due to Solar generator in paisa/unit			Total Impact
		(Rs.Cr.)	(MW)	(Rs./MW/Month)	(paise/kWh)	Trans. Charges	Due to system Loss	Total	%
	National Grid	1400.16	1,35,849	1,03,067	14.31	-			
1	Injection and demand PoC charges:3000 MW	**1431.08 (A)**	**1,38,849 (B)**	**1,05,343 (C)**	**14.63 (D)**	**0.32 (E)**	**0.11 (F)**	**0.43 (G)**	**2.9 (H)**
2	Injection and demand PoC charges: 5000 MW	**1451.69**	**1,40,849**	**1,06,861**	**14.84**	**0.53**	**0.18**	**0.71**	**4.8**
3	Injection and demand PoC charges: 8000 MW	**1482.61**	**1,43,849**	**1,09,137**	**15.16**	**0.84**	**0.28**	**1.12**	**7.6**
4	Injection and demand PoC charges :15000 MW	**1554.76**	**1,50,849**	**1,14,448**	**15.90**	**1.58**	**0.52**	**2.10**	**13.9**

Notes:

(A) = 1400.16+{1,03,067X3000)/(10**7)}
(B) = 1,35,849+3,000=1,38,849 MW
(C) = 1431.08/1,35,849
(D) = (1,05,343 x100)/(720 x1000)
(E) = 14.63-14.37
(F) = Impact of loss as detailed in table below
(G) = (E) +(F)
(H) = G/D

IMPACT OF SOLAR INJECTION ON ISTS LOSSES CALCULATED FOR VARIOUS SCENARIOS						
CUF considered = 19%						
LTA+MTOA = 1,35,849 MW						
1.	Solar Power Generation (A)	MW	3000	5000	8000	15000
2.	Annual Solar Energy Flow in BU (B)=(A)x 0.19 x (8760)/(1000*1000)	BU	4.993	8.322	13.315	24.966
3.	Annual Solar loss @ 3.5% (C)= (B)x 3.5/100	BU	0.175	0.291	0.466	0.874
4.	Annual Impact of transmission loss due to solar power assuming @cost of energy @ Rs.3per kWh (D)= (C) *3	BillionRs.	0.52	0.87	1.40	2.62
5.	Annual flow on ISTS (E)	BU	500	500	500	500
6.	Additional Impact on other DICs due to Solar (Paisa /unit)= (D/E)*100	Paisa/Unit	0.11	0.18	0.28	0.52

The transmission loss impact is derived by considering averages loss of 3.5 % in ISTS and 500 Billion Unit of annual energy flow in ISTS.

30.12 The total impact of addition of 3000 MW, 5000 MW, 8000 MW and 15,000 MW on the transmission charges on other DICs (including the loss factor) would be of the order 2.9 %, 4.8 %, 7.6 % and 13.9 % respectively. In monetary terms it amount to 0.42p, 0.71p, 1.12p and 2.10 p /unit of electricity respectively. Keeping in view the marginal impact on the DICs due to exemption to solar based generation from transmission charges and losses in the next two and quarter years or so and its role in energy security, climate change and sustainable development, we have extended the exemption already granted to solar based generation till 30.06.2017.

30.13 In regard to request of stakeholders for grant of benefit to other Renewable Energy sources as well, we have also considered the World Bank Study: 70265 (2012): Transmission Expansion for Renewable Energy Scale Up (p.101-103) and relevant extract are given below:

a. *The benefits of renewable energy are the lack of emissions and the lack of fossil-fuel imports. These benefits are generally national or global, so it would not be rational to charge only users of renewable energy or only renewable generators. More importantly, what we want to avoid is inefficient solutions to the trade-off.*

b. *The transmission cost allocation mechanisms that track power flows are not relevant when the problem is to track power that has not been generated by fossil fuel. Similarly, license plate charges for deep system reinforcement that vary from one region to another in order to capture the differentials in the cost of transmission make no sense. The benefits from renewable energy flow from the fuel that is not burned.*

c. *So the cost of transmission that is not covered by economically efficient transmission prices should be distributed as widely as possible. This is analogous to charging everyone in the town for the bridge, it is a way of charging that does little harm. This can be done by charging all generation in a per-megawatt-hour charge. Such a charge will be passed through to load, since it increases the variable production cost of every megawatt-hour uniformly. So if a per-megawatt-hour charge is to be used, it can be charged to generation or to load customers, and the choice should be a matter of convenience or ease of implementation. As shown in Chapter 2, more pricing systems are moving toward charging most of the uncovered network costs to consumers.*

d. *By contrast, it may be better to charge large customers a demand charge. This is a charge based on the customer's demand during the system's period of peak use. This would not be necessary or desirable if an accurate system of real-time pricing is already in place.* ***If such system is not in place, a demand charge can serve to significantly reduce the need for on-peak generation****. This will save costs and improve reliability in a system that frequently sheds load during times of peak load. A combination of demand charge and energy charge might spread the burden most evenly while making use of demand charges. The exact mix that is best is difficult to determine because this is a second-best solution compared with real-time pricing. Renewable transmission charges will not be large, since they are spread so widely. If transmission is proactively developed and if the planner has made all the effort to reduce costs, the regulator will likely support allocating uncovered costs broadly.* ***If a proactive planning process is not in place and costs are broadly allocated to consumers, there will be no incentive for the efficient development of transmission***

30.14 In the light of our discussion and as a promotional measure for the solar generation, which is still in nascent stage of development in the country as compared to wind generation and small hydro, we are of the view that solar based generation be exempted from payment of transmission charges (injection and drawal) or sharing of transmission losses on ISTS till 30.6.2017as proposed in the draft regulation. While calculating LTA/MTOA of a DIC, part of solar portion shall not be considered in its LTA/MTOA. Further, no transmission charges shall be payable for sale of solar power in STOA under bilateral or collective transactions.

30.15 Further, we have considered the submission of wind and small hydro generators, regarding payment of transmission charges on per unit basis (MWh method) in view of their low CUF as compared to conventional generation. However, this proposal was not part of draft regulations and comments from the other stakeholders in this regard have not been sought. We direct staff of the Commission to examine the issue and submit a proposal after analyzing its cost implications

30.16 The following proviso shall be added under sub-clause (u) of clause (1) of Regulation 7 of the Principal Regulations:

"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."

30.17 The following proviso shall be added under sub-clause (v) of clause (1) of Regulation 7 of the Principal Regulations:

"*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*."

31 Clause (1) of Regulation 8

The words "for both peak and other than peak conditions" have been deleted in view of consequential changes in other Regulations.

32. Clause (5) of Regulation 8

32.1 It was proposed that Clause (5) of Regulation 8 of the Principal Regulations shall be substituted as under:

"**(5)** *In case of Approved Withdrawal or Approved Injection not materializing either partly or fully for any reason whatsoever, the Designated ISTS Customer shall be obliged to pay the transmission charges allocated.*

Provided that in case commissioning of the generating station is delayed due to any reason not attributable to transmission licensee, generator shall be liable to pay injection and withdrawal charges from the date on which access granted by CTU and communicated to Implementing Agency, became effective, at the *average rates of injection and withdrawal for the plant capacity.*

Provided further that during the period when a generating station draws startup power or injects infirm power, withdrawal or injection charges corresponding to actual injection or withdrawal shall be payable by the generating station and amount received through this shall be adjusted in next quarter against the ISTS transmission charges, to be recovered through PoC mechanism, from all DICs."

32.2 Comments have been received from Association of Power Producers (APP), Adani Power limited (APL), Lanco Kondapalli, CTU, DVC, Madhya Pradesh Power Limited (MBPPL), AD Hydro Power Limited, NTPC and Torrent Power Limited (TPL), Thermal Powertech, SN Power and Shri Ravinder.

32.3 APP has suggested that relaxation from payment of transmission charges be given to generator when the commissioning is delayed due to factors beyond its control.

32.4 Adani Power Limited (APL) has stated that if a generator is not able to commission the generating station due to force majeure, it shall be given relaxation in payment of transmission charges.

32.5 Lanco Kondapalli Power Limited (LKPL) has suggested that if a generator is not able to commission the generating station due to force majeure, it shall be given relaxation in payment of transmission charges

32.6 CTU has suggested that in the second proviso, "**before commencement of LTA**" may be inserted.

32.7 DVC has suggested that if the associated transmission system for the evacuation of power is already pooled in the regional assets, then the imposition of injection/withdrawal charges is not necessary. Further, mode of recovery of sharing of injection/withdrawal charges is required to be provided. DVC has also suggested that in the event that a generator is ready but ATS for evacuation of power for which LTA was sought is not ready, injection/withdrawal charges be borne by the transmission licensee.

32.8 MB (Madhya Pradesh) Power Limited has suggested that in view of various uncertainties related to land acquisition, fuel availability, statutory clearances etc. in the current scenario, a flexible time of one year may be allowed between commissioning of generation project and transmission assets before levy of transmission charges on the generator. During this period, certain LDs/penalties may be imposed on the generator as a deterrent to prolong deliberate commissioning of the project. It is further suggested that for a delay more than a quarter, 25%, 50%, and 75% of the applicable monthly transmission charges may be recovered every month for the delay beyond 3, 6, and 9 months respectively till one year.

32.9 Shri Ravinder has also suggested levy of 25%, 50% and 100% of transmission charges for delay beyond 3 months, 6 months and 1 year respectively. If the transmission is delayed beyond 3 months, CTU should start compensating the generator by same amount, as generator would have paid to it.

32.10 AD Hydro Power has stated that the proposed amendment does not specify (a) the basis for allocation of transmission charges, (b) compensation to generator in the event of its power getting bottled up due to non-readiness of transmission system. Further in case an existing transmission system is to be used to provide connectivity to a new generating station, the generator should not be asked to pay the transmission charges.

32.11 NTPC has stated that as per existing arrangement, LTA charges should be charged from the procurer of transmission services as per Sale Purchase Agreement and any other provision shall be against the agreement and the system in vogue. Further, any mismatch is covered by the Indemnification Agreement between NTPC and POWERGRID and therefore the claims in case of delay of generators should be dealt in accordance with IA. In case the transmission system comes up and generation is delayed, the same may be used by some other entity in the intervening period. Even otherwise, the charges will have to be borne by the transmission system users (beneficiaries) as a generator's obligation is sale at its bus bar. Further there is no provision in the Regulations in case of stranding of Generation capacity due to delay in transmission. NTPC has proposed that in case commissioning of generating station is delayed due to reasons not attributable to transmission licensee, the *generator shall be liable to pay IDC for stranded capacity out of its ATS as per the agreements*.

32.12 Torrent Power Limited (TPL) has stated that the transmission charges should be payable only for the quantum of effective open access rather than installed capacity as given in second para of the proposed amendment. Further adequate provision for the settlement of drawal and injection during commissioning have already been provided in DSM Regulations and therefore, the proposed amendment for start-up power is redundant.

32.13 We have considered the submissions.

32.14 In regard to the suggestions of APP, APL and LKPL, we are of the view that transmission asset having been created for the generator, in the event of delay in commissioning of generator, transmission charges need to be paid by the generator. Further, generating company and transmission licensee should periodically coordinate progress of construction work so that the transmission line gets commissioned matching with the commissioning of generation.

32.15 We agree with the submission of CTU for insertion of the words 'before commencement of LTA' in the second proviso.

32.16 In regard to the suggestions of DVC, we are of the view that the provisos are for the transmission system considered for LTA and if there is delay in commissioning of generator, the generator has to share transmission charges corresponding to its LTA granted in the ISTS.

32.17 In regard to the suggestions of MBPPL and Shri Ravinder, we are already seized of this issue and have included this solution in the Staff Paper on Transmission Planning Connectivity, Long/Medium Term Open Access and Other Related Issues (September, 2014). However, these shall be applied for deep connection. The Commission will take a view based on the comments received from the stakeholders on the staff paper and this suggestion will be considered there.

32.18 In regard to suggestions of AD Hydro, we are of the view that after the scheduled commencement date of LTA, the generator is liable to pay charges as the capacity has been booked for it.

32.19 In regard to suggestions of NTPC, we are of the view that the generator and transmission licensee need to coordinate to ensure matching of commissioning of generation and evacuation system. They should enter into IA and may accordingly take care of matching the schedule of commissioning. Further, we are of the view that transmission system is planned considering the future requirement of generation and load. It is necessary for both generation and transmission to come up simultaneously by phasing the implementation of transmission system as far as possible to match the commissioning schedules of generation project with the transmission systems. The burden due to delay cannot be passed on to existing users. There should be an IA between the generator and the transmission licensee. Beyond the period covered in IA, the generator is liable to pay transmission charges. We would consider the suggestion regarding compensation to generator in the event of its power getting bottled up due to delay in commissioning of transmission system after considering the views of the stakeholders when we take up amendments in the Regulations based on feedback of all stakeholders on the aforementioned staff paper on Connectivity, LTA, etc. issued in September, 2014.

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

32.21 In regard to submission of TPL, we agree to the first suggestion that the transmission charges shall be payable for the LTA quantum and not on the installed capacity. Further, DSM is for treatment of deviation in generation and not for sharing of charges of ISTS. The present regulation deals with payment of transmission charges during start up.

32.22 Another important issue is how to handle the situation when the dedicated line constructed by ISTS licensee and the generator gets delayed. The Connectivity Regulations 8(8) (second amendment) dated 21.3.2012 provided as under:

The following two provisos shall be added after the proviso to clause (8) of Regulation 8 of the Principal Regulations, namely:

"Provided further that the construction of such dedicated transmission line may be taken up by the CTU or the transmission licensee in phases corresponding to the capacity which is likely to be commissioned in a given time frame after ensuring that the generating company has already made the advance payment for the main plant packages i.e. Turbine island and steam generator island or the EPC contract in case of thermal generating station and major civil work packages or the EPC contract in case of hydro generating stations for the corresponding capacity of the phase or the phases to be commissioned, subject to a minimum of 10% of the sum of such contract values:

Provided also that the transmission charges for such dedicated transmission line shall be payable by the generator even if the generation project gets delayed or is abandoned."

32.23 The provisions are very clear that it would be the duty of the generator to pay the transmission charges for the dedicated transmission line constructed by an ISTS license for the generator till commencement of its LTA..

32.24 Accordingly, Regulation 8(5) has been substituted as under:

"Clause (5) of Regulation 8 shall be substituted as below:

(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 during the period when a generating station draws start-up power or injects infirm power before commencement of LTA, withdrawal or injection charges corresponding to the actual injection or withdrawal shall be payable by the generating station and such amount shall be adjusted in the next quarter, from the ISTS transmission charges to be recovered through PoC mechanism from all DICs:

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."

33. <u>Clause 6 of Regulation 8 of the Principal Regulations:</u>

33.1 Clause 9 of Explanatory Memorandum to Draft Regulations provided as under:

9."Issue of High PoC Charges in Exporting Region:

9.1 This issue is for consultation and stakeholders comments. As this involves a major conceptual change, it requires a detailed analysis.

9.2 As power from exporting region(for example ER) flows to drawal centres in NR and WR through longer transmission network, the injection charges become high. As States in the host region also have share in these generating stations and charges are allocated based on their allocation in these generating stations, these states are not convinced about the distance sensitivity of PoC.

9.3 For addressing this problem, there is a need to look into the allocation of injection charges. At present the injection charges are computed using Uniform Charges and PoC charges. If uniform charges are not applied, then it will correctly reflect the usage of transmission system by the generators .In addition, following change is proposed to correct it further:

(a) As the basic philosophy of PoC mechanism is based on usage, the present methodology that after computing injection charges based on usage, it is allocated to its beneficiary based on allocation in the generating station, dilute the usage based charging to a certain extent and again the concept of contract comes into picture in place of actual usage.

9.4 This creates a situation that even a beneficiary which is not actually receiving its allocated power from Generating Station(s), it had to bear injection charges corresponding to its allocation. The participation factor as computed by software to compute PoC charges clearly indicates this difference and an example is given below:
Example: Consider a case of generating station located in Eastern Region with allocation to different DICs as given below:

S.No.	State/DIC	% Allocation
1	Bihar	42.89%
2.	Jharkhand	8.13%
3.	DVC	0.31%
4.	Orissa	31.8% plus temp allocation
5.	West Bengal	9.1% plus temp allocation
6.	Sikkim	2.4
7.	Tamil Nadu	0.85%
8.	NER	3.22%

In comparison to this participation factors for this generating station indicate that the power injected by this generator is used by following DICs:

S No.	DIC	% as per participation factor
1	Orissa	82.97
2	DVC	12.1
3	West Bengal	4.93

As Bihar is actually not receiving power from this generating station as indicated by participation factors, charging transmission charges from Bihar for the injection from this generator because Bihar has allocation from this generating station is not in consonance with the principle that transmission charges should be based on actual usage of the network. Similarly as Odisha is getting most of its power from this nearby generator, it should pay commensurate transmission charges for the injection from this generator.

From the above example it emerges that actual power consumption as indicated by participation has no correlation with allocation factors.

<u>Therefore, it is proposed that injection charges be allocated to Withdrawal DICs in accordance with participation factors, which reflect the usage."</u>

33.2 Comments have been received from GRIDCO Ltd, BSPCL and CEA.

33.3 GRIDCO has welcomed the proposal of allocating injection charges as per participation factors. GRIDCO has stated that this should be made effective from 1.7.2011 i.e. retrospectively. It has also suggested that injection charges of TSTPS-I are increased due to flow of TSTPS-I power through HVDC to SR. Corrective measures should be taken in POC determination so that flow through Gazuaka doesnot burden PoC for Odisha.

33.4 BSPCL has stated that under PoC methodology allocation of power from a generation plant has lost its significance because it is not necessary that allocated power is coming to the beneficiary from the same generation plant from which power is allocated. BSPCL have submitted that each DIC should be billed for the lines which actually carry power up to the DIC from a specific plant in place of allocation of injection POC as per allocation of power from the plant as is being done currently, in regard to injection POC charges. BSPCL has also stated that transmission charge of the Inter State transmission licensees is borne by the beneficiaries only as it was done prior to the 01.07.2011 as the injection PoC charges borne by the generators is ultimately passed on to the DISCOMs. Therefore consideration of PoC injection charges & PoC withdrawal charges by Ld. CERC is confusing.

33.5 BSPCL has also alleged that there are so many assumptions in every step of calculating PoC Charges which results into illogical sharing of transmission charges.

33.6 We have considered suggestions of the Stakeholders.

33.7 Before taking a decision, Commission has considered international practice in regard to allocation of transmission charges to Generators and comments of stakeholders. The issue is how much charges are to be allocated to Generators and how generator would further allocate it to users. The power market structure in a country is main factor affecting this decision.

33.8 First let us consider whether the transmission charges are to be allocated to Generators. If however it is decided that transmission charges are to be allocated to generators as well, it is necessary to understand how they will further allocate it to users. In WebNet software based on Hybrid methodology, about 50% charges are allocated to generator and 50% to load. If generator allocates it to their beneficiaries based on allocation (contract) in the particular generating station, then it will be a deviation from basic principle of PoC mechanism as half of that i.e. withdrawal charges are based on usage and 50 % injection charges which were calculated based on usage of a particular generator are allocated to beneficiary based on "Contract" rather than their actual usage. This results in a situation that a particular DIC is paying for one set of transmission line for its withdrawal of power and another set of transmission lines for power injected by generator in which it has allocation. As both these sets have different subsets of lines, so in addition to common lines in these sets, payment for additional lines are incident on load. Hence while deciding to allocate charges on generator, this aspect needs to be seen whether they will pass on to consumers /loads or they would pay the charges themselves.

33.9 A study done MIT in this regard is quoted bellow:

MIT Study on the Future of the Electric Grid:

"*Where there are wholesale markets for electricity, generation and loads generally are both beneficiaries of new transmission capacity. Generators use the transmission system to deliver their product, benefit financially from doing so, and should therefore be responsible for paying for a fraction of the network costs. Load also benefits from new transmission through reduced energy costs, increased reliability, or both. Cost-allocation procedures should seek to apportion the costs of a line to generation and load proportional to aggregate economic benefits realized by the two groups. As in any highly competitive market, if wholesale markets are highly competitive and there are no special opportunities for any generator to capture extra rents, all costs levied on generators will end up being passed on to load via wholesale electricity prices, either in the short or in the long term. This is true even if network charges are levied as an annual lump sum or on a per megawatt basis rather than per megawatt-hour of produced energy. In some markets, however, some generators may enjoy unique location-specific or other advantages, so they will retain benefits from transmission that is built to these locations. Moreover, not all generators operate in highly competitive environments, and changing market conditions typically provide multiple opportunities to generators to enjoy short-*

term rents (and suffer short-term losses), so these generators can be charged transmission costs without any anticipated pass-through to consumers.

33.10 A survey of allocation of transmission charges in European countries given at Annexure-I indicates only a small fraction of charges is allocated to generators.

33.11 On the principle that "Contract" should not be basis of transmission charges, views expressed in international papers as detailed below:

33.11.1 Internationally also this principle is accepted and Prof. Ignacio Perez-Arriaga (PhD in Electrical Engineering, MIT, 1981), on whose suggested methodology PoC method is based, in his submission to FERC, stated following :

"Cost Allocation Principle: Independence from Commercial Transactions

A second principle of transmission pricing holds that there should be no distinction made between different types of transactions when calculating network charges[4]. In other words:

"In the internal electricity market one should not discriminate between bilateral contracts and any other kind of network use, since the efficient operation of the…power system – on which all network flows depend – should be the same, regardless of the type of transactions and dispatch mechanisms that have been actually used to put into operation the most efficient production means."[5]

Instead, transmission charges should depend on the location of the network users within the system topology and on the temporal patterns of injection and withdrawal. While this was not contradicted in the NOPR, it was also not articulated. I believe that it would be worthwhile in the final rule to include this requirement for any future cost allocation procedures.

[4]This principle has been accepted by the European Commission and an example of its codification can be found in Article 14 of "Regulation (EC) No. 714/2009 of the European Parliament and of the Council" of July 2009.

[5]From a discussion paper entitled "Transmission and Trade of Electricity in Europe" submitted to the European Electricity Regulation Forum in Florence in 1998

The wisdom of decoupling transmission charges from commercial transactions can be illustrated by a simple example. Suppose a set of generators and loads in a specific area are asked to establish commercial transactions to buy and sell electricity in order to ensure that all loads are served for a specific time period. Given that any load-generator pair can execute a transaction, and that everyone has information about the costs of each generator, when the arrangements are completed all demand will be met using the lowest cost set of generators. This experiment could then be repeated one million times, and the specific *transactions will vary because of chance occurrences during each iteration (e.g. contact order between generators and loads, limited bandwidth over internet connections, finite number of phone lines and operators). What is significant is that in every instance all of the loads would be served with the same set of least cost generators, resulting in the exact same flows over the network. Thus, if commercial transactions have no influence on the physical network flows, then charges for network utilization should not depend on commercial transactions.*

33.12 In India, decentralized scheduling and despatch model is used. It can therefore be said by law of physics that loads would be served by nearby generators while their Long Term PPAs may be from other distantly located generators.

33.13 Further MIT study also emphasizes delinking contract from transmission charges:

<u>MIT study on the Future of the Grid :</u>

Principle 2. Transmission charges should be independent of commercial transactions. Regardless of any specific, pre-arranged commercial electricity trades, the physical flows on the network will remain unchanged, and loads will always be served by the least-cost set of available generators that does not violate any network constraints. Because commercial transactions have no influence on the physical network flows, charges for network use should not depend on individual commercial transactions. Instead, transmission charges should depend only on the location of the network users within the system and on when and where power is injected and withdrawn from the system. According to this second principle, a generator located in a region A that trades with a load serving entity in a region B should pay the same transmission charge as if, instead, it were contracted to supply a neighboring load sited within its own region—and vice versa. The existence of any contracts voluntarily signed by any agents should not affect application of this principle because they should modify neither the physical real-time efficient dispatch of generation nor the pattern of demand. This second principle is not tantamount to socialization of network costs; as indicated before, transmission charges should depend on the location and the timing of network utilization.

33.14 A very comprehensive view is given in study " A national Perspective of transmission development (P-51 to 53) – (A White Paper Prepared by The Blue Ribbon Panel on Cost Allocation – Professor Ross Baldick, The University of Texas, Austin Mr. Ashley Brown, Harvard Electricity Policy Group Dr. James Bushnell, University of California Energy Institute Dr. Susan Tierney, Analysis Group Mr. Terry Winter, American Superconductor, For WIRES, the Working group for Investment in Reliable and Economic electric Systems)

The Third Context – The Transaction Chain

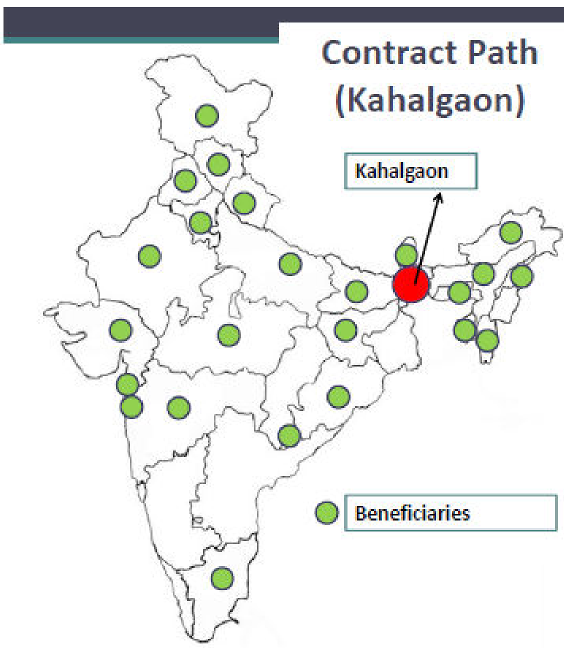
Cost allocation decisions are obviously about who pays. It is important, however, to decide not only who benefits, but also where in the transaction chain the costs should be assigned. Do they get assigned at the consumption (load or sink) end of the chain, or should they be allocated at the upstream production (generation *or origination) end of the chain? Certainly, much of the 2005 legislative debate over "participant funding" of new transmission had to do with various generating interests seeking competitive advantage or defenses through allocation of transmission costs. Many companies owning existing generators contend that new entrants should have to bear a larger percentage of the costs of new transmission since their appearance on the scene necessitated otherwise unforeseeable transmission expansions. The new generators obviously argued, to the contrary, that they were simply seeking to serve normal demand growth, so their entry into the market was nothing more than meeting reliability requirements for load growth. Nor were new generators the only "participants" wanting to get on the grid. Markets require both sellers and buyers and all are "participants" and eligible for consideration as the participants who benefit from and should bear the costs of system expansion. There are pros and cons to assigning costs to each end of the transaction chain – that is, to loads versus to suppliers, or to both. Assigning costs at the generation end of the transaction chain, as the debate over participant funding has demonstrated, almost inevitably leads to continuing battles between generators over who should pay and how much with respect to every expansion of the grid. Such cost allocation battles, of course, will make planning and building new transmission more contentious, more protracted, and more likely to discourage transmission investors. And, while deterring a particular project for land use or other reasons may be a desired outcome in specific instances, processes that lead to disinvestment across the board are ill-advised from the point of view of the nation's economic goals. Reliance on generators for transmission cost recovery may also prove less reliable as a revenue stream than funds derived from load. That is simply the result of the fact that specific generators go in and out of service or may experience insolvency or other financial or technical ailments that cause them to default or fall short on financial obligations to transmitters. That uncertainty could make transmission expansion more difficult to finance, or more likely, will cause the cost of capital to increase. Finally, assigning transmission expansion costs to specific generators based on their contribution to capital cost requirements is considerably less than a scientifically precise exercise, the outcome of which can have a significant impact on marketplace outcomes. While planners and regulators can make educated guesses as to which generator is causing which expansion to be built, those calculations are, at best, snapshots in time that almost inevitably turn out to be quite different over the course of the asset's lifetime.*

Assigning capital cost recovery responsibility to load is a preferable course to follow. However, this does place a burden on planners to set up an economic framework that demonstrates they are acting in the interests of loads. (To our knowledge, this is the approach used in most, if not all, RTO-administered OATTs; therefore, the need to resolve this question of assignment of cost responsibility for new transmission investment to "load-versus-generator" is still critically important for regions without RTOs.) While there is likely to be jockeying for position among customers and customer groups to obtain favorable cost allocations, similar to that noted in regard to generators, the outcomes of cost allocations to consumers would appear to have less effect on the overall competitiveness of the market than would allocation among generators. Perhaps *more importantly, the revenue to support transmission investment will come ultimately from consumers even if the immediate cost allocation is to generators. Given that they are the ultimate source of revenues and given that the revenue stream they provide is, for reasons noted above, more reliable and stable than a stream from generators, it would seem to follow logically that costs should be allocated to them in the first instance. In fact, allocating costs to customers is also consistent with practice in some RTOs which use license plate prices; namely having the license plate rate determined at the sink rather than the point of origination of energy.*

Another consideration in favor of assigning cost allocation to load is the "chicken or egg" dilemma in transmission planning. In a nutshell, do we build lines to connect loads only to known sources of generation, or do we build transmission to potential sites and hope that generators eventually develop? Do generators come and then we build, or do we build first and hope generators will come? This has become a particular thorny challenge in the open access era, particularly when utilities stopped carrying out combined generation and transmission planning and moved to an era in which Federal policy required the separation of generation planning from transmission planning. California's policy challenges regarding transmission for wind power, discussed earlier in the paper, illustrates this type of problem. Texas is developing a conceptually similar program in order to facilitate the development of wind resources in areas with significant resources but far from load centers. These approaches – supporting up-front transmission investment that in turn stimulates investment in generation – work conceptually well with allocating costs to load rather than to generation since they allow for socializing the risks of infrastructure development (at least to a well-defined and tolerable degree) that in turn facilitates the development of a socially desirable resource. In sum, allocating risk to load provides a somewhat increased opportunity to promote socially and economically desirable ends in regards to the development of generation. While cost socialization poses risks of diluting price signals, skewing competition, and allowing waste and inefficiency, it also presents opportunities for diversifying society's resource base. In order to achieve the positive result and avoid the negative one, strong regulatory policy and oversight in regard to defining acceptable levels of cost socialization is necessary.

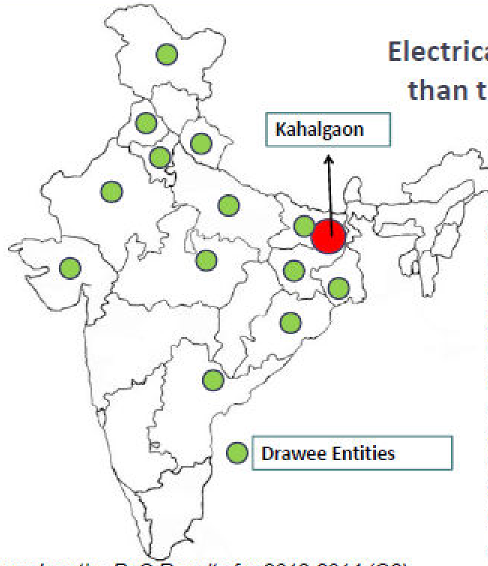
One argument sometimes advanced in favor of allocating costs to generators is that such cost allocations allow for better locational signals for siting new plants. While the argument has merit, it does not mean that allocating costs to load dilutes that signal. It simply means buyers will take the location of generators, and their economic distance from loads, into account when they plan their energy and capacity purchases. In markets with LMPs, there will still be signals to generators provided by locational prices. In markets without LMPs and in which the load plans for and procures generation resources at different distances, transmission-related costs will be part of the analysis of the relative attractiveness of different resource options, albeit with signals attenuated due to spreading transmission costs across various loads. Moreover, where the location of a specific new generator imposes significant, otherwise avoidable costs, on the network, there is a high probability that the transmission investment required to interconnect that facility will be deemed a "radial" connection, the costs of which we have *specifically excluded from this paper. Thus the allocation of transmission costs (and attended rights) to load does not do material injustice to proper location pricing signals in either system*."

33.15 From laws of physics it can be concluded that the power flow is not governed by allocation but depends on load generation balance and relative spatial distance between generator and load. This is reflected in "Electrical distance" which a stakeholder is considering deviation from Regulations'the load flow based on basic laws of physics can only capture this and there should not be any confusion or comparison based on physical distance. The practical conditions for few generating stations and their beneficiary and actual power flow are given below for illustrations:



State	Contract (%)
Bihar	25.37
Uttar Pradesh	12.93
Odisha	8.84
Delhi	8.28
Punjab	7.05
Rajasthan	5.08
Maharashtra	4.94
Gujarat	4.70
J & K	4.62
Haryana	3.81
Assam	3.43
Jharkhand	2.73
Madhya Praesh	2.47
Meghalaya	1.13
Chhattisgarh	1.00
Sikkim	0.94
Uttarakhand	0.94
Himachal Pradesh	0.77
Tamilnadu	0.35
Nagaland	0.23
Arunachal Pradesh	0.11
Chandigarh	0.10
DNH	0.10
Mizoram	0.08
D&D	0.07

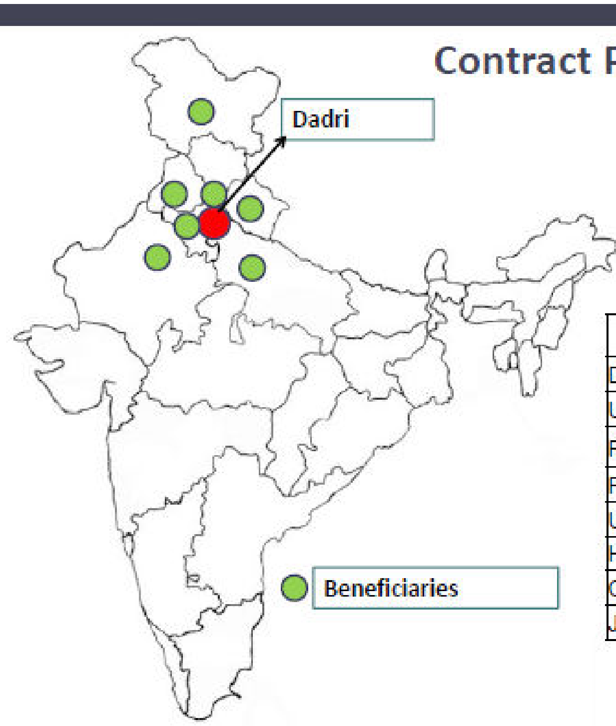
Electrical Path is different than the contract path



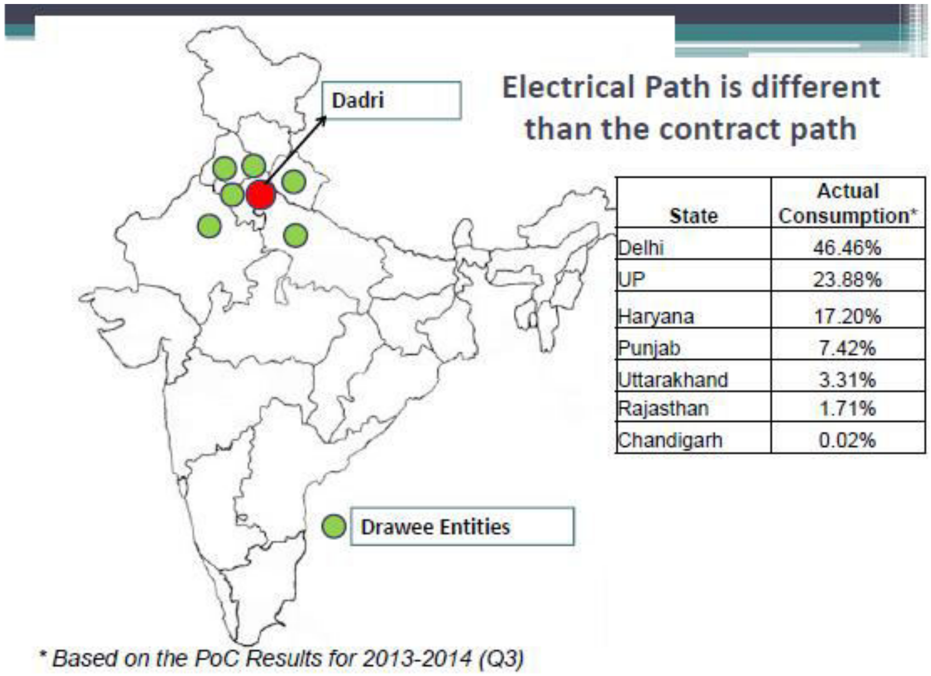
State	Actual Consumption*
Bihar	45.67%
Rajasthan	23.26%
UP	16.50%
Punjab	4.68%
MP	3.59%
Uttarakhand	2.71%
DVC	1.00%
J&K	0.92%
Haryana	0.88%
Delhi	0.65%
Odisha	0.05%
Gujarat	0.05%
Jharkhand	0.03%
Andhra Pradesh	0.01%

** Based on the PoC Results for 2013-2014 (Q3)*

Contract Path (Dadri)



State	Contract (%)
Delhi	82.5 %
UP	12.00 %
Rajasthan	3.56 %
Punjab	0.94 %
Uttarakhand	0.35 %
Haryana	0.25 %
Chandigarh	0.24 %
J & K	0.16 %



33.16 Also issues are sometimes raised that if cost is not allocated to the generators, then they will not participate in planning process. In this regard it is important to note that in India, Regional transmission planning process is quite inclusive and from the very beginning, generators in the central sector, even though they are selling power at their bus bar, are participating in transmission planning process as timely completion of evacuation system is in the interest of all stakeholders.

Also, after new reforms in Indian Electricity Sector through Electricity Act, 2003 even IPPs are participating in the meeting for grant of Connectivity and LTA. Also the initial cost allocation is towards applicant generators and as and when it finds its beneficiary, the transmission charges are shifted to users. So the generators have sufficient reasons and incentives to participate in planning process.

A list of TSO tariffs for various European Countries is enclosed as Annexure-I. It can be seen that sharing of network charges by Generator varies from 0% - 35% in European Countries. In the enclosed data, the TSO tariffs shared by Generator are 0% in 19 countries out of list of 31 Countries.

33.178 Currently the transmission charges are calculated as Injection POC and Withdrawal POC separately. The charges assigned to generation nodes are billed to beneficiaries of the generating station in proportion to their allocation from such generating station. In India such long term transactions are of the order of 90%, where beneficiaries are finally loaded with generation POC charges. The power generated from generating stations flows as per laws of physics depending on demand scenario. This power may be actually absorbed by such States where demand is more and not by the State who has the allocation of power. Software gives sufficient insight in regard to tracing of power from the generator to demand nodes and it clearly demonstrates that it is either not going to beneficiary at all or quantum reaching the beneficiary has no relationship with % allocation. The issue was raised for stakeholders' comments vide the Explanatory Memorandum to Draft Regulations.

33.18 GRIDCO has welcomed the proposal of allocation based on participation factor as it will capture the actual usage of generator for drawing its approved quantum of power. Bihar has also raised the issue that under PoC methodology allocation of power from a generation plant has lost its significance because it is not necessary that allocated power is coming to the beneficiary from the same generation plant from which power is allocated.

33.19 We have considered suggestions of Bihar and GRIDCO. The National Electricity Policy specifies that the transmission charges should be reflective of distance, direction and quantum of usage. However due to billing of generation end transmission charges to beneficiaries based on their share of power in such generating stations, the final charges loaded to beneficiaries become non reflective of distance, direction and quantum of usage. We have therefore decided that charges shall not be calculated separately for generation end where generators have a contract for long term supply to identified beneficiaries. The charges shall rather be calculated only at the Withdrawal nodes so that charges reflect usage of lines by a particular Withdrawal node/zone.

33.20 It is true that for power market, separate injection rates are required for generators. In European countries where separate injection rates are given, generators sell their output in day ahead power market and information is very much required there. But in a country with 90% power allocation being in long term, the information given in Rs/MW/month will not have much use in power market where transactions are based on energy. Therefore, in order to facilitate generators to participate in power market, transmission charges in paise/kWh are given. For long term beneficiaries, allocation of transmission charges in proportion to their share shall be discontinued and transmission charges only based on usage shall be recovered. To give effect to this, after first stage computation, the injection charges of generator who have identified beneficiaries will not be calculated. With already available information of marginal factor, the transmission charges will be allocated only to drawee entities and generators having long term access to target region.

33.21 The calculations as explained above resolves following cases also:

(i) A sample case study for Talcher TPS Stage-I (Q4 2013-14) from which power is allocated to ER and few constituents of SR and NER was done and following results emerged:

While Odisha has allocation of about 32% in Talcher Stage-I, actually 83% of Talcher power is consumed in Odisha. Bihar has allocation of 43% in the station but no power flows to Bihar from the station. Therefore, seeking payment of injection charges on the basis of allocation is not reflective of actual usage.

(ii) Set point for HVDC: GRIDCO in its letter dated 23.7.2014 brought the issue of high injection POC rate for Talcher STPS- I after synchronization of SR grid with NEW grid. It is stated that injection PoC rates of TSTPS-I which were in the lower slab of Rs.1,14,425/- per MW per month till March, 2013 were Rs.1,17165/- per MW per month during the first quarter of 2014-15. It is found that power is forced to be flown from TSTPS-I to Southern Region through Talcher-Kolar HVDC system, since the HVDC control is 2000 MW. The schedule generation of stage-2 of Talcher during the first quarter of 2014-15 was kept at 1592 MW and hence approximately 408 MW power was considered to be supplied from Stage-I. Similarly during the second quarter of 2014-15, the schedule generation of stage-2 was considered as 1314 MW and approximate 686 MW inrushes to SR through Talcher-Kolar due to HVDC setting of 2000 MW. Hence such power flow form stage 1 cannot be considered as actual flow as per law of physics, rather the same may be termed as artificial flow, such flow to SR is resulting in high injection PoC charges of Talcher stage 1 and burdening its allottees. In the present quarter (second quarter of 2014-15, the schedule generation of TSTPS-1 is only 718 MW out of which flow of 686 MW is to SR and only 32 MW is injected to ER for which the allotees of Talcher stage 1 have to pay total injection PoC of TSTPS-1, that to at higher slab rate. On the other hand this power though almost completely utilized by SR beneficiaries, they have to pay nothing since they have no allocation from Talcher stage-1. However, it is observed that for optimal use of Talcher-Kolar link and keeping in view the load requirement in SR, power would be forced to flow from TSTPS-I to SR through SR has got no allocation from the said generator. This problem shall get solved through the new methodology since injection charges for Talcher shall not be calculated and only drawal charges for drawing DICs shall be calculated.

For set point of HVDC one more observation is important. It was found that the HVDC set point considered in the study for PoC computation and operational set point was different in case of HVDC Balia–Bhiwadi. As the same base case is being used for allocation of losses, it is necessary that operational situational is correctly captured in allocation of PoC charges and losses. A different set point affects relative usage of AC lines. The Implementing Agency, therefore, should consider the set point corresponding to near actual scenario.

33.23 The issue of high transmission charges of DICs in exporting region even when the DICs are located near the generating station was flagged in the Explanatory Memorandum and effect of allocation based redistribution of injection charges on sensitivity to distance and direction was discussed and suggestions were sought from stakeholders on this issue. After considering three possibilities i.e. allocation of injection charges based on shares in the generating station, participation factors of drawal nodes in the particular generating stations and directly allocating injection charges to withdrawal nodes, this methodology was found technically correct and it addresses the issue of transmission charges of DICs of exporting regions. In this methodology, the basic principle of PoC mechanism i.e. the charges of transmission assets are payable by the entity who actually uses it and hence usage, distance and direction sensitivity is captured.

33.24 In the prevailing mechanism it is important to see how generators allocate the transmission charges allocated to it further. In India, as most of central sector generating stations having PPA sell power at generator bus, they do not bear the transmission charges. It is their beneficiaries who arrange for transmission system. Thus, even at present, these generators are not billed for transmission charges for injection; rather these injection charges are allocated to their beneficiaries in the ratio of their share in the generating stations. This introduces a situation wherein injection charges computed based on usage, are allocated based on contract. A DIC then has to pay withdrawal charges computed based on usage which is sensitive to relative spatial distance between generators and load points and the injection charges which are based on allocation. A DIC when it considers its total bill and compares it with others' usages, just compares physical distance form a particular generator in which both of these are beneficiary, finds that even though it is located near the generator, it is paying more transmission charges.

33.25 Similarly a DIC which is located near new generating stations find a typical scenario that for withdrawal portion, its power is coming from nearby generator, but for injection portion it is paying for a far off generator and for lines in which it does not have any Marginal Participation.

33.26 The generation POC charges as calculated currently, reflect actual usage of transmission system by the generator's power and not usage by beneficiary of such power. Removing such generation POC charges and allocating transmission charges only to demand zones based on their actual usage of lines will allocate transmission charges on the basis of actual usage by beneficiaries and not on the basis of theoretical allocation of power. However, for Generators who have LTA to target region and do not have identified long term beneficiaries, generation end POC charges shall be calculated and billed to respective generators for such supply for which long term beneficiaries have not been tied up. Such generators shall be liable to pay only the injection charge for such untied quantum. The Withdrawal DICs shall pay for only the Withdrawal Charges. By such modifications, each Withdrawal DIC shall pay for the lines which it is actually using for drawal of power. Hence, Delhi shall pay for inter-State transmission lines from which it is drawing power and similarly Bihar shall pay for lines which it utilizes to draw power and not for the lines on which power from Kahalgaon travels to Northern Region/Western Region. The point made by Bihar that the lines created under ER system strengthening for evacuation of ER surplus power beyond ER are being charged to ER beneficiaries, will get addressed since charges for such lines shall be paid for by the beneficiaries who are actually drawing power through such lines.

33.27 We have considered the suggestions of BSPCL and have modified determination of POC charges only on load points and specified generation points. This amendment shall make the injection charges levied on beneficiaries as per their usage of transmission lines and not as per their allocation of power.

33.28 Bihar has commented that "NLDC for computation of the Injection & Withdrawal transmission charges based on PoC methodology has considered electrical distance in spite of the physical distance at its own which is against the provision of Clause 5.3.5 of the National Electricity Policy notified on 12.2.2005 and Clause 7.1 (2) of the National Tariff Policy notified on 6.1.2006". In this regard it is mentioned the clause of National Electricity Policy and National Tariff policy quoted by Bihar specifies that "the tariff mechanism would be sensitive to distance, direction and related to quantum of flow" which implies that tariff should be reflective of its actual usage which can best be represented by "electrical distance" and not the "physical distance" of contract. Hence, the spirit of POC methodology is very much in line with National Electricity Policy and Tariff policy. Also we are not in agreement with the BSPL views that the assumptions made in computation of PoC charges make sharing of transmission charges illogical. The assumptions were agreed after detailed deliberation in six meetings of implementation committee in 2010-11. These assumptions are discussed in validation committee and also Commission approves assumptions made in computation of PoC charges for each quarter.

33.29 We have considered the contention of Bihar that it is paying charges for lines not being used by it. Accordingly we have amended Regulation 17 which provides for sharing of information. The lines being used by each DIC as per the software output shall be clearly listed out and published for information of stakeholders by the nodal agency on its website.

33.30 We proposed in the draft amendment for allocation of generation end charges on participation factor basis. However we are not inclined to consider the same since allocation of generation end charges may lead to allocation of charges for such lines to a beneficiary which is not using them. For example, if power from Kahalgaon STPS of NTPC is reaching Delhi, U.P. and Rajasthan in the ratio of 20%, 30% and 50% respectively. Let us suppose lines used for transfer of power of Kahalgaon to Delhi, UP and Rajasthan are 2nos 400 kV lines, 4nos 765 kV lines and 4nos 400 kV lines respectively. The generation end charges shall be calculated as sum total of lines used for transfer of 20%, 30% and 50% power to Delhi, U.P. and Rajasthan respectively. The sum of transmission charges corresponding to all the lines being used by Kahalgaon shall be allocated to Delhi as 20%, U.P. as 30% and Rajasthan as 50%. The aggregate whose percentage shall be shared between Delhi, U.P. and Rajasthan shall include the lines being used for transfer of power for other beneficiaries also and hence is non reflective of charges being allocated on usage basis. Hence generation end charges shall not be allocated on participation factor basis but shall be calculated only for withdrawal nodes and specific generation nodes with untied capacity under LTA.

33.31 The decision to arrive at revised methodology has been taken after considering all options and testing their effectiveness to resolve this issue and considering its implications.

33.32 An illustrative example for Kahalgaon STPS is given below, considering the following

(a) Allocation of transmission charges due to contract

(b) Allocation due to participation factor

(c) Transmission lines which are being used by Kahalgaon

(d) Transmission lines which are being used by Bihar.

(e) The additional lines which were shared by Bihar due to its allocation in Kahalgaon even if withdrawal nodes of Bihar have no marginal participation in these lines.

Q2 Truncated Network Average Case 2014-15		
STATE	**Percentages Allocation as per participation factor**	**Percentage allocation as per ERPC July 2014 Bill**
Bihar	36.92	42.15
Haryana	20.12	3.04
U.P	15.90	9.12
Rajasthan	13.70	3.04
Punjab	6.60	6.07
Uttarakhand	3.54	0
Jharkhand	2.07	3.28
Delhi	1.15	6.07
DVC	0	0.59
ODISHA	0	15.56
West Bengal	0	0.64
Sikkim	0	1.55
TAMILNADU	0	0.7
J&K	0	3.68
Assam	0	2.27
Nagaland	0	0.42
ARUNACHAL PRADESH	0	0.19
MIZORAM	0	0.14
POWERGRID(PASAULI)	0	0.15
NVVN POWER A/C BPDB	0	1.19
TOTAL	100%	100%

33.32.1 It can be seen that while participation factor though software indicates BIhar getting 36.92% of power from Kahalgaon, allocation of power to Bihar from Kahalgaon is 42.15 %. Hence injection charges of Kahalgaon to the extent of 42.15 % are shared by Bihar under present methodology.

33.32.2It is further noticed that there are lines which are used by Kahalgaon node but not by Bihar as detailed below:

- Number of Lines used by Kahalgaon : 420Lines
- Number of Lines used by Bihar: 545 Lines

- Number of Lines used both Kahalgaon and Patna (Common Lines used): 396Lines
- Number of lines used by only Kahalgaon not Bihar: 24Lines
- Number of lines used by only Bihar not Kahalgaon : 149Lines

Hence it can be seen that if injection PoC charges of Kahalgaon are allocated to Bihar based on its allocation in Kahalgaon, it shall have to bear additional charges for 24lines used by Kahalgaon and not by Bihar.

33.33 The change in methodology for allocating injection charges is not merely to resolve the issue of transmission charges of exporting region but is also required to address the transmission planning and execution. It is necessary to remove misconception of some of the DICs that creation of transmission infrastructure for new generating stations increases home State's transmission charges. This misconception was due to the reason that withdrawal DICs pay for transmission charges of nearby transmission system, and they continue to pay for injection charges of generators in which they have allocation whereas power actually does not come from these generators. Actually, the position is reverse. By having a new generating station at a new location, the extent of transmission network usage reduces, as power is received from spatially closer generating stations. The benefits accrue to such Withdrawal DICs since it leads to reduction in Withdrawal Charges. For example, if in a particular scenario in an application period, Odisha is not receiving power from Tala and power is reaching to it on displacement basis from nearby Generating stations using shorter length of transmission lines, this misgiving/misconception can be removed to a large extent and it will create a conducive environment for transmission system development. Also opposition to transmission system for nearby generating station due to its multiple buyers spread across the country would diminish and insistence of home State on seeking separate line for itself for availing power from this station would decrease. Optimal Transmission system planning needs to focus on planning and utilizing the transmission assets in a collectively efficient way, thus obviating the need for duplication of assets. Practical example of this is available in the form of reduction of withdrawal transmission charges of Odisha after commissioning of IPPs in Orissa.. From other similar studies for Q2 2014-15 scenario, it emerges that methodology now finalized solves the problems of States of exporting region.

33.34 So keeping the basic philosophy of PoC computation in mind that an entity should pay for only those transmission assets which it uses, it has been decided that for generator having beneficiary, the injection charges shall not be declared. For generator having LTA for target region, injection charges to the extent of untied capacity shall be computed. This is accordingly provided in Regulation 8(6) of the Sharing Regulations.

33.35 However, if in a particular contract, the Generator has itself taken the responsibility for paying transmission charges upto load end, it will pay the transmission charges to the extent of contracted capacity. For example if a generator X is selling 400 MW to TANGEDCO, then out of total withdrawal charges of TANGEDCO, this generator will pay withdrawal charges for 400 MW. Either TANGEDCO will be billed for total withdrawal charges and then it can take payment from Generator or it can inform billing agency that Generator will pay these charges.

33.36 The allocation of transmission charges to only withdrawing entities will serve purpose in case of Case I bidding wherein the procurer States/DISCOMS will consider the same withdrawal charges for all bidders irrespective of their location.

The Commission had also raised the issue in the draft amendment about the State embedded generators using ISTS but not paying ISTS Charges. The amendment providing of calculation of charges only on withdrawal nodes will take care of charges for the usage of ISTS by State generators. Since majority of power from such intra-state generators is consumed within the state, the transmission charges for use of ISTS by these intra-State generators shall automatically be attributed to State DISCOMs under the methodology as per third amendment . Earlier the usage of ISTS by embedded generators of a State was calculated under the base case. However, such charges were being recovered through scaling up. Under the methodology as per this amendment, the charges attributable to such generation shall automatically be attributed to the concerned State(s).

33.37 To facilitate participation of all generators in power exchanges, and 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. These rates shall be other than the rates specified for billing under Bill No. 1 of Regulation 11. The injection and withdrawal rates in paise/kWh shall be computed before transferring injection charges of ISGS having long term customers on withdrawal DICs. Hence these rates shall be determined for zones including generators with identified beneficiaries

33.38 The Regulation 8 (6) has accordingly been amended as under:

"(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.”

Further methodology for billing has been specified at Para 2.8.1 of Annexure-I as follows:

"2.8.1.a. Methodology for calculation of POC rates and billing of POC charges

(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.

(iii) 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.

(iv) For balance injection i.e. difference between Approved Injection and Quantum of withdrawal, generator shall pay Injection Charges only.

(v) 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

vi) 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. "

33.40 The methodology for determining PoC rates towards withdrawal DICs and for Generators having LTA to target region is detailed below:

A. Methodology for calculation of POC charges for Long term/Medium term billing under Bill No. 1

1. Para 2.8.1 of Annexure-I of Principal Regulations provides as under:

"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. "

2. The following steps shall be followed for calculation of PoC charges:

(1) Following files shall be taken:
   i. Monthly Transmission Charge (MTC) file and
   ii. Base case file (based on Maximum Injection and Maximum Withdrawal)

(2) Import Base case file in software

(3) Run Load flow and obtain Marginal Flow (MF) file.

(4) Marginal flow file shall be modified as follows:
   i. For Generators with identified beneficiaries for full capacity (for example- Rihand, Sipat etc.)- MF be reduced to zero
   ii. For Generators having LTA to target region, MF values to be retained as it is.
   iii. For Generators having part LTA to target region and part tied up capacity - MF for injection corresponding to tied up capacity to be reduced to zero and MF for injection corresponding to untied capacity is retained (Example is detailed at 3 (7) below).
   iv. Negative Marginal Factors be made zero as was being done earlier.
   v. MF file to be normalized so as to make total MF as '1'.

(5) Multiply MF file (as modified above) with MTC file

(6) Node wise cost is allocated.

3. An example is detailed below for clarity for carrying out Step No. 2 (7) (iii) above

(1) A Generator "A" (1000 MW) is located in Western region. "A" has taken Long term Access to target region as NR-300 MW, WR-400 MW. "A" enters into PPA with Haryana (say) for 250 MW. Now his LTA to target region for untied capacity shall be NR-50 MW, WR-400 MW.

(2) "A" has projected maximum injection of 900 MW for the ensuing quarter. This injection has to be segregated into injection corresponding to untied capacity and injection corresponding to long term PPA with Haryana. This shall be done as follows:
   (i) Injection corresponding to united capacity of (400+50) MW = 450* 900 / 700 = 578.6 MW
   (ii) Injection corresponding to capacity tied Long term / Medium term = 250 *900 / 700 = 321.4 MW

(3) For the capacity under 2(i) above, Generator A will have to bear the injection charges and its marginal factor shall be retained

(4) For the capacity under 2(ii) above long term beneficiary of Generator A will bear the Withdrawal Charges and this injection at 2(ii) above shall not be considered while calculating injection charges for Generator A.

(5) In case Generator A has a contract with its beneficiary that Generator A will bear charges for both injection and drawal end, its long term beneficiary i.e. Haryana will inform CTU, who shall in turn indicate the same to IA. Generator A shall be raised bill for 250 MW * (withdrawal slab rate for Haryana) in addition to its bill as at (3) above. Haryana's withdrawal charges shall get reduced for 250 MW since same shall be recovered from 'A'.

(6) For MTOA transactions, following needs to be followed:
MTOA is always with identified beneficiary. Hence MTOA transactions shall be treated same as LTA with tied up capacity. In case a generator has agreed to pay withdrawal charges for the MTOA quantum, Withdrawee DIC shall inform CTU and bill for this quantum shall be raised by CTU to generator by multiplying Withdrawal rate for the identified beneficiary with MTOA quantum and Withdrawee entity shall not be raised bill for this MTOA quantum. In case as per the contract, generator has to pay generation end charges and withdrawee has to pay Withdrawal end charges, Withdrawee may raise bill directly to generator in this regard based on STOA rates/mutual agreement.

(7) Let us consider an example for Sugen Power Plant of Torrent Power with Long term Access as 300 MW (100 MW tied up with M.P. and 200 MW untied capacity). Its injection considered in the base case is 319 MW. It has two units. Injection corresponding to 200 MW is to be retained in marginal flow file. i.e. (200/300)*319 MW= 212 MW. Marginal flow for Injection corresponding to tied up capacity i.e 100 /300 *319= 107 MW is to be removed from marginal flow file. Hence the Injection shall be modified as at Table B.

Marginal Flow file- Original	TABLE A			
Entity/Branch	**Gen-483(SUGEN4)**	**Gen-484(SUGEN4)**	**Gen-485(SUGEN4)**	**Total**
Injection/Drawal	159.645	159.645	0	319
ABDULLAP-KARCHAMW:1	0.000004	0.000004	0	
ABDULLAP-KARCHAMW:2	0.000004	0.000004	0	
ABDULLAP-PANCH-PG:1	0.000004	0.000004	0	
ABDULLAP-PANCH-PG:2	0.000004	0.000004	0	
ABDULLAP-SONEP-PG:1	-0.000001	-0.000001	0	

ABDULLAP-SONEP-PG:2	-0.000001	-0.000001	0	
	TABLE B			
Marginal Flow file-Modified	X	Y	Z	
Entity/Branch	**Gen-483(SUGEN4)-----$**	**Gen-484(SUGEN4)**	**Gen-485(SUGEN4)**	**Total**
Injection/Drawal	212	107	0	319
ABDULLAP-KARCHAMW:1	0.000004	0.000004	0	
ABDULLAP-KARCHAMW:2	0.000004	0.000004	0	
ABDULLAP-PANCH-PG:1	0.000004	0.000004	0	
ABDULLAP-PANCH-PG:2	0.000004	0.000004	0	
ABDULLAP-SONEP-PG:1	-0.000001	-0.000001	0	
ABDULLAP-SONEP-PG:2	-0.000001	-0.000001	0	

The Marginal Flow for column 'Y' shall be reduced to "zero" and Column 'X' shall be retained as it is.

B. Methodology for distribution of Transmission charges attributable to Generators who have not sought LTA or whose LTA has not become effective and are injecting under STOA and using ISTS.

1. There are a few generators whose LTA has either not become effective or the generators have not sought LTA to ISTS. Such generators are injecting power in ISTS under STOA (Injections of approximately 3100 MW). Such generators shall continue to be considered in the base case as being done earlier by Implementing Agency. The transmission charges attributable to such generators shall be calculated as injection charges (as for generators with LTA to target region). Since such generators do not have any long term/medium contract to pay for ISTS charges, the charges attributable to this generation cannot be recovered under Bill No. 1.

2. The charges of other DICs under Bill No. 1 shall be scaled up to the extent of charges attributable to such generators. This is logical since these generators shall pay transmission charges under STOA which are reimbursed back to DICs in proportion to Bill No.1. Hence the charges which are being scaled up shall be reimbursed back.

3. A sample of Generators who donot have LTA and are injecting under STOA has been taken and their injection for Quarter-2 of 2014-15 has been considered as detailed below. Under previous methodology, the usage of ISTS by injection of such generators would have been divided into injection charges at injection node and drawal charges at withdrawal node (where such injection is being absorbed). Under the current methodology, the Marginal Flow values for such generators shall

be retained as a Generator with LTA to target region corresponding to its full injection considered in base case. The total charges calculated for such generators shall then be distributed among all nodes considered in MF file as modified after Step (A) (2) (7) above in proportion to the charges calculated by the software. This distribution shall be done prior to determining slab rates. An illustrative example is detailed below for few such generators:

S.No.	Name of Generator	Injection considered in Base Case (MW) of Quarter 2, 2014-15	Charges in Cr
1.	Meenakshi	193	1.53
2.	Simhapuri	313	2.48
3.	Shree cement	201	0.59
4.	Sterlite	700	12.12
5.	Vandana	87	1.72

A sample calculation depicting nodal charges as calculated after retaining MF values for such generators and scaled up charges at other nodes is attached below at Table C. The slab rates shall be determined after this step of scaling up of charges.

	Quarter 2, 2014-15				
Code for Node	Node name	State Name	Injection/ withdrawal considered in base case	Charges as calculated by software	
			MW	Z (Rs. Cr.)	Scaled up Charges = Z X Sf (Rs. Cr.)
Load-1012	KALASHO1	Tripura	8.062	0.098	0.101
Load-1013	ZIRO-PG1	Arunachal pradesh	5.35	0.066	0.069
Load-15	JETPU2	Gujarat	102.297	0.681	0.705
Load-150	UJJAI1	M.P	34.417	0.538	0.557
Load-1500	SRIP10KV	Tamilnadu	353.204	6.156	6.376
Load-1501	SALEM21	Tamilnadu	183.089	2.838	2.939
Scaling factor	Sf		**1.04**		

Scaling factor = Sf= Total charges allocated through software / Charges without STOA generators = 1270 Cr. / 1226 Cr. =1.04

In above case charges for STOA generators came out to be Rs. 44 Cr. Such charges shall be recovered through scaling up charges of other nodes.

34. Clause (4) of Regulation11

34.1 Second proviso to clause (4) of Regulation 11 of the Principal Regulations was proposed to be substituted as under:

"Provided further that the charges for the DICs having long term access without beneficiaries shall include the Injection PoC charges and average of the Demand PoC charges among all the DICs, and shall be based on peak injection"

34.2 Comments have been received from NTPC, AD Hydro and Thermal Powertech.

34.3 NTPC has suggested that PoC rates be multiplied with Actual Injection to determine PoC Charges.

34.4 AD Hydro has suggested that the Generators who do not have the beneficiary should be exempted from payment of average of demand PoC charges; or based on their short term contract with any utility the average demand PoC charges should be refunded back.

34.5 Thermal Powertech has objected to the proposed Regulations stating that it would be unfair to charge generators average of demand PoC charges who might not dispatch full capacity. Hence lowest of demand PoC charges should continue.

34.6 We had proposed the amendment in line with proposed amendment for considering peak injection/withdrawal.

34.7 We have considered suggestions/objections of the stakeholders.

34.8 While dealing with clause 6 of Regulation 8 at para 33 of this SOR, we have explained that the charges shall not be calculated separately for generation end where generators have a contract for long term supply to identified beneficiaries. The charges for such generators shall rather be calculated only at the Withdrawal nodes. However injection charges shall be calculated for generators who have LTA to target regions. We have also provided at sub-clause (q) of clause (1) of regulation (7) that transmission charges shall be recovered as PoC charges, Reliability Support Charges and HVDC charges (as explained at para 13 and 45 of this SOR). Second proviso to clause (4) of Regulation 11 of the Principal Regulations shall be substituted to incorporate these changes.

34.9 We do not agree with suggestions of NTPC for billing on actual injection. We have done detailed deliberation in regard to analysis of billing on LTA/MTOA under para 4 and para 5 of this SOR dealing with sub-clauses (c) and (d) of clause (1) Regulation 2.

34.10 The contention of AD Hydro for providing offset for STOA for generators with LTA to target region is accepted and the same has been provided vide clause (9) of Regulation 11.

34.11 The contention of Thermal Powertech to continue charging generators with lowest of demand charges is not acceptable. The reasons for using maximum injection/maximum withdrawal have been given at Para 4 and Para 5 of the SOR. Further such generators with LTA to target region shall be provided offset for its short term transactions to any region as provided in the amended Regulation at clause (9)of Regulation 11. Accordingly, only Injection charges for Generators with LTA to target region shall be calculated. Accordingly the Regulation has been amended.

34.12 Further there shall be only one peak scenario as base case. Hence there shall be no separate rates for "peak hours" and "off peak hours". Hence the formulae for calculation of PoC charges have been amended to incorporate "Approved Injection" for Generators with LTA to target region and "Approved Withdrawal" for Withdrawal DICs. The methodology for calculation of charges has been detailed at Para 33 of this SOR. Accordingly we have modified this Regulation to incorporate these changes.

34.13 The comments and detailed methodology with regard to Reliability Support Charges have already been dealt in Para 13 of this SoR. However, the formula for billing the Reliability Support Charges has been spelt out in this Regulation. Accordingly we have modified this Regulation to incorporate these changes.

34.14 The comments and detailed methodology with regard to HVDC charges have been dealt in Para 45 of the SoR. However, the formula for billing the HVDC charges has been spelt out in this Regulation. Accordingly we have modified this Regulation to incorporate these changes.

34.15 In view of the foregoing, Clause (4) of Regulation 11 of the Principal Regulations has been substituted as under:

"(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:

$$[PoC\ transmission\ rate\ of\ generation\ zone\ in\ Rs/MW/month] \times [(Approved\ Injection)]$$

For Demand:

$$[PoC\ transmission\ rate\ for\ demand\ zone\ in\ Rs/MW/month] \times [(Approved\ Withdrawal)]$$

2. Reliability Support Charge

For Generators having LTA to target region:

$$[\text{Reliability Support Rate}\ in\ Rs/MW/month] \times [(Approved\ Injection)]$$

For Demand:

$$[\text{Reliability support rate}\ in\ Rs/MW/month] \times [(Approved\ Withdrawal)]$$

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:

$$[\text{HVDC Charge for Region in Rs/month}] \times [\text{Approved Injection}] / [\text{Total Approved Withdrawal of the Withdrawal DIC and Approved Injection of the Generator having LTA to target Region}]$$

For Demand:

$$[\text{HVDC Charge for Region in Rs/month}] \times [\text{Approved Withdrawal}] / [\text{Total Approved Withdrawal of the Withdrawal DIC and Approved Injection of the Generator having LTA to target Region}]$$

(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."

35 **Clause (5) of Regulation 11**

35.1 The para below the computation formulae in clause (5) of Regulation 11 of the Principal Regulations was proposed to be substituted as under:

"The second part of the bill shall be raised on the Designated ISTS Customers along with the first part of the bill.

Provided that the revenue collected from the approved additional Medium-term Open Access customers in the synchronously connected grid, which has not been considered in the Approved Injection / Approved Withdrawal, shall be reimbursed to the DICs located in the same synchronously connected grid having Long-term Access in the following month, in proportion to the monthly billing of the respective month;

Provided further that the Injection POC charges and Demand POC charges for Medium-term Open Access to any region shall be adjusted against Injection POC charges and Demand POC charges for the Long-term Access to the target region without identified beneficiaries;

Provided also that a generator who has been granted Long-term Access to a target region without identified beneficiaries, shall be required to pay POC injection charge plus the average of the POC demand charge among all the DICs in the target region for the remaining quantum after offsetting the quantum of Medium-term Open Access subject to the last proviso of clause (4) of this regulation ".

35.2 Comments have been received from CTU, Association of Power Producers (APP), Lanco Kondapalli Power Limited (LKPL) and Torrent Power Ltd.

35.3 CTU has suggested that the revenue collected from the approved Medium-term Open Access customers in the synchronously connected grid, shall be reimbursed to the DICs located in the same synchronously connected grid having Long-term Access in the following month, in proportion to the monthly billing of the respective month. The above changes are suggested to keep the billing against MTOA under second part of the bill so as to avoid arrear billing under third part of the bill to the MTOA customer which may arise after the expiry of MTOA period

35.4 APP has stated that the provisions under the existing regulation of application of 'lowest of Demand PoC charges among all the DICs in the target region" should be continued. Further, POC charges for Long-term Access with firm beneficiaries to any region shall be adjusted against Injection POC charges and Demand POC charges for the Long-term Access to the target region without identified beneficiaries. They have also requested that the set-off provided for MTOA should be extended to LTA with firm beneficiaries as well.

35.5 LKPL has stated that connectivity to the Generators without having identified beneficiary should be granted to facilitate commissioning by allowing injection of infirm power or drawal of startup power as unscheduled interchange and should be charged at UI rates applicable till COD is achieved. LTA should be granted only after beneficiary is identified. Even after COD is achieved, LTA should not be granted if beneficiary is not identified. In case where strengthening/system augmentation is required, LTA should be applicable only from the date when system is ready.

35.6 We have considered the submissions.

35.7 In regard to submission of CTU, we are of the view that with synchronization of all India Grid, adjustment shall be applicable to all DICs in the country. The second point for keeping the billing against MTOA under second part of the bill is not acceptable because the Approved Injection and Approved Withdrawal include MTOA and form part of first bill. We have decided to calculate transmission charges on Withdrawal nodes and for Generators who have LTA to target region without identified beneficiaries.

35.8 In regard to suggestion of APP, we are of the view that under the changed methodology where generators with target region shall have to pay only the Injection Charges, the issue of demand PoC charges will not be relevant. Further, offset is available against LTA in any region.

35.9 The issue stated by LKPL regarding grant of LTA only after the identification of beneficiaries is not relevant under the proposed amendment. The Regulations provide that transmission charges are payable on commencement of LTA whether beneficiaries are identified or not. As the expenditure done on the line for connectivity /LTA is to be recovered, the generator should pay for the asset created for it.

35.10 Comments of Torrent Power Limited have been dealt in clause (9) of Regulation 11 under Para36 of the SOR.

35.11 We have decided to calculate transmission charges on Withdrawal nodes and for Generators who have LTA to target region. As per Connectivity Regulations, LTA can be with "target region" i.e. without identified beneficiaries but there is no such provision for MTOA to target region. MTOA shall be with identified beneficiaries only. Hence the formula for calculation of charges for Generators under Additional Approved Medium Term Open Access shall not be applicable.

Accordingly the formula for injection has been deleted. The methodology for billing as per the MTOA contract has been clarified at Para 33 of this SOR.

35.12 In view of the foregoing **<u>Clause (5) of Regulation 11</u>** has been amended as under:

"(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:

$$[PoC\ Transmission\ rates\ for\ demand\ zone\ in\ Rs/MW/month] \times [(Approved\ Additional\ Medium\ Term\ Withdrawal)]$$

The second part of the bill shall be raised on the DICs along with 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 Withdrawal POC charges for Medium-term Open Access to any region shall be adjusted against Injection POC charges for the Long-term Access to the target region without identified beneficiaries:

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."

36 **<u>Clause (9) of Regulation 11:</u>** It was proposed that all provisos under Clause (9) of Regulation 11 of the Principal Regulations would be substituted as under:-

*"Provided that the **<u>DICs</u>** which were granted LTA without identified beneficiaries and are paying both injection and withdrawal charges for long term access, the liability of the DICs for injection POC charges and Demand POC charges for Short-term Open Access to any region shall be adjusted against the injection POC charges and Demand POC charges for long term based on <u>Peak injection</u>;*

Provided further that a generator who has been granted Long-term Access to a target region without identified beneficiaries, shall be required to pay POC injection charges plus the Average of the POC demand charges among all the DICs for the remaining quantum of long term access after offsetting the quantum of Medium-term Open Access and Short-term Open Access;

Provided also that the injection POC charges/withdrawal POC charges for short-term open access granted to DIC shall be offset against the corresponding injection POC and withdrawal POC charges to be paid by the DIC for approved injection/Approved withdrawal based on Peak Injection/Withdrawal;

Provided also that this adjustment shall not be allowed for collective transactions and bilateral transactions carried out by the trading licensees who have a portfolio of generators in a State for which LTA was obtained to a target region."

36.1 Comments have been received from Association of Power Producers (APP), CTU, Torrent Power Limited (TPL), Adani Power Limited (APL), Jindal Power limited (JPL), POSOCO, Indian Energy Exchange (IEX) and Shri. Ravinder.

36.2 APP has submitted that offset should be provided against the LTA charges irrespective whether MTOA/STOA is applied by generator/trader/customer for a particular generating station. APP has further suggested considering the offset against MTOA as well. It has also suggested for offset of injection charges under the collective transactions against the corresponding charges paid by generators for approved injection.

36.3 CTU has suggested that adjustment against approved injection PoC charges and approved demand PoC charges in the following months shall be limited to first part of the bill for injection and withdrawal charges, each settled separately. Similarly for other provisions also, CTU has suggested that adjustment should be limited to only first part of the bill for injection and withdrawal charges for each DIC separately. CTU has further requested the Commission that the corresponding changes may be accordingly incorporated in the BCD procedure also.

36.4 TPL has mentioned that beneficiaries need to draw power from other resources than the identified generator due to various reasons. In such situation, the beneficiaries would be drawing power from other sources under MTOA/STOA using the same drawal network. However, the proposed amendment is not clear whether such beneficiary/DIC would get offset for MTOA/STOA.TPL has also submitted for adjustment against injection/drawal PoC charges under collective transactions.

36.5 APL has in regard to collective transactions suggested that the DIC who is paying the injection PoC is known, whereas the beneficiary who is drawing this power is not known. It has suggested that the DICs are to be allowed to offset the injection PoC for the collective transactions and lowest withdrawal PoC charges against LTA without identified beneficiaries. APL has further submitted that at present CTU allows 2% rebate on gross LTA bill amount only in the event of payment of net amount (gross-setoff) within 5 days by the DICs. CTU is not allowing 2% rebate on the set-off amount, if the payment of net billed amount is made after 5 days. It may be seen that for the month of March, 2014, the LTA bill is issued in the first week of April, 2014 with setoff for STOA transactions for the month of March 2014. Hence, setoff amount is already available well in advance with the CTU. In view of the above, APL has requested to facilitate full rebate (2%) on setoff amount irrespective of actual date of payment of net bill.

36.6 JPL has raised the issue of transmission charges with peak injection/withdrawal for hydro power generators. The PLF for hydro station is about 50% or half of the PLF of thermal plants. Hence, for the same installed capacity, the actual per unit transmission charges being paid by hydro station is about double the transmission charges of the thermal generators. The proposed methodology seems punitive / penalizing to hydro generators for doing peaking operation and supporting the grid during peak demand hours. JPVL has suggested that in view of unique nature of hydro plants and to promote hydro generation in country, hydro generators should be liable to pay LTA charges only to the extent of their Design Energy.

36.7 POSOCO has suggested that adjustment is proposed to be based on quantum rather than charges paid. This would be prone to error/disputes and has suggested that the adjustment may be continued to be done based on charges paid. With respect to adjustment of withdrawal charges, POSOCO is of the view that there are many intra-State entities that draw power through STOA. The adjustment should be for the State utility only and will have to be done for each 15 minutes block after segregating different transactions. The proposal will become very complex and prone to disputes.

36.8 IEX has suggested considering collective transactions also for adjustment of LTA charges.

36.9 Shri Ravinder has welcomed the proposal; however he has stated that the proposal is very complex and requires paying charges a number of times. He has also suggested that STOA customer having LTA for target region would have higher priority in STOA service. He has further suggested payment of premium at the rate of 50% as opportunity cost for seeking STOA without a back up LTA.

36.10 We have considered comments of the stakeholders and individuals. In regard to suggestions of APP, we are of the view that offset would be applicable for MTOA/STOA including collective transactions, as the case may be. Further, if a generator with LTA to target region has contract under (MTOA/STOA) to pay withdrawal charges also, it shall be liable to pay with drawal charges as explained in Regulation 8 (6) at para 33 of SOR. In such a case the generator with LTA to target region will be given offset for withdrawal charges. Further adjustment shall also be applicable, if the transaction is done through a trader on behalf of DIC if one to one relationship is established at the time of application of STOA itself. However, offset will not be allowed for a trader, who does not happen to be a long term customer having portfolio of a generator in a state.

36.11 In regard to suggestions of CTU, we are of the view that with the changed methodology, Withdrawal DICs are now to pay withdrawal charges which includes charges attributable to ISGS. The injecting DIC having LTA to a target region shall pay Injection charges as per the revised methodology. Withdrawal DIC and injection DIC shall be given offset in Part-I of the bill.

36.12 Regarding submission of TPL, it is clarified that offset to drawee entity shall be granted irrespective of source because LTA is given for withdrawal of a certain quantum. Further, we agree to the submission of TPL in regard to adjustment against injection/drawal PoC charges under collective transactions. However, injection charges would be offset for Injecting DIC without beneficiary and withdrawal charges for withdrawal DIC, for the transaction done by DIC itself. It would be the responsibility of SLDC of the concerned State to indicate the quantum for different DISCOMs.

36.13 In regard to suggestion of APL, we are of the view that for generators, adjustment of collective transactions against injection PoC charges would be allowed and for drawal DICs, adjustment for withdrawal charges would be allowed for the transactions done by DIC itself. Further, in regard to suggestion of APL on rebate, we are of the view that rebate should be applicable for gross billed amount only and if the payment is not made within specified period, no rebate is applicable for part payment. .

36.14 In regard to suggestion of JPL, we are of the view that though the average operating level of hydro stations is much less than the PLF of thermal stations, it must be appreciated that hydro stations are located far from the load centers and evacuation of their power needs substantial amount of transmission system. Further the transmission lines are built based on maximum generation which includes overload capacity. Hydro stations by virtue of their seasonal variability and spatial position use transmission system in a particular manner. As we are adopting maximum injection approach in the PoC calculation, the transmission charges during the lean period will be lesser for hydro stations. Further, the Commission has also provided additional RoE of 1% for Pondage type of hydro generators. Even in the earlier methods of sharing of transmission charges, beneficiaries were sharing charges of the transmission system built for Hydro stations in proportion to their share in installed capacity, irrespective of season, time and day of usage. The beneficiaries of these stations are aware from the time of planning and approval of transmission system that power from these stations will be available in Peak Hours depending on availability of water but the transmission system cost needs to be serviced for full year. Merchant hydro power stations want that a system should be created to evacuate their full power but want to pay only for few hours in particular months of the year. This will shift the responsibility for payment of transmission charges to others. Even in the case of a fully allocated Central sector hydro stations, the transmission charges in lean season are paid by the beneficiaries. If a generator wants to get benefit of open market, it should bear the charges for the system created for it.

36.15 We agree with the suggestion of POSOCO with respect to adjustment based on charges paid corresponding to energy quantum. For adjustment of intra-State entities that draw power through STOA, the adjustment should be done considering it in the State utility. SLDC should coordinate with NLDC/RLDCs/CTU in this regard and the adjustment shall be given when the entity has LTA and where DIC is clearly identified.

36.16 We agree to the suggestion of IEX and have accordingly allowed adjustment for collective transactions.

36.17 In regard to suggestions of Shri. Ravinder, we are of the view that there is no inter-se priority between two types of STOA applicants as suggested by him and priority cannot be granted to STOA applicant having LTA. We are allowing adjustment of STOA charges offsetting its approved injection. This suggestion in regard to 50% premium charges for seeking STOA without a backup LTA cannot be considered as it was not proposed in the draft regulation.

36.18 We would like to clarify that STOA adjustments of any region shall be offset against the LTA in target region.

36.19 It was proposed in the draft amendment that the injection POC charge/ withdrawal POC charge for Short term open access granted to a DIC shall be offset against the corresponding injection POC and withdrawal POC charges to be paid by the DIC for Approved injection/ Approved withdrawal based on Peak Injection/ Withdrawal. Individual DICs are also to get adjustment in the light of methodology for preparation of Base Case and charges incident upon these DICs where drawl was captured in Approved Withdrawal w.r.t. peak demand. The objective is to avoid double charging the Withdrawal DICs through STOA adjustment, similar to the generators.

36.20 In the Sharing Regulations, it was provided that computation would be done considering Long Term Access and Medium Term Open Access and for this all DICs would give node wise injection and drawal based on their forecast. However, during implementation phase, it was decided to use published State wise data of monthly power supply position prepared by CEA as DICs were not coming forward with node wise data and an agreed base data was required.

36.21 As the monthly power supply position reports of CEA cover all types of transactions, in base case usage of each DIC captures all types of transactions (Long Term, Medium term & Short Term) and Deviation (UI), usage of transmission system is captured for all these transactions. The PoC charges computed for these DICs, specifically Withdrawal DICs, are already captured. However when these DICs enter into short term transactions-either bilateral or collective, they pay these charges in advance and without adjustment would amount to double charging. Although total STOA charges collected through these transactions are paid back to these DICs in proportion to PoC charges paid, but such returns do not have one to one correspondence. For example, one DIC in a particular region is engaged in STOA purchase, so in base case this usage is captured and State pays this in first bill. When during the month it performs STOA transaction(s), the charges are distributed to all DICs and only a fraction of amount comes back to this DIC. So the question is to what extent this relief is to be provided i.e. to the extent of LTA up to which billing is done or to the extent of their net drawal from ISTS considered in base case.

36.22 As any DIC can draw power from ISTS only subject to its access, drawal of a DIC from ISTS in excess of LTA would be under MTOA and STOA plus a small fraction under deviation.

36.23 Capturing adjustment of STOA and mapping of STOA transactions is difficult for withdrawal DICs as compared to injecting DICs whose injection is at single node. This problem becomes more acute if there are multiple DISCOMs in area of a DIC (for example Delhi, Karnataka, Rajasthan etc.). But only due to administrative issues, the legitimate right of DICs cannot be ignored. To address this, a mechanism needs to be evolved and concerned DISCOM, in coordination with its respective SLDC, should submit required details to segregate transactions of individual entities. SLDC in consultation with DISCOM, CTU and NLDC may finalize the process for submission of information to avail the STOA adjustment.

36.24 One more important issue needs to be underlined here. Because certain transmission usage is considered in computation based on LTA in target region and is being adjusted, it does not create any right on transmission system. Only commercial adjustment is being done to avoid double charging and no right on transmission is being created. Right of transmission access is coming through LTA/MTOA / STOA and equivalent Power Purchase Agreement.

36.25 We would like to clarify the methodology for adjustments with the following example:

Present Regulation:

Generator in Western Region with LTA without Beneficiary=500 MW in WR				
	Monthly LTA BILL			
	Rate	LTA	Monthly Charges	
	Rs./MW/Month	(MW)	(Rs.)	
Injection	1,15,000	500	5,75,00,000	
Withdrawal	1,00,000	500	5,00,00,000	
Total charges			10,75,00,000	(a)
Sale under STOA			**MW**	
Average Sale during the month	in WR		300	
	in SR		150	
	Collective		30	
Generator Will Pay in Advance:	STOA Rate (Rs/kWh)	STOA AV. Sale (MW)		
Injection charge in WR@16 p/kWh	0.16	300	3,45,60,000	(b)
Withdrawal charges in WR@ 14p/ kWh	0.14	300	3,02,40,000	(c)
Injection Charges in WR for WR –SR @ 16p / kWh	0.16	150	1,72,80,000	(d)
Withdrawal charge in SR@ 14p/ kWh	0.14	150	1,51,20,000	(e)
Injection Charges in WR for Collective @16p/ kWh	0.16	30	34,56,000	(f)
			10,06,56,000	
Adjustments under Present Regulations:	STOA Rate (Rs/ kWh)	STOA AV Sale (MW)		
Injection charge in WR@16p/ kWh	0.16	**300**	3,45,60,000	
Withdrawal charges in WR@14p/ kWh	0.14	**300**	3,02,40,000	
Injection Charges in WR for WR-SR@16p/kWh	0.16	**150**	1,72,80,000	
			8,20,80,000	
Next Month LTA Bill [(a)-(b)-(c)-(d)]			**2,54,20,000**	

Under Third Amendment:

Generator in Western Region with LTA without Beneficiary=500 MW in WR				
	Monthly LTA BILL			
	Rate (Rs./MW/ Month)	LTA (MW)	Monthly Charges	
Injection	205000	500	12,50,00,000	
Total charges		Rs	**12,50,00,000**	(a)
Sale under STOA			MW	
Month Average	in WR		**300**	
	in SR		**150**	
	Collective		**30**	
Generator Will Pay in Advance:	STOA Rate (Rs/kwh)	STOA average sale (MW)		
Injection charge in WR@16 p/kwh	0.16	300	3,45,60,000	(b)
Withdrawal charges in WR@ 14p/kwh	0.14	300	3,02,40,000	(c)
Injection Charges in WR for WR-SR@16p/kwh	0.16	150	1,72,80,000	(d)
Withdrawal charge in SR@ 14p/kwh	0.14	150	1,51,20,000	(e)
Injection Charges in WR for Collective @16p/kwh	0.16	30	34,56,000	(f)
(b)+(c)+(d)+(e)+(f)		Rs	10,06,56,000	(g)
Adjustment as per Third Amendment:				
Next Month LTA Bill (a-g)		Rs	**(-) 2,43,44,000**	

For Drawee Entity:

Drawee entity having LTA of 3000 MW				
	Monthly LTA Bill			
	Withdrawal Rate (Rs./MW/Month)		LTA (MW)	Monthly Charges (Rs)
Withdrawal	2,00,000		3000	**60,00,00,000**
	(A)		**Total**	**60,00,00,000**
			MW	**MU**
Drawing in STOA	**In bilateral**		**300**	216
	Collective		**50**	36
Generator Will Pay in Advance for STOA:	Monthly Energy (MU)	STOA Rate (Rs/kwh)	Rs.	
Withdrawal charges in WR @14p/kwh	216	0.14	3,02,40,000	
Withdrawal charges in WR for Collective@14p/kwh	36	0.14	50,40,000	
Total			**3,52,80,000**	
Next Month Bill corresponding to LTA			**60,00,00,000**	(a)
Adjustment to withdrawal also is to be given		**MU**		
Entitlement of energy as per LTA=30*24*LTA / 1000(in MU)	(E)3000 MW	2160		
Schedule during the month (assume actual withdrawal is 2600 MW)	(Actual) 2600 MW	1872		
Check if Energy Schedule is less than Energy Entitlement (in MU)		**Yes**		
Entitlement for adjustment (MU)	E-Actual	288		
STOA	216+36	252		
Withdrawal Charges in WR	216	0.14	**3,02,40,000**	(b)
Withdrawal charges in WR for Collective @14p/kwh	36	0.14	**50,40,000**	(c)
Next Month LTA Bill after adjustment- =a-b-c)		Rs.	**56,47,20,000**	

36.26 Consider the case wherein DIC withdrawal considered in computation is less than or equal to LTA plus MTOA. However there are cases wherein Net withdrawal of the particular State (Withdrawal-injection) is more than LTA plus MTOA. For example, in the Table of Southern Region for Q2 of 2014-15, the position in regard to maximum drawal and average drawal of Southern States was as under:

	Max (MW)				
Month	AP+TSAct	KA Act	TN Act	PO Act	GO Act
Max (MW) **LTA**	**2933**	**2073**	**4442**	**352**	**100**
July	6273	1559	4047	331	102
August	6898	1209	3505	318	116
September	5871	1977	3884	327	105
	Average (MW)				
Month	AP+TSAct	KA Act	TN Act	PO Act	GO Act
July	4304	779	3223	277	59
August	4007	619	2868	260	70
September	3823	856	2808	271	58

AP-Andhra Pradesh, TS-Telangana, KA-Karnataka, TN-TamilNadu, Po-Pondicherry, GO-Goa

36.27 The net drawal of a state can be more than or less than LTA. From the above Table it may be seen that for AP (combined), net withdrawl has been more than LTA during Q2 of 2014-15. However in PoC computation, software considers load which includes all types of drawal and own generation of a control area to allocate the total transmission charges. The offset should be allowed considering the above aspect.

36.28 In the Q2 of 2014-15, the load of AP was 6428 MW and own generation 2355 MW. The net drawal considered in PoC Computation for the State was 4073 MW (6428-2355); which was almost equal to actual data of SEMs for interstate power. Hence even if the State is having LTA to the tune of 2933 MW, it actually needs to pay for drawal of 4073 MW from ISTS. As the software captures PoC Charges (Rs.) for 4073 MW, and any additional charges till 4073 MW may lead to double charging. Accordingly, it has been decided that adjustment for STOA/MTOA under this Regulation shall be given to the extent of net drawal (Withdrawal- own injection affecting ISTS) considered in the base case for the application period. Regulations are amended accordingly.

36.29 In sample case for Delhi, the scenario is just opposite. Delhi's LTA is higher than the maximum Withdrawal. For Q2 2014-15, LTA of Delhi was 4680 MW, load was 2966 MW, and own generation 69 MW only. It means 2897 MW (2966-69) is the quantum considered by the software in PoC calculation. Delhi can only be given adjustment up to 2897 even though it has LTA of 4680 MW.

36.30 This issue has one more aspect. There are few generators where LTA has either not started or they have not taken any LTA to ISTS and inject power under STOA. Such generators have been considered under Base Case until now and the use of transmission system by such generator is being captured in PoC calculation. As such, generators who donot have LTA/MTOA, cannot be billed under Bill No. 1.The transmission charges attributed to such generators so computed in PoC shall be distributed among all DICs. The methodology for such charges is detailed at Para 33 of this SOR.

36.31 Based on the above discussion, clause 9 of Regulation 11 has been substituted as under:

"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."

37 <u>Regulation 17</u>

37.1 Regulation 17 was proposed to be substituted as under

"17. Information to be published by the Implementing Agency

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 or nodal transmission charges for the ensuring application period;*

   c. *Zonal or nodal transmission losses data;*

   d. *Schedule of charges payable by each constituent for the ensuring Application Period;*

   e. *YTC detail (Information submitted by all transmission licenses and computation by implementing agency)".*

37.2 Comments have been received from GRIDCO and POWERGRID in this regard.

37.3 GRIDCO has suggested that in addition to Basic network, nodal generation/demand and load flow results, additional data (Marginal Participation Details, Avg. Participation Details for withdrawl and injection nodes, Zone-wise injection and withdrawl PoC, Computation of Schedule Charges payable by the DICs, % of Scaling, % Participation) should also be displayed on the website

37.4 POWERGRID has suggested that computation tool may be made more transparent which should provide details such as which DIC is receiving power from which generators and what quantum, given generator is serving which DICs and for what quantum, which DIC is using which lines and in what percentage.

37.5 We have considered suggestions of GRIDCO and POWERGRID.

37.6 We had discussed the objective of the proposed amendment in the Explanatory Memorandum to draft amendment as follows:

"The Sharing Regulations provides for complete transparency of data and information used for computation of PoC transmission charges. One more important information regarding Yearly Transmission Charges (YTC) is proposed to be shared to explain how the YTC of all transmission licensees is considered for computation of transmission charges. The objective of the Commission is to share as much information as possible with the stakeholders. In every order for the PoC rates issued by the Commission, it is mentioned that Implementation agency must publish all the details that will enable a clear understanding of the calculations used for arriving at these rates."

37.7 There is a need of increasing visibility of PoC charges attributable to the DICs through appropriate tables. Hence we have added that PoC charges details should be available at website which enables each DIC to see details of transmission lines it is using and whose transmission charges it is sharing. Further the date of commencement of LTA/ MTOA is currently not available on the website which needs to be made available. In addition to this, the details of contractual liability of payment of transmission charges under a particular contract (LTA/MTOA) which is currently provided by CTU to IA should also be available for stakeholder's convenience.

37.8 Regarding suggestions of POWERGRID and GRIDCO for additional details, it is clarified that the Commission's objective is to provide complete transparency of data to stakeholders. Implementing Agency should provide the data as requested by a stakeholder to enable clear understanding of calculations to DICs. We would also refer to our Order No. L-1/44/2010-CERC dated 29.06.2011 in this regard:

" We also direct the Implementing Agency to publish zonal PoC Rates and zonal Transmission Losses and associated details that will enable a clear understanding of the calculations used for arriving at these rates, along with the underlying network information and base load flows used, in accordance with the Regulation 17(3) of Sharing Regulation."

37.9 The Commission is of the view that DICs should be provided with access to all data that go into the computation of POC charges. However, in order to ensure that only the authorized users get access to the details of the data put on the website, we are of the view that Implementing Agency may provide the data to the DICs with access control keeping in view sensitivity of data.

37.10 In view of the foregoing, Regulation 17 has been amended asunder:

"17.Information to be published by the Implementing Agency

(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."

38 Para 2.1 of the Annexure-I of the Principal Regulations

Keeping in view amendments in the current (third) amendment to Regulations, the word 'peak and other than peak conditions' appearing in the first sentence shall be substituted with the words 'maximum injection/maximum withdrawal'.

39 **Para 2.1.1 of the Annexure-I of the Principal Regulations**

39.1 In view of the amendments to Sharing Regulations through the Third Amendment, para 2.1.1 of Annexure-I needs to be amended. We have specified the methodology for forecast of maximum injection/withdrawal keeping in view stakeholders comments in this regard covered under Regulation 2(1) (d) , 2(1) (e), 7 (1) (d) and 7 (1) (e).

39.2 Para 2.1.1 of the Annexure-I of the Principal Regulations has been substituted as under:

"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 Agency

For 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 year's 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."

39.3 The methodology for vetting maximum injection /maximum withdrawal is detailed below for clarity of stakeholders:

State/ UT	Y1 2012(Peak Met)	Average Peak Met for Quarter 2 for year 1	Y2 2013 (Peak Met)	Average Peak Met for Quarter 2 for year 2	Y3 2014(Peak Met)	Average Peak Met for Quarter 2 for year 3	Y4 2015 (Projected) (Peak)	Normalized Peak met
	July August Sept.		July August Sept.		July August Sept.		Quarter 2	Quarter 2
	M1 M2 M3		M1 M2 M3		M1 M2 M3			
S1 S2 S3 S4 S5 . . S35	$S_5Y_1M_1$ S_5Y_1 M_2, $S_5Y_1M_3$	S_5Y_1AV	$S_5Y_2M_1$ $S_5Y_2M_2$ $S_5Y_2M_3$	S_5Y_2AV	$S_5Y_3M_1$ $S_5Y_3M_2$ $S_5Y_3M_3$	S_5Y_3AV	S_5Y_4 (Projected)	(S_5Y_4) X (N_f)
Sum of Individual Peak met							$\sum_{x=1}^{35} SxY4$ = $SumY_4$	
All India Peak Met	PY_1M_1 PY_1M_2 PY_1M_3	Py_1AV	PY_2M_1 PY_2M_2 PY_1M_3	PY_2AV	PY_3M_1 PY_3M_2 PY_3M_3	PY_3AV	PY_4 (projected)	

$SumY_4$ = summation of projected peak met for ensuing quarter (application period)

M_1, M_2, M_3= Month1, Month2, Month3 in the quarter corresponding to application period

Y_1, Y_2, Y_3, Y_4= years

S_1, S_2, ….. S_{35}= States

P= All India Peak met

Normalisation factor (N_f)= PY_4(projected)/$SumY_4$

39.4 A sample calculation detailing methodology for normalization of peak met (projected) for Quarter 2 for 2015-16 based on demand of 2 of 2012, 2013 and

2014 is detailed below for sake of clarity:

DEMAND FORECAST USING PAST 3 YEARS DATA					
Peak Demand Met (MW)					
	1	2	3	4	5
	Averag e July - Sep 12	Average July - Sep 13	Averag e July - Sep 14	Forecast based Projectio n of Demand for July -Sep 15	Normalise d Peak demand for July - Sep-15 (5) = (4) X Nf*
Chandigarh	310	312	331	339	321
Delhi	4972	5058	5438	5622	5323
Haryana	6499	7752	8710	9865	9340
Himachal Pradesh	1229	1213	1282	1295	1226
Jammu & Kashmir	1709	1783	1875	1956	1852
Punjab	8324	8483	9229	9584	9074
Rajasthan	7291	7784	9651	10603	10039
Uttar Pradesh	11182	11688	11441	11696	11074
Uttarakhand	1527	1666	1785	1917	1815
Chhattisgarh	2778	2986	3098	3274	3100
Gujarat	11082	11222	12955	13627	12902
Madhya Pradesh	5832	6224	7483	8164	7729
Maharashtra	14872	14957	17995	19065	18050
D&D	283	291	297	305	288
DNH	624	654	660	682	646
GOA	425	450	454	472	447
Andhra Pradesh	9958	11512	12719	14158	13404
Karnataka	7794	7771	7996	8055	7627
Kerala	3215	3106	3267	3249	3076
Tamilnadu	10597	11762	12856	13997	13252
Puducherry	306	322	331	345	326
Lakshadweep	8	8	8	8	8
Bihar	1722	2122	2481	2868	2715
DVC	2280	2476	2473	2602	2464
Jharkhand	1014	959	987	959	908
Odisha	3361	3543	3628	3778	3577
West Bengal	6707	7093	7280	7600	7196
Sikkim	95	80	78	67	63

Andaman -Nicobar	32	32	32	32	30
Arunachal Pradesh	108	106	116	117	111
Assam	1080	1206	1212	1298	1229
Manipur	115	120	130	136	129
Meghalaya	277	275	286	288	272
Mizoram	62	62	80	86	82
Nagaland	96	101	116	125	118
Tripura	184	215	243	273	258
			TOTAL	158504	
All India	**118072**	**126772**	**139898**	150073	
		Normalisation Factor (NF)		0.95	

* **Normalisation Factor (Nf)** = Projected All India Peak for Quarter-2 of 2015-16 / Sum of projected peak met for all States/UTs = 150073 /158504=0.95

It is clarified that average for maximum generation/withdrawal for the corresponding application period of last 3 years should be calculated without considering any null/zero values. It is also clarified that regarding vetting of maximum injection of the concerned State as 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), the corresponding time block shall be as provided by RPC to IA failing which IA may consider the figures as deemed fit by IA

40 Sub- para 2.1.3 of Annexure-I of Principal Regulations

40.1 It was proposed that sub-para (g) of Para 2.1.2 should be modified as under:

"*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 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.

Overall charges to be allocated among nodes shall be computed by adopting the YTC of each of the lines of the ISTS licensees, and any other non-ISTS line that has been certified by the respective RPCs as being used for interstate transmission. The YTC for such lines shall be based on the YTC of the *transmission licensee/SEB as approved by the Appropriate Commission. The YTC of the sub-station shall be apportioned to the lines emanating from each sub-station as per the provisions of these Regulations. The YTC of the transmission assets expected to be commissioned in the Application Period would be incorporated by the IA on the basis of provisional approvals or benchmarked capital cost and operating costs as determined using the regulations of the Commission."*

40.2 The issue has already been dealt with in para 15 of this SoR

40.3 Accordingly, this sub-para has been named as 2.1.3 and the same has been substituted as under:

"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."

41. Para 2.2 of Annexure-I of Principal Regulations

In view of amendments vide third amendment, there are consequential changes in this Para. Para 2.2 of Annexure-I of Principal Regulations has been substituted as under:

"2.2 COMPUTATION OF LOAD FLOWS ON THE BASIC NETWORK

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.

42. Para 2.3 of Annexure-I of Principal Regulations

Para 2.3 of Annexure-I of Principal Regulations has been deleted as detailed at Para 21 of this SOR.

43. Para 2.5 of Annexure-I of Principal Regulations

Keeping in view amendments vide the third amendment, various consequential changes have been carried out in para 2.5 as detailed below:

i) In third sentence of para 2.5 of Annexure-I of the Principal Regulations, the words "peak and other than peak conditions" shall be deleted.

ii) In first sentence of sub-para (3) of para 2.5 of the Annexure-I of the Principal Regulations, the words "and for every scenario" shall be deleted.

iii) In sixth sentence of sub-para (3) of para 2.5 of Annexure-I of the Principal Regulations, the words "typical seasonal system peak and other than peak periods" shall be substituted with the words "maximum injection/ maximum withdrawal".

iv) In first and fifth sentences of sub-para (3) of para 2.5 of the Annexure-I of the Principal Regulations, the word "seasonal" shall be deleted.

44. Sub-paras 1, 5and 6 under Para 2.7 of the Annexure-I of the Principal Regulations:

Keeping in view amendments vide the third amendment, various consequential changes have been carried out in Sub-paras 1, 5and 6 under Para 2.7. Sub-paras 1,5 and 6 have been substituted as follows:

“1. Converged AC Load Flow data for the all India Grid shall be used directly for the implementation of the Hybrid Methodology.

5. Hybrid Methodology shall be applied to Application Period.

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

45. Sub-para 2 under Para 2.7 of the Annexure-I of the Principal Regulations:

45.1 It was proposed that the following proviso under Step-4 under Para 2.7.2 of the Sharing Regulations Annexure as quoted below should be deleted:

“Provided that after the entire country is synchronously connected, the cost of all the HVDC systems shall be borne by all the DICs in the country by scaling up the YTC calculated without including the HVDC costs.”

The above deletion implies that transmission charges for HVDC system would be calculated based on ‘with and without method’ for all the HVDC systems except Talcher-Kolar, whose charges would be shared by Southern Region as per existing Regulations. Thus, in effect it was proposed in the draft amendment not to socialise the HVDC charges.

45.2 Comments have been received from POSOCO and CEA.

45.3 POSOCO has suggested that, if charges of HVDC are apportioned to nodes which get benefitted because of presence of HVDC, then there would be opposition from the States to termination of HVDC lines in respective States. There is substantial impact of set point of HVDC (direction and quantum of power flow) considered in base case on nodal charges. Thus, the assumptions would be questioned by stakeholders affected. A 800kV 6000 MW multi-terminal HVDC link from Biswanath Chariali/ Alipurdwar to Agra is under construction. If charges are shared based on usage, PoC rates nodes nearer to the stations like NER / ER States may be affected. Further, POSOCO has emphasized that since HVDC systems are national assets, the existing provision may be retained.

45.4 CEA has stated that, in the present methodology, the impact of PoC rate on account of HVDC bi-pole/multi-terminal/back-to-back links is being determined through a ‘with and without’ methodology in marginal participation algorithm. CEA has suggested that instead of ‘with and without’ methodology for HVDC, the power order on the HVDC link, as given in the base case under consideration, may be reduced by 1% to account for the impact of cost of HVDC on PoC rates of various nodes. This methodology would be in line with basic principle of marginal participation i.e. to have a small perturbation.

45.5 POSOCO has suggested to continue with existing philosophy of socializing the cost of HVDC system whereas CEA has suggested a modified With & Without methodology. After the notification of Sharing Regulations, a technical study was conducted by IIT Bombay, which also included the method now suggested by CEA. The extracts from the views expressed by IIT, Bombay are given below:

“A Study on Alternatives for Cost Allocation of HVDC Lines with Reference to Central Electricity Regulatory Commission (Sharing of Inter State Transmission Charges and Losses) Regulations, 2010 was conducted by Prof. S A Soman, Power Anser Labs Department of Electrical Engineering, IIT, Bombay during Feb, 2011 on the request of CEA. However the method as suggested by CEA of changing power order was not found suitable".

45.6 We intend to recapitulate the issue of allocation of cost of HVDC from the beginning.

45.6.1 "With and Without" HVDC method provision was made in the Sharing Regulations notified in June, 2010 as under:

"2.7 COMPUTATION: DETERMINATION OF SHARING OF YTC AND TRANSMISSION LOSSES

The simulations will be carried out by the IA by using software duly approved by the CERC. The following steps shall be followed:

1. Converged AC Load Flow data for the NEW Grid and the SR Grid for the truncated network shall be used directly for the implementation of the Hybrid method.
2. Treatment of HVDC lines: Flow on the HVDC line is regulated by power order and hence it remains constant for marginal change in load or generation. Hence, marginal participation of a HVDC line is zero. Thus, MP-method cannot directly recover cost of a HVDC line. Therefore, to evaluate utility of HVDC line for a load or a generator, the following methodology shall be applied:

   Step 1: Evaluate the Transmission System charges (of AC network) for all loads and generators corresponding to base case which has all HVDC lines in service.

   Step 2: Disconnect the HVDC line and again compute the new flows on the AC system. Hence, evaluate the new transmission system charges (of AC network) for all the loads and generators.

   Step 3: Compute the difference between the Nodal Charges (unit- Rs) with and without HVDC line and identify nodes which benefit from the presence of the HVDC lines. Benefit is new (with disconnection) usage cost minus old (with HVDC) cost. If benefit is negative, it is set to zero.

   Step 4: The cost of the HVDC line is then allocated to the nodes in proportion of the benefits they derive from its presence as computed above. **In the case of SR Grid, which is not synchronously connected with the NEW grid, the 'benefits' shall be computed at nodes which were indicated to have higher transmission usage costs attributed to them 'without' the HVDC line (Talcher-Kolar).** When Talcher-Kolar link is disconnected**, the loads in**

the SR are reduced proportionately such that net reduction is equal to the power received from the Talcher-Kolar link. Then, new usage costs are worked out. Benefit herein is defined as old cost **(base case with injection from Talcher-Kolar**) minus new usage cost i.e. with link disconnected if any.

HVDC line can be modeled as a load with MW equal to P-order at the sending end and a generator with corresponding MW at the receiving end. A 'without' scenario for a HVDC line, corresponds to disconnecting the corresponding load-generation pair. Sensitivities for these fictitious loads and generators are not computed as they are not to be priced.

45.6.2 However, KPTCL had brought out disadvantages of With and Without method to the State in which the terminals are connected, and same was explained in the Explanatory Memorandum of the draft second amendment as under:

Quote:

1.3 Subsequently, some further difficulties were either pointed out by others or noted by the staff of the Commission. M/s LANCO pointed out that the Point of Connection (PoC) ***injection rate (in `/MW/month) for its generating station in the State of Andhra Pradesh was coming unreasonably high,*** *as the PoC injection rate was obtained by dividing the injection PoC charge of the zone by the total long-term access (LTA) of the State and LANCO was the only ISGS in Andhra Pradesh with LTA. It is observed that this would happen when a State has inter-State generating stations with small quantum of LTA connected to the 400 kV systems in any State. There is, therefore a need to remove this anomaly.* ***Further, Karnataka Power Transmission Corporation Ltd. (KPTCL) pointed out that while adopting the methodology as given in the Sharing Regulations, around 45% of the Yearly Transmission Charges (YTC) of the Talcher – Kolar HVDC bi-pole links was being booked to the State of Karnataka, whereas the allocation of power to the State from Talcher – II STPS, for which the HVDC bi-pole link was built to evacuate this power to the constituents of Southern Region, was only 18.86%.***

6.0 ISSUE OF SHARING OF TRANSMISSION CHARGES OF TALCHER-KOLAR

HVDC BI-POLAR LINK

6.1 Step 4 of para 2.7 of Annexure to the principal regulations is reproduced as below:

"Step 4: The cost of the HVDC line is then allocated to the nodes in proportion of the benefits they derive from its presence as computed above. In the case of SR Grid, which is not synchronously connected with the NEW grid, the 'benefits' shall be computed at nodes which were indicated to have higher transmission usage costs attributed to them 'without' the Talcher-Kolar HVDC line. ***When Talcher-Kolar HVDC link is disconnected, the loads in the SR are reduced proportionately such that net reduction is equal to the power received from the Talcher-Kolar link****. Then, new usage costs are worked out. Benefit herein is defined as old cost (base case with power received from Talcher–Kolar HVDC link) minus new usage cost i.e. with link disconnected. If any HVDC line can be modeled as a load with MW equal to P-order at the sending end and a generator with corresponding MW at the receiving end. A 'without' scenario for a HVDC line, corresponds to disconnecting the corresponding load-generation pair. Sensitivities for these fictitious loads and generators are not computed as they are not to be priced."*

It is observed that the transmission charges for the Talcher-Kolar HVDC line are to be borne by the constituents of the Southern Region. It is seen, however, that this method of transmission charge allocation, loads the transmission charges of Talcher-Kolar HVDC line to the extent of approximately 45% on the State of Karnataka, since this HVDC line terminates in Karnataka (Kolar). Before the Sharing Regulations came into force, the charges of ***Talcher-Kolar HVDC line were being borne by the Southern Region constituents in the ratio of the allocation of power from Central Generating Stations of the Southern Region and Eastern Region****.*

Moreover, it is seen that for transmission of power from NEW grid to SR grid, other than for evacuation of power from Talcher Stage - II generating station, there are only three HVDC links i.e., HVDC back-to-back links at Gazuwaka and Chandrapur and the Talcher-Kolar HVDC bi-polar link. For ***Gazuwaka back-to-back HVDC link and Chandrapur back-to-back HVDC link, the charges are shared in the ratio of 1:1 as*** *given in the Central Electricity Regulatory Commission (Sharing of inter-State Transmission Charges and Losses) (First Amendment) Regulations, 2011. For Talcher-Kolar HVDC line, it is mentioned that that the charges shall be shared by the DICs of SR. The same is reproduced below:*

*"The charges of the HVDC back to back inter-regional links at Chandrapur and Gazuwaka shall be included in the YTC of the **NEW grid and the SR grid in the ratio of 1:1 and charges** for Talcher–Kolar HVDC bi-pole link shall be shared by DICs of SR only."*

*6.2 The methodology for the sharing of charges of Gazuwaka back-to-back HVDC link and Chandrapur back-to-back HVDC link is to increase the YTC of the NEW grid and SR grid in 1:1. However, the **methodology for the sharing of charges of Talcher-Kolar HVDC bi pole link, as is given in the Sharing Regulations, is being done based on the difference of PoC charge between injection of Talcher Stage-II generating station at Kolar (Karnataka) end and without that injection, as provided in the Sharing Regulations.***

*In view of the above, the sharing of charges of Talcher-Kolar HVDC bi pole link should be done in the same way, as is being done for the HVDC back-to-back links at Gazuwaka and Chandrapur, i.e. by including the YTC of Talcher-Kolar HVDC bi pole link to the total YTC of SR grid. **This implies that the charges of Talcher-Kolar HVDC bi pole link shall be shared by all the DICs of the Southern Region on pro-rata basis.***

For the case of injection PoC rate of Talcher Stage-II STPS for 200 MW share of Odisha in Talcher-II STPS, this shall be as per Sharing Mechanism in the NEW grid.

*The Commission has further given thought on the issue of treating all the HVDC systems in the country. It is **observed that the cost of HVDC systems is high, but they are important from the point of view of security and reliability of the whole grid**. **All the HVDCs shall be treated/ classified as national assets and once the whole country is synchronously connected, the total YTC of all the HVDC systems shall be pooled and shared among all the beneficiaries by scaling up the YTC of the all India grid.***

Accordingly, it has been proposed to substitute Step 4 under sub-para 2 of Para 2.7 of Annexure of the Principal Regulations as under:

"Step 4: The entire YTC of the Talcher-Kolar HVDC transmission link shall be borne by the DICs of the Southern Region by scaling up their PoC charges. PoC injection charge for 200 MW allocated from Talcher–II station to the State of Odisha shall be charged at the PoC injection rate of Talcher–II station as per Sharing Mechanism in the NEW grid.

Provided that after the entire country is synchronously connected, the cost of all the HVDC systems shall be borne by all the DICs in the country by scaling up the YTC calculated without including the HVDC costs.

Unquote

After considering the comments of the stakeholders on the draft proposal, the commission decided as under:

"Step 4: The entire YTC of the Talcher - Kolar HVDC transmission link shall be borne by the DICs of the Southern Region by scaling up their PoC charges. However, the PoC injection rate for the allocated share from Talcher – II station to the State of Odisha shall be the PoC injection rate of Talcher – I station as per Sharing Mechanism in the NEW grid.

Provided that after the entire country is synchronously connected, the cost of all the HVDC systems shall be borne by all the DICs in the country by scaling up the YTC calculated without including the HVDC costs."

45.7 Though it was proposed in the draft third amendment to delete the proviso under Para 2.7 of Annexure-I, which effectively meant that "with and without method" would be adopted for calculation of HVDC charges (except for Talcher-Kolar), the Commission after keeping in view the rationale explained in the Explanatory Memorandum to the draft Second amendment and SOR to the Second amendment and the comments received from POSOCO on the draft third amendment, has decided not to go ahead with the proposed amendment. The liability for payment fo HVDC charges shall be that of the regions for which HVDC has been built.

45.8 Technical literature was referred to in this regard. It is found that there are various methods suggested for allocation of cost of HVDC system. However, as per the literature, none of the solutions is ideal which implies that methods for sharing of charges for HVDC are in evolving stage.

45.9 FERC order recognizes the concept of different cost allocation methods for different type of transmission assets as under:

"Principle 6:

Interregional Cost Allocation Principle 6: The public utility transmission providers located in neighboring transmission planning regions may choose to use a different cost allocation method for different types of interregional transmission facilities, such as transmission facilities needed for reliability, congestion relief, or to achieve Public Policy Requirements."

45.10 In India, both types of systems are there i.e. HVDC Back to back and evacuation assets. While there is broad consensus on usage of back to back HVDC for common grid benefit due to power flow in both directions, the evacuation assets were planned to cater the requirement of a particular set of users or a pair of Generator and Demand customers bound by PPA as power flow is mostly unidirectional, transmission cost allocation needs to be on a separate principle. As tariff of HVDC links cannot be allocated with marginal participation method, a separate treatment is unavoidable.

45.11 It is important to mention that such a different treatment of HVDC assets specifically set up for evacuation purpose under Regional Transmission planning system, prevailed in the past. The HVDC systems were treated in the following ways:

S No	Name of HVDC System	Methodology before PoC	Methodology After PoC (w.e.f 01.7.2011)	Methodology after 1st Amendment (25.11.2011)	Methodology after 2nd Amendment (29.3.2012)
1.	Talcher-Kolar	Sharing by SR beneficiaries including Goa in the ratio of weighted average allocation ratio of all CGSs.	With and without method.	T-K HVDC shared by all DICs of SR	Existing method By all DICs, post synchronization of SR Grid with NEW Grid by scaling up of YTC of AC lines.
2.	Rihand-Dadri	In the ratio of weighted average allocation of all CGSs by NR		With and without method.	
3.	Balia-Bhiwadi				
4.	Mundra-Mohindergarh	N/A			

HVDC Back to Back					
1.	Sasaram	100 %NR	With and without method.	With and without method.	By all DICs, post synchronization by scaling up of YTC of AC lines.
2.	Gajuwaka	100 %SR		50:50 SR-NEW	
3.	Chandrapur (Bhadravati)	50:50			
4.	Vindhyachal	50.:50		With and without method.	

***CGSs = Central Generating Stations**

45.12 It may be seen from above that prior to introducing POC in July 2011, the charges for HVDC were borne by beneficiaries for whom the asset was created.

We note that HVDC system helps in voltage control, relieving loading of intervening AC network, power oscillation damping, sub synchronous resonance damping and enhancing power transfer capability. However the benefit to other regions has not been stated by NLDC. We have decided that 10 % of YTC of the ISTS system shall be recovered through charges known as Reliability Support Charge except for capacity for which the transmission charges for any HVDC system are to be partly borne by a DIC under a PPA or any other arrangement. While HVDC Back to Back system shall be borne by all the DICs of the country, we are not inclined to distribute the cost of HVDC lines among all DICs. For allocation of remaining 90% of cost of HVDC Line, we rely on the principles for payment of HVDC historically and principle of causation (as given in FERC order 1000 in Tariff Provisions and Agreements for Interregional Transmission Coordination - page 348 – 400). In the event of better projection and appreciation of benefits of HVDC links in due course, keeping in view evolving methodologies worldwide, the Commission may consider the proposal for review of sharing of transmission charges of HVDC links. NLDC may in consultation with CEA, CTU, IITs and international consultant submit a technical report indicating various solutions for allocation of cost of HVDC system in India supported by adequate calculations.

45.13 We have also considered the view of FERC that the challenges associated with allocating the cost of transmission system appear to have become more acute as the need for transmission infrastructure has grown. FERC noted that constructing new transmission facilities requires a significant amount of capital and, therefore, a threshold consideration for any company considering investing in transmission is whether it will have a reasonable opportunity to recover its costs. It should be ensured that transmission rates are just and reasonable; the costs of jurisdictional transmission facilities must be allocated in a way that satisfies the "cost causation" principle. FERC noted that the D.C. Circuit defined the cost causation principle stating that "it has been traditionally required that all approved rates reflect to some degree the costs actually caused by the customer who must pay them. Also the cost causation principle requires that the costs allocated to a beneficiary be at least roughly commensurate with the benefits that are expected to accrue to it.

45.14 Talcher-Kolar HVDC line was specifically set up for transfer of Bulk power to Southern Region (SR) constituents. Accordingly, the beneficiaries for this HVDC are Withdrawing DICs of SR and Injecting DICs with target region as SR. However, in the present Regulations, we are providing that withdrawing DICs shall bear the injection charges for generators having beneficiaries with PPA/LTA. Hence, the charges for such HVDC will be borne by withdrawing DICs of SR and the DICs having LTA to target region (as SR). Similar logic is applicable to NR constituents for Rihand-Dadri and Balia-Bhiwadi HVDC.

45.15 Accordingly, it has been decided that 10% of YTC of these three HVDC links as discussed in para above, shall be recovered through Reliability Support Charges and the balance cost of these lines shall be borne by respective constituents in proportion to their approved withdrawal i.e. Talcher-Kolar by SR constituents and Balia-Bhiwadi and Rihand-Dadri by NR constituents. Similarly generating station which has SR or NR as target region, as the case may be, shall bear the HVDC's charges in proportion to their approved injection.

45.16 Mundra-Mohindergarh HVDC was built as dedicated line to transfer 1495 MW power to Haryana. Subsequently, it was made ISTS and M/s Adani has obligation to bear withdrawal charges of Haryana corresponding to 1495MW. Accordingly, 1495/2500 part of YTC of the HVDC line shall be borne by M/s Adani Power Ltd (APL). The remaining 1005 MW capacity can be utilized for transfer of power to any DIC in any region. Hence 1005/2500 part of YTC of the HVDC line shall be included in the PoC calculation by scaling up YTC of AC lines on all India basis. However, this arrangement will not give any right or preference to M/s APL to schedule its power on this line. The scheduling shall be done by RLDC based on system requirement. As M/S Adani Power Limited will pay transmission charges for HVDC to deliver power at Haryana periphery, and with modified approach of allocation of injection charges of Generator wherein generator would pay injection charges only for untied power, APL would not be liable to pay PoC Charges for 1495 MW, so there shall not be any double charging to APL.APL will pay MTC towards 1495 MW for Mundra-Mohidergarh HVDC as specified by Commission in the Order.

45.17 For any new HVDC line, the Commission shall decide the methodology through an order. However, the above principle of sharing of transmission charges of HVDC lines may be reviewed based on the national transmission planning, if certain HVDC systems are planned to cater to multiple needs i.e. evacuation or reliability or Renewable integration or change in the benefits derived by the stakeholders.

45.18 Accordingly, we have decided the treatment of HVDC lines as under:

"Treatment of HVDC Lines: 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 lines were specifically set up for transfer of bulk power to specific Regions, the DICs of the Region shall share the cost of HVDC lines. HVDC lines also help 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, HVDC charge shall be payable in proportion to their Approved Injection.

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, HVDC 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."

45.19 Accordingly, the cost of HVDC system (other than HVDC Back to Back systems) shall be shared as under:

a. Transmission Charges of Talcher-Kolar HVDC transmission link shall be borne by (a)Withdrawal DICs of the Southern Region in proportion to their

Approved Withdrawal and (b) Injecting DICs having LTA to target region in proportion to their Approved Injection.

b. Transmission charges of Rihand-Dadri and Balia-Bhiwadi HVDC transmission links shall be borne by (a) Withdrawal DICs of Northern Region in proportion to their Approved Withdrawal and (b) Injecting DICs having LTA to target region in proportion to their Approved Injection.

c. HVDC charges for a region shall be calculated by multiplying

[{90% of the Monthly Transmission Charges of HVDC systems} /

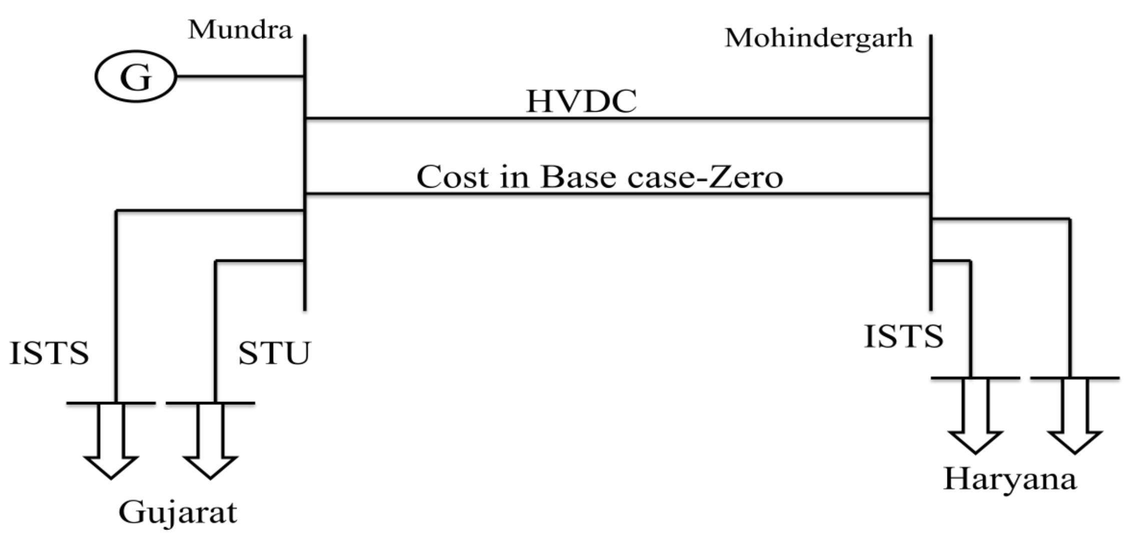
{Total Approved Withdrawal of the Withdrawal DICs and Approved Injection of the Injecting DICs having LTA to target region}]

with

Approved Withdrawal of the Withdrawal DICs or Approved Injection of the Generators having LTA to target region or additional MTOA, as the case may be.

d. Transmission charges of Mundra-Mohindergarh HVDC link shall be borne by M/s Adani Power Limited in proportion to its share for transfer of capacity to Haryana (1495/2500). Balance 1005/2500 of YTC of the link shall be borne by all the DICs in the country by scaling up of YTC of the AC system considered in PoC.

45.20 To explain the above, the schematic diagram of HVDC system of APL is given below:

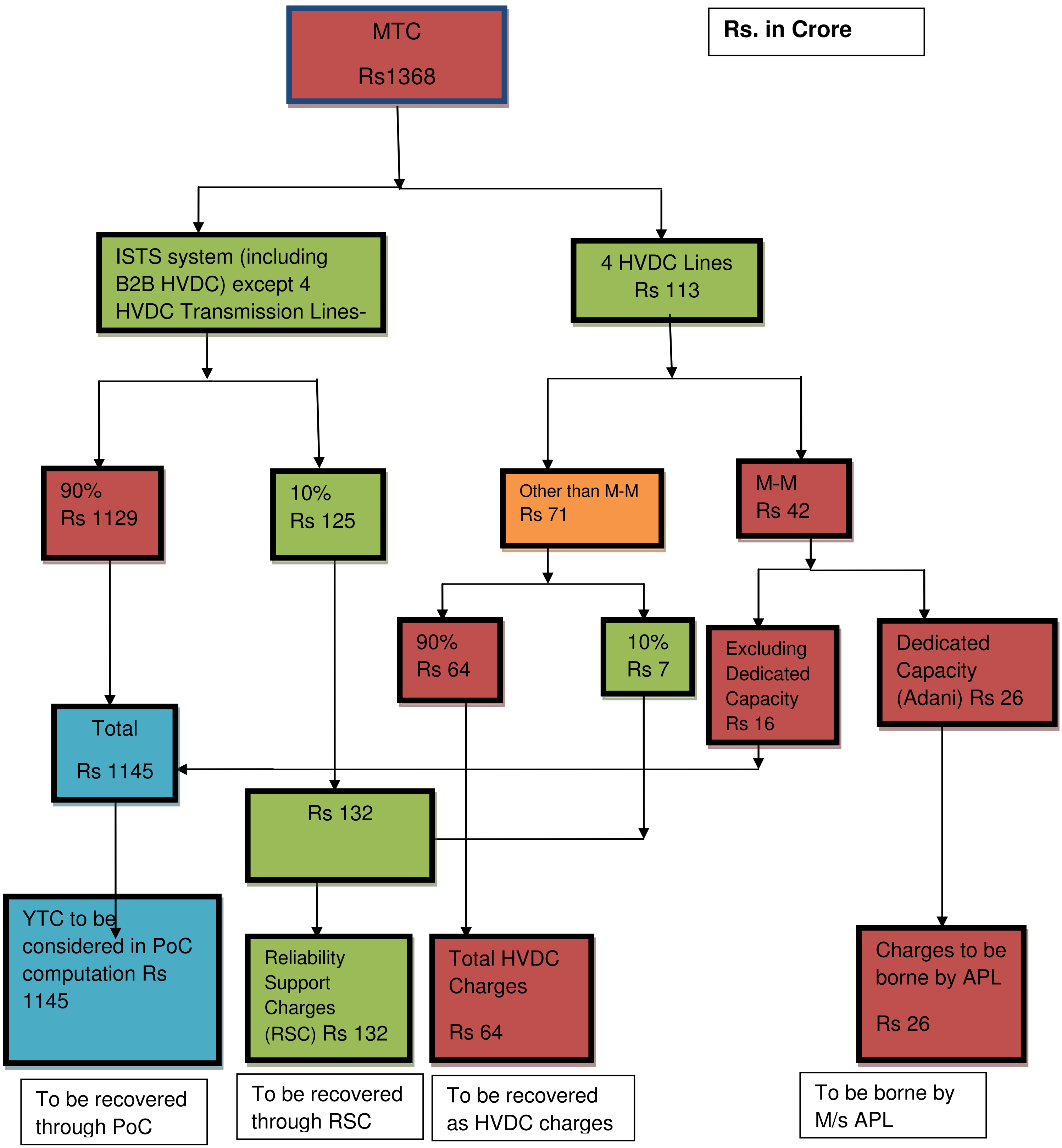


45.21 For 1495 MW of power the transmission charges are to be paid by M/s Adani Power Ltd. as per PPA with Haryana. Accordingly, 1495/2500 part of transmission charges of Mundra-Mohindergarh HVDC system donot form part of recovery through the PoC mechanism and are to be borne by M/s. APL itself. However, M/s. APL will not have any exclusive right on this transmission capacity.

45.22 Remaining part (1005/2500) of HVDC charges shall be considered in PoC and recovered through scaling up of YTC of the transmission system in the PoC calculations. It may be seen that Haryana uses this HVDC system for drawal of its power from Mundra TPS with transmission charges which are already built in the generation tariff. Accordingly LTA for this quantum shall not be considered in computation of Withdrawal PoC Rate of Haryana. Since in base case no cost of HVDC has been considered, Haryana uses the HVDC system at zero cost for receiving power from Mundra TPS, as per PPA, the injection of corresponding capacity transferred through HVDC doesn't affect charges of other DICs of other DICs as the HVDC cost considered in base case is Zero.

45.23 Cost of all HVDC B2B systems shall be borne by all the DICs in the country after deducting Reliability Support Charge as specified. The cost of these B2B systems shall be included in the PoC computation by scaling up of YTC of AC system or by including the Cost of all HVDC B2B system in the AC system A diagram on the next page will clarify the calculations.

Indicative calculation of various charges:



M-M: Mundra-Mohidnergarh

45.24 Accordingly Clause (4) of Regulation 11 of the Principal Regulations has been amended as detailed at para 34 of this SOR.

46. Sub para 12 at the end of Para 2.7of the Annexure of Principal Regulations:

46.1 Sub para 12 at the end of Para 2.7 of the Annexure of Principal Regulations was proposed to be deleted.

46.2 Comments have been dealt with at Para 27 of this SOR under regulation 7 (1) (s).

46.3 Sub para 12 at the end of Para 2.7 of the Annexure of Principal Regulations has been substituted as under:

"12. There shall be slabs for the percentage transmission losses in the All India grid till such period the Commission may consider appropriate."

47. Table under para 2.8.1 of Annexure to the Principal Regulations

47.1 The table under para 2.8.1 of Annexure to the Principal Regulations was proposed to be substituted as under:-

<table>
<tr><th></th><th>Transmission [rate] (`/month)</th><th>Approved Injection/ Approved withdrawal*(MW)</th><th>Zonal Transmission Rate (`/MW/month)</th></tr>
<tr><td>PP</td><td>45,00,000</td><td rowspan="3">250</td><td rowspan="4">70,000</td></tr>
<tr><td>AA</td><td>50,00,000</td></tr>
<tr><td>KK</td><td>80,00,000</td></tr>
<tr><td>ZZ - Zone</td><td>1,75,00,000</td><td>250</td></tr>
</table>

**Approved Injection/ Approved Withdrawal (MW) shall be the Long-term Access for the average scenario based on the CEA generation and demand data. Otherwise, or the scenarios mentioned in Regulation 7 (1) (o) of the Principal Regulations, it shall be the Approved Injection/ Approved Withdrawal.*

a. Comments have been dealt under Regulation 2(1) (c) at para 4 of this SOR. It was proposed to determine POC rates based on Approved Injection/ Approved Withdrawal considered in the base case vide the draft amendment. However we have decided to consider LTA/MTOA as Approved Injection while calculating POC rates as detailed in Regulation 2(1)(c).Accordingly para 2.8.1 of Annexure-I of the Principal Regulations has been substituted as under:

"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.

<u>ZZ - zone computation in a particular scenario:</u>

Node	*Transmission Charges*	*Approved Injection/ Withdrawal**	*Zonal Transmission Rate*
	(`/Month)	*(MW)*	*(`/MW/Month)*
PP	*45,00,000*	*250*	*70,000*
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."*

sd/- sd/- sd/-

(A S Bakshi)
Member

(A K Singhal)
Member

(G B Pradhan)
Chairperson

Annexure-I

Table 1. Main characteristics of the TSO tariffs in Europe (ENTSO-E 2010).

	Sharing of network operator charges		Price signal		Are losses included in the tariffs charged by TSOs?	Are the system services included in the tariffs charged by TSOs?
	Generation	Load	Seasonal/ time-of-day (1)	Location		
Austria	15%	85%	-	-	Yes	Through a specific component to generators
Belgium	0%	100%	xxx	-	Not included for grid>=150 kV	Tariff for ancillary services
Bosnia and Herzegovina	0%	100%	-	-	No	No
Bulgaria	0%	100%	-	-	Yes	Yes
Croatia	0%	100%	x	-	Yes	Yes
Czech Republic	0%	100%	-	-	Yes	Yes
Denmark	2-5%	95-98%	-	-	Yes	Yes
Estonia						Yes
Finland	11%	89%	x	-	Yes	Yes
France	2%	98%	-	-	Yes	Yes
Germany	0%	100%	-	-	Yes	Yes
Great Britain	27% TNUoS Tariff (2) 50% BSUoS Tariff (2)	73% TNUoS Tariff (2) 50% BSUoS Tariff (2)	xx	TNUoS - locational; BSUoS - non-locational	No, recovered in the energy market	Included in BSUoS Tariff
Greece	0% Use of system 0% Uplift charges	100% Use of system 100% Uplift charges	x	-	No, recovered in the energy market	Included in Uplift charges
Hungary	0%	100%	-	-	Yes	Tariff for ancillary services
Ireland	20%	80%	-	Generation only	No, recovered in the energy market	Yes
Italy	0%	100%	-	-	No	Yes
Latvia	0%	100%			Yes	Yes
Lithuania	0%	100%	-	-	Yes	Yes
FYROM	0%	100%	-	-	Yes	Yes
Nertherlands	0%	100%	-	-	Yes	Tariff for ancillary services
Northern Ireland	25%	75%	xxx	-	No	Tariff for ancillary services
Norway	35%	65%	xxx (via losses)	Location	Yes	Yes
Poland	0.60%	99.4%	-	-	Yes	Yes
Portugal	0%	100%	xx	-	No, included in energy price	No, included in energy price
Romania	20.69% Use of system 0% system services	79.31% Use of system 100% system services	-	6 G zones = 6 G tariff values 8 L zones = 8 L	Yes	Tariff for ancillary services
Serbia	0%	100%	x	-	Yes	Yes
Slovak Republic	0%	100%	-	-	Through a specific fee	Through a specific fee
Slovenia	0%	100%	xx	-	Yes	Tariff for ancillary services
Spain	0%	100%	xxx	-	No, included in energy price	No, included in energy price
Sweden	28%	72%	-	Location	Yes	Yes
Switzerland	0%	100%	-	-	By a separate tariff for losses	By a separate tariff for losses

(1) The "X" indicates time differentiation. With one "X", there is only one time differentiation ("daynight", "summer-winter" or another one). With two "X" (or more), there are two (or more) time differentiations.

(2) TNUoS: Transmission Network Use of System; BSUoS=Balancing Services Use of System

Annexure-II

Extracts from paper or Tom Brown (Energynautics GmbH)

Transmission Network Loading in Europe with High Share of Renewable

C. Incorporating HVDC Lines

Until now most High Voltage Direct Current (HVDC) lines have been built to connect non-synchronous AC zones and connect power systems across large bodies of water. Increasingly they are also being considered within synchronous zones. The advantages they offer include: lower losses for long distance power transport; no need for reactive power compensation along the lines; and, because they provide point-to-point controllable power transfers, loop flows through indirect routes common in AC networks can be avoided. This last point is relevant for example in Germany, where the power from high winds in the north are not transported directly to the loads in the south, but spread out on the way into the neighboring countries such as Poland, the Czech Republic, the Netherlands and Belgium. In Germany's Network Development Plan [6] three north-south HVDC corridors are currently under consideration.

Further into the future, it may be possible to build a meshed DC 'overlay' network that supplements the AC network by providing for continent-wide power transport, cf. Figure 1. The power flow equations for a meshed DC network can be linearised in a similar manner to the AC load flow equations and a DC PTDF can be built, with all the Marginal Participation allocation technology that goes with it,

The problem is that knowing how the flows in the DC network can be allocated to the DC injection nodes only gets us part of the way. If the main loads and generators are still connected to the AC network, it is not always clear which actors are making use of the DC network. For example, a north-south HVDC link in Germany could be used by Denmark to export its power to Austria or Switzerland.

HVDC lines between synchronous zones, like that between France and England or that between Germany and Sweden, can be assigned proportionally to the two countries. However, even this is not unproblematic, as will shortly be discussed. For HVDC lines inside synchronous zones it is even less straight-forward, but we have several suggestions for how to deal with this problem:

1) Ideally one would assign **each node of the DC network where power is injected to the various AC nodes that feed it with generated power and each DC node where power is withdrawn to the various AC loads that it supplies. Then it is clear who is using the DC assets. This mapping between AC and DC nodes is however non-trivial.**

2) When the line is between two countries, one can treat it the same way as for lines between synchronous zones. First, divide the flow 50-50% between the two countries. Within the country from where the flow comes, divide it among all net generating nodes according to their power; within the country, to which the power goes, divide it among all net consumers in the country. This has the disadvantage that it cannot see the usage of the HVDC line by third countries and that it does not provide a node-sharp resolution within the country. On the other hand, by reducing the allocation to the two countries where the HVDC line ends, this would probably reflect how the investment in building the line is made and how the power flows are contracted between the two parties.

3) An alternative is to look at each HVDC line separately and see which AC lines it is most directly replacing (for example by studying the change in the AC network flows with each MW dispatched through the HVDC line and identifying the lines which are most strongly affected). Then do the allocation of the HVDC line according to that of the AC lines it is replacing.

4) The simplest option is just to remove all HVDC lines that sit within synchronous zones and force the flows into the AC network, even if the AC network becomes overloaded. The allocation can then be done via the AC network. This method will give higher cross-border flows, because new loop flows will be created by removing point-to-point DC transfers.

None of these solutions is ideal; we consider a selection of options in the application section that follows.

Interlude on HVDC Lines in the Model

Before we can apply Marginal Participation to analyze the network (lows, we must decide how to allocate flows in the HVDC lines, as discussed in Section II-C.

Because of the way the network and market models were coupled, the HVDC lines were split into two categories and operated differently. Lines between countries were treated as independently operable. As can been seen from Figure 1 the overlay DC network between countries is partially meshed, so this treatment does not correspond to the load flow within a DC network which follows voltage differences, but rather treats the lines as if at each node the lines were coupled by back-to-back converters so that they are independently dispatchable. The reason this was done was to allow the optimization algorithm the possibility not to build out the lines. If the meshed DC flow had been modeled exactly, it would have had to exist in the first place with non-trivial capacity and flows in order for the optimizer to see it was there and expand it, like it does for the AC network.

In the following section the international lines between countries are modeled following suggestion 2) from II-C, i.e. according to the two countries which the lines connect. Method 3), where the allocation is copied from the AC line on which the HVDC most relieves the flow, was found to be unstable, producing too strong a reliance on the behavior of the particular AC line. Method 4), whereby the HVDC lines inside synchronous zones are simply removed and the flows are forced into the AC network, was useful in Section III-D to quantify the effects of the HVDC lines on cross-border flows.

The lines inside the countries, such as the two that connect north with south Germany, were treated in the optimization like AC lines, i.e. incorporated into the AC PTDF, where their flows were linearly proportional to the nodal balances in the model. Since their operation is similar to AC lines, the Marginal Participation algorithm works automatically. This allocation strategy more or less corresponds to suggestion 3) from Section IT-C.