Appendix-I

Comments/suggestions on Draft Amendment to Central Electricity Regulatory Commission (Sharing of Inter State Transmission Charges and Losses) (Third Amendment) Regulations, 2014

S. No.	Company/Stakeholder/Individual
1.	AD Hydro Power Limited (adhpl)
2.	Adani Power Ltd.
3.	Association of Power Producers (APP)
4.	Bihar State Power (Holding) Company Limited
5.	Bhakra Beas Management Board (BBMB)
6.	Central Electricity Authority (CEA)
7.	Central Transmission Utility (CTU),
8.	DVC
9.	GRIDCO Limited
10.	Indian Energy Exchange (IEX)
11.	Indian Wind Energy Association (IWEA)
12.	Indian Wind Power Association (IWPA)
13.	Jaiprakash Power Ventures Limited (JPVL)
14.	Lanco Kondapalli Power Limited (LKPL)
15.	MB Power (Madhya Pradesh) Ltd.
16.	Moser Baer Engineering and Constructions Ltd.
17.	NTPC Ltd.
18.	NSL Power Ltd.
19.	Power System Operation Corporation Limited (POSOCO)
20.	Sandhya Hydro Power Projects Balargha Pvt. Ltd.
21.	Shri Ravinder
22.	SN Power
23.	Steel Authority of India Limited (SAIL)
24.	Surajbari Windfarm Development Pvt. Ltd.
25.	Thermal Powertech Corporation India Ltd (thermal powertech)
26.	Torrent Power Ltd.
27.	West Bengal State Electricity Transmission Company Limited (WBSETCL)

1. Amendment in Regulation 2

1.1. Sub-clause (b) of clause (l) of Regulation 2

1.1.1. **Association of Power Producers (APP):** As desired in the third amendment, the computation of transmission charges will be based on peak usage for the period of three months. However the period of three months may not be appropriate as there may be different peak periods during these three months. For example, if during 3 months say there was a maximum peak of 20000 MW then proposed calculation for transmission charges will reflect 20000 MW for all the three months. But there would be instances where any of the months may have lower peaks than 20000 MW. Therefore, it is requested to assume peak scenarios on monthly basis.

1.1.2. **NTPC Ltd.:** Application period [2 (1) (b)] is defined as 12 months coinciding with the Financial Year and also as each quarter in Financial Year. It is submitted that that the definition of application period needs to be unique and not both a Financial Year as well as quarter.

1.1.3. **AD Hydro Power Limited:** The draft amendment proposes that:

"it means the period for application of the transmission charges determined in accordance with these regulations and shall ordinarily be 12 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."

Comments

Based on the submissions in the foregoing paras, it is stated that:

1) There is always a large variation in case of renewable sources such as ROR/Hydel, Wind, Solar or any Biomass Generation Plants (such as Baggass etc) from month to month due to variation in the availability of inputs.
2) Period of quarters as proposed in the Draft Amendment may not give a true picture to suit with the requirements of all type of generators including renewable source and non renewable sources.

Suggestions:

Instead of fixing the four quarters on financial year basis, the entire year should be divided in six blocks of two months each starting from April-May, June-July, August-September, October-November, December-January, and February-March. In this manner it will be able to take care of the issues of all type of energy generation sources which are based on renewable energy, i.e. hydro, wind and solar etc.

1.1.4. **Individual (Shri Ravinder):** Initially it was one year then it was reduced to 6 months. Now it is proposed as 3 months which means the ISTS rates would be revised 4 times in a year. Reducing it to one is neither practical nor desirable.

1.2. Sub-clause (c) along with Proviso of clause (1) of Regulation 2

1.2.1. **POSOCO:** The definition of Approved injection was modified in the 1st amendment as well as the 2nd amendment. The definition assumes significance in view of the fact that DICs are to be billed based on this amount. Accordingly, this amount has to be sacrosanct and not subject to any dispute. As per draft Regulations, it is the maximum injection in MW computed based on injection during peak period of corresponding application period of last year. The following possibilities exist in this regard:

1) One or more units may be under shutdown during last year / there was no generation during last year due to natural calamity etc.
2) The generator could have generated more during off-peak than peak hours
3) New units could have been commissioned
4) Commissioning of new lines / transformers could have facilitated full evacuation of power from the station
5) The draft Regulations propose to charge intra-state entities also for injection, where SEM readings may not be available and it would be difficult to compute maximum injection during peak period.

It is suggested that in case of regional entities, installed capacity including overload capacity, less auxiliary consumption or Long Term Access, whichever is higher may be considered. In case of intra-state entities, LTA / MTOA quantum may only be considered as approved injection.

1.2.2. **Central Electricity Authority (CEA):** The transmission charges payable are equal to approved injection/withdrawal multiplied by the nodal/zonal PoC rate. In this regard, the tariff policy mandates that transmission charges may be payable on usage basis. Therefore, CERC has suggested for calculating transmission charges based on the maximum actual usage of the ISTS during a quarter. This maximum injection/withdrawal may be more than or less than the 'LTA+MTOA' quantum. If the ISTS Customers (DICs) are using ISTS for injecting more than 'LTA+MTOA' /approved quantum, they must be charged accordingly, however, if they are using less than 'LTA+MTOA' /approved quantum they must be charged at least for the 'LTA+MTOA' /approved quantum for which the system has been made available for use by them. However, it is observed that this may result in total collection which may be more than the Monthly Transmission Charges

(MTC). In this respect, it is proposed that the Commission may consider normalization of the total transmission charges payable by each DIC so as to match the total MTC required to be recovered. A sample calculation in this regard is given in following table:

		Injectors				Drawees			
	Node/Zone/DIC	**A**	**B**	**C**	**D**	**E**	**F**	**G**	Total
1	Approved Injection/Withdrawal (LTA+MTOA) as taken for calculation of PoC rates, MW	500	1200	1600	1700	1500	1000	2500	
2	PoC rate as calculated for the Quarter, Rs**(Lakh)**/MW/Month	0.80	2.00	0.40	1.20	1.20	0.60	2.00	
3	Total collection as per PoC calculations, Rs**(Lakh)**/Month	400	2400	640	2040	1800	600	5000	12880
4	Approved Injection/ Withdrawl(LTA+MTOA etc) **or** actual Withdrawl/Injection, whichever is higher in a month, MW	800	1200	1800	2200	1600	1400	3000	
5	Total collection as per Maximum of Approved/ Actual Injection/ Withdrawal, Rs**(Lakh)**/Month	640	2400	720	2640	1920	840	6000	15160
6	Total Collection **after normalization**, Rs**(Lakh)**/Month	544	2039	612	2243	1631	714	5098	12880

1.2.3. **NTPC Ltd.:** Approved injection [2 (1) (c)] may be defined and treated as the maximum injection as per the amended regulation but should not be used to realize charges if the actual injection is less than the approved injection as provided in Amendment of regulation 8 (5) reproduced below:

"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."

Further, the definition [2(1) (c)] includes a prescription that approved injection shall be determined on the basis of generation data submitted by the Designated ISTS Customers incorporating total injection into the grid**.** Injection by a generating station is determined by the requisition by the beneficiaries aggregated and issued as SG by the RLDC. Generating stations have no say in the matter. In view of the above, it is submitted that the requirement of injection data by the generator may be removed.

1.2.4. **Central Transmission Utility (CTU):** The implication of above change in definition of Approved Injection is understood as below:

1) The injecting entities shall be levied injection charge, plus the proportional withdrawal in case entity has LTA based on target regions, based on either (i) maximum injection in the same quarter during last year or (ii) the modified injection amount given by entity with supporting justification and accepted by the validation committee. This shall inter-alia mean that entity shall be charged for the maximum power it has/shall be injecting with disregard to the quantum for which LTA has been availed by the entity.
2) The proposed amendment shall in turn mean levy of transmission charges be based on actual usage rather than on the basis of commitment made while availing LTA. This may give rise following situation:
   a. If some generator had availed LTA for 1800 MW from its 3x660 MW plant. It has commissioned all the three units but, due to fuel shortage etc. generates peak power of 500 MW from only one unit during all the four quarters. Then in the next years' computation he shall give injection as 500 MW with valid justification. Then he shall be charged for Approved injection of 500 MW with dis-regard to fact that LTA has been availed for 1800 MW and the system has also been constructed for 1800 MW.
   b. The situation shall be more difficult if due to later development of lack of coal availability entity has commissioned only one unit. Then again for reason mentioned above he shall be charged for Approved injection of 500 MW.
   c. The situation is absolutely difficult if entity has not commissioned any unit at all. Then again for reason mentioned above his Approved injection shall be zero with dis-regard to fact that under LTA entity had got built transmission system for 1800 MW.
3) The proposed amendment has merit in the sense that the provision shall ensure levy of charges from those entities who had used the system and not the basis of deemed usage. Levy of charges from entities that had not been able to use the system due to lack of generation shall always be resisted leading to defaults. Never-the-less, complete disregard to the commitment shall prompt the new IPPs to seek LTAs for any amount with complete disregard to the actual likelihood of generation project plan.
4) Due to criticality of the issue Hon'ble Commission may like to suitably address these in Statement of Reasons of Regulation to avoid mis-interpretations and disputes at a later date.

1.2.5. **Thermal Powertech:** Present mechanism: Transmission charges to be paid by DICs based on LTA, it is resulting in conservative LTA declaration from new IPPs and if it is continued to be done on the basis of LTA, may lead to poor transmission planning due to which we may see the congestion in future.

It is appreciable initiation from the Hon'ble Commission that transmission charges shall be calculated based on the peak injection instead of LTA. It helps in capturing the DICs whose actual utilization is more compare to LTA granted. (Transmission charges determination based on the peak injection will make sure that all DICs to take LTA for full quantum otherwise also charges will be levied based on the peak injection). Further, it is relief for IPPs, who taken LTA for full quantum and actual access is less with the grid due to various issues. (DICs having LTA for X quantum and accessing less than X with grid will be billed for actual access. Hence, it will not be burdensome the DIC as billing is going to be for actual utilization).

Hence, this will bring confidence over the transmission tariff mechanism also encourages all IPPs to take LTA for quantum. These are the initiative steps towards General Network Access (GNA).
It is understood that 3rd amendment is proposed to capture the DIC's, who have declared conservative LTA and actual utilization is more than LTA. It is a very good initiative from Honorable Commission to charge for the actual utilization.

However, we request Honorable commission to give clear mandate to 0/Cs in levy of transmission charges and it shall be based on the peak injection even though DIC LTA > peak injection, but not on LTA (Ambiguity in Regulation 11).

1) Some of the IPPs who are granted LTA for full quantum, but due to unavailability of PPA, fuel etc. their peak injection are less than LTA quantum. In these conditions, levy of transmission charges shall be on peak injection/actual injection only, which were not clearly mentioned in the regulation 11.

2) Illustrative: Say LTA granted for an IPP is 1320 MW without identified beneficiaries and total injection considering all the contracts is only 1000 MW which is less than LTA of 1320MW. In this condition peak injection is only 1000MW and billing of Transmission charges shall be limited to 1000MW only, which reflects the actual utilization of the Transmission system.

1.2.6. **AD Hydro Power Limited:**

RoR/hydel plants are mostly seasoned based plants and are able to inject the maximum load i.e. installed capacity plus designed overload. This period is generally a summer/monsoon period which is June to September which means as per concept of the proposed sharing Regulations i.e. peak injection during a quarter, the transmission charges shall be based on injection during the quarter of April to June based on the injection in the months of April to May is comparatively insignificant.

Due to division of the entire financial year in four quarter as proposed in the draft amendment, RoR/hydel plants will always be under compulsion to pay higher transmission charges during the quarter of April to June because generation during June will always be high which is installed capacity plus designed overload whereas in the month of April and May, these plants hardly reach their installed capacity.

Further, RoR/hydel plants are generally able to provide the peak power due to pondage facility available with them for a fixed duration which is approx 3-4 hours. This peak power will always be near to their installed capacity which means even during the lean season these plants shall have to pay the transmission charges for the entire quarter based on their peaking capacity which is not more than 3-4 hours duration.

In view of this, a RoR/Hydel Plant with the peaking facility will always be under prejudice and shall be required to pay the maximum transmission charges round the year despite the plant load factor of less than 50%.

Suggestions:

1) The transmission charges should be based on the energy injected in terms of Rupees per MWh or
2) A mechanism is required to evolve and incorporated to factor-in the difference in the plant load factor for such a large variation in generation due to this.

1.2.7. **Lanco Kondapalli Power Limited (LKPL):** In proposed Amendment as Approved injection is 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 or 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 Customer incorporating total injection into the grid.: If LTA has already been granted to a DICs for a target region without identified beneficiary for the purpose of grant of connectivity and that DICs max injection during corresponding application period of last year or determined on basis of generation data is less than LTA quantum then Approved injection must be computed based on actual usage or actual injection not considering LTA figure.

1.3. <u>Sub-clause (f) along with Proviso of clause (1) of Regulation 2</u>

1.3.1. **CEA:** The transmission charges payable are equal to approved injection/withdrawal multiplied by the nodal/zonal PoC rate. In this regard, the tariff policy mandates that transmission charges may be payable on usage basis. Therefore, CERC has suggested for calculating transmission charges based on the maximum actual usage of the ISTS during a quarter. This maximum injection/withdrawal may be more than or less than the 'LTA+MTOA' quantum. If the ISTS Customers (DICs) are using ISTS for injecting more than 'LTA+MTOA' /approved quantum, they must be charged accordingly, however, if they are using less than 'LTA+MTOA' /approved quantum they must be charged at least for the 'LTA+MTOA' /approved quantum for which the system has been made available for use by them. However, it is observed that this may result in total collection which may be more than the Monthly Transmission Charges (MTC). In this respect, it is proposed that the Commission may consider normalization of the total transmission charges payable by each DIC so as to match the total MTC required to be recovered. A sample calculation in this regard is given in following table:

		Injectors				**Drawaees**			
	Node/Zone/DIC	**A**	**B**	**C**	**D**	**E**	**F**	**G**	Total
1	Approved Injection/Withdrawal (LTA+MTOA) as taken for calculation of PoC rates, MW	500	1200	1600	1700	1500	1000	2500	
2	PoC rate as calculated for the Quarter, Rs**(Lakh)**/MW/Month	0.80	2.00	0.40	1.20	1.20	0.60	2.00	
3	Total collection as per PoC calculations, Rs**(Lakh)**/Month	400	2400	640	2040	1800	600	5000	12880
4	Approved Injection/ Withdrawl(LTA+MTOA etc) **<u>or</u>** actual Withdrawl/Injection, whichever is higher in a month, MW	800	1200	1800	2200	1600	1400	3000	
5	Total collection as per Maximum of Approved/ Actual Injection/ Withdrawal, Rs**(Lakh)**/Month	640	2400	720	2640	1920	840	6000	15160
6	Total Collection **after normalization**, Rs**(Lakh)**/Month	544	2039	612	2243	1631	714	5098	12880

1.3.2. **DVC:** In the third amendment of Sharing of Inter State Transmission Charges and Losses Regulation, DICs are asked to provide "Approved withdrawal" which is simultaneous peak withdrawal in MW. It is very difficult to forecast maximum peak of "Approved withdrawal" on projection basis. There may be some reasons not controllable by DIC e.g. low schedule, schedule low demand due to technical snag etc. Since DIC has to depend on the historical data based on actual peak during corresponding application period of last year, the deviation charge based on projected figure either may be withdrawn if it is beyond the control of DIC or suitable permissible variation along with range with specified rate of deviation charge may be considered.

1.3.3. **POSOCO:** Similar to Approved Injection, the definition of Approved Withdrawal is also proposed to be changed and it would be based on peak drawl during same period of last year and data submitted by the DICs. However, factors like long outage of major intra-state generating unit, normal / scanty rainfall, availability of peak power at right price, commissioning of new units or lines / transformers, withdrawal of rotational load-shedding etc. would have substantial impact on the quantum of approved withdrawal. Further utilities trying to meet own consumer load during peak hours would be in a disadvantageous position vis-à-vis utilities resorting to load-shedding. In case of some of the utilities, peak drawl may be less than LTA quantum. Moreover, transmission charges cannot be levied on a quantum, which is subject to change depending on justification furnished by the DIC.

It is suggested that Approved Withdrawal may be considered as LTA+MTOA, which are sacrosanct or peak drawl, whichever is higher. In any case, for additional drawl, STOA charges or deviation charges would have to be paid.

1.3.4. **Central Transmission Utility:** The suggested definition for approved withdrawal is as below:

Approved Withdrawal shall mean peak withdrawal of each demand DlCs to be considered for computation of POC and sharing of transmission charges. This figure shall be as validated for each DICs by Validation Committee and shall be based on (i) actual peak during corresponding application period of last year and (ii) demand data submitted by Designated ISTS Customers.

1.3.5. **GRIDCO Ltd**.: Maximum withdrawal vis-a-vis LTA Dy different DICs (States/ STs) is enclosed at Annexure-t and exhibit-I. The maximum drawal figure shown for Odisha is 1955 vis-s-vis the LTA approved quantum of 1165 is completely false and erroneous. GRIDCO have never *exceeded its* drawal quantum from its LTA. If it is so the date and time on which GRIDCO have drawn the excess quantum may be specified.

1.3.6. **Lanco Kondapalli Power Limited (LKPL):** With reference to the above said comment when Approved injection is to be computed on the actual usage or actual injection not considering LTA figure, Approved withdrawal for those DICs must be computed in line with the Approved injection.

1.4. Sub-clause (I) of clause (1) of Regulations 2

1.4.1. **Central Transmission Utility:** The amendments have suggested a change in definition of DIC and the process of its working. In this regard, the following is to be stated:

It may be mentioned that the revenue streams are with the DISCOMs, and the STU shall depend upon the respective DISCOMs for collection and payment of POC charges to CTU. Payment of POC charges by STU shall create uncertainty in the revenue realization by the CTU. Also the new proposed definition in the amendments may give rise to issues regarding Regulation of Power Supply in the event of non-payment.

The collection of transmission charges is a very tedious process requiring a lot of follow up and persuasion starting from lowest level up to the highest level in a State/constituent. The pain to collect the dues shall never be felt by such agencies like STUs as there will be no pressure or urgency to collect the dues from DISCOMs on CTU's behalf. Further. There will be conflict of interest as DISCOMs and STUs are under the same holding company in many states, which may cause hindrance / interference in collection of the dues.

Therefore, we apprehend that the proposed procedure would lead to serious bottleneck and all the ISTS Licensees including POWERGRID will be sick in no time. Further, there is already a problem on account of TDS, since POWERGRID is collecting for ISTS licensee as per present practice. Therefore, with increase in one more level of in the collection channel there will be a serious Tax issue if the proposed method is followed. **In view of above, definition of DIC may be retained as per the Principal Regulations and amendment.**

Further, we are facing lot of difficulties in getting consent from Generators while carrying out the regulation of power supply to the defaulting entities. This is mainly because Generators do not want to go to market to sell the power. This problem shall be further pronounced with introduction of PLF in place of PAF for incentive purposes. It is therefore proposed that selection of Generator for carrying out Regulation of power supply should rest with RLDCs.

Towards the methodology for payment, following is proposed:

1) A Methodology should be given by CERC in its SOR regarding collection of such payments and disbursement from every DISCOM (or embedded customer) for ISTS usage and STU network usage by giving examples of Delhi (meshed network, 4 DISCOMs), UP(Large state,5 DISCOMs).

2) Payment securitization is of prime concern. CERC must provide for secured payment mechanism to be strictly adhered to by all paying entities. The transmission is a common carrier of Electricity. It is proposed that provision be made in the Regulations for priority in payment for transmission services over other payments and in case of default in payment for more than three months its power should not be scheduled as has been provided in the Central Electricity Regulatory Commission (Open Access in inter-State Transmission) Regulations, 2008, as follows:

"25A. When so directed by the Commission, the National Load Despatch Centre or the Regional Load Despatch Centre, as the case may be, shall not grant short-term open access to the entities and associates of such entities, who consistently and willfully default in payment of Unscheduled Interchange charges, transmission charges, reactive energy charges, congestion charges and fee and charges for National Load Despatch Centre or Regional Load Despatch Centre including the charges for the Unified Load Despatch and Communication Scheme ."

1.4.2. **Association of Power Producers (APP):** The proposed amendment makes a provision for the concerned STL; "who may make interim arrangement". This being the Regulation, it should be a clear direction and the margin of "may" and "interim" should not be left.

In some of the ATE judgments, such provisions had been interpreted in different way that the word "may" does not make it mandatory. Since STU is being made responsible to bear the liability of injection payment or withdrawal payment for intra-State entities, STU should have full authority to recover the same from the concerned intra-State entity.

1.4.3. **WBSETCL's Comments / Suggestions**

It is clear that the users of ISTS elements / segments have to pay Transmission Charge and this has been in place even before the CERC (Sharing of ISTS charges & Losses) Regulation 2010, through several Agreements like BPTA etc which are still valid.To satisfy those Agreements, there were several Financial Arrangements (LC etc.) to take care of the obligations of CTU and DISCOMs / ISTS users.

Now STUs are formed basically to maintain intra-State Network and no way related to ISTS payment mechanism. As the tariff and business of STU are under purview of SERCs, hence entering into vis-à-vis payment security mechanism (opening LC etc.) will increase further complications. Under these scenarios we feel that the proposed definition of DIC in draft 3rd amendment will bring complicacy and the existing definition may be retained.

1.4.4. **Steel Authority of India Limited:** Captive generators and captive consumers who have constructed their own dedicated lines, not using any intra or inter-state transmission systems, captive use in close proximity of the captive power plant, notwithstanding the way the captive user is connected to the state utility with certain contract demand, shall not be considered as a DIC.

1.4.5. **AD Hydro Power Limited:**

1) It is not clear that embedded customer and Intra State Entity are same or different specially in case of generating projects (ROR/Hydel or any other source) which have been allotted to sell their entire power in interstate.
2) In case they are same, the Intra State/embedded customer shall be falling within the scope of DICs who are connected to ISTS through STU without a dedicated/ /identified/point to point transmission system.
3) It will be a non practical scenario that after classifying the Intra State/embedded entity as DICs, their charges will be collected by STU. This will lead to mixing up of the intrastate and interstate issues and will affect the operation and sale of power by the embedded customer/Intra State entities in the Inter-state as was experienced by our Parent Company MPCL in case of Malana Hydro Electric Project (86 MW) during the UI regime wherein the HPSEB enforced various non practical and non tenable conditions for sale of power in the Interstate whereas the Government had actually allotted this Project for sale of power in the Inter-state only.
4) It is also not practical to allow STU to make their own interim arrangement for collection of charges.
5) Further, in case if a Generator, who has been allotted a project to sell the entire power in interstate and is connected to State Utility and are selling the power on Short Term Basis, will they be treated as DICs?

Suggestions:

It is suggested that the generating Facilities, who have been planned to sell their power in interstate only, their energy accounting and collection of charges may be directly handled by CTU as is being done in case of direct customers.

1.5. Sub-clause (u) and (v) of clause (1) of Regulation 2

1.5.1. **CEA:** We agree with proposal given in draft regulation for dispensing with uniform charges as given in the explanatory memorandum. This will be in accordance with basic philosophy of sharing in conformity with the basic principle of sharing regulations i.e. transmission charges allocation should be sensitive to distance, direction and usage.

1.5.2. **Thermal Powertech:** It is a welcome step to dispense off with the uniform charges method of calculating transmission charges as the Uniform charge method was not accounting for commensurate usage of transmission system. It overlooked or undermined the aspects of sharing of transmission on account of direction, location and load factors and therefore the allocation of transmission charges was not equitable.

Though it seems logical to do away with uniform charges mechanism and use only PoC mechanism but real impact in terms of absolute numbers fot Each DIC may be studied in terms of Estimated/determined Load Flows and the actual transmission charges may be computed and placed on the public domain before final amendment is done. Sudden shock of drastic changes may be avoided as was being considered in the earlier amendments.

1.5.3. **SN Power:** SN Power supports Commission's proposal to do away with the charging for transmission system based on uniform charges which socializes all costs. It is requested that the Commission may consider a market based system with auctioning/trading of transmission capacity along with pricing based on actual usage.

1.5.4. **GRIDCO:** Removal of Uniform charges sharing mechanism is a welcome proposal. But the same should be made effective from 1.7.2011 i.e. retrospectively.

1.5.5. **Bihar State Power (Holding) Company Limited:** Bihar having allocation of power from CSGS in ER only, the uniform charge mechanism applicable prior to implementation of PoC was beneficial as it was liable to pay transmission charges for the regional assets only which were used by Bihar. Further, considering the decision of the PERC as guiding principle for regional and inter-regional cost allocation for the transmission assets within the planning region in which that transmission facility is located, in a manner that is at least roughly commensurate with estimated benefit from those facilities.

Let us consider an example of the transmission schemes and their commensurate estimated benefit e.g new transmission scheme i.e. 400 KV Quad moose D/c Manan - Kishanganj transmission line, 400 KV quad moose D/c Manan - Rangpo, 400 KV quad moose D/c Rangpo - Kishanganj and ± 800 KV Kishanganj - Agra line is under construction stage for evacuation of surplus power from upcoming Sikkim HEP i.e. Testa-Ill (1200 MW), Teesta -VI (510 MW), Panan (280 MW), Sada Mangder (71 MW), Rangit-TU (60 MW) etc. Similarly, 400 KV D/c Patna - Balia (UP) - Mau (Raj), 400 KV D/c Barh - Balia (UP) - Bhiwatidi (Raj), 765 KV Tilaiya - Balia - Lucknow, ± 800 KV HVDC Bipole Angul (orissa) - Aligarh (UP) transmission lines, 400 KV quad D/c Purna (PG) - Gokarna - Rajarhat - Bangladesh etc. The above mentioned transmission schemes supply surplus power from NER & ER to beneficiaries outside ER and as such is beneficial for other regions & for the States within the region having surplus power to export.

Hence, the above said transmission schemes, in no manner provides any benefit to Bihar in spite Bihar has to pay transmission charges for above said assets without using those facility as pet extant PoC methodology.

1.5.6. **POSOCO:** The draft Regulations proposes to dispense with uniform charge component. Though review of uniform charge has been specified in the principal regulations, it could have been reduced to 25% instead of removing it altogether. An exercise had been carried out at NLDC on impact of change in uniform charge component from 50% to 25% and submitted to the Hon'ble Commission (letter included as Annexure to the Explanatory Memorandum). 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. It may relevant to mention here that 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.

It is suggested that uniform charge may be reduced to 25% and it may be renamed as "reliability charge."

1.6. <u>Sub-clause (w) of clause (1) of Regulation 2</u>

1.6.1. **GRIDCO:** Removal of Uniform charges sharing mechanism is a welcome proposal. But the same should be made effective from 1.7.2011 i.e. retrospectively.

1.7. <u>Sub-clause (x) of clause (1) of Regulation 2</u>

1.7.1. **POSOCO:** The draft Regulations proposes to dispense with uniform charge component. Though review of uniform charge has been specified in the principal regulations, it could have been reduced to 25% instead of removing it altogether. An exercise had been carried out at NLDC on impact of change in uniform charge component from 50% to 25% and submitted to the Hon'ble Commission (letter included as Annexure to the Explanatory Memorandum). 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. It may relevant to mention here that 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.

It is suggested that uniform charge may be reduced to 25% and it may be renamed as "reliability charge."

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

1.8.1. **Bhakra Beas Management Board (BBMB):** In case separate line wise capital cost is not available for non-ISTS lines being used for carrying ISTS power, then average YTC of the similar lines of the ISTS, proportionate to actual usage, may be reimbursed to the concerned STU instead of only proportionate O&M charges, as Transmission lines whether old or new renders similar service.

1.8.2. **POSOCO (Intra-state entities using ISTS):** There are a number of cases where intra-state generators use ISTS and vice versa. In the draft regulations, it has been proposed that the intra-state entities using ISTS shall also be considered as DIC for their injection payment liability. Many of the intra-state generators use ISTS to some extent or other, and as the proposal, all these generators would be required to pay ISTS charges. However, the quantum on which they are to be charged would always be subject to dispute. It is suggested that in case of intra-state entities, LTA / MTOA quantum only may be considered as approved injection.

Usage of Intra-state lines:

It has been proposed that for intra-state lines, tariff proportionate to actual usage shall be reimbursed. Such a formulation will lead to disputes as there are a number of assumptions in the base case. *It is suggested that full tariff of intra-state lines may be considered, wherever the same is certified by RPC.*

1.8.3. **Central Transmission Utility:**

In the earlier notification the YTC for all ISTS licensees and non-ISTS lines , the YTC was to be considered only as determined or adopted by Appropriate Commission. This meant that the YTC for CTU / ISTS licenses lines or STUs lines used as ISTS shall be considered only when appropriate commission has adopted / determined the same.

However, in the present draft there is relaxation granted for STUs lines used as ISTS power transfer by considering the YTC even without such tariff determination/adoption by the appropriate commission. The draft provision stipulates that YTC for STU lines (used as ISTS) may be considered as average YTC of similar ISTS in absence of any order by appropriate commission. In practices, at times it is found that in case of CTU lines, a number of assets are projected to be commissioned during PoC period but their YTC could not be captured in PoC calculations in absence of any tariff order by CERC. Since, the PoC calculation is now on quarterly basis and the number of assets to be commissioned is large in number, this situation is likely to arise frequently.

It is therefore proposed that in order to remove the disparity and adopt an nondiscriminatory approach, the YTC of ISTS lines of CTU/ISTS licensees shall also be captured based on the principal of average YTC of similar of ISTS transmission elements whenever such situations arise. The Hon'ble Commission may authorize Implementation Agency to recommend the same to Validation Committee for inclusion of the same. This will avoid knee-jerk adjustments in billing and collection shall be more near to the actual.

1.8.4. **Bihar State Power (Holding) Company Limited:**

As regard to provision 2 (1) (y) of the draft Regulations, it is submitted that Separate Line wise capital cost in case of non ISTS lines of the intra-state transmission utility may not be available. It is therefore 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 able to recover cost and equity invested in the said transmission assets.

1.8.5. **AD Hydro Power Limited:** The draft amendment proposes to add following at the end of the Sub-clause (y) of clause 1 of Regulation 2 i.e. Yearly Transmission Charges.

"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, 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."

Comments:

1) The proposed draft amendment read along with the Sr. No. 10 of the explanatory note infers that in case of use of Intra-state network, these States shall be compensated for proportional uses of the State network to carry the inter-state power which is subject to a maximum of ARR as approved by the State Commission based on ratio of different voltage level and circuit km.

2) It is submitted that 86 MW Malana HEP, by virtue of the Implementation Agreement signed with the State government and Wheeling Agreement signed with HPSEB, has been selling the entire power in the inter-state. The plant is connected to HPSEB sub-station where entire power is injected and the said power loss royalty and losses is deemed to have been delivered at interstate point to MPCL/its customers. There is no identified corridor in the State which is actually used for transmission of power generated by Malana HEP from the point of injection onward within the State. As per the wheeling agreement signed, Malana HEP is also required to pay the wheeling charges to HPSEBL.

3) It is noted that the draft amendment/explanatory notes do not clarify the situation where only point of injection within the State is known to us but actual length of the State System used for flow of power generated for interstate is not known.

4) **Suggestions:** It is suggested that:-

   i) In case of wheeling of interstate power through a wheeling agreement with the State Utility, the State Utility may be asked to freeze the transmission element to arrive at the actual charges required to be shared for use of state system for interstate purposes.
   ii) Wherever the charges are being paid to the State Utilities from the Inter State Pool as per the ARR, the State Utilities may be asked to adjust the same from the amount payable by the Generator in terms of the Wheeling Agreement/Transmission Agreement signed with the State Utility.

1.8.6. **Steel Authority of India_Limited:** 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.

1.8.7. **GRIDCO:** The amendment proposal to the Para 7(2) envisages that the yearly Transmission charges shaft be calculated for each Transmission Licensee based on indicative cost level provided by the CTU for different voltage levels and conductor configuration, it is proposed that actual line cost for the Transmission lines whose tariff are available should be considered instead of indicative cost

The lines whose tariff are not available or could not be determined due to some reason, the indicative cost- concepts should be utilized

2. Amendment in Regulation 3

2.1. Sub-clause (b) of Regulation 3

No Comments received from Stakeholders

3. Amendment in Regulation 7

3.1. Sub-clause (d) and Sub-clause (e) of clause (1) of Regulation 7

3.1.1. **CEA:** In the existing regulations, the PoC rates are determined using average load demand scenario on quarterly basis. This average load is determined taking energy consumed during the quarter in the previous year and an appropriate growth for the current year. In the new amendment, it is proposed to determine the PoC rates based on peak load scenario for the quarter under consideration. It is understood that, the load demand of each State will be taken as was at the instant of all-India peak that arrived in the same quarter in the previous year and an appropriate growth factor to take care of the yearly growth in load demand. In this regard, we have following suggestions:

1) We agree with the proposal to take peak load for calculation of PoC rates instead of the average rate. However, as the peak load achieved in some States during a particular quarter may not coincide with the all India peak, therefore, the load demand of such States corresponding to the instant of all-India peak load, would not reflect the demand of the State. In fact because of diversity, only a few States may be peaking at the instant of all-India peak.
2) In this regard, it is worthwhile to note that any base case scenario assumed for calculation of PoC rates would only be a projected theoretical load flow case and which may not happen in any day of the quarter. However, the base load flow case should reflect injections and withdrawals corresponding to 'LTA/allocations+MTOA' quantum which were basis of investment into the transmission system. It is essentially this investment which is required to be recovered from ISTS customers (DICs).
3) Therefore, while constructing the base load flow case corresponding to the quarterly peak scenario for calculating PoC rates, following principles may be adopted:

i) It is suggested that peak load of each State arrived during the same quarter in previous year may be summed up and normalized with the projected all-India peak of the quarter under consideration for the current year.

ii) The net injection of each State from ISTS (i.e. Load – self generation) may be taken equal to its 'LTA/allocations+MTOA' quantum. The auxiliary consumptions if any may be considered as per norms.

iii) The ISGS generators having long term PPAs/allocations or MTOA may be dispatched as above.

iv) The generators who have target beneficiaries, and do not have an operative MTOA in the said quarter may be dispatched as proposed in draft i.e. the maximum dispatch happened in same quarter previous year or the proposed maximum dispatch for the quarter under consideration. This would then become approved injection for such generators.

v) Because of 'd' above, the sum of total ISGS dispatches may be more than the sum of total withdrawal over ISTS. The dispatches for ISGS may be proportionately reduced to match sum of total withdrawal over ISTS.

3.1.2. **POSOCO**: In view of non-availability of node-wise peak and off-peak data average scenario based on data available at CEA website was considered. However, the same was fully not capturing peak usage of the transmission system and hence the proposal to consider peak case instead of average is welcome. At present average case is prepared based on energy generation / consumption data available at CEA website. If peak case is considered, source of data and methodology to be followed to arrive at the basic network may be specified clearly in the Regulations. The peak demands figures available at CEA website are one-time peak achieved during the month and may not correctly represent the real scenario. Similarly, though injection figures in respect of ISGS may be calculated based on SEM data, it would be difficult to arrive at correct figures in case of intra-state generators. Hence, the method to arrive at injection / drawl to be considered in peak case may be clearly specified in the Regulations instead of leaving it to subjective assessment.

3.1.3. **Central Transmission Utility:** A new generation (materializing in the ISTS network as a DIC) shall before-hand indicate its Generation dispatch to the NLDC so that the same may be considered in the procedure.

3.1.4. **Bihar State Power (Holding) Company Limited:** In the principal regulations of the Ld. CERC, Load flow profile is set for average loading which results into high injection charges which are ultimately borne by the constituents as per the share allocation. In the instant draft regulation Ld. CERC has now proposed Approved Injection by the generator & Approved Withdrawal by DICs on the basis of peak injection & peak withdrawal based on actual peak during corresponding application period of last year validated by Implemented Agency for any Designated ISTS customer.

It is relevant to mention that significant fluctuation in generation & demand of power has been witnessed during peak and off peak conditions. It is also imperative to point out that hydel generation start to decrease w.e.f. mid October and operate during peak hours only that too on reduced generation up to April and full generation from hydel power stations are available only during peak monsoon period on RTC basis. It is also difficult to predict rightly about the good monsoon owing to significant climatic change being witnessed since last few years.

Hence, if the Load flow profile if set on the basis of maximum injection & maximum demand may cause high Injection & Withdrawal PoC charges which are ultimately borne by the DICs (DISCOMs) as per the share allocation and ultimately by the end consumers. It may not be out of place to mention that good monsoon period is also linked with considerable decline in demand of power which also compels the DICs to surrender power owing to poor demand. Since, surrender of power comes into effect in the schedule after four 15 minute time block, wastage of power offered for surrender to RLDC either at zero price or lesser price wider UI between the intervening period and mandatory payment of Capacity charges of the quantum of power surrendered, all these factors causes severe financial shock to DICs. As regard to para 7 (1) (d) of the draft regulation, BSP(H)CL suggest that Point of Connection Charges shall be determined based on peak & off peak scenario separately in view of the variation of demand.

3.1.5. **SN Power:** The proposed amendment to allocate charges based on peak injection/withdrawal should be coupled with the right to trade transmission capacity. While it is considered fair to charge for transmission based on peak injection and withdrawal, the peak injection/withdrawal for many DICs is seasonal and based on natural resources such as wind and hydro as noted by the Commission. Under the proposed framework these DICs will be charged for the peaking injection/withdrawal which may occur once during the year. Since it is argued that these DICs need to pay for peaking capacity designed for their peaking injection, the DICs should be given corresponding right to trade their unused capacity to other users when their injection/withdrawal may be lower than peaking requirements.

3.2. <u>Sub-clause (i) of clause (1) of Regulation 7</u>

3.2.1. **Central Transmission Utility:** The following statement to be modified:

“Basic network along with the converged load-flow results for various grid conditions shall be validated by validation committee.”

This may be modified as below:

"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."

3.3. **Sub-clause (k) of clause (1) of Regulation 7 and Para 2.3 of Annexure to the Principal Regulations**

3.3.1. **POSOCO:** As per provisions of the existing Regulations, the entire network is modeled and the network except NER is truncated to 400 kV level. The Commission had observed the following vide SoR to the Sharing of inter-state charges and losses Regulations, 2010:

"3.3.4 Order / Analysis: The mandate of CERC is to allocate YTC of the transmission assets owned by ISTS licensees. However, consideration of assets owned only by the ISTS licensees leads to formation of Islands in the network. Connection of these islands through selected lines for the purposes of load flow convergence has commercial implications for various stakeholders. Therefore a need was felt for a consistent policy in this regard. There were two options:

1) *Consider the entire network*
2) *Consider the network where most of the assets are owned by ISTS licensees – i.e. consider 765 kV and 400 kV transmission system (except for NER where assets of 132 kV are considered) – because at these voltage levels most of the assets are owned by the ISTS licensees*

As per recommendation of CEA, the second option was considered and the Network was truncated at 400 kV level for the NEW Grid (excluding NER where assets upto 132 kV were considered) and SR Grid. The truncation at this voltage level was accorded two reasons:

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."

The rationale of consideration of full network as discussed in the Explanatory Memorandum of the 3rd amendment is contrary to reason-II stated above. Example of Tenughat has been cited. Tenughat is connected to Biharshariff in Bihar and Patratu in Jharkhand through 400 kV lines charged at 220 kV. Because of truncation, part of Bihar load at Biharshariff is met from Tenughat generation, and balance only is reflected as flow through 400/220 kV ICTs. Thus there is no need of removing truncation as objective of the Hon'ble Commission is being met even now.

Further, a lot of new EHV lines at 765 kV and 400 kV have been commissioned during the last few years after notification of the Sharing Regulations. Further, 132 kV and 110 kV lines are mostly being used in radial mode. Since charges of most of the 132 / 220 kV lines are not to be recovered, it is suggested that truncation may be continued as per present methodology.

3.3.2. **CEA:** The draft proposes to abolish the practice of computing PoC charges on transacted system. This is alright provided each state generation is also perturbed and cost of State transmission network is accounted for in computation of PoC charges. The net charges payable by (or to, if any) the State may thus be arrived.

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

3.4.1. **POSOCO:**

To smoothen the transition process, after due consideration of various factors, the Hon'ble Commission had specified 3 slabs rates and 3 slabs for losses. As per the draft Regulations, slabs are proposed to be dispensed with and each of the DICs would have unique rate and loss. There would be wide variance between highest and lowest (NIL) and may lead to heartburning amongst DICs. Further, there are a number of assumptions in the computation process (e.g. Tariff of many transmission assets is provisional, load / generation scenario, commissioning of new transmission assets etc). Also, the line wise tariff is still not being determined and substation cost is not separated. Thus the results of computation can, at best be an indication of range of PoC rate in the next application period. Under such a situation, charging exact rate computed to each DIC may not be prudent. Entities whose rates go up may dispute the entire computation process including assumptions.

It may be seen that other cybernetics also follow slab rates e.g. metro rail ticket, bus fare, taxi fare etc. In examinations also instead of giving exact marks, grades are being awarded. Further, too much granularity may at times be counter-productive and difficult to comprehend for the stakeholders. With slab rates in place, upfront declaration of average rate and slab rates is possible. The objective of the Hon'ble Commission to bring in locational signal can also be achieved with gradual increase in number of slabs, e.g. 5 slabs going up to 7 or 9 slabs in a phased manner. Similarly, 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.

3.4.2. **CEA**:

1) In the proposed amendment, the provision of slab rates is being deleted. In the existing provisions, there are three slab rates for transmission charges and also for transmission losses. As given in the explanatory memorandum, we agree that removal of slab rate would be in conformity with the basic principle of sharing regulations i.e. transmission charges allocation should be sensitive to distance, direction and usage. However, if the Commission considers it appropriate, a lower and upper cap on PoC rates may be decided by CERC to avoid extremely high or low PoC rates. In this regard, it is suggested that minimum PoC rates may be capped at 33% of all-India Postage Stamp Rate and maximum may be 300% of all-India Postage Stamp Rate.

2) Presently, the costs attributed to the substations are not explicitly considered for calculation of PoC rates and neither the flow through the transformer is considered in the marginal participation algorithm for cost allocation of transformer branch. In this regard, it is important to note that the transformers are in fact branches having specific impedance and they must be treated in the same manner as the transmission lines. The methodology adopted for assigning per kilometer cost for various types of transmission lines i.e. 400 kV/ 765kV/ or SC/ DC or twin/Quad, etc. can be extended to include cost of substations based on voltage levels and MVA capacity. Ignoring perturbation through transformer impedance in the marginal participation algorithm would not be appropriate from electrical engineering point of view.

3) **Regarding allocation of transmission losses:** In the previous paragraphs, it has been suggested to use DC load flow for calculation of PoC rates for transmission charges. However, the AC load flow may be continued to be used for allocation of transmission losses under PoC mechanism till a better alternative could be found.

4) **Use of DC load flow versus AC load flow for determination of PoC rates:** The philosophy of Marginal Participation (MP) Method is based on linear relationship between cost of transmission line and change in power flow on the line due to small perturbation of loads/generations, where in it is assumed that small perturbation can be scaled up to actual flow. Presently, AC load flow method is being used for calculation of Marginal participation factors, which is non-linear in nature. Therefore, it is 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.

3.5. <u>Sub-clause (n) of clause (1) of Regulation 7</u>

3.5.1. Comments are as quoted for Sub-clause (y) of clause (1) of Regulation 2 at para 1.8 of this Appendix.

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

3.6.1. **Association of Power Producers (APP):**

This proposed amendment makes provision for calculations of the charges for each Application Period for peak hours. However, peak hours have not been clearly defined. It has been confusingly left at the disposal of Implementing Agency.

It would be desirable for the network users to know in advance the definition of peak hours in clear terms. It would be desirable that the period of peak hours is defined in the Regulations (it is not necessary that peak hours are the same during different four Application Periods. They may even differ for different injection points.

3.6.2. **NTPC Ltd.:** The Draft Regulations have proposed that Implementing Agency (IA) may specify a date preferably the mid of each application period for computation of peak scenario injection by generators. It is submitted that injection on a specific date can give misleading data. Instead it is suggested that the RLDC/SLDC may consider the likely highest demand day and work out that day's injection for the purpose.

3.6.3. **Central Transmission Utility:**
If a particular date is stipulated for choosing the peak load condition upon which the load flow studies and computation shall be carried out, the DICs may be urged to become involved in gaming.

The Hon'ble Commission may like to take a view on it.

Further it is to be clarified that since each quarter shall have one YTC computation (say the Base case YTC), all the modifications in this may be taken up in truing up exercise only. Therefore, it is considered prudent that the above proviso may be deleted.

Provided further that the load how 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 (i) of clause (1) of this Regulation.

3.6.4. **Bihar State Power (Holding) Company Limited:** As regard to Para 7 (1) (o) of the draft regulation, it is submitted that participation factors and Point of Connection nodal and zonal charges shall be computed for peak and off peak scenario for each application period.

3.6.5. **AD Hydro Power Limited:**

1) The whole concept of peak injection or maximum drawl will not be a prudent methodology to arrive at the charges to be shared unless the variation in the Plant Load Factor for different type of Generation is factored in for arriving at the POC for Generators.

2) The concept of application period by dividing the whole financial year in four quarters as proposed in the draft agreement will also not give a correct picture as mentioned in the following para.

3) It is also reiterated that the peak injections may be due to some emergency or exigency requirement and may not be a continuous phenomena, therefore, the concept of considering peak injections or maximum drawl 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 the sharing of charges as compared to any other sources.

3.6.6. **Shri Ravinder:** If peak hours are defined in advance, the DICs i.e. Transmission users may try to game or manipulate. Moreover, the hours keep shifting. The duration and time of peak hours should be left to the implementing agency.

3.7. **Sub-clause (q) of clause (1) of Regulation 7**

3.7.1. **Association of Power Producers (APP)**

It is a welcome step to dispense off with the uniform charges method of calculating transmission charges as the Uniform charge method was not accounting for commensurate usage of transmission system. It overlooked or undermined the aspects of sharing of transmission on account of direction, location and load factors and therefore the allocation of transmission charges was not equitable.

Though it seems logical to do away with uniform charges mechanism and use only PoC mechanism but real impact in terms of absolute numbers should be presented /demonstrated before final amendment is done. Sudden shock of drastic changes may be avoided as was being considered in the earlier amendments.

3.8. **Sub-clause (s) of clause (1) of Regulation 7**

No Comments received from Stakeholders

3.9. **Para (iv) under sub-clause (t) of clause (1) of Regulation 7**

No Comments by Stakeholders

3.10. **Para (vii) under Sub-clause (t) of clause (1) of Regulation 7**

3.10.1. **Association of Power Producers (APP):**

1) **(Para 1)**There are certain ISGS which are connected to both STU and ISTS where the Home State is supposed to offtake power at the station bus bar using the State transmission system. At time, due to various reasons not attributable to the ISGS, the Home State is not able to draw the entire Contracted Capacity through State Network and the balance power is drawn through ISTS network. In other words, the injection by the ISGS through ISTS network includes a portion of Home State share also, which is supposed to be drawn through STU network.

2) Further, the tripping of any transmission element in STU network may lead to inadvertent flow of power through ISTS system, leading to higher injection from ISGS through ISTS. Similarly, change in power order of HVDC transmission system can also affect the power flow through ISTS network.

3) In such circumstances, if the transmission charges are levied corresponding to the Peak injection of power through ISTS, the ISGS would be unnecessarily required to pay higher amount of transmission charges, which is unreasonable.

4) The Commission is requested to address this anomaly by specifying that out of the total injection by the ISGS into ISTS, the difference between the scheduled power and actual power drawn through STU network by the Home State should be accounted for and the transmission charges should be levied on the ISGS corresponding to the net injection (injection into ISTS minus the difference between the scheduled power and actual power drawn through STU network) only.

5) **(Para 2)** The draft regulation proposes that the application of losses shall depend on whether RLDC or SLDC is doing scheduling for the same. In case scheduling is being done by RLDC, ISTS losses shall be applicable for those schedules.

6) In this regards, we would like to submit Para 7.2(1) of the Tariff Policy notified vide Govt. of India Ministry of Power Resolution No. No.23/2/2005-R&R (Vol.111) 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"

<u>Application of losses based on agency that is carrying out the scheduling activities is not reasonable</u>.

7) In our view, the applicability of transmission losses shall be in accordance with the National Electricity Policy and shall be based on the zonal PoC losses for Injection as well as Withdrawal, corresponding to each transaction Schedules. **Hence, the existing methodology of allocation of losses should be continued.**

3.10.2. **Adani Power Ltd.**

1) Transmission charges based on actual usage

i) It is to submit to the Hon'ble commission that certain Inter State Generating Stations (ISGS) are connected to both STU and ISTS networks at their bus bar. The offtake on STU or ISTS network is in accordance with the schedules under Long/Medium/Short term PPAs or collective transactions of ISGC with the Home State or with States other than Home State. At various instances, due to reasons not attributable to ISGS, the Home State is not able to draw the entire Contracted Capacity through the STU Network resulting in the balance power being drawn through ISTS network and vice-versa. The actual energy flows are different from scheduled flow and sometimes power from State generating stations flows on ISTS and sometimes ISGS power flows on state transmission network. The power flow in an interconnected system takes place as per the load generation conditions based on laws of Physics and is bound to flow towards the line which has low impedance.

ii) Also, if there is an inadvertent flow of power through ISTS system due to tripping of any transmission element in STU network, this will lead to higher injection from ISGS through ISTS and vice versa.

iii) In such circumstance, if the transmission charges are levied corresponding to the Peak injection of power through ISTS, ISGS would be unnecessarily required to pay higher amount of transmission charges, which is unreasonable.

Hon'ble Commission is therefore requested to address this anomaly.

iv) In our view, out of the total injection by the ISGS into ISTS, the difference between the scheduled power and actual power drawn through STU network by the Home State shall be reduced and transmission charges shall be levied on the ISGS corresponding to the net injection only. Further, if there is any inadvertent flow due to tripping of any STU line or if there is increase in power flow as per instructions of System Operator, such incidences shall not be considered for levy of transmission charges on ISGS.

v) The regulation proposes that the application of losses shall depend on whether RLDC or SLDC is doing scheduling for the same. In case scheduling is being done by RLDC, ISTS losses shall be applicable for those schedules.

vi) In this regards, we would like to submit Para 7.2(1) of the Tariff Policy notified vide Govt, of India Ministry of Power Resolution No. N0.23/2/2005-R&R (Vol.111) 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"

vii) Application of losses based on agency that is carrying out the scheduling activities is not reasonable. While the transmission charges are proposed to be levied on actual power injection, there is no rationale for considering the losses based on the Control Agency rather than the system involved.

viii) In our view, the applicability of transmission losses shall be in accordance with the National Electricity Policy, the previous decisions of the Hon'ble Commission on the subject issue and shall be based on the zonal PoC losses for Injection as well as Withdrawal, corresponding to each transaction Schedules. **Hence, the existing methodology of allocation of losses shall be continued**.

3.10.3. **Thermal Powertech:**

Requested commission to modify the stated point as below:

If an ISGS or IPP is connected to both STU and ISTS, the injection corresponding to flow on ISTS based on RLDC schedule shall only be considered for transmission charges and same will levied on ISGS or IPP.

However, if it is found to be ISTS network handling additional injection over and above RLDC schedule from ISGS or IPPs at that particular point, corresponding additional participation (transmission Charges) shall be levied on the Home state due to which it is happening. This also identifies network requirement at interconnection points, which bring positive impact for transmission strengthening schemes by STU. In this regard we also request commission clause 7 (1) (t) (vii) has to cover the above stated issues.

3.10.4. **Sh. Ravinder:** Needs review**.**

3.11. **<u>Sub-clause (u) and Sub-clause (v) of clause (1) of Regulation 7</u>**

3.11.1. **Indian Wind Power Association (IWPA):** We request the Hon'ble commission that the condition of this clause shall be made applicable for a period in line with the national targets for effective results and also be requested that the same shall be extended to wind based generation.

And the same clause may be amended to be read as:

"(u) No transmission charges for the use of ISTS network shall be charged to wind and solar based generation. This shall be applicable for the useful life of the projects commissioned in next year's i.e. between 1.7.2014 to 30.6.2020".

3.11.2. **NSL Power:** We introduce ourselves as one of the leading Renewable energy generators in the country with 185 MW installed capacity of wind/Solar/SHP/Bio-mass plants in operation, and over 1100 MW of wind/ Hydro/ Solar plants under various stages of development in different States. We submit the following suggestions for consideration by this Commission.

1) At the outset we thank the Commission for proposing to extend the benefit of exemption from ISTS charge/ losses for the solar projects to be commissioned SB 30-6-2017 as a measure of promotion of Renewable Energy as envisaged in the EA 2003.

2) We wish to submit that the other Renewable Sources like Wind/ Small Hydro also deserve such treatment in view of the their infirm nature, abundant potential, low level of exploitation, environmental protection etc. Hence the Commission may be pleased to extend this benefit to Wind/ SHP sources also.

3) We also submit Hydro Power Projects (above 25 MW) also deserve this benefit for the following reasons:

   a. Hydro power is essentially a Renewable Energy source and needs promotional measures for its development as per the scheme and object of EA 2003;

   b. The vast Hydro potential is under-exploited for various reasons including cost overruns;

   c. The GOI has proposed an amendment to EA 2003, defining the RE sources and also empowering itself to include any other source m RE category from time to time;

d. GOI has also circulated a draft amendment to Sec 61 of EA 2003, mandating to Appropriate Commissions to be guided by, inter-alia, the need for promotion of Hydro power generation, in specifying the terms and conditions for determinate of tariff;

4) In view of the above, we suggest that the Commission may insert a proviso under each of the sub-clauses (u) *and* (v) of Regulation 7

"Provided *that the Commission* may *extend the above* ***promotional measure to*** *the* ***Wind/SHP/Hydro*** *projects by an order or by any appropriate* ***proceedings*** *Suo-motu* or *on representations from such RE* developers ***for*** *fulfillment of objects of EA 2003"*

3.11.3. **Association of Power Producers:** The impact on wind based generation on account of transmission charges and losses is huge due to low CUF / PLF as is the case in solar based generation. Hence the waiver of the transmission charges and losses may be made applicable to wind based generation commissioned in next three years i.e. for the period (1.7.14 till 30.6.17).

3.11.4. **Shri Ravinder:** Don't agree that losses should not be applied to Solar and Wind power. It will increase our losses too much once ultra mega solar plants come up.

There are different agencies to encourage renewable energy. It is not the job of transmission customers. The proposal is against the principle of non discriminatory open access. Conventional hydro power is also green energy.

3.11.5. **CEA: (Transmission charges and Losses for solar power projects for use of ISTS)**

In the original regulation dated 15.06.2010, it is stated that - no transmission charges or losses for the use of ISTS network shall be charged to solar based generation. This shall be applicable for the useful life of the project commissioned in next 3 years. In support of this provision, the Statement of Reasons dated 11.02.2010 has mentioned the following:

The regulations facilitate solar based generation by allowing zero transmission access charge for use of ISTS and allocating no transmission loss to solar based generation. Solar power generators shall be benefited in event of use of the ISTS. Since such generation would normally be connected at 33 kV, the power generated by such generators would most likely be absorbed locally. This would cause no / minimal use of 400 kV ISTS network and might also lead to reduction of losses in the 400 kV network by obviating the need for power from distant generators. Further, this is also aligned with the objectives of the section 3(1), section 4, section 61 of the Electricity Act 2003 and the Jawaharlal Nehru National Solar Mission which is "to establish India as a global leader in solar *energy, by creating the policy conditions for its diffusion across the country as quickly as possible." The cost of energy from solar based generation is in the range of Rs 14- I8 / kWh and application of ISTS charges and losses would further reduce the acceptability of power generated from solar sources. This regulation encourages solar based generation."*

As is evident from above, it was anticipated that the solar generations would cause no/minimum burden on the 400 kV ISTS and as such no additional/new Inter State Transmission System may need to be planned for solar generation. The amendments under consideration propose to extend the above duration for further three year i.e. up to 30-06-2017. In order to conform with the spirit of the Statement of Reasons, it is suggested that the proposed amendment to regulation 7(u) and 7(v) may be modifies as-

"(u) No transmission charges for the use of ISTS network shall be charged to the solar based generation, provided no additional transmission system is required to be created because of the solar generation, or provided there is no additional flow on any of the ISTS elements because of the solar generation. This shall be applicable for the useful life of the projects commissioned in next three years i.e. between 1.7.2014 to 30.6.2017."

"(v) No transmission losses for use of ISTS network shall be attributed to the solar based generation provided no additional transmission system is required to be created because of the solar generation or provided there is no additional flow on any of the ISTS elements because of the solar generation. This shall be applicable for the useful life of the projects commissioned in next three years, i.e. between 1.7.2014 to 30.6.2017."

3.11.6. **SN Power**: It is important that the renewable energy plants such as hydro and wind are not penalized for lower plant factors (controlled by resource/nature). Hence it is requested that a fair way of allocating transmission cost without burdening them with unreasonably high cost should be devised.

3.11.7. **Indian Wind Power Association (IWPA):** We request the Hon'ble commission that the condition of this clause shall be made applicable for a period in line with the national targets for effective results and also be requested that the same shall be extended to wind based generation

And the same clause can be read *as:*

"(v) No transmission losses for the use of ISTS network shall be attributed to wind and solar based generation. This shall be applicable for the useful life of the projects commissioned in next year's i.e. between 1.7.2014 to 30.6.2020".

3.11.8. **Indian Wind Energy Association:** Our comments on the captioned Draft Regulations pertain to the proposed amendment no. 12 & 13 which is regarding transmission charges and losses for solar based generation. In this regard, our comments are as follows:

1) At the outset, InWEA would like to acknowledge and appreciates the Hon'ble Commission's constant endeavors in promoting the renewable energy sector through its various regulations and orders/provisions. "These have enormously contributed to the growth of Indian renewable energy sector so far. However, with passage of time newer challenges have emerged forcing the policy makers and stakeholders to device innovative solutions to enable further expansion of the sector towards the realization of ultimate goal of achieving energy independence and energy security for the country.
2) The Commission has proposed various amendments to the CERC (Sharing of Inter State Transmission Charges and Losses) Regulations dated 7th February 2014. In one of the amendments the Commission has proposed continuation of zero transmission charges and transmission losses for solar power projects. InWEA welcomes this move by Commission which is bound to provide boost to solar energy market. At the same time, we would also like to highlight the need for extension of similar provisions for other renewable energy generators, most notably the wind energy sector.

3) The Commission has given the following reasoning in the statement of reason document accompanying the draft notification:

"11. No ISTS charges for Solar based Generation:

11.1 Exemption from payment of ISTS charges and losses was granted to Solar generating stations for 3 years. Decision need to be taken on this issue for solar projects to be commissioned after 1.7.2014. MNRE has also requested for an early decision on this matter to facilitate next phase of competitive bidding for solar generating stations.

11.2 The rationale stated in the Statement of Reasons for Sharing Regulations is extracted below:

"The regulations facilitate solar based generation by allowing zero transmission access charge for use of ISTS and allocating no transmission loss to solar based generation. Solar power generators shall be benefited in event of use of the ISTS. Since such generation would normally be connected at 33 kV, the power generated by such generators would most likely be absorbed locally. This would cause no / minimal use of 400 kV ISTS network and might also lead to reduction of losses in the 400 kV network by obviating the need for power from distant generators. Further, this is also aligned with the objectives of the section 3(1) and section 4 of solar mission which is "to establish India as a global leader in solar

energy by creating the policy conditions for its diffusion across the country as quickly as possible". The cost of energy from solar based generation is in the range of Rs. 14-l5/kWh and application of /STS charges and losses would further reduce the acceptability of power generated from solar sources, this regulation encourages solar based generation."

7.7.3 *In view of MNRE's request and the encouragement being provided by Government of India for development of Solar Power in the country, this exemption is proposed to be continued for the solar power plants to be commissioned up to June, 2017*"

4) In WEA humbly submits before the Commission that, <u>the above reasoning supporting the provision of zero transmission losses and charges for solar power projects can also be said to be valid for wind power projects</u>. However, given the level of maturity achieved vis-a-vis solar energy sector, such absolute concessions may not be required for wind energy sector. Nevertheless, what is necessary is the rationalization of transmission charges for wind energy in order to provide a viable model for interstate sale of energy.

5) The country has abundance of renewable energy sources; however their availability is not uniform across all the states, which has been one of the greatest challenges constraining the greater realization of this available renewable energy potential in the country. Currently the wind energy potential is estimated to be more than 100 GVV (CVVET estimation @ 80 meter hub height), whereas the installed capacity is just over 20 GW.

6) The wind capacity installation picked up quite significantly until FY 2011-12, aided by various promotional policy/regulatory support at central and state level. However, in the past two years the wind energy sector is witnessing decline in growth rate, partly due to the global economic slowdown but largely due to unique localized problems.

7) While this slowdown appears to be cyclic in nature, its revival has been made possible every time by introduction of a new market model by way of policy/regulatory intervention, which also addressed the problem prevalent at that time. At every stage some policy intervention was required to unlock greater market penetration by renewable energy generators.

8) In the existing market scenario, renewable energy generators are selling power either through Feed in Tariff route or to captive/third party sale via the Open Access route. Under the Renewable Energy Certificate (REC) framework the FIT is replaced by Average Power Procurement Cost (APPC) and normal open access charges are applicable instead of concessional charges for RE open access transactions under REC mechanism. The

notional green component, REC, is being sold at national level trading platform in monthly trading.

9) However, the sale of energy component in both REC and non-REC market has been limited within the local state boundaries. The result is that, distribution utilities in some of the resource rich states are finding it difficult to accommodate more renewable energy than that required under respective Renewable Purchase Obligation (RPO) target. This is more prevalent in wind resource rich states, e.g. in Tamil Nadu the DISCOM has achieved 1l % RPO as against target of 9% in FY 12-13. Similarly, in Karnataka where the RPO is as high as 10% the utilities have been regularly surpassing this target. Similar is the situation in small hydro rich potential states like Himachal Pradesh and Uttrakhand. Other resource scarce states like Uttar Pradesh, Haryana, Punjab, Bihar, Delhi etc continue to struggle to fulfill their renewable energy obligations despite the low RPO targets set by them.

10) The Renewable Energy Certificate mechanism was expected to break the shackles of state boundaries and provide renewable energy generators access to national RPO markets. However, over a period of time, the non seriousness of the obligated entities and their reluctance to pay for virtual green component has lead to poor performance of the REC market. The RPO/RFC mechanism is yet to gain credibility among investors as the inventory of unsold RHC continues to pile up and the obligated entities keep on deferring fulfillment of their RPO target. The following table indicates the inventory of unsold RECs for recent RHC trading sessions:

Non Solar RFC trade statistics during last one year

Month	REC Traded	Closing Balance (Unsold REC)	REC Weighted Avg. Price of PXIL & IEX (Rs./REC)
Mar,13	4,27,871	17,76,296	1,500.00
Apr,13	44,459	19,91,136	1,500.00
May,13	52,968	21,87,389	1,500.00
Jun,13	72,486	24,07,831	1,500.00
Jul,13	1,61,402	27,09,391	1,500.00
Aug,13	40,889	31,57,326	1,500.00
Sep,13	49,831	37,19,067	1,500.00
Oct,13	1,50,640	40,58,852	1,500.00
Nov,13	3,08,928	41,51,020	1,500.00
Dec,13	4,03,862	41,51,127	1,500.00
Jan,13	3,58,997	43,70,006	1,500.00
Feb,13	3,78,825	43,10,208	1,500.00

11) In resource rich states, the Renewable energy procurement is already at highest level in the country, thereby discouraging any further realization of renewable energy potential as utilities are generally reluctant to procure more power than required under respective RPO targets. Thus the problem is twofold, on one hand the local DISCOMs in these states are reluctant to procure power under the conventional PIT (PPA) route and the State Commissions refuse to enhance their RPO. On the other hand, the sale of power under the REC framework is not yet reliable for investors. One of the reasons for reluctance of obligated entities to buy RECs is that it is a notional component and does not result in any benefit to the purchasing entity as there is no real transfer of energy.

12) It is thus imperative that sale of power from one state to other is essential for optimal utilization of wind resource. The current constraints of state boundaries, namely the high transmission charges and losses, needs to be addressed to expand the renewable energy market. Although, interstate sale of energy is not prohibited as such, but the conventional transmission charges applicable on the basis of contracted capacity make renewable energy open access transactions prohibitive, thereby putting renewable generators in a very disadvantageous position.

13) InWEA humbly submits that the electricity generation from a wind power plant is entirely dependent on the vagaries of wind which varies throughout the year. A wind generator generally does not operate at its full designated (installed) capacity at all the times. The maximum capacity utilization is achieved during monsoon season from the month of June to September, when the wind flow is highest. Whereas, during rest of the months the wind speeds are low resulting in much lower capacity utilization then the installed capacity. Therefore, Plant load factor of wind power plant, also known as capacity utilization factor (CUP) is lower in the range of 20% to 25% as compared to PLF of conventional power plants such as coal or gas based generating stations (70%-90%).

14) Normally, the transmission charges applicable to the conventional power plants are specified in terms of transmission capacity to be utilized in MW terms (Rs/MW/month). However, when these normal transmission charges are applied to open access transactions from wind power projects, they become highly prohibitive because of lower capacity utilization in terms of per unit cost of energy wheeled. As a result, the per unit charges for NCES open access transaction can shoot up to 300% to 400 % in comparison to open access charges for conventional generators.

15) At state level, these concessional open access charges for wind generators have been provided as a promotional measure and to offer them a level playing field vis-a-vis conventional generators. These reduced charges bring parity among the renewable and non renewable generators. Without this the wind generators would be in a disadvantageous position as the open access transactions would be highly prohibitive in terms of per unit cost. The provision of concessional Open Access charges by various State Electricity Regulatory Commissions for intra-state open access has provided a major fillip to the wind energy sector in these states.

16) In case of Maharashtra, the transmission and wheeling charges have been specified in terms of per unit (Rs/unit) rather than on capacity basis (Rs. /MW) which is normally done in case of open access transaction from conventional generators.

17) It can be seen that majority of SERCs have made provided for concessional treatment for open access transactions from RE generators. InWEA, thus request the Commission to consider the same provide for special dispensation by way of introducing reasonable transmission charges for wind energy open access transactions.

18) The reasonable charges could be a matter of discussion and deliberation with the stakeholders from wind industry as well as grid operator. Though for wind instead of providing complete exemption like solar, as the higher transmission charges is a result ot low PI.P of wind power projects, if instead such charges are applied based on Rs/kWh the total transmission charge would come down drastically. This would make such transaction commercially viable on one hand and also make the cost of transmission for wind power comparable to the long term transmission cost for conventional power on the other hand.

19) InWEA humbly submits that a provision similar to the dispensation given to short term users of transmission facility may be suitable for wind energy. The Central Commission vide its CERC (Sharing of Inter State Transmission Charges and bosses) Regulations, 2010, has specified Point of Connection Transmission Charges and allocation of Losses, according to which the charges for long-term and medium term open access transactions should be on Rs/MW/month basis and the for short term open access transactions, it should be on Rs/unit basis.

20) InWEA humbly submits that, with the introduction of RRF mechanism under

the CERC Indian Electricity Grid Code 2010 (IEGC), we expect the issues related to scheduling and forecasting of power would be appropriately addressed. Thus the time is opportune to introduce new market model by rationalizing the Inter-state open access charges for renewable energy generators. This would go a long way in giving much needed boost to the wind industry and encourage further investment in the sector in future.

21) With encouragement of the interstate open access for renewable energy sources, the hurdles being faced due to the regional imbalance of resource for exploiting the potential in resource rich states would be greatly addressed. The consumers from resource scares state resorting to lower RPO could avail renewable energy through the RE generators available in these states. It will also give a strong positive signal to private investors about serious commitment of the policymakers and regulators towards serious development of renewable energy capacity in accordance with the targets as specified in various national plans/missions. This also brings solution to some extent where the utilities would prefer to procure wind /RE power if such power is available at economical rate. Reduction of transmission cost for such transactions, instead of blanket exemption, at a level equivalent to that of conventional power could make such interstate sale of wind power viable and kick start such market model which is going to be the future for growth of wind power in India.

3.11.9. **Moser Baer Engineering and Construction Limited:** Paras 3(12) *&* 3(13) of proposed Amendment Regulations: The initiative of <u>continuing the exemption of any Transmission Charges and Transmission Losses for use of ISTS network by Solar based generation as provided in Regulation 7(1)(u) & (v) is indeed a progressive step</u>. This will encourage new investments in Solar energy and thus, helping the power scenario in our country through an environment friendly way. We therefore, support the far sighted approach of the Commission.

3.11.10. ....**Surajbari Windfarm Development Pvt. Ltd:** Our comments on the captioned Draft Regulations pertain to the proposed amendment no. 12 & 13 which are regarding transmission charges and losses for solar based generation. In this regard, our comments are as follows:

1) **Support to solar power:** We completely agree that inter-state transfer of solar based generation should be supported by exempting it from ISTS transmission charges and losses, and hence the proposed regulations.
2) **Support to wind power:** At the same time, we wish to submit that inter-state transfer of wind based generation is also worthy of similar support on account of the below mentioned points.
   i) The promotional measures for optimal utilization of renewable energy

sources, mentioned in the National Electricity Policy 2005 (Clause 5.12.2, 5.2.20) and the Electricity Act 2003 (Section 3(1)), are for all renewable energy sources without any distinctive treatment to solar and wind energy sources. As per CEA; wind energy is contributing only about 7% in net electricity generation in the country. It has not achieved a perpetration maturity of 15-20%. In addition to providing environment friendly sustainable energy, wind energy is also contributing to more employment creation of about 3 person/MW.

ii) Inter-state transfer of wind power is in same plight and nascent stage as solar power. Despite being given a Must-Run status, there are instances of backing down wind based generation. Rather, though there presently examples of inter-state transfer of solar power in India, on contrary we understand that there is virtually no example of wind power being transferred across states. This highlights that wind power is equally worthy of being supported by way of exemption from ISTS transmission charges and losses as it is for solar power.

iii) It is further to be highlighted that wind power faces stricter regime under RRF mechanism as compared to solar power. As per the RRF mechanism, under IEGC Regulations, solar power generator has been exempted from commercial implication for any deviation between actual generation and schedule. On other hand, IEGC had specified commercial implication on wind power generators for deviation beyond allowed limits; though the commercial implication has been stayed presently, yet exemption has not been allowed and it is unclear how the new RRF mechanism would specify treatment of deviation in case of wind power. This highlights that degree of difficulty and the risk of penalty for deviation is much more in case of inter-state transfer of wind power than that for solar power. In such scenario, it is imperative to extend the support of exemption from ISTS transmission charges and losses to wind power.

iv) Since, there are no alternative, either bilateral or collective markets available under the short term and long term sale of wind power, the risk for sale of power increases by multifold. In additional to that, transmission charges for state as well as Central utilities are usually determined in Rs./MVV/month basis and due to low Capacity Utilization Factor (CUF), the per unit impact of such charges are much higher than the normal conventional power. This make it commercially unviable for such renewable source to chose the inter-state sale. Therefore, a special consideration and promotion for the wind power is required to implement the actual inter-state market.

v) Wind power plants are usually having a small generating capacity (up to 2.1 MW) and injected at low voltage level (normally be connected at 33 kV) and due to the same it cause less impact on ISTS.

vi) It is further to be highlighted that DISCOMS in states rich in wind potential are off-lately showing increased resistance towards contracting with further wind projects in those states. For example, it is a known fact that MSEDCL has been openly opposing further wind power procurement and has been delaying/ avoiding contracting with wind power projects in the Maharashtra. Similarly, the DISCOMS in other states rich in wind potential have been discouraging wind power citing the financial impact of such power on host DISCOM. In such scenario, supply of wind power to states deficient in wind/ RE potential presents an excellent viable and natural option for creating alternate market for wind power. Exempting wind power from ISTS transmission charges and losses would be a significant support towards creation of this alternate market.

vii) It is further to be highlighted that wind power sector, which constitutes about 70 % a renewable energy based installed capacity, is in quite distress situation present gets evident from the fact that wind capacity addition has dipped significantly in last couple of years.

viii) This assumes further importance considering the fact that targeted capacity addition during the 12th Plan period is ~32 GW from all renewable, comprising ~20 GW from wind. However, approx. 3 GW wind capacity additions during the first two years of 12th Plan period implies that wind capacity addition would be required at approximately 5.7 GW every year for the balance three years in order to meet the target.

Thus, considering the present distress situation of wind power sector in India and to facilitate India in meeting its RE target, the need of the hour is to support wind sector by way of exempting wind power from ISTS transmission charges and losses. This would help in revival of the market by creating an additional market for wind power. Considering the above mentioned points, <u>we humbly request the Commission to support inter-state transfer of wind power by exempting it from ISTS transmission and losses, in-line with that for solar power</u>.

3.11.11. **Sandhya Hydro Power Projects Balargha Pvt. Ltd.:**

Our comments on the captioned Draft Regulations pertain to the proposed amendment no. 12 & 13 which is regarding transmission charges and losses for solar based generation. In this regard, our comments are as follows:

1) **Support to other renewable power:** At the same time, we wish to submit that inter-state transfer of other renewable based generation is also worthy of similar support on account of the below mentioned points.

2) The promotional measures for optimal utilization of renewable energy sources, mentioned in the National Electricity Policy 2005 (Clause 5.12.2, 5.2.20) and the Electricity Act 2003 (Section 3(1)), are for all renewable energy sources without any distinctive treatment to solar, wind and small hydro energy sources.

3) Inter-state transfer of all the renewable power is in same plight and nascent stage as solar power and other renewable power is equally worthy of being supported by way of exemption from ISTS transmission charges and losses as it is for solar power.

4) Since, there are no alternative bilateral or collective markets available under the short term or long term sale of renewable power, the risk for sale of power Increases by multifold. In additional to that, transmission charges for state as well as Central utilities are usually determined in Rs./MW/month basis and due to low Capacity Utilization Factor (CUF), the per unit impact on renewable sources of such charges are much higher than the normal conventional power. This make it commercially unviable for such renewable source to chose the inter-state sale. Therefore, a special consideration and promotion for the wind power is required to implement the actual inter-state market.

5) These renewable power plants are usually having a small generating capacity and injected at low voltage level (normally be connected at 33 kV) and due to the same it cause less impact on ISTS.

   Thus, considering the present distress situation of renewable power sector in India and to facilitate India in meeting its RE target, the need of the hour is to support renewable sector by way of exempting such renewable power from ISTS transmission charges and losses. This would help in revival of the market by creating an additional market for such renewable power. Considering the above mentioned points, we humbly request the Hon'ble Commission to support inter-state transfer of all the renewable power by exempting it from ISTS transmission charges and losses, in-line with that for solar power.

4. Amendment in Regulation 8

4.1. <u>Clause (5) of Regulation 8</u>

4.1.1. Association of Power Producers (APP):

In case if the generator is not able to commission the generating station due to force majeure or other factors beyond the control of the generator, the generator shall be given relaxation in payment of transmission charges as the commissioning is delayed due to events beyond its control.

In case of delay in commissioning of the generating station attributable to the generator, the charges should not be levied on the generator unless the transmission system identified as part of the system planning for evacuation of power from the generating station is ready.

4.1.2. Central Transmission Utility:

"(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."

It is submitted that the above shall serve very useful purpose in recovery of transmission charges.

The second proviso reads as below:

"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."

This may be modified as below:

Provided further that during the period when a generating station draws startup power or injects infirm power <u>before commencement of LTA</u>, 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."

4.1.3. DVC: DVC submits that if <u>associated transmission system for the evacuation of power of the concerned generator is already pooled in the regional asset then this imposition of injection / withdrawal charges on the concerned generator only is considered not necessary</u>. Moreover the mode of recovery for sharing of that injection and withdrawal charges by the generators is required to be provided. Further to above, the following provision is also proposed to be included in the amendment of the Regulation, <u>where a generator is ready for commercial operation and the associated transmission system has not been made ready by the Transmission Licensee for evacuation of power for which LTA is sought for.</u>

In the above circumstances, injection / withdrawal charges are to be borne by the Transmission licensee.

4.1.4. MB (Madhya Pradesh) Power Ltd. (Amendment in Regulation 8 of Principal Regulations and Amendment in Regulation 11 of Principal Regulations**)**

1) In respect of the above, we would like to submit that under the current regulatory framework, a developer is required to make an application to CTU for **LTA** around 4 years prior to actual LTA requirement duly mentioning the target region. Hence at the time of making this application, a thermal power project is under early stages of implementation as the gestation period of such projects is generally around 4-5 years.

2) However, the actual date of LTA commencement for power project broadly depends on two factors viz. a) actual commissioning of power projects transmission asset & b) power tie-up from power project.

3) In the current scenario marred with various uncertainties related to land acquisition, fuel (coal) availability, statutory clearances like environment & forest clearances, challenges faced by the project developers in achieving financial closure and tie-up project funding with Banks/ investors, increasing litigations/ PILs being filed against the projects etc, it has become increasingly difficult for a power project developer to achieve commissioning of power project commensurate to the requisitioned LTA commencement date.

4) Even the transmission licensee(s) face the issues related to RoW and other statutory clearances like environment & forest clearances, statutory clearances under Sec-164 of the Electricity Act 2003 etc. Further, making of Tariff Based Competitive Bidding (TBCB) route mandatory for construction of transmission assets has also resulted in elongation of the construction timelines in view of substantial time involved in closure of bidding process. All these have resulted in challenges being faced by the transmission licensee(s) in timely commissioning of transmission assets.

5) Thus there is a need to ensure optimum utilization of generation & transmission capacities by phasing the implementation of the transmission system matching the commissioning schedule of generation projects. Even the Hon'ble Commission has emphasized this need in its order dated 13th Dec' 2011 in the Petition No. 154/MP/2011 & IA. No. 17/2011. The relevant extracts of this order are reproduced below:

6) **Page 27 of 44: Para #34**

"34. *In order to ensure optimum utilization of capacity in generation as well as transmission, there is an imperative necessity for both generation and transmission* *to come up simultaneously by phasing the implementation of the transmission system as far as possible to match with the commercial operation of the generation projects.*"

7) **Page 29 of 44: Para #36**

"36. We are of the view that these transmission systems need to be implemented matching with the commissioning scheduled of the IPPs."

8) **Page 29 of 44: Para #38**

"38. The petitioner should ensure that the phasing of commissioning of transmission elements shall be done to match with the generation projects for optimum utilization of the system and to avoid stranded transmission assets"

9) This spirit has also been captured in the various agreements entered into between power project developer and CTU/ Transmission Licensee(s) like Transmission Agreement, LTA Agreement etc., which provide for having regular Joint Coordination Committee (JCC) meetings for cohesive implementation of transmission systems and generation projects.

10) With regard to the other factor affecting the actual commencement of LTA i.e. power tie-up by the generator, it is submitted that while initial LTA application indicating the target-region wise quantum of LTA sought is based on our future assessment of power-tie up. However, in the last 3-4 years, very few Case-1 bids for power tie-ups have been invited and successfully closed by various States. In this backdrop, it is very difficult for any project developer to assess the precise LTA commencement date and target-region wise quantum of LTA requirement at the time of making LTA application to CTU.

11) Under this backdrop, the proposed amendment in the Clause (5) of Regulation 8 of the Principal Regulations to make a generator liable to pay for transmission charges under PoC mechanism (in form of injection and withdrawal charges) in event of delay in commissioning of generating station would cause an adverse and irreparable financial burden on such generating projects which are already under duress due to uncertainties related to land, fuel, statutory clearances, unwarranted litigations, financial closure and project funding, challenges in power-tie up due to limited Case-1 opportunities in the market etc. as the same are beyond the reasonable control of a generator.

12) **Our Prayer:** In view of the above, it is respectfully prayed that the Hon'ble Commission may be pleased to:

a) Allow a flexible time period of at least 1 year between commissioning of generation projects and transmission assets before levying of transmission charges on the generator i.e. a time period of at least 1 year from commissioning of transmission asset may to be allowed to a generator for commissioning of its generation project, subsequent to which generator to be made liable for payment of the applicable transmission charges. With-in this permissible time period of 1 year, certain LDs/ Penalties may be imposed on the generator as a deterrent to prolong deliberate commissioning of the Project as under:

Delay in commission of generation project from the date of commissioning of transmission asset	LD/Penalties to be imposed on the Generator
Up-to 3 Months	NIL
3-6 Months	25% of the applicable monthly transmission charges for every month's delay beyond 3
6-9 Months	50% of the applicable monthly transmission charges for every month's delay beyond 6
9-12 Months	75%o of the applicable monthly transmission charges for every month's delay beyond 9

b) Allow the generator to transfer part/ full quantum of the already secured LTA from the initially declared target region to any other region without any cost implications, subject to the generator furnishing a long term PPA for the same quantum of power with the beneficiary in the revised region.

13) We trust that the Hon'ble Commission would appreciate the genuine merits set out in our comments above and would review the same favorably while finalizing the final amendment to Principal Regulations. This will go a long way in mitigating the current challenges being faced by both generators and transmission licensee(s) in phasing the implementation of the transmission system matching the commissioning schedule of generation projects.

4.1.5. Adani Power Ltd.: In case, if 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.

In case if the generator is not able to commission the generating station due to force majeure, the generator shall be given relaxation in payment of transmission charges as the commissioning is delayed due to events beyond control of the generator.

4.1.6. AD Hydro Power Limited:

1) The proposed amendment does not specify the basis for allocation of transmission charges. Further, wherever the allocated transmission charges have been asked to be shared, the same should be subject to the adjustment on materializing the approved withdrawal or approved injection.
2) In case if the CTU/STU/licensee is not able to provide the connectivity/access to the generator within its commissioning schedule, how, the generator will be compensated whose power will be bottled up and hence tremendous loss to him in terms of Generation?
3) In case an existing transmission corridor/sub-station/element, (where no system strengthening is required) is to be used to provide the connectivity to a new generating station, why he should be asked to pay the transmission charges specially when the cost of the element is already being recovered fully (By way of LTOOA/MTOA/STOA) from the existing loads connected to the element.

4.1.7. Lanco Kondapalli Power Limited: In case of commissioning of generating station is delayed for reasons not attributable to the generator due to force majeure condition, DICs shall not be liable to pay injection and withdrawal charges from the date on which access granted by CTU, till they come out of force majeure situation.

4.1.8. NTPC Ltd: It is submitted that "Approved Injection" as proposed vide draft amendment is quoted below:

Quote

"(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."*

Unquote

The above definition provides that "Approved Injection" shall be the **"maximum"** injection. Generator mostly would not be injecting up to the Approved Injection, on a continuous basis. Moreover, injection by a generator is determined by consumer demand and despatch schedule as well as unavoidable break downs. Therefore, realizing charges against Approved Injection which is a notional uncontrollable parameter may not be logical and fair. It is proposed that the charges may rather be realized based on actual injection. Since the entire demand in the system shall be served by injection from some generator (which may vary depending on real time decisions taken by customers on the basis of merit order), the entire transmission charges would in any case be recovered if billing is done on actual injection.

It is submitted that URS of NTPC stations for the year 2013-14 up to Feb 2014 was 39 BU. This year depending on commercial position and decisions taken by beneficiaries, the peak injection may vary. Hence billing for transmission must be done on actual injection & actual drawl. Further the additional charges recovered through STOA, MTOA may be adjusted at the end of the quarter (which are currently adjusted monthly) only to cater under recovery, if any. This proposition shall be just and based on principle of "actual usage" as the theme of New "Sharing of Transmission Charges & Losses Regulations"

The figure of estimated peak injection may be used for the purpose of load flow studies to estimate nodal charges, but billing should be on actual basis only.

Proposal:

In view of the above, it is suggested that the stipulation in the Regulation 8(5) quoted above may be deleted.

4.1.9. NTPC Ltd.:

Quote

"(5)………..

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."

Unquote

NTPC Comments:

1) It is submitted that there are two components of sale of electricity.
   a. Electricity
   b. Transmission system to carry the electricity to end consumers
2) In Indian context there are various options to buy the above two services which are detailed below:
   a. Beneficiary to buy both "a" and "b" i.e. where the generator sale is "ex-bus".

b. Beneficiary to buy "a" from generator which incorporates "b" which is to be arranged by the Generator i.e. sale of power is at beneficiary end for e.g. Case 1 bidding in case of Adani Power Limited at Mundra.
c. In addition to above Long term arrangements of power there are Short term sales where generator sale includes power charges (capacity energy) and its end POC charges for injection and buyer bears cost of power as bought + buyer end POC drawl charges.

3) For the above quoted Long term arrangements for sale of power there is a system of arranging the above services as detailed below:

a. Historically Associated Transmission System has been planned for evacuation of power from CGS to its beneficiaries. Even presently, in Govt. of India Controlled Companies allocation of power to beneficiaries is done by GoI considering the federal structure of the country and national priorities. The beneficiary(s) contracts generation capacity by signing Power Purchase Agreements where sale of power to beneficiaries is at ex-bus and it is the responsibility of beneficiary to arrange for necessary transmission services.
b. Historically when an ISGS project was envisaged, the transmission system was finalized in Regional Standing Committee Meeting and the comfort for bearing transmission charges was obtained in respective RPC. After ratification in RPC, PGCIL constructed the inter-state transmission lines.
c. Post 1.1.2010, all ISTS has to be planned & executed on the basis on CERC (Grant of Connectivity, Long term Access & Medium term Open Access) Regulations 2009. Although in case of NTPC stations, sale of power was ex-bus and it was responsibility of beneficiary to arrange for necessary evacuation, in order to facilitate the planning of ATS for power evacuation arrangement, LTA is being applied by the generating company on the behalf_of the beneficiaries initially just before the investment approval of the CGS. After the LTA is granted, the agreement for payment of charges is entered between the transmission company and the beneficiaries as agreed by beneficiaries in PPA and as provided in Detailed Procedure under Long Term Access Regulations 2009 at Page 89 of 130 at Clause 26 (vi) whereby it is clearly indicated that in above referred cases, Long Term Access Agreement shall be signed directly by beneficiaries.

d. The above arrangement is also applicable for various UMPP like Tata Mundra & Sasan Power Plant where sale of power is ex-bus.
e. However in case a generator is planned as merchant power plant, it applies Long term Access as a generator without identified beneficiaries.

4) As per the above arrangements Long Term Access charges should be charged from the procurer of transmission service as per the sale purchase agreement entered as detailed above. Any other provision shall be against the agreements and the system in vogue.
5) It is also submitted that transmission system is planned to have redundancy and system strengthening schemes are also undertaken. Further the associated transmission system (ATS) may comprise of a line connecting generator to nearest grid point and further system strengthening lines. In case of delay of generator and commissioning of ATS, it may happen that the associated lines are already in use by other generating stations and the capacity is not stranded. Any penalty to merchant generator getting delayed should be limited to the stranded transmission capacity of its ATS and not the entire system charges which is unfair.
6) Generation capacity is added in commercial service progressively and SCOD of different generating units in a station are different. Transmission system cannot be scheduled to be built to match the exact transmission capacity requirement corresponding to SCOD and there are bound to be differences. Almost always, some part of the transmission system is required to be made available well in advance (about 10-12 months) for the connectivity and drawal of startup power. Further, there is close monitoring and co-ordination between NTPC and PGCIL so as to ensure matching of generation with its associated transmission system so as to avoid any mismatch and consequent stranding of assets.
7) However, if there is any mismatch the same is covered by the Indemnification Agreement executed between NTPC and PGCIL. Indemnification agreement indemnifies POWERGRID for IDC in case of delay of generator. By way of the Indemnification agreement, the transmission company gets benefited in ensuring funds & servicing of funds for the project. Therefore its claims in case of delay of generation should be dealt in accordance with the Indemnification Agreement. The transmission company should not be permitted to abandon the Indemnification Agreement after taking advantage of the agreement for financial closure at the beginning. Any regulatory comfort to the transmission company beyond the agreement signed by it with the generator will be beyond the principles of equity and fairness and must be avoided.
8) In case the Transmission system comes up in time and the generation is delayed, the same may as well be used by some other entity in the intervening period. Even otherwise the charges will have to be borne by the transmission system user (the beneficiaries) as the Generators obligation is sale at its bus bar.
9) The Regulations have provision in case of stranding of transmission due to delay of generator but neither the Sharing Regulations nor the Tariff Regulations provide any provision in case of stranding of generation due to delay in transmission. This is not fair and equitable and the same needs to be addressed.

Hence, the following is proposed:

i) In case of generators where sale is ex-bus by way of PPA with beneficiaries & there is an Indemnification Agreement between generator & CTU and an Agreement between beneficiary & transmission provider for payment of evacuation charges, in such cases the liability of generator should be as per the Indemnification Agreement.

ii) The transmission charges for the stranded capacity (where there is no flow) only should be leviable in case of delay of merchant generators as the beneficiary is not identified. Such transmission lines may be included in POC only when they are actually put to use.

iii) The charges should be payable by the entity who has sought Long term Access & agreed to take liability of transmission charges.

iv) Hence the draft Proviso as quoted above may be modified as

"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 IDC for the stranded capacity out of its associated transmission system as per the Agreements"

Methodology of Recovery of Charges - NTPC Comments:

The methodology for simulation study for assigning node/zone wise charges as proposed in draft amendment proposes use maximum injection data which is appropriate. However once the nodal charges are assigned they are converted to rates in Rs./MW/month whereby they are divided by Approved Injection /Approved drawl which may not be appropriate since it will not provide representative Rs/MW/month POC charges. In this regard following methodology may be considered for adoption and is generally based on globally accepted practices:

Nodal charges may be arrived at by assigning charges to nodes by simulation using historic peak scenario data, extrapolated to the application period. The said charges may be divided by historic Average Injection, duly extrapolated for the Application Period to arrive at the injection PoC rate. During the Application Period, the charges payable may be arrived at by multiplying the Actual Injection by the rate arrived at. Over realization/under realization then will only be corresponding to the difference between the originally estimated average injection and the actual average injection. This will require minimum adjustments to be carried forward.

Payment of transmission charges by beneficiaries from synchronization

NTPC Comments: The Generating stations where sale is ex-bus and it is the responsibility of beneficiaries to procure & make available transmission services; such transmission system is required by the date of synchronization since power up to full load may be required to be injected. Also CERC Tariff Regulations provides that any revenue earned by generating company from supply of infirm power after accounting for fuel expenses shall be applied in adjusting capital cost accordingly. For generating stations where sale of power is at ex-bus basis and responsibility of transmission is with the customers, transmission charge should be billed directly to the beneficiaries with effect from synchronization of unit / injection of infirm power since the transmission is a must condition for synchronization & this would also avoid increase in capital cost. However, the transmission charges as per actual withdrawal of startup/commissioning power shall be payable by generator. In view of above suitable provision may be provided in Regulation 8 (5) of CERC regulation on CERC regulation on (Sharing of Inter State Transmission Charges and Losses).

4.1.10. Torrent Power Ltd.: Open access will be provided based on the available transmission capacity only i.e. the access would become effective only after the implementation of associated transmission system.

Hence, we would like to submit that transmission charges should be payable only for the quantum of effective open access, rather than the installed capacity as proposed in the 2nd para of the proposed amendment *to* Regulation 8(5).

Further, we would also like to submit that adequate provisions for the settlement of drawl & injection of power during commissioning have already been provided in the Deviation Settlement Mechanism Regulations. Therefore, the proposed amendment for payment of transmission charges for drawl of start up and injection of infirm power is redundant.

Hence, we would like to submit that the 3rd para of the proposed amendment to Regulation 8(5) may not be needed and may therefore be removed.

4.1.11. Thermal Powertech:

In case if the generator is not able to commission the generating station due to force majeure or other factors beyond the control of the generator, the generator, the generator shall be given relaxation in payment of transmission charges as the commissioning is delayed due to events beyond its control.

In case of delay in commissioning of the generating stations from committed COD of the generating station; generator can't be utilize the network; in this case it may not be reasonable to ask a generator to pay the entire transmission charges.

Deviations are very in any generating commission schedule in this regard requested commission to give grace period from 3 to 6 months from the COD of transmissions system to till commission of the generating unit.

We understand that NTPC and PGCVIL have these kind of arrangements for taking care the delays for a period of 6 months from schedule COD to Actual COD of the Generating Station by paying only IDC of the Transmission system.

It is requested commission to bring some sought of remedy for all the DICs without any bias during this transition period as below:

1) If generator commission schedule is delays below 3 months from the date of commission of transmission systems, generator need not pay nay transmission charges.

2) If generator commission schedule is delays more than 3 months and within 6 months, from 3rd month onward till commission of the generator the IDC alone will be paid by the generator as a non poc charges instead of avg. POC rates.

(**Para 2)** Generator startup power transactions (infirm injections and Drawl) are governed by Grant of Connectivity regulations 2009 amended time to time. During this period generator is allowed to do power transactions (infirm power) without any LTA/MTOA/STOA contracts. However the draft regulation proposes such intermittent transactions also to be billed as per POC mechanism. We request Honorable Commission to waive off the transmission charges for infirm injection/drawl (unscheduled power transactions) for any ISTS Generator.

4.1.12. SN Power: SN power is supportive of charging for transmission system if a generator is delayed beyond the proposed Commission date. However, it is requested that the following two amendments are considered:

1) Force Majeure Conditions: Under a Force Majeure condition, a generator should be allowed to reset the date of LTA. This will be fair since the management has no control on such risks.
2) Penalty on TRANSCO for delay: It is requested that penalty equivalent to revenue lost by a generator should be imposed on the TRANSCO for delay in commissioning of transmission line. This will ensure that rewards and penalties are symmetrical and balanced between the two parties

4.1.13. Individual (Sh. Ravinder): This is a very serious matter. The proposed formulation is unfair as there is no relief if the transmission is not built in time or it is inadequate and there is frequent congestion in the network. <u>Both generation and transmission can get delayed. The consequences of delay should be reciprocal</u>.

Suggestions:

1) If the generation or transmission is delayed up to 3 months, there should be no consequences.

2) If the generator is delayed beyond 3 months up to 6 months it should pay @ 25 percent PoC. Beyond 6 months up to one year it should pay @ 50 percent PoC. Full rate later.
3) If the transmission is delayed beyond 3 months, the CTU should start compensating the generator by the same amount the generator would have paid as per para 2 above.
4) There is such a mutual compensation clause in the case of first three UMPPs.

Additional comments on first para of clause 8 (5):

If the rates are calculated on the basis of peak period power flow and revenue is recovered on 100 percent installed or contracted capacity it may result in over recovery.

It is suggested that only for the initial period of five (5) years after the COD of generating station as a whole, the charges should be allocated by multiplying the PoC rate with actual peak injection in the application period. There should be a mirror clause for the drawing entities.

4.2. Clause 6 of Regulation 8 of the Principal Regulations:

4.2.1. **GRIDCO:** Injection charges allocated to withdrawal DICs in accordance with participation factors is a welcome proposal as it was capture the actual usage of generator for drawing its approved quantum of power. Accordingly, Clause 8(6) of the Principal Regulation requites to be amended. However, the same should be made effective from 1.7.2011 i.e. retrospectively.

4.2.2. **Bihar State Power (Holding) Company Limited**: In inter connected mesh grid, the power flows as per law of physics. Since, all the five regions are now interconnected and operating as one grid. It is now therefore essential to identify the participation factor of each DICs in the generation plant from which power is allocated/LTA of them as well as participation of each transmission line instead of nodes in the evacuation of power to each DICs. The transmission lines/assets which actually participate in the evacuation of power from a specified generation plant to DIC shall be billed in proportion to the power supplied to DIC.

4.2.3. **CEA:** The draft proposes to abolish the practice of computing PoC charges on transacted system. This is alright provided each state generation is also perturbed and cost of State transmission network is accounted for in computation of PoC charges. The net charges payable by (or to, if any) the State may thus be arrived.

4.2.4. **CEA: (PoC rate for Short Term Open Access)**

The general PoC rates are in the form of 'Rupees per MW per Month' whereas PoC rates for Short Term Open Access transactions are in the form of 'Rupees per Unit'. The PoC rates for Short Term transactions are arrived at considering a PLF of 100%. However, as the Short Term transactions are only for few hours in a year say even less than 20% of the total number of hours. It would be pertinent to calculate the PoC rates for Short Term transactions considering at the most a PLF of 20%. For example, if PoC rate is Rs. 1 Lakh per MW per Month, the Short Term transaction rates in Rs./Unit is presently calculated as: Rupees 100000/ (720 hrs x 1000) = 13.8 Paise/Unit. Instead of this, the rate may be calculated as: Rupees 100000/ (20% of720 hrs x 1000) = 69.4 Paise /Unit

5. Amendment in Regulation 11

5.1. Clause (4) of Regulation11

5.1.1. NTPC Ltd: The above quoted Regulation may be modified as under:

For generators:

[PoC Transmission Charge of generation zone in Rs /MW/month for peak hours] × [Approved Injection for peak hours] + [PoC Transmission Charge of generation zone in Rs /MW/month for other than peak hours] × [Approved Injection for other than peak hours]

The same formula may be modified based on actual injection as under:

"POC Transmission Charge for the generation zone in Rs./MW/month X Actual Injection"

5.1.2. AD Hydro Power Limited: It is submitted that the proposed regulation is actually increasing the liability to pay the drawl charges in two forms i. e. Peak injection and payment of average of demand PoC charges among all the DICs for the following reasons:-

1) Justification against peak injection concept has already been given above.

2) Any discom/drawyee utility by virtue of the status of DIC and long term access is already bound to pay the PoC charges of their purchases either in long term/medium term/short term. Therefore, under the present regulation asking the generator who do not have beneficiary to pay the demand PoC charges will simply increase the share of transmission charges.

Suggestions:

1) The Generators who do not have the beneficiary should be exempt from payment of average of demand PoC charges; or

2) Based on their short term contract with any utility the average demand PoC charges should be refunded back.

5.1.3. Thermal Powertech:

The draft regulation provides that a generator, who has been granted Long Term Access to a target region without identified beneficiaries, shall require paying Injection PoC Charge plus the average of the Demand PoC Charges among all the DICs in the target region based on the peak injection.

In such a scenario where it is likely that generating plants might not be able to dispatch their full capacity, it would be unfair for the generators to pay more in terms of Demand PoC charges. Therefore in our view, 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.

5.2. <u>Clause (5) of Regulation 11</u>

5.2.1. Association of Power Producers (APP):

The draft regulation provides that a generator, who has been granted Long Term Access to a target region without identified beneficiaries, shall require paying Injection PoC Charge plus the average of the Demand PoC Charges among all the DICs in the target region based on the peak injection.

Many generating plants have been set up on the basis of demand surveys done by Government agencies. However, despite the presence of significant power demand in many areas, the distribution companies have not been signing power purchase contracts and have been keeping the demand low artificially in view of their poor financial health. Therefore, we have been seeing an artificial created scenario of generation supply outstripping demand.

In such a scenario where it is likely that generating plants might not be able to dispatch their full capacity, it would be unfair for the generators to pay more in terms of Demand PoC charges. Therefore in our view, 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.

In addition to the clause 11(5), the following provision should also be provided for

"Provided further that the Injection POC charges and Demand POC charges for Long-term Access with firm beneficiaries to any region shall he adjusted against Injection POC charges and Demand POC charges for the Long-term Access to the target region without identified beneficiaries. "

Justification: Let us say a 350 MW thermal power plant has 100 MW LTA to Northern Region (without identified beneficiaries) and 100 MW LTA to Western Region (without identified beneficiaries), and firms up a beneficiary in Southern Region for 100 MW for 12 years. The approved injection for the generator is say 200 MW.

1) **Scenario 1:** In case, the Generator chooses to supply through MTOA initially for 3 years and new MTOAs from date of expiry of previous MTOAs, then Injection POC charges and Demand POC charges paid for MTOA to beneficiary in SR would be adjusted against the Injection POC charges and demand POC charges payable for 200 MW LTA without identified beneficiaries in NR and WR. Hence, the total Injection POC charges and Demand POC charges payable by the Generator would be for 200 MW only.

2) **Scenario 2:** In case, the Generator chooses to supply through LTA and in case the Injection POC charges and Demand POC charges paid for LTA to beneficiary in SR are not adjusted against the Injection POC charges and demand POC charges payables for 200 MW LTA without identified beneficiaries in NR and WR, then the total Injection POC charges and Demand POC charges payable by the Generator would be for 300 MW.

So, in case adjustment is provided only for MTOA and not for LTA with firm beneficiaries, then Generators would opt to supply even Long Term PPAs through multiple MTOAs rather than opting for LTA. All Generators having LTA without identified beneficiaries would always opt for MTOA over LTA.

Further, many Utilities are delaying power procurement bids significantly or not coming out with bids at all. This places generators in a very difficult position as they would like to synchronize the Long Term Access with their COD schedule. Today also there are many plants with LTAs but unable to utilize it to supply power as there have been no bids. To balance the current scenario, It is requested that the set-off provided for MTOA should be extended to LTA with firm beneficiaries as well.

5.2.2. Lanco Kondapalli Power Limited:

Under Connectivity Regulations 2009, as there is a provision for grant of connectivity without having identified beneficiary, Generators apply for the purpose of grant of connectivity by specifying indicative region as its target beneficiary. As beneficiary cannot be identified under target region, system strengthening cannot by carried out for granting long term access by CTU. Therefore, LToA should not be granted till beneficiary is not identified. LToA to be granted only after beneficiary is identified.

Under Connectivity Regulations 2009, Sub clause 7 of Clause 8:

"A generating station, including captive generating plant which has been granted connectivity to the grid shall be allowed to undertake testing including full load testing by injecting its infirm power into the grid before being put into commercial operation, even before availing any type of open access, after obtaining permission of the concerned Regional Load Despatch Centre, which shall keep grid security in view while granting such permission. This infirm power from a generating station or a unit thereof, other than those based on non-conventional energy sources, the tariff of which is determined by the Commission, will be governed by the Central electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2009. The power injected into the grid from other generating stations as a result of this testing shall also be charged at UI rates."

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

Further, LToA already granted for generators without identified beneficiary, would come into effect only when developer is able to firm up the quantum and the beneficiary for the system. Till that time LToA shall be deemed not come into operation. Till then as per Clause 33 (7) of the CERC's Tariff Regulation, 2009 a generator is liable to pay only applicable SToA/MToA Charges as the entire power is sold under SToA/MToA in the absence of beneficiary.

5.2.3. Central Transmission Utility: The term 'Additional Approved Medium Term' may be replaced with ‘Approved Medium Term'. The first proviso reads as:

“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.”

This may be modified as below:

Provided 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 arises after the expiry of MTOA period.

5.2.4. Torrent Power Ltd.:

It is possible that the beneficiary may need to draw power from other sources than the identified generator due to various reasons (also mentioned in the Explanatory Memorandum of the proposed amendment). In such situation, the beneficiary would be drawing power from other sources under MTOA/STOA using the same drawl network. However, the proposed amendment is not clear whether such beneficiary/DIC would get offset for the MTOA/STOA.

We sincerely request that the CERC may like to provide better clarity on such situations as PoC charges are now proposed to be payable based on peak injection *or* drawl for the applicable period (i.e. inclusive of drawl under LTOA, MTOA, STOA & Deviation (if any)). The same would ensure avoiding burden of double recovery of transmission charges from DIC.

In view of above, we would like to submit that the proposed amendment in clause (5) of Regulation 11 of the Principal Regulations may be modified as given below:

"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 payable by DICs for the Long-term Access to the target region without identified beneficiaries.

Provided also that a DIC who has been granted Long-term Access to beneficiaries shall be required to pay applicable POC injection charge plus the average of the POC demand charge 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."

5.2.5. Lanco Kondapalli Power Limited: In line with the above said comment, as per Clause 33 (7) of the CERC's Tariff Regulations, 2009. "Transmission charges corresponding to any plant capacity for which a beneficiary has not been identified and contracted shall be paid by the concerned generating company." A generator is liable to pay only applicable SToA/MToA Charges as the entire power is sold under SToA/MToA in the absence of beneficiary, till the beneficiary is identified. From the time when beneficiary is identified proposed clause shall be applicable.

5.3. Clause (9) of Regulation 11

5.3.1. Association of Power Producers (APP):

1) (Para 2)It is to be clarified that off-set should be provided against the LTA charges irrespective whether the MTOA/STOA is applied by the generator (or) trader (or) customer for a particular generating station.

2) (Para 3)This clause should be changed to include the MTOA as well. For example, a power plant which does not have any LTA, but is supplying under MTOA (or) STOA should be allowed to set off the charges paid under both MTOA and STOA against the charges paid for approved injection.

3) (Para 4) Injection charges paid under collective transactions should be offset against the corresponding charges paid by generators for Approved injection POC.

5.3.2. Central Transmission Utility:

1) The draft amendment suggests four provisos. The following changes in the respective provisos are suggested: The first proviso of Draft Regulations (Third Amendment) (at page 10) may be re-drafted as below:

"Provided that the DICs 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 Approved injection POC charges and Approved Demand POC charges in the following month limited to first part of the bill for injection and withdrawal charges, each settled separately."

2) The second proviso of Draft Regulations (Third Amendment) (at page 10) may be re-drafted as below:

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 Approved injection, after offsetting the amount of Medium-term Open Access and Short-term Open Access in the following month limited to first part of the bill for injection and withdrawal charges, each settled separately.

3) The Third proviso of Draft Regulations (Third Amendment) may be re-drafted as below:

Provided also that the injection POC charge/ withdrawal POC charge for Short-term open access granted to a DIC (other than generators and traders) shall be adjusted in the following month limited to first part of the bill for injection and withdrawal charges, each settled separately.

4) These modifications are suggested to smoothen the process of the adjustment of Short Term Open Access and medium term open access charges. It is submitted that the corresponding changes may accordingly be incorporated in the BCD procedure also.

5.3.3. Torrent Power Ltd.:

It is possible that the beneficiary may need to draw power from other sources than the identified generator due to various reasons (also mentioned in the Explanatory Memorandum of the proposed amendment). In such situation, the beneficiary would be drawing power from other sources under MTOA/STOA using the same drawl network. However, the proposed amendment is not clear whether such beneficiary/DIC would get offset for the MTOA/STOA.

We sincerely request that the Hon'ble CERC may like to provide better clarity on such situation as PoC charges are now proposed to be payable based on peak injection or drawl for the applicable period (i.e. inclusive of drawl under LTOA, MTOA, STOA & Deviation (if any)). The same would ensure avoiding burden of double recovery transmission charges from DIC.

In view of above, we would like to submit that the proposed amendment in Clause (9) of Regulation 11 of the Principal Regulations may be modified as given below:

"Provided that the DICs 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 access based on Peak Infection/withdrawal;

Provided further that a DIC generator who has been granted Long-term Access to a target region without identified beneficiaries, shall be required to pay applicable POC injection charges plus the Average of the POC demand charges among all the DIGs 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 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;*

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."

In addition to the above, we also like to submit that short term charges of collective transaction may also be adjusted against Injection/Drawl PoC charges (as applicable).

5.3.4. Adani Power Ltd.

1) It is welcome step. It will encourage generator to seek appropriate LTA at right time enabling concerned agencies to plan and develop transmission system on time.

2) Injection PoC charge/withdrawal PoC charge for bilateral short term open access are allowed for the adjustment of transmission charges against LTA without identified beneficiaries whereas the same is not allowed under collective transactions. Presently, majority of the power procurement by DISCOMS are taking place through collective transactions and not through bilateral contracts. In collective transactions, the DIC who is paying the injection PoC charge is clearly known whereas the beneficiary who is drawing this power is not known. Hence, in our view, the DICs are to be allowed to set off the injection PoC charges for the collective transactions and lowest withdrawal PoC charges against LTA without identified beneficiaries.

<u>Rebate associated with adjusted charges:</u>

With regard to adjustment of transmission charges of STOA against transmission charges of LTA without identified beneficiaries the following is submitted before the Commission on the issue relating to rebate on the amount paid towards STOA transactions and adjustment of the said amount from the LTA bill of DIC who has taken LTA without identified beneficiary.

<u>For example:</u>

When the DIC has transacted the power under STOA in any month, the DIC will pay the applicable STOA charges within two days from the date of application. Whereas the DIC will receive the bill for LTA charges for the any month in the first week of next month after issuance of RTA i.e. LTA bill for March 2014 will be issued to DIC in the first week of April 2014.

In the LTA bill, CTU has been showing the LTA charges corresponding to the full LTA quantum and claiming the balance amount after deducting the applicable amount corresponding to the STOA transaction under taken during the month preceding month for which the LTA bill is claimed, i.e. in the LTA issued for March 2014, set off is allowed for the STOA transactions undertaken in February 2014.

This tantamount to receipt of LTA charges from the DIC for the month of March 2014 well in advance i.e. in February 2014 itself, which means that the LTA charges are paid more than one month in advance. Under these circumstances, it would be reasonable and logical to allow full rebate (if not interest) on such setoff amount irrespective of the date of payment of the net amount by the DIC.

As per present practice CTU has been allowing *2%* rebate on the gross LTA bill amount only in the event of payment of the net amount (Gross amount - Setoff) within five days by the DICs. CTU is not allowing 2% rebate on the setoff amount, if the payment of the net billed amount is made after 5 days.

In view of the submission made above, we request the Commission to kindly incorporate a suitable amendment to the Regulation to facilitate full rebate on the setoff amount irrespective of the actual date of payment of the net billed amount.

5.3.5. Jaiprakash Power Ventures Limited:

In reference to the cited subject, it is submitted that the company, while, appreciating the view/stance taken by the Commission to link the payment of Transmission Charges with peak injection / withdrawal, would like to bring to the kind notice of the Commission, the appalling state of the Hydro Power Generators with respect to the payment of Transmission Charges as per the Central Electricity Regulatory Commission (Sharing of Inter State Transmission Charges and Losses) Regulations, 2010.

As per the aforementioned regulations, the Long Term Access (LTA) charges are currently being levied on the basis of quantum of LTA taken which is generally the installed capacity and also, it is well known that in the case of Run of River (RoR) with pondage or without pondage Hydro Power Plants, the Plant Load Factor (PLF) is about 50% which is about half of the PLF at which the Thermal Power Plant runs. Therefore, in effect, the current scenario is that, for the same installed capacity, the actual per unit transmission charges being paid by the Hydro Generator is about double the actual per unit transmission charges being paid by the Thermal Generator. This unjust burden of transmission charges on the Hydro

Generators is a cause of disappointment for not only the existing Hydro Generators who are feeling brunt of this but also for the developers who are planning to venture into Hydro Generation.

It may be noted that, as per the report of CEA, during last sixty years, the share of hydro Power Generation has considerably reduced in the country from 45.68% (End of 3rd Plan) to 25% (End of 9th Plan). The percentage of Hydro Generation as on 31st July 2013 was only 17.5% whereas "Hydro Power Policy 2008 of Ministry of Power, Government of India" specifically preferred an ideal mix of Thermal and Hydro of 60:40 to meet the present demand of peaking and non-peaking power requirement uses its inherent capability of peaking to supply maximum power during the peak demand hours of the day even during the season when wafer levels are low. Therefore, the proposed methodology seems punitive / penalizing to the Hydro Generators for doing peaking operations & supporting the grid during peak demand hours. The proposed amendment may prove to be huge disincentive for the Hydro Generators who knowing that they would be charged on the basis of peak injection may ultimately resort to avoid peaking in the peak demand hours during the season when water levels are low and therefore, defying the very purpose of hydro plant which is peaking.

Also, to mention, the commission has very well addressed the concern of merchant Hydro Generators in clause 4.4.12 of the "Explanatory Memorandum - Third Amendment to Sharing Regulations", but the same has not been incorporated in the draft amendment. It is suggested that a different methodology for application of transmission charges may be designed for Hydro Generators keeping in mind its seasonal variations, low PLF etc. Also, the applicability of charges need to be clarified with respect to the plants which are selling power under Long Term but a part of their generation is being also sold through merchant route.

Thus, it is requested to the commission that keeping in view the unique nature of Hydro Power Plants and to promote hydro generation in the country, the Hydro Generators should be made liable for payment of LTA charges only to the extent of their Design Energy.

5.3.6. GRIDCO: Peak injection or peak withdrawals are momentary in nature and are approximately 16% of day. For momentary drawal or injection, the transmission charges for rest 85% of the day should not be charged at same rate. If possible the transmission charge rate should be calculated for peak and off peak hours.

5.3.7. POSOCO:_Adjustment of STOA / MTOA charges against LTA charges paid
In the draft Regulations adjustment of STOA charges against LTA charges has

been proposed. However, adjustment is proposed to be based on quantum rather than charges paid. This would be prone to errors / disputes and it is suggested that adjustment may continue to be done based on charges paid.

Further adjustment of withdrawal charges has also been proposed. It may be relevant to mention that there are many intra-state entities that draw power through STOA. The adjustment would be for the state utility only, and will have to be done for each 15 minute block after segregating different transactions. The process will become very complex and prone to disputes.

5.3.8. Bihar State Power (Holding) Company Limited

(1) In the principal regulations of the Ld. CERC, Load flow profile is set for average loading which results into high injection charges which are ultimately borne by the constituents as per the share allocation. In the instant Draft Regulations Ld. CERC has now proposed Approved Injection by the generator & Approved Withdrawal by DICs on the basis of peak injection & peak withdrawal based on actual peak during corresponding application period of last year validated by Implemented Agency for any Designated ISTS customer.

(2) It is relevant to mention that significant fluctuation in generation & demand of power has been witnessed during peak and off peak conditions. It is also imperative to point out that hydel generation start to decrease w.e.f. Mid October and operate during peak hours only that too on reduced generation up to April and full generation from hydel power stations are available only during peak monsoon period on RTC basis. It is also difficult to predict rightly about the good monsoon owing to significant climatic change being witnessed since last few years. Hence, if the Load flow profile is set on the basis of maximum injection & maximum demand may cause high Injection & Withdrawal PoC charges which are ultimately borne by the DICs (DISCOMs) as pet the share allocation and ultimately by the end consumers. It may not be out of place to mention that good monsoon period is also linked with considerable decline in demand of power which also compels the DICs to surrender power owing to poor demand. Since, surrender of power comes into effect in the schedule after four 15 minute time block, wastage of power offered for surrender to RLDC either at zero price or lesser price under UI between the intervening period and mandatory payment of Capacity charges of the quantum of power surrendered, all these factors causes severe financial shock to DICs.

5.3.9. **<u>Indian Energy Exchange:</u>** As per para 5 (3) at page 10 of the Draft Notification, adjustment of Short Term Open Access (STOA) charges with Long Term Open Access (LTOA) charges are provided in case sale of power is on bilateral basis.

Further, Para 5 (3) Fourth proviso of draft notification stipulates that there would not be any adjustment of STOA charges with LTOA charges if transaction has taken place in the collective mode. This stipulation will increase cost under collective transaction as compared to cost under bilateral transaction because of which a generator will prefer to sell power under bilateral and will resort to sell through Exchange (collective transaction) only as a last option. This will put exchanges in a disadvantageous position.

5.3.10. **Lanco Kondapalli Power Limited:** In line with 4th comment, as per Clause 33(7) of the CERC Tariff Regulations, 2009, transmission charges corresponding to any plant capacity for which a beneficiary has not been identified and contracted shall be paid by the concerned generating company. A generator is liable to pay only applicable SToA/MToA Charges as the entire power is sold under SToa/MToA in the absence of beneficiary, till the beneficiary is identified. From the time when beneficiary is identified proposed clause shall be applicable.

5.3.11. **SN Power**: Payment of Demand STOA Charges by generators: Retail customers are ultimate beneficiaries of the upstream system development and responsible for payment of fair and efficient prices as determined by the market or regulatory process. This includes charges for energy, transmission system, distribution system and any incidental costs. Under the current system, generators selling in the merchant mode are required to pay for both injection as well as demand charges and recover the same through the tariff. However, generators selling under long term PPA are not required to pay the same. This practice is detrimental to development of a robust merchant market as it distorts and biases the commercial strategy. As transmission system costs are to be paid ultimately by the distribution companies/retail customers, it is requested that the method of charging for transmission capacity should be independent of mode of selling power i.e. short term/medium term/long term.

Adjustment of Transmission Charges in Collective Transaction: Payment against LTA is currently adjusted towards short term transactions in case of bi-lateral deals. However the same is not done for collective transactions. A similar adjustment is requested to ensure a level playing field is maintained between different platforms

5.3.12. **Shri Ravinder:** Clause 11 (3) & clause 11 (9):

(1) These are very progressive proposals to undo the current formulation of double charging the generator in case of selling outside the target region on medium and short term service. The intent is to offset the charges recovered through short and medium term service from the monthly invoice for LTA

Service and also take in to account the quantum of power in MW as per LTA and quantum of power reserved under MTA and STOA.

(2) The proposal is very complex and requires paying charges a number of times. A simple and more elegant solution is explained below through an example: Say there is a 2*660 mw power plant coming up.

(3) It should be obliged to seek LTA of 1320 MW. If say long term PPA is there for 320 MW then balance 1000 MW would be treated as LTA target regions and transmission would be built accordingly. 320 MW would fall in effective LTA category and 1000 MW in LTA target category. Up to 1000 MW the generator would have the flexibility to avail MTA, STOA or access through Power Exchange without having to pay MTA or STOA or PX charges. He will be simply billed for 1000 MW LTA target. In case the above generator applies for STOA beyond 1000 MW it will have to pay 50 percent premium over and above the applicable PoC rate as opportunity cost. STOA customers having LTA target would have higher priority in STOA service. Similarly the drawing entities would have the option to seek LTA target for their short term need, the transmission capacity would be built for their additional drawl and they get a monthly LTA target bill at applicable drawl rate and average injection rate. If a load seeks STOA without a back up LTA then it would have to pay premium @50 percent as in the case of generator. New sub stations for additional drawl by a State would be created against LTA not simply on request.

6. Amendment to Annexure of the Principal Regulation

6.1. **Existing:** Proviso under Step 4 under Para 2.7.2 of Annexure of the Principal Regulations

6.1.1. **<u>POSOCO:</u>** **Treatment of HVDC:** The 2nd amendment to the Sharing Regulations provides as under:

"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."

In the draft Regulations, the above proviso is sought to be removed. The reason of the proposed change has not been discussed in the explanatory memorandum. The NEW grid and SR grid have been synchronized on 31st

December 2013 and a single model for the entire country would be prepared for the next PoC computation for Q1 of 2014-15. Thus impact of the above change in Regulation is yet to be seen. It may be appreciated that a hybrid system is necessary for transfer of large quantum of power and new HVDC lines have to be facilitated. The Hon'ble Commission vide SoR to 2nd amendment to PoC Regulations had observed as under:

"We have considered the suggestions and objections of the stakeholders. It is clarified that the Talcher-Kolar HVDC Bipole link was specifically constructed for evacuation of power from Talcher Stage– II to the Southern Region. This link is also used for transfer of power to other DICs in Southern Region. We are therefore of the view that the cost of this asset has to be borne by the DICs of the Southern Region by scaling up the POC charges of DICs of Southern Region proportionately."

The following may be taken into account regarding sharing of HVDC charges:

1. 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.
2. 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.
3. An 800 kV 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.

It suggested that since HVDC systems are national assets, the existing provision may be retained.

6.1.2. CEA Comments: 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. In this regard, it is suggested that instead of the with 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.

7. General Comments from Stakeholders

7.1. Indian Wind Power Association (IWPA):

1) **Point No. 4.4.13** of explanatory memorandum of draft regulation proposed: *As the computation of transmission charges is proposed to be done on Peak scenario, there may be problem that during the system Peak, injection of wind /solar will be minimum and their usage will not be reflected. However, transmission system is being created to evacuate its full capacity at least for some duration during high wind season. Therefore, it is proposed that for computing the rates, their injection corresponding to maximum energy during the quarter shall be considered but for sharing of transmission charges, these rates shall be applied on installed capacity for injection as well as withdrawal.*

2) **Point No. 4.4.15** of explanatory memorandum of draft regulation proposed: This change will address the concern of various stakeholders and it will also balance the need for transmission planning process and more appropriate allocation of transmission cost among various users. This will require consequential amendments in following clauses of the Regulation:

   a) Clause (5) of Regulation 8 of the Principal Regulations shall be modified.

   b) For Hydro and Wind generation, suggestions are invited from stakeholders on methodology to be followed for computation of transmission charges so that sufficient transmission system for their evacuation is created and sharing of the transmission charge is fair, considering environmental benefit and mandate of Electricity Policy on promotion of Hydro Power and Renewable Power. Specific Provision shall be formulated on the basis of suggestions.

3) IWPA Suggestions:

   i) Fixation of point of connection transmission charges and losses for hydro and wind generators availing ISTS shall be without prejudice to the figures specified by honorable commission in its order for conventional. We would request Honorable Commission to consider following grounds for calculating the charges applicable for hydro and wind generator availing ISTS**.**

   ii) Let suppose the Transmission charges are specified as Rs 95442/MW/Month which works out to Rs 3181/MW/Day. We observe that the appropriate way would be to charge in MWH and not MW since 1 MW of conventional power is not the same as 1 MW of Wind Power. If the 1 MW of conventional power transmits 24 MWH in a day then the same 1 MW of Wind Power transmits 6 MWH (considering PLF of 25%) in a day on an average*, therefore the charges should be on MWH basis as considered in the state of Maharashtra to treat*

Conventional and Wind Power on equal footing. Sample example depicting the variation in charges is tabulated below for ready reference.

Sample Calculation for Transmission Charges for RE Generator					
PLF **(**Conventional Generator)	100	*95*	90	85	
CUF (For Wind)	23	23	23	23	
Normal Transmission Charges as per Retail Tariff order, FY 13-14	95442	95442	95442	95442	Rs./MW/ Month
Transmission charges for Conventional generators	0.133	0.133	0.133	0.133	Rs./Unit
Transmission charges for RE Generator for Wind	21951.66 0	23107.01 1	24390.733	25825.432	Rs./MW/ Month
Transmission Charges per Unit	0.030	0.032	0.034	0.036	Rs./Unit

Transmission charges/losses for Wind Power may be levied on Energy Basis and not on capacity basis as the PLF of Wind Power projects is not more than approx. l/3rd of that of conventional.

Formula for Transmission charges calculation

4) Normative PLF for conventional/CUF for respective wind and hydro Generator = Normal Transmission charges as per retail tariff/Transmission charges for wind and hydro Generator.

Transmission charges for wind and hydro *Generator = CUF for respective* wind and hydro *Generator * Normal Transmission charges as per retail tariff/ Normative PLF for conventional*

i) Transmission charges for RE Generator.

ii) Applicable normal Transmission Charges Rs. 95,442/MW/Month

iii) Transmission Charges for RE Generator (23%/ 85%)*95,442

iv) Rs. 25,825/MW/Month

v) Rs. 0.036/Kwh

5) The other part of determination of point of connection charges and losses is basis of peak injection and peak drawl as basis taken for conventional which will

not reflect the true picture for wind and hydro, this difficulty is already envisaged by the regulator in its draft, where seasonal variation need to be accounted.

6) **IWPA Request w.r.t point 3**

i) We request the Honorable Commission to kindly consider the below formula to determine the transmission charges applicable for wind and hydro generators respectively

Transmission charges for wind and hydro *Generator = CUF for respective wind and hydro Generator * Normal Transmission charges as per retail tariff/ Normative PLF for conventional*

ii) We request the Honorable Commission to kindly consider the <u>high wind and low wind season for complying the charges and tosses</u>. In view of the above we pray before this Honorable Commission that in order to optimally harness the Wind Potential of country *as* well with solar , the above suggestions may be implemented in best interest of all in general.

iii) Further, this Hon. Commission may look into certain matters being not addressed in the draft regulation, while have direct impact on workability of the proposed amendment in the existing regulation. Hence, we request this commission to please consider such issues also while pronouncing the final order in this matter.

7.2. Association of Power Producers:

7.2.1. **Applicability of Transmission Charge and Losses:** CERC may give directives to the State Electricity Regulatory Commission to exempt levy of state transmission charges & losses for solar and wind based generation selling power outside the host state through combination of STU/CTU network commissioned before 30.06.17.

Exemption of state transmission charges and losses to wind and solar based generation projects will encourage / augmentation of renewable power capacity in the country and would also help reduce carbon emission intensity of GDP as announced by GOI in recent Conference of Parties on climate change and the same also would be in line with the National Action Plan on Climate Change for reduced carbon emissions.

7.3. Additional inputs from Indian Energy Exchange (IEX)

In the Day-Ahead markets, the final set of buyers and sellers are selected and set of buyers and sellers are scheduled without identifying one-to-one pair. All these DICs (buyers and sellers) pay PoC charges irrespective of their locations. Had there been pairing of buyer and sellers, there would not be any PoC Charge payment for pairs within a DIC. We have observed that in current market situation, there are substantial intra-State (or say intra-DIC) transactions. We propose that to further rationalize the transmission charges payable by participants in Day-Ahead Market, we may allow to prepare a sub-set of buyers-sellers within a DIG and there will be no POC Charge payable for such a sub-set. The benefits so accumulated by preparing sub-sets will be socialized among all participants within DIC.

For example, if there is cleared buy volume within a State (DIC) of 200 MW and sell within the State was 500MW, then for 200 MW intra-State sub-set, no PoC Charges should be payable, Sell PoC Charge on 300 MW should only be payable. If Total cleared volume in the market is 2000 MW, then PoC Charges will be payable by 1800 MW of buyers and 1800MW of sellers, the savings from no PoC Charge payment for 200 MW would be socialized among all participants within DIC.

7.4. Additional comments by POSOCO: Implementing Agency (Sub-clause n of Clause 1 of Regulation 2 of the Principal Regulations)

<u>As per provisions of the Regulations, NLDC was the Implementing Agency for 1st two years from date of notification of the Regulations</u>. Further, the Hon'ble Commission, vide order dated 31.8.2012 has designated <u>NLDC as Implementing Agency till 15.6.2014</u>.

As the PoC mechanism was being introduced for the 1st time in the country, a lot of efforts were required to bring all stakeholders on board and implement the Regulations. Now, more than two and half years have elapsed and computation process has been streamlined. <u>Computation of PoC charges and losses is not one of the core functions of NLDC and it is suggested that w.e.f. 16.6.2014 the role of implementing agency may now be assigned to some other organization</u>.

7.5. Additional Comments by Sh. Ravinder

7.5.1. Clause 2 (1)(i) Needs review.

7.5.2. **Clause 7 (1)(t):Regarding losses**

Comments are not clear. Losses have to be applied as per Regulations. National Electricity Policy gives general recommendation. What amendments are required in the existing regulations and why, should be made clear.

7.6. Additional Comments by Central Transmission Utility:

7.6.1. **Sub-clause (d) of Principal Regulation 2 (**Approved Medium term injection**),**

7.6.2. **Sub-clause (e) of Principal Regulation 2 (**Approved Short term injection**),**

7.6.3. **Sub-clause (g) of Principal Regulation 2 (**Approved Medium term drawal**),**

7.6.4. **Sub-clause (h) of Principal Regulation 2 (**Approved Short term drawal**):**

This carries no relevance now as the load flow file is proposed to be made on actual peak condition. Therefore, this may be deleted.

7.6.5. **Sub-clause (4) of Principal Regulation 5**

The Regulation states that PoC charges shall be computed in terms of Rs/MW/month. In this regard, it is not clear as to which 'MW' quantum shall be used / applicable in the Denominator. One of the anomalies in the explanatory memorandum is pertaining to using different values for arriving at the Rate (Rs/MW) and then reconverting it into Rs. Crore by multiplying with entirely different values. The present methodology does not bring out as to how this anomalous situation shall be addressed. Here, it would be pertinent to mention that in our opinion, the 'MW' value as appearing in the load - flow studies should be used for computation of charges.

7.6.6. **Sub-clause (p) of clause (1) of Principal Regulation 7**

The concept of seasons has been replaced by quarters. Thus, the following sentence may be deleted. Such changes shall then be attributed to peak and other than peak periods of such seasons based on the hours constituting these periods.

7.6.7. **Sub-clause (r) of clause (1) of Principal Regulation 7**

The concept of seasons has been replaced by quarters. The first sentence may be replaced by:

The loss allocation factors shall be computed for each application period using the hybrid method as explained in Annexure -I of these Regulations.

7.6.8. **Regulation 10(1) (b)**

The term 'Zonal Point of Connection charges' may be replaced by 'Zonal charges.

7.6.9. **Clause (4) of Principal Regulation 11:**

The first proviso of clause 4 of regulation 11 reads as below:

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.

The above provision may be re-drafted as below:

Provided that the list of transmission assets along with the approved transmission charges for which billing has been done shall be uploaded on the website of CTU.

7.6.10. **Clause (6) of Principal Regulation 11**

The third part of the bill shall be used to adjust any variations in interest rates, FERV, rescheduling of commissioning of transmission assets, etc. as allowed by the Commission for any ISTS Transmission Licensee. Total amount to be recovered / reimbursed because of such under-recovery / over-recovery shall be billed by CTU to each Designated ISTS Customer in proportion of its average first part of bill over an Application period. This part of the bill shall be raised on 1st working day of the months of March (for Oct-Dec), June (for Jan-Mar), September (for Apr-Jun) and December (for Jul-Sep) in the year.

7.6.11. **Clause (7) of Principal Regulation 11**

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

For Generators:

In case Average MW injected during time block of positive deviation is greater the sum of Approved Injection, Approved Additional Medium Term Injection and Approved Short Term Injection, then for the first 20% deviation, transmission charges shall be at the zonal Point of Connection charges for the generation zone. For deviation beyond 20%, the additional transmission charges shall be 1.25 times the zonal Point of Connection charges for the generation zone.

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

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

[(Average MW Withdrawal during time blocks of such negative deviation)]

For Demand:

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

For deviation beyond 20%, the additional transmission charges shall be 1.25 times the zonal Point of Connection charges for the demand zone. In case a withdrawing DIC becomes a net injector the additional transmission charges shall be computed as

[*1.25×PoC Transmission Charge for the generation zone in Rs/MW /time block****]***
× [(Average MW Injected during time blocks of such negative deviation)]

This bill shall be raised by the CTU within 3 working days of the issuance of the Regional Transmission Deviation Account by the RPCs.

The last sentence may be re-drafted as below:

This bill shall be raised by the CTU for every quarter period based of Regional Transmission Deviation Account issued by the RPCs within 15 days of its issuance. The bills for such deviation accounts are quite small. This modification shall reduce the billing activity for such small amounts of bills.

7.6.12. **Clause (5) and clause (7) of Principal Regulation12**

These clauses deal with provisions of payment by DICs and disbursement to transmission licensees and owners of deemed ISTS and also pro-rata reduction in disbursement due to delayed payment to ISTS licensees and other non-ISTS licensees whose assets are being used for Interstate Transmission services.

In the existing Regulations, the network was terminated to 400 kV level whereas in the 3rd amendment full scale network is to be considered for load flow and YTC corresponding to such network. It is apprehended that substantial Intra-state Network plays a role in delivering ISTS power resulting into accrual of their charges.

The billing to DICs should therefore be based on the Net of charges after adjusting the charges for usage of intra-state network. Accordingly, the relevant provisions of above referred clause and also elsewhere required in the Regulations may suitably be amended.

7.7. Comments on Transmission Charges for Hydro plants:

7.7.1. **AD Hydro Power Limited:** It is submitted that:

1) **A D Hydro Power Limited (ADHPL)** is operating a 192 MW Run of the River Hydro Electric Power Plant with small pondage and utilizes water of Allain and Duhangan Nallahs (tributaries of Beas River in District Kullu) for generation of electricity. Pursuant to the Long Term Open Access Approval in NR and BPTA signed with CTU, it is injecting the power at Nalagarh s/stn of PGCIL. The plant is selling the power on short term basis.

2) **Malana Power Company Limited (MPCL)** is operating an 86 MW Run of the River Hydro Electric Power Plant with small pondage and utilizes water from Malana River for generation of electricity. Pursuant to the Implementation Agreement signed with the State Government, entire power is required to be sold in the interstate for which a Wheeling Agreement has been signed with HPSEB according to which, Plant through a dedicated transmission line has been connected to the substation of HPSEB at Bajaoura and as per Wheeling Agreement upon injection of Injected Energy by the Company at the Interconnection point, Transferable Energy (injected energy less state losses and free energy) shall be deemed to have credited to Company's account and debited to Himachal Pradesh Board account at the Inter-state Point (which is Nalagarh Sub-station of PGCIL). The plant is selling power on short term basis. Based on the operational issues of both type of plants, it is submitted that for ROR/Hydel Plants, following issues are very important and need to be addressed while finalizing the Third Amendment Regulations for Sharing of Transmission Charges and Losses.

3) Any Run of the River Hydro Electric Project solely depends on the availability of water and this water is obtained from the water source. Generally these water sources are snow fed as well as rain fed and the water available at any point of time depends upon the vagaries of nature. During the Peak Season (Monsoon and summer), the inflow available, feed water in large quantities to the project and this water can be used for the generation of electricity round the clock at full design energy. The peak season is generally considered during the months of June, July, August and September in any year.

4) During Lean Season, water available is mainly from melting snow from the higher reaches and the quantity of water depends upon climatic conditions.

During this period, the flow of the water is not sufficient to run the generators at full capacity and therefore during these months the water is first stored in the pondage and when the quantity of water in the pondage is sufficient to generate electricity at full installed capacity, then the plant is run to generate electricity. The volume of the pondage is designed based upon the geographical and hydrological constraints of the area and thus has a limited capacity. The water in the pondage can generate electricity only for a fixed period of time only. In case of ADHPL, it is able to run the plant for about three hours in a day only.

5) Therefore, in a Run of the River (ROR) Hydro Electric Plant, generation of electricity varies grossly from month to month, even from day to day due to variation in the availability of water depending upon the climatic conditions. Therefore, a ROR Hydro Power Plant, is capable of operating at the full capacity during the Peak Season, when there is sufficient discharge and sometime it is not even able to operate even at the 10% of the installed capacity when there is minimum water in Lean Season. It is also a note worthy fact that energy generation grossly varies from similar size of Hydro power Plants located at different locations / River Basins as the availability of water in each River Basin is different. As such most of the time the capacity in the ISTS remains unutilized by the Hydro Power Generator.

6) While comparing generation in terms of units and plant load factor for the generation corresponding to same installed capacity grossly varies from one source of generation to another source of generation. A thermal power plant using coal as source of generation can operate at about more than 90% plant load factor, a thermal power plant using gas as source of generation can operate at an about more than 70% plant load factor at all times whereas a run of river hydro power plant using water in a river can operate at an average of about 45% plant load factor in a year only which means the run of river Hydro Power Plant cannot be run for the full installed capacity. This leads to a gross variation (which is almost double) in capacity to generate energy from one source to another for the same installed capacity, incidentally in case of a run of a river Hydro Power Plant the generation of energy is lowest as compared to any other source like Thermal Generation from Fossil Fuel or Gas.

7) In case of Hydro Power Generator, free power / royalty is required to be paid to the State Government under the power policy. In addition to this, before being injected into the ISTS, the generation further gets reduced by virtue of

the auxiliary consumption, transformation losses and transmissions losses wherever generating plants are connected to ISTS by a dedicated transmissions line because these plants are located in remote areas only.

8) Unlike the power generators whose generation of power is not affected at any time, the ROR Hydro Power Plant is constrained from generating power equal to its installed capacity for the major part of the year even if the plant is available for generation and is liable to pay LTOA charges/POC Charges at the equal level without factoring in the difference in the plant load factor. The result is that the cost of transmission of power is more than (almost double) the cost of the transmission of power of generators other than Hydro Electric Power Generators.

9) <u>The Present Regulations do not provide the level playing field for different type of Generators</u>. In view of this ADHPL filed a Petition no. 180/2013 before CERC prayed for suitable amendment/issue of new regulations to provide for a level playing field. CERC dismissed the petition stating that:

"We have perused the petition and heard the learned counsel for the petitioner. After going through the contents of the petition, it appears to us that the petitioner is seeking to get incorporated certain provisions in the relevant Regulations so that transmission charges for all types of generators are same for equal amount of energy injection i.e independent of LTA. According to the petitioner, regulation is required to provide for a level playing field to sustain in the competition and CERC has the power to make regulations at any time for removal of difficulties. The Commission is of the view that the existing provisions of Sharing Regulations are adequate for calculation of transmission charges. Without going into the merit of the issues raised, we intend to clarify that filing of the petition is not the proper process for initiating the amendment to the existing regulations. The Commission under Section 178 of the Act has been vested with the power to make, amend and repeal the regulations on the subjects which have been authorized under various provisions of the Act. Action to make or amend the regulations is initiated when the Commission is satisfied that there is a need for such regulations or amendment to the existing regulations. Therefore, no direction is required to be issued on the prayers of the petitioner."

10) It is mentioned in Explanatory Notes that ADHPL's maximum injection during the year 2012-13 was 229 MW against the LTA of 192 MW. The noteworthy fact is that, ADHPL injected this energy during the peak season with in its installed capacity and permissible overload which was not constant throughout the year. The explanatory also do not inform about the reduction

in energy during the off peak season and average energy injected by ADHPL during the year to exactly understand the utilization of the system.

11) **Existing Regulations:** It is submitted that Sharing Regulations are not adequate to provide the level playing field. Main issues involved in the present regulations are as under:

a. Regulation 5 deals with the Mechanism to share the Transmission Charges. Regulation 5(4) specifically mentions that Point of Connection Transmission Charges shall be computed in terms of Rupees per Mega Watt per Month. Therefore Regulation is not able to fully address the grievance of ROR/Hydel or any renewable source of generator unless such computation effectively takes into consideration the Plant Load Factor to arrive at the actual usage of the Transmission System.

   This grievance will further increase in case the concept of the Maximum Injection will be used to arrive at the POC charges to be shared by Generators because ROR Plants are seasonal in nature and are also able to meet the peaking requirement of the utilities on daily basis for a very small duration of 3-4 hours only. In this manner, it will be their maximum injection at any point of time in the Application Period shall be considered for sharing of the POC Charges irrespective of the fact that maximum injection will be only for a small duration in a day or for a very small part of the year which is only 4 months in case of ROR Plants.

b. Regulation 4(1) of Principal Regulations Dated 15th June 2010 stated that POC charges and Loss allocation factors for all DICs shall be based on: (a) Using load flow based methods; and (b) Based on Point of Connection charging method. This means the node charges will vary for different DICs based on the carrying distance of the power flow.

   However, while notifying the charges as per the procedure mentioned in the regulation, a uniform POC charge has been notified for each node/point which is required to be paid by the DICs connected at that point. Therefore, it appears that during this period, all the DICs have paid POC charges in the corresponding slab irrespective of the actual power flow.

   In case of ADHPL, power is injected at 220 kV voltage level at Nalagarh. However, it was required to share the POC at the notified rates without knowing the actual power flow. As a result, increase in Transmission charges after Sharing Regulations were enforced, was significant. In view of this, it is also needful to revisit the charges paid by DICs for use of the system. ADHPL has requested to NLDC to provide the details of the Power

Flow.

c. Regulation required the submission of Data by the DICs for the block of months i.e. April to June, July to September, October to November, December to February and March.

   It is submitted that, in case of ROR Plant the data furnished in the above blocks and used for arriving at the transmission charges to be shared, might not have given the correct picture because June, July, August and September are the peak season months, therefore needed to be classified together.

d. It is submitted that Tariff is approved under the Tariff Regulation for any new Transmission Element or strengthing for the purpose of a new generating station or utility for a designed capacity irrespective of the Generation and is required to be recovered. This means use of maximum injection concept under Sharing Regulation will simply increase the Revenue of CTU/Licensee.

e. IEGC which requires to deviate from the schedule based on the availability of the water to a ROR Hydel Plant. This means a Hydel Plant will always be subject to change in the generation, therefore Scheduled Injection and actual injection will not be same. In view of this ROR Plant will always be under prejudice because of the concept of Maximum Injection.

7.8. Consolidated Comments from Bihar State Power (Holding) Company Limited:

In the light of the Hon'ble Chief Minister, Bihar letter to Hon'ble Prime Minister, India on the issue of increase in transmission charges of Bihar based on PoC mechanism, Ministry of Power, Govt. of India has taken a meeting under the Chairmanship of Additional Secretary on 10.02.2014, to discuss the Method of Sharing of Inter State transmission charges based on PoC mechanism. After detailed deliberation, following decisions were taken in the said meeting to carry out three models of study as mentioned below:

a. Model-I: POSOCO to carry out study on existing mechanism i.e. PoC;

b. Model-II: IIT Bombay to carry out study on minimizing the maximum regret basis;

c. Model-III: CERC to work out study on the proposed draft regulations;

Ld. CERC vide notification dated 07.02.2014 has issued draft CERC (Sharing of Inter State Transmission Charges & Losses) (Third Amendment) Regulations, 2014 and invited comments from the stakeholders. However, the main concerns of Bihar in the CERC (Sharing of Inter State transmission charges & Losses) Regulations, 2010 notified on 15.06.2010 & the draft regulation notified on 07.02.2014 are as follows:

(1) As per philosophy of PoC mechanism, the distant consumer from generation sources has to pay more charges for the same quantum of power drawl than nearest consumer.

(2) This implied that DISCOMs are supposed to tie up power contracts with their nearest generation sources otherwise the generation plant located in generation rich areas has higher transmission charges than plants located near the load centers.

(3) With the implementation of PoC mechanism w.e.f. 01.07.2011, the transmission charges of Bihar increases substantially (above 64%) causing additional financial burden of Rs. 13.00 crores per month (approx.) despite using the same transmission assets and for same quantum of power.

(4) It is relevant to mention that as per the new mechanism CERC slab for PoC charges based in the CERC Regulations, 2010, the applicable transmission charges payable to CTU for drawal of power by Bihar from Kahalgaon STPS of NTPC situated within the State is 30.22 P/Kwh, whereas the same power is drawn by West Bengal & Orissa at the rate 26.00 P/Kwh each. Similarly, the applicable transmission charges for drawl of power from Kahalgaon STPS by Delhi, Chandigarh, Uttrakhand & Jammu & Kashmir is at the rate 26.22 P/Kwh & 28.22 P/Kwh respectively. This lopsided tariff has resulted in increase of transmission charges of Bihar from Rs. 23 crores per month to Rs. 36 crores per month i.e. increase of 64% for the same assets.

    It is also essential to mention that as per Section 107 of the EA - 2003. "Learned CERC is guided by such directions, in the matter of policy involving public interest, as the Government of India gives to it in writing". In this regard, Additional Secretary, Ministry of Power, Government of India in the meeting held on 10.02.2014 has directed Lei CERC to workout study on the proposed draft regulation. But provisions of draft regulation issued on 07.02,2014 prior to the meeting held on 10.02.2014 have proposed some amendments in the Principal regulation, which are also not in consonance to the sensitivity of distance, direction and quantum of power flow

    Objections of Bihar on the Principal regulation on Sharing of Inter State transmission charges and losses notified by Ld. CERC has been communicated in writing to POWERGRID, Ministry of Power, CEA and also to Ld, CERC through petition and rejoinders lied by Bihar in the Hon'ble Patna High Court & Delhi High Court. The concern of Bihar on the Principal Regulation [i.e. CERC (Inter-State Transmission Charges & Losses) Regulations, 2010] and draft regulations issued vide notifications dated 7th February, 2014 are again highlighted for information of the Ld. CERC:

i) All the above mentioned factors needs appropriate resolution from Ld. CERC to strike a balance between Generators & Procurer to prevent financial loss for both otherwise proposal of CERC for determination of Approval Injection and Approval Withdrawal based on maximum injection & maximum drawal under peak condition will further compel the DISCOMs to incur huge financial loss owing to the discriminatory provisions in the draft regulation. Thus, the above said provision of the Draft Regulations is not sensitive to usage and therefore contrary to the provision of the National Electricity Policy & National Tariff Policy of Govt. of India & Section 61 (d) of Electricity Act, 2003.

ii) It is also essential to mention 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 by Ministry of Power, Govt. of India in the Gazette of India.

iii) It is a fact 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. AS per the applicable extant PoC mechanism the total transmission charges of the Inter State transmission licensee is divided in two part i.e. Injection & Withdrawal PoC charges. This transmission charge of the Inter State transmission licensee 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.

    Ld. CERC under para 9.4 of the Explanatory Memorandum-Third Amendment to Sharing Regulation is of the view that since Bihar is not receiving allocated power from ER generation plant, it should not be charged for injection PoC charges. But it is not clear whether Bihar under such situation shall be charged only for withdrawal PoC charges and if injection PoC charges are to be claimed along with withdrawal PoC charges then for which generating station. This also needs to be clarified by the Ld. CERC.

Similarly, it is also essential to point out that, under para 4.3.4 of the Explanatory Memorandum - Third Amendment to Sharing Regulation, Ld. CERC has stated that Delhi has low injection charges due to proximity of load. Delhi has an allocation of ER central sector power stations and also from DVC. It has also been stated by CERC that Bihar is not getting allocated power from ER Similarly; Delhi is also getting most of its power from Jhajjar thermal plant against allocation of power from ER, central sector generating plants. POWERGRID in every meeting have stated that the transmission lines are planned based on load flow/power tracing carried out keeping in view the future demand and supply & nature of power flow.

Surprisigly, such behavior of power flow pattern has not come in light in the simulation done by POWERGRID during planning stages; this shows the complete lack of foresightedness. This slackness of POWERGRID had caused aid will cause Bihar and other ER constituents to bleed profusely as it is the infrastructure and public money of Bihar and other ER constituents only are at stake. Bihar and other ER constituents had on every forum including before Ld. CERC objected for recovery of transmission charges of such lines (regional and inter regional transmission lines) created under the guise of ER system strengthening and for evacuation of ER surplus power beyond ER from its actual beneficiaries.

The above said issues have not been addressed by Ld. CERC in the CERC (Sharing of Transmission Charges & Losses) Regulations, 2010 (Principal regulations) nor in the current draft regulation. The provisions of the Principal regulations are mainly bent towards recovery of full transmission charges of POWERGRID from DISCOMs & also in favour of regions which were earlier used to pay higher transmission charges based on postage stamp method for supply of ER power to them. Now with the promulgation of the new PoC methodology the regions which were making payment of lower monthly transmission charges arc now subjected to pay higher monthly transmission charges for the same quantum of power and usage of same transmission, assets. Thus the provisions of the Principal Regulations and Draft Regulations is contrary to sub section 61 (c), 61 (d) & 62 (l) of the Electricity Act, 2003.

POWERGRID is implementing various high capacity corridors for evacuation of power from Bhutan Hydel projects & hydro projects located in Sikkim & North Eastern region mainly for Northern, Western & Southern Region. At the time of planning these high capacity corridors, Bihar was against the Sharing of the transmission, charges of the said transmission schemes as there was no identified beneficiaries and assets were planned for evacuation of surplus power to other regions. These transmission schemes were approved subject to payment of transmission charges by IPP developers.

iv) It may be out of place to mention that POWERGRID have signed Bulk Power Transmission Agreement with IPPs which provides for payment of transmission charges against the utilization of identified transmission system to be built, own and operate by POWERGRID. In the Regulatory approval also CERC clearly stated that IPPs are supposed to pay transmission charges as per the terms and conditions of BPTA.

v) There are so many assumptions in every step of calculating PoC Charges which results into illogical sharing of transmission charges. PoC rates is calculated on the usage of peak injection & peak withdrawal rather than actual power flow shall give wrong signal owing to the variation in demand during peak & off peak period.

vi) BSP(H)CL is not in favour of provisions of regulation 2 (1) (f) of the Draft Regulations in view of the deployment of additional manpower by BSPTCL for collection of the injection charges and withdraw charges from such Intra-state entities connected to STU and using Inter-state transmission system. The said provision of the Draft Regulations will cause BSPTCL to bear additional financial implication on the STU. It is suggested that Inter-Stale transmission licensee should settle injection & Withdrawl charges for utilizing the Inter-State transmission system directly with the concerned intra state entity in respect of the collection of the PoC injection & drawal charges. The said provision of the draft regulation should be deleted.

vii) As per para 4.3.3 of the Explanatory Memorandum - Third Amendment to Sharing Regulations, the provision of Scaling of transmission charges is incorporated to recover total transmission charges of the ISTS transmission licensee. Such provision will cause further penalization to DISCOMs, which are already getting higher transmission charges under existing PoC mechanism

It has been stated in the Explanatory Memorandum - Third Amendment to Sharing Regulation of the draft regulation that Scaling of PoC charges has been increased by 10 % to take care of the under recovery of the transmission charges arises owing to the injection of power by the State embedded entities in ISTS through STU and not paying transmission charges for use of ISTS. BSP(H)CL is not against recovery of such charges but it oppose the flat increase of PoC charges by 10 % as such an attempt is to penalize the DISCOMs for no fault of its own. POWERGRID should be directed by CERC to identify such state embedded entity and recover charges or bring the same in to the notice of Ld. CERC / BEERC. BSP(H)CL oppose such provisions as it is contrary to sub section 61 (d) of EA 2003.

viii) During the presentation given by the Director NLDC on Point of Connection (PoC) on 28.01, 2014 based on the direction of the Additional Secretary. Ministry of Power in the meeting held on 20.01.2014, NLDC suggested creation of more Grid S/s in Bihar, which will reduce the impedance level, and help in reducing the PoC rate (Injection & withdrawal) for Bihar. It is difficult to comprehend the suggestion of NLDC, why an additional transmission assets at 400 KV &, 220 KV is created knowing well that it is not actually required under the present demand scenario but to reduce only the impedance level.

ix) It was also clarified by the NLDC in the said presentation on 28.01.2014 that NTPC, Kahalgaon power allocated to Bihar is not coming from its original path i.e. associated transmission lines of Kahalgaon Stage-I & II created by POWERGRID for evacuation of Kahalgaon power and also due to non existence of transmission link between Purnea (PG) & Biharshariff (PG) Grid S/s, Kahalgaon power is taking longer route via Purnea Grid S/s (Powergrid) to reach Bihar causing higher PoC withdrawal charges for Bihar.

x) Since, Inter-State transmission lines are planned, designed and constructed by POWERGRID after carrying out load flow study & simulation of the power to be evacuated, therefore, lapses made in the planning and design of the transmission infrastructure by POWERGRID for not linking Purnea (PG) with Biharshariff (PG) Grid S/s resulting into higher PoC withdrawal charges due to inefficiency of POWERGRID is a callous mistake, which requires to be examined by CEA before according approval of the said scheme. Ld. CERC inadvertently had not gone in details while framing the regulations and PoC rate such wrong planning, design & construction of the existing inter-state transmission infrastructure at the cost of the beneficiary & public money for which the beneficiaries are being penalized. In this regard another example as cited by Ld. CERC in para 12.3 (2) of the Explanatory Memorandum - Third Amendment to Sharing Regulation is also referred to as an evidence of incompetency,

xi) It is also essential to mention that Bihar has an allocation of only 5.52 % (82.2 MW) from Kahalgaon Stage-II (1500 MW). Major percentage share from Kahalgaon Stage-II has been allocated to the beneficiaries in NR, WR & SR.

POWERGRID has created comprehensive associated transmission system for evacuation of power from this power station for supply of power to beneficiaries outside ER. The transmission charges of these transmission lines are being claimed by Bihar under PoC methodology from Bihar without using the said transmission assets.

Ld. CERC in Para 9 of the Explanatory Memorandum - Third Amendment of Sharing Regulation has also accepted that the present methodology adopted for determination of PoC charges is not in consonance to the actual usage based on the participation factor as computed by Software to compute PoC charges for injection of power as indicated below:

S. No	DIC	% as per participation factor
1	Orissa	82.97
2	DVC	12.10
3	WEST Bengal	4.93

In view of Section 61 (d) of the EA-2003, Ld. CERC is requested to review the Draft regulations so that inefficiency of the POWERGRID should not be passed on to the beneficiaries and to the end consumers.

xii) It is also essential to mention that prior to the implementation of the PoC w.e.f, 01.07.2011, the state sector transmission lines connecting two states (non ISTS) are also used for transfer of power of other constituents under open access for which open access transmission charges was also paid by the RLDC based on the applicable open access rate determined by CERC and quantum of power supplied as per ERLDC approval. Consequent upon the implementation of PoC methodology, States are now compensated for proportional usage of such intra-state non-ISTS assets if more than 50 % power of inter-state nature is flowing. Learned CERC has now proposed 23 % power of inter-state nature to flow through such intra-state non-ISTS line to qualify for reimbursement of proportionate 23 % tariff.

Learned CERC under para 13.2 of the Explanatory Memorandum-Third Amendment to Sharing Regulation has also admitted that non-ISTS line also carry more or less inter-state power and would therefore have to be inter-State lines.

Since, in an interconnected system when all the five regions are now inter connected and operating as one grid, impact on any transmission line either intra-state or inter-state may cause effect on power flow on other transmission lines. As such all non-ISTS transmission lines are now important and cannot be discriminated on the percentage of power flow basis of inter-state nature.

xiii) BSP(H)CL therefore not agreement with the contention of the Ld. CERC and proposed that no such restriction on flow of power of inter-state nature through non-ISTS line should be imposed to qualify these transmission lines as ISTS lines for reimbursement of transmission charges for usage of such lines for evacuation of inter-state power.

xiv) In view of the position explained above, it is humbly submitted that there are serious anomalies in Sharing of transmission Charges implemented by CERC w.e.f. 1st July 2011 based on CERC (Sharing of Inter State Transmission Charges & Losses) Regulation, 2010. The transaction for "short distance transmission" cross-subsidise transaction with "long distance transmission". The objective of Electricity Policy of Govt. of India is to ensure that transmission system users share the total transmission cost in proportion to utilization of transmission system. Further, the users of old assets cross-subsidies "users of new assets", whereas the users of old assets have already paid depreciated value of the transmission system erected long back.

xv) The National Tariff Policy mandates that the national tariff framework implemented should be sensitive to distance, direction and quantum of power flow. The ultimate objective of electricity Policy of the Govt. of India is to ensure that transmission system users should share the total transmission charges in proportion to respective utilization of the transmission system.

In view of the position explained above, the draft regulation and the Principal Regulations may please be reviewed.

Comments/suggestions on Draft Amendment to Central Electricity Regulatory Commission (Sharing of Inter State Transmission Charges and Losses) (Third Amendment) Regulations, 2014 during Public Hearing on 12.6.2014

S. No.	Company/Stakeholder/Individual
1.	Adani Power Ltd.
2.	Central Transmission Utility (CTU),
3.	GRIDCO Limited
4.	Himachal Small Hydro Power Association
5.	NTPC Ltd.
6.	Power System Operation Corporation Limited (POSOCO)
7.	Shri. S. A. Soman and Shri. Somasekara Rao Manda
8.	Thermal Powertech Corporation India Ltd (thermal powertech)
9.	Torrent Power Ltd.

2. Amendment in Regulation 2

1.1. Sub-clause (b) along with Proviso of clause (1) of Regulation 2

No Comments during presentation

1.2. Sub-clause (c) along with Proviso of clause (1) of Regulation 2

1.2.1. TPCIL Comments: It is appreciable concept from Honorable Commission which ensures levy of transmission charges based on the peak injection / actual instead of LTA.

1) It helps in capturing the DICs whose actual utilization is more compare to LTA granted.

2) Further it is relief for IPPs, who have taken LTA for full quantum and actual utilization of the grid is less due to various issues (fuel shortage, unavailability of PPA's).

This will encourage generators to declare actual LTOA requirements meanwhile avoiding unnecessary burden in case of lower PLF's/under generation.

1.2.2. POSOCO:

(1) **Issues:**

- Sanctity of Approved Injection quantum
- Wide variation in generation
- Jurisdiction issues

(2) **View:**

- Implementation of GNA before changing the Sharing regulations
- Approved Injection
  - Regional Entities: Installed capacity including overload capacity, less auxiliary consumption or LTA whichever is higher

- Intra State Entities: LTA / MTOA quantum

(3) **Support**: CEA suggested the concept of GNA for sharing of Transmission Charges based on connected quantum

1.2.3. Torrent Power Ltd.:

1) The existing practice of sharing the POC charges is based on the quantum of Open Access and average case scenario.

2) As said validly in the explanatory memorandum, transmission planning is based on peak scenario and to cater to the maximum demand, the computation of PoC charges by current method does not capture the usage of transmission system correctly.

3) Due to large difference in peak and off peak usage and considering the fact that the transmission system designing is required on peak scenario, 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.

4) Therefore, CERC's draft (Sharing of Inter State Transmission Charges and Losses) (Third Amendment) Regulations, 2014 is a welcome step which is a step forward for levy of transmission charges based on maximum injection and pick withdrawal (ACTUAL USAGE) instead of OPEN ACCESS AVAILED.

5) We request to kindly amend the existing Regulations so that Transmission Charges should be charged on the Maximum Injection/ Peak Withdrawal instead of quantum of OPEN ACCESS AVAILED or average usage.

6) We also request to allow DICs to send quarterly forecast of the injection and withdrawal alongwith proper justification which can be vetted by the Implementing Agency.

   ✓ Revision in such forecast may be allowed with proper justification

   ✓ In such cases, the transmission Charges should thus be applicable on such forecasted/revised injection / withdrawal

1.3. <u>Sub-clause (f) along with Proviso of clause (1) of Regulation 2</u>

1.3.1. <u>Torrent Power Ltd.:</u>

1) The existing practice of sharing the POC charges is based on the quantum of Open Access and average case scenario.

2) As said validly in the explanatory memorandum, transmission planning is based on peak scenario and to cater to the maximum demand, the computation of PoC charges by current method does not capture the usage of transmission system correctly.

3) Due to large difference in peak and off peak usage and considering the fact that the transmission system designing is required on peak scenario, 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.

4) Therefore, CERC's draft (Sharing of Inter State Transmission Charges and Losses) (Third Amendment) Regulations, 2014 is a welcome step which is a step forward for levy of transmission charges based on maximum injection and pick withdrawal (ACTUAL USAGE) instead of OPEN ACCESS AVAILED.

5) We request to kindly amend the existing Regulations so that Transmission Charges should be charged on the Maximum Injection/ Peak Withdrawal instead of quantum of OPEN ACCESS AVAILED or average usage.

6) We also request to allow DICs to send quarterly forecast of the injection and withdrawal alongwith proper justification which can be vetted by the Implementing Agency.

   - ✓ Revision in such forecast may be allowed with proper justification
   - ✓ In such cases, the transmission Charges should thus be applicable on such forecasted/revised injection / withdrawal

1.3.2. POSOCO:

(1) **Issues:**

- ➢ Sanctity of Approved Withdrawal quantum
- ➢ Transmission charges based on subjective quantum
- ➢ Fast change in demand due to several factors

(2) **View:**

- ➢ Implementation of GNA before changing the Sharing Regulations
- ➢ Approved Withdrawal – Present system more appropriate.
  - LTA+MTOA or Peak drawl, whichever is higher

- For additional drawl, STOA charges or deviation charges would have to be paid

(3) **Support:** No linkage to the data submitted by DICs which may be prone to gaming

1.4. Sub-clause (l) of clause (1) of Regulations 2

No Comments during presentation

1.5. Sub-clause (v) of clause (1) of Regulation 2

1.5.1. TPCIL Comments:

It is a welcome step to dispense off with the uniform charges method of calculating transmission charges as the Uniform charge method was not accounting for commensurate usage of transmission system.

1.5.2. POWERGRID:

Changes in Computation of PoC charges – Welcome step

a. Proposed amendments addresses concerns of different stakeholders.

b. Transmission charges allocation being aligned with the planning

1.5.3. GRIDCO Ltd.: Extra payment to the tune of Rs. 90Crs due to 50% uniform sharing charges.

1.5.4. Torrent Power Ltd.:

1) The very concept of evolving POC Regulations is to devise the mechanism to reflect distance, direction and quantum sensitive transmission charges so as to give right signals to the market for optimization of overall cost.

2) In the existing system, the cost of transmission charges gets pooled and the beneficiaries require to bear the cost though the transmission assets are not being used.

3) For smooth implementation, the Hon'ble Commission has initially adopted hybrid system. During last 2 yrs, the necessary systems have been evolved and therefore, it is right time to dispense with the Uniform Charge & Slab system. The existing slab system distorts the transmission charges and results into the skewed recovery of transmission charges i.e. though actual

transmission charges are lower, the beneficiary end up paying higher transmission charges despite into lower slab and vice versa.

4) The suggestion of POSOCO to reduce the weightage to Uniform Charges and increasing the number of slabs also in line with spirit of the Regulations to reflect the actual cost.

5) Therefore, we request the Hon'ble Commission to dispense with the existing system of Uniform Charges and Slabs.

1.5.5. Shri. S. A. Soman and Shri. Somasekara Rao Manda

1) Dispense with 50% component from postage stamp method.

2) Marginal participation approach is the right way to proceed but present dispersed slack bus selection rule based on average participation method is a heuristic. It cannot be argued to be fair.

1.6. <u>Sub-clause (w) of clause (1) of Regulation 2</u>

No Comments during presentation

1.7. <u>Sub-clause (x) of clause (1) of Regulation 2</u>

No Comments during presentation

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

1.8.1. <u>GRIDCO Ltd:</u> Hon'ble Commission's determined cost for Tr. Assets should be adopted for determination of YTC

6. Amendment in Regulation 3

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

No Comments during presentation

7. Amendment in Regulation 7

3.1. <u>Sub-clause (d) of clause (1) of Regulation 7</u>

No Comments during presentation

3.2. Sub-clause (e) of clause (1) of Regulation 7

No Comments during presentation

3.3. Sub-clause (i) of clause (1) of Regulation 7

3.3.1. **POSOCO:**

(1) Issues:

- There would be wide variance between highest and lowest (can be NIL)
- Unique rate for each entity may not be prudent
- Many Assumptions in the computation process
  - Tariff of many transmission assets is provisional
  - Varying Load/Generation scenario represented by single scenario
  - Commissioning of new assets
  - Substation cost is not separated

(2) View: 5 slabs in next step and gradually to more no. of slabs, say 7 or 9

(3) Support:

- All cybernetics follow slab/tier rates e.g. metro rail tickets, bus fare etc.
- The aberrations arising out of assumptions would get evened out

3.4. Sub-clause (l) of clause (1) of Regulation 7

3.4.1. **GRIDCO Ltd.:** Extra payment of Rs. 34Crs due to slab rates.

3.4.2. **Torrent Power Ltd.:**

1) The very concept of evolving POC Regulations is to devise the mechanism to reflect distance, direction and quantum sensitive transmission charges so as to give right signals to the market for optimization of overall cost.

2) In the existing system, the cost of transmission charges gets pooled and the beneficiaries require to bear the cost though the transmission assets are not being used.

3) For smooth implementation, the Hon'ble Commission has initially adopted hybrid system. During last 2 yrs, the necessary systems have been evolved and therefore, it is right time to dispense with the Uniform Charge & Slab system. The existing slab system distorts the transmission charges and

results into the skewed recovery of transmission charges i.e. though actual transmission charges are lower, the beneficiary end up paying higher transmission charges despite into lower slab and vice versa.

4) The suggestion of POSOCO to reduce the weightage to Uniform Charges and increasing the number of slabs also in line with spirit of the Regulations to reflect the actual cost.

5) Therefore, we request the Hon'ble Commission to dispense with the existing system of Uniform Charges and Slabs

3.5. Sub-clause (k) of clause (1) of Regulation 7

3.5.1. **Shri. S. A. Soman and Shri. Somasekara Rao Manda :**Avoid truncation of network while determining PoC tariffs.

3.5.2. **POSOCO:**

(1) **Issues:**

- Most of the Inter State transmission system in the country is on 400 kV and above.
- Transmission charges of these lines are to be recovered

(2) **View:** Truncation may be done at 220/230 kV level in rest of the country and 132 kV level in NER

(3) **Support:** 132 kV and 110 kV lines are mostly being used in radial mode.

3.5.3. **GRIDCO Ltd**.: Truncation of Network to 400kV Level failed to take account of Odisha's STU Networks

3.6. Sub-clause (l) of clause (1) of Regulation 7

3.6.1. **IIT Mumbai: Shri. S. A. Soman and Shri. Somasekara Rao Manda**

1) We recommend that min-max fair marginal participation approach can be used for solving a fair transmission system cost allocation problem as
   i) 'extent of use' calculations confirm to KCL and KVL and
   ii) every price taking entity has a guarantee that its price cannot be reduced without increasing price of another entity which pays equal or higher price.
2) It resolves the dilemma (or ambiguity) in calculating the 'extent of use' in marginal participation approach
3) Price vector obtained in min-max MP is unique

4) Fairness of dispersed slack selection rule can be established beyond any reasonable doubt by using min-max fairness policy.

5) Cost allocation should be done in linearized load flow framework also known as DC load flow framework. It will guarantee unique min-max fair PoC tariffs

Case study on all India 400kV truncated network

From the results presented, we observe the following:

1) Min-max fair MP approach is both direction and flow sensitive cost allocation method.
   i) Maximum PoC in different cases as high as 5.09 times postage stamp rate in 2012-13 scenario.

2) Min-max fair MP approach improves equity.
   i) Least standard deviation is achieved in min-max MP vis-a-vis min-max fair power flow tracing, AP and MP-AP hybrid approach.
   ii) Note that 50% of MP-AP + 50% postage stamp method artificially giving better equity as 50% combination is by postage stamp method which disregards the usage based framework.
   iii) Adding 50% postage stamp contribution in MP-AP hybrid approach damps the direction and flow sensitivity.

3) Maximum PoC tariff in min-max fair MP approach is lower than any other approach.

4) Instead of addressing equity concerns in MP-AP hybrid approach by mixing it with postage stamp allocation, it is better to follow a rigorous and fair cost allocation method like min-max fair MP method.

5) The minimum PoC tariff according to the method proposed in CERC regulations 2010 (MPAP+PS) is non zero, wherein other methods the minimum PoC is zero. Zero PoC cases are important as it indicates that load or generator does not use network at all.

6) Thus, min-max fair MP approach leads to a fair selection of economic slack busses.

3.7. <u>Sub-clause (n) of clause (1) of Regulation 7</u>

No Comments during presentation

3.8. <u>Sub-clause (o) of clause (1) of Regulation 7</u>

3.8.1. **<u>Comments by Stakeholders:</u>**

(1) **POSOCO:**

(2) **Issues:**

- Average data is well accepted and available at CEA website
- Peak data available at CEA website are one-time peak achieved during the month and may not correctly represent the real scenario.
- Difficulty in obtaining peak generation from intra-state generators

View: Continue with Average case

Support: Undisputed and well accepted procedure

3.9. Sub-clause (q) of clause (1) of Regulation 7

3.9.1. Comments by Stakeholders:

1. **POSOCO:**

Issues:

- Every entity avails reliability support from the grid
- Many entities would have 'NIL' charge
- Disparity among DICs

View:

Uniform Charge component should be at least 25% and may be renamed as "reliability charge.

Support:

All the entities are availing reliability support of the grid and must be liable to pay some charges.

3.10. Sub-clause (s) of clause (1) of Regulation 7

3.10.1. No Comments received from Stakeholders

3.11. Para (iv) under sub-clause (t) of clause (1) of Regulation 7

3.11.1. No Comments by Stakeholders

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

3.12.1. **<u>Stakeholders Comments:</u>**

1. **<u>Adani Power Ltd.</u>:**

“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.

If an ISGS is connected to both STU and ISTS, the injection corresponding to flow on ISTS shall only be considered for transmission charges…..”

APL’s View:

- When an ISGS is connected to both STU and ISTS, power flow in ISTS changes based on various conditions such as demand, line impedance etc.
- There can also be situations where Home State is not being able to draw its share through STU.
- Tripping of any transmission element in STU network may lead to higher injection in ISTS and vice versa.
- Such circumstances, lead to ISGS paying higher transmission charges, which is unreasonable.
- The transmission capacity considered for levy of transmission charges shall not exceed installed capacity of ISGS under any circumstances.

APL’s suggestion:

- Injection by the ISGS into ISTS = Actual Injection by ISGS into ISTS – (Difference between the scheduled power and actual power drawn through STU network by the Home State)
- Inadvertent power flows due to tripping of any line shall not be considered as actual injection.
- Increase in power flow as per instructions of System Operator, such incidences shall not be considered for levy of transmission charges on ISGS

*"…….*However, the application of losses shall depend on whether RLDC or SLDC is doing scheduling for the same. In case scheduling is being done by RLDC, ISTS losses shall be applicable for those schedules.

APL's View:

- While the transmission charges are proposed to be levied on actual power injection, there is no rationale for considering the losses based on the Control Agency rather than the system involved.
- In the following cases Hon'ble Commission has stated that losses would be based on contract path:
    - Petition No. 220/2009 (WRLDC Vs SLDC, Gujarat)
    - Petition No. 95/MP/2013 (JPVL vs MPPTCL)
    - Petition No. 189/MP/2012 (LANCO Anpara vs UPPTCL)

APL's suggestion:

- Transmission Losses shall correspond to the system on which open access is granted.
- Should be in line with the decisions of Hon'ble Commission on the subject issue
- Existing methodology of allocation of losses shall continue

Petition No. 189/MP/2012 (LANCO Anpara vs UPPTCL) – Judgement

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

Petition No. 220/2009 (WRLDC Vs SLDC, Gujarat) - Judgement

"*26. The Petitioner has submitted that since the generating station is connected to the Northern Region and Western Region, SLDC may find it difficult to coordinate with the other regions in case of system contingency. It is obvious that any line which joins two Regions is an inter-Regional line and would be* *operated as such, under the combined jurisdiction of the RLDCs of the two Regions, irrespective of ownership. The generating station would have to be operated independent of the operation of the transmission line. Therefore, we see no difficulty in the generating station coming under the control area jurisdiction of the State.* ***As far as WRLDC's contention of power becoming costlier due to of levy of STU charges transmission charges and transmission losses) in case it comes under the control area jurisdiction of the SLDC is concerned, the same would depend on the utilization of the transmission system of the STU, i.e. GETCO, and not on the control area jurisdiction of SLDC."***

2. **TPCIL Comments:**

As stated above, charges are based on the actual flow on the ISTS system.

- However in the event it is found that ISTS network is handling additional injection over and above RLDC schedule from ISGS or IPP's at that particular point, corresponding additional participation (Transmission Charges) should be levied on the Home state network/STU since mismatch is caused due to congestions in STU network.
- This also identifies network requirement at interconnection points, which bring positive impact for transmission strengthening schemes by STU.

Illustration:

An IPP generating 1200MW, has long term PPA with State for 500MW but due to STU drawl capability at that node, the actual flow on the ISTS network found to be 900MW.

In this condition, applying above amendment, transmission charges have to be levied on 900MW.

However, the additional participation (900-700=200) on ISTS is due to STU network which is not attributable to an IPP. Therefore corresponding participation (200MW) charges should be levied on the STU rather than on generator

3.13. Sub-clause (u) of clause (1) of Regulation 7

3.13.1. Comments by Stakeholders:

1. Himachal Small Hydro Power Association

The ISTS Charges & Losses should be waived off for all renewable projects to make open access a viable option. These Charges & Losses should be waived off for projects commissioned in 11th & 12th Plan atleast till their loan repayment period i.e. up to 2025.

3.14. Sub-clause (v) of clause (1) of Regulation 7

3.14.1. **Comment by Stakeholders:**

1. Himachal Small Hydro Power Association

The ISTS Charges & Losses should be waived off for all renewable projects to make open access a viable option. These Charges & Losses should be waived off for projects commissioned in 11th & 12th Plan atleast till their loan repayment period i.e. up to 2025.

8. Amendment in Regulation 8

4.2. Clause (5) of Regulation 8

4.2.1. Comment by Stakeholders:

1. **Adani Power Limited**:

***"*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."

APL's Suggestion:

- If delay in commissioning is due to force majeure, the generator shall be exempted from payment of transmission charges as the delay is due to events beyond control of the generator.

2. NTPC Ltd.

- As per the EA-2003, CEA is vested with responsibility of transmission planning – formulate short-term and perspective plans & co-ordinate activities of planning agencies.
- CTU is entrusted to discharge all functions of planning and co-ordination relating to ISTS with all stakeholders and ensure development of an efficient, co-ordinated and economical system of ISTS lines for smooth flow of electricity from generating stations to load centres.
- Accordingly, regional transmission lines as well as ATS of ISGS is finalised considering various technical requirements, such as, load flow, voltage profile, stability & security of grid besides power requirement of the beneficiaries from the ISGS.

- ATS is finalized in the Regional Standing Committee for Transmission Planning and is executed after ratification by beneficiaries in RPCs.
- Thus, ATS is planned & developed with the involvement of the beneficiaries / buyers at all stages.
- Post 2010, ISTS is now planned & executed as per CERC Grant of Connectivity, LTA, MTOA Regulations, 2009,
- LTA applied by NTPC on behalf of beneficiaries
- After grant of LTA, LTA Agreement is signed by beneficiaries with transmission service provider.
- As per the above agreement, LTA charges to be borne by beneficiaries.
- Mismatch of generation and its ATS

    - Generating units added progressively & transmission required in advance for connectivity & start-up power; therefore exact matching not feasible.
    - Indemnification Agreement (IA) is entered by NTPC & CTU which

        - Indemnifies CTU for IDC in case of delay of generating unit.
        - Ensures close monitoring & co-ordination for matching of schedules

    - As Transmission company is benefitted in ensuring funds through IA, any delay in generation should be dealt in accordance with the IA & liability of generator to be as per the IA signed.

- Even in case of delay of ISGS, transmission system is often put to use and made part of the network and the benefits are availed by the beneficiaries.
- Only in case of some generating stations where the beneficiaries are not identified there may be cases of stranded transmission assets.
- Therefore, exempting upcoming ISGS would also be consistent with the Tariff Regulations 2014 which acknowledges the agreements entered between ISGS and CTU for development of ATS.
- In light of the above the first proviso to Regulation 8(5) may be modified as under:

  "*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 IDC for the stranded capacity out of its associated system as per the Agreements.*"

  "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."

- Approved Injection is defined as the maximum injection. Generators would not be injecting up to approved injection on a continuous basis.
- As URS of stations is increasing and Peak injection for the year may vary based on commercial decisions of beneficiaries.

- Entire transmission charges shall anyway be recovered based on actual injection based on merit order.
- In view of above,
    - Estimated peak injection may be used for load flow to estimate nodal charges, but billing of transmission charges may be done Actual basis.
    - The provision quoted above may be deleted
-

3. **TPCIL Comments:**
    - Request Hon'ble Commission to appreciate the practical difficulties which may lead to delay of ~6 months in commissioning the project. In this regard requested commission, to give grace period from 3 to 6 months from the COD of transmission system to till commission of the generating unit.
    - We understand that NTPC and PGCIL have these kind of arrangements for taking care the delays for a period of 6 months from Schedule COD to Actual COD of the Generating station by paying only IDC of the transmission system.

Request Hon'ble Commission to consider some sought of remedy for all the DICs without any bias during this transition period (suggestions as below):

If generator commission schedule is delayed upto 3 months from the date of commission of transmission system, no transmission charges to be levied on the Generator.

If generator commission schedule is delayed more than 3 months but commissions within 6 months, from 4^{rd} month onward till commission of the generator, the IDC alone to be levied on the generator as non POC charges instead of avg. POC rates. Beyond above said delay, request to levy only injection transmission charges instead of total PoC (Inj+ Demand POC).

Further, above said remedy shall also be applied as per the unit wise commission schedule (generally a period of 3-5 months between COD ot 2 units) instead of the total LTA quantum.

4. **Torrent Power Ltd**.:

Draft Regulation: 1st Proviso

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.

Comments/Suggestions:

- Open access will be provided based on the available transmission capacity only i.e. the access would become effective only after the implementation of associated transmission system. Hence, transmission charges should be payable only for the quantum of effective open access, rather than the installed capacity as proposed in the 2nd para of the proposed amendment to Regulation 8(5).
- We also request the Hon'ble Commission to clarify that the transmission charges should not be levied unless the identified/ associated transmission system is ready.

Draft : 2nd Proviso

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.

Comments/Suggestions:

- We would like to submit that adequate provisions for the settlement of drawl & injection of power during commissioning have already been provided in the Deviation Settlement Mechanism Regulations, 2011. Therefore, the proposed amendment for payment of transmission charges for drawl of start up and injection of infirm power seems to be redundant.
- Hence, we would like to submit that above para of the proposed amendment to Regulation 8(5) is not needed and same be removed

5. **TPCIL Comments:**

During this period, Generator is expected to inject (infirm power) without any LTA/MTOA/STOA contracts. However the amendment proposes such intermittent transactions without any open access are also to be billed as per PoC mechanism.

Also, the transmission charges recovery will anyways happen post COD under POC regime, including the charges for the interim period of ~ 6 months (during commissioning stage) will unnecessary burden the generator

4.3. Clause 6 of Regulation 8 of the Principal Regulations

4.3.1. GRIDCO Ltd.:

HIGH PoC CHARGES IN EXPORTING REGION

1) As established in Cl. 9 of SoR, Odisha gets 82.97% of Power from TSTPS-I

2) Odisha meets its Central Sector Maxm. Drawl (700-800MW) from the above ISGS
3) As Load Centre of Odisha is very nearer to above ISGS, usage of ISTS Network is minimal
4) In Cl. No. 9 of SoR, it has been recommended that Injection charges be allocated to withdrawl DICs as per participation factors (Actual Usage)
5) The above recommendation not incorporated in 3rd Amendment.
6) Hon'ble Commission to kindly incorporate the above in 3rd Amendment.
7) Effective date of implementation should be 01-07-2011

POWER FLOW THROGH HVDC LINE TO SR

1) No Allocation to SR from TSTPS-I
2) From TSTPS-II, capacity allocation to SR 1800MW and Odisha 200MW
3) 400MW Power is forced to flow to SR from TSTPS-1 through HVDC line
4) Controlled/forced Power results in Power flow to SR(Coverage of large distance)
5) The above forced power flow to SR results in high injection charges to TSTPS-I
6) Hon'ble Commission to direct to limit the power flow through Talcher-Kolar HVDC to scheduled quantum from TSTPS-II
7) Similar is the case for power flow to SR through HVDC Gazuaka
8) Corrective measures should be taken in PoC determination so that flow through Gazuwaka should not burden the withdrawl PoC of Odisha.

IMPACT OF DILUTION IN PoC CONCEPT ON ODISHA

- Odisha avails maximum 700-800MW against Central Allocation of 1165MW (Wrong mention of drawl as 1955MW at ANNEX-I of SoR)
- Odisha meets above demand (700-800MW) from TSTPS-I (As per Example at Cl. No. of SoR)
- Load Centres are very nearer to TSTPS-I
- Actual usage of ISTS Network by Odisha minimal
- Injection charges for TSTPS-I increased due to flow in SR (HVDC line)
- Dilution in original PoC concept not conforming to sub sec. 2 of sec. 36 and sec. 61 of EA-2003

FERC DECISION AS GUIDELINE

1) FERC decision, reflected at Cl. No. 4.4 of SoR to 3rd Draft Amendment.

2) Sole objective of FERC decision to ensure cost of Tr. Charges, commensurate the estimated benefits.
3) New Tr. Systems set up in Odisha for transmission of power to other states.
4) There may be power flow through such Tr. Lines, attributed to Odisha, as may be arrived through load flow study
5) As Odisha is not benefited by this power flow, no Tr. Charge should be imposed on Odisha for such load flows

9. Amendment in Regulation 11

5.4. Clause (4) of Regulation11

5.4.1. Comment by Stakeholders:

1. **NTPC Ltd.:**
   - Regulation 11(4) of Principal Regulations provides computation of Tr. charges as under:

   For Generators:

   [PoC Transmission Charge of generation zone in Rs /MW/month for peak hours] × [Approved Injection for peak hours] + [PoC Transmission Charge of generation zone in Rs /MW/month for other than peak hours] × [Approved Injection for other than peak hours]

   - The above formula may be modified based on actual injection as under –

POC transmission charge for generation zone in Rs./MW /month × Actual Injection

5.5. Clause (5) of Regulation 11

5.5.1. Comment by Stakeholders:

1. **Torrent Power Ltd**.:

   - It is possible that the beneficiary may need to draw power from other sources than the identified generator due to various reasons. In such situation, the beneficiary would be drawing power from other sources under MTOA/STOA using the same drawl network. However, the proposed amendment is not clear whether such beneficiary/DIC would get offset for the MTOA/STOA.

   - Hon'ble CERC may like to provide better clarity on such situations as PoC charges are now proposed to be payable based on peak injection or drawl for the applicable period (i.e. inclusive of drawl under LTOA, MTOA, STOA &

Deviation (if any)). The same would ensure avoiding burden of double recovery of transmission charges from DIC.

- In view of above, we would like to submit that the proposed amendment in clause (5) of Regulation 11 of the Principal Regulations may be modified as given below:

*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 **payable by DICs** for the Long-term Access **to the target region without identified beneficiaries**.*

*Provided also that a **DIC generator** who has been granted Long-term Access **to a target region without identified beneficiaries**, shall be required to pay **applicable** 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."*

5.6. Clause (9) of Regulation 11

5.6.1. Comment by Stakeholders:

1. Adani Power Limited:

"-----Short term open access to any region shall be adjusted against the injection PoC charges and demand PoC charges for long term access based on Peak injection."

APL's View:

- Adjustment of STOA charges for drawl in any region was principally agreed in CAC meeting held on 20th March, 2013.
- As the decision has been taken long back and the existing regulation is resulting in double charging, aforesaid draft amendment may be implemented immediately
- This will avoid unnecessary cost to generator but also to benefit the consumer.

APL's suggestion:

Proposed amendment may be implemented with immediate effect.

*"**Set-off of STOA charges 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."*

APL's View:

- Majority of power procurement by Discoms are taking place through collective transactions and not through bilateral contracts.

- Therefore collective transaction also need to be considered for adjustment of charges
- In collective transactions, the injection point is known, only the beneficiary who is drawing is not known.

APL's suggestion:

- Adjustment facility to be extended for collective transaction also
- In respect of collective transactions, adjustment may be allowed as follows:
  - Injection PoC charges: Applicable PoC charges of the DIC
  - Withdrawal PoC charges: Average of the all India withdrawal PoC charges

APL's Request:

- If the DIC has transacted the power under STOA in any month, the DIC will pay the applicable STOA charges within two days from the date of application.
- Whereas, the DIC will receive the bill for LTA charges for any month in the first week of next month after issuance of RTA.
- As per present practice CTU has been allowing 2% rebate on the gross LTA bill amount only if the net amount (Gross amount – Setoff) is paid within five days by the DICs.
- CTU is not allowing 2% rebate on the setoff amount, if the payment of the net billed amount is made after 5 days.

Suitable Amendment to Regulation:

- To allow rebate on Set off amount irrespective of payment of net LTA bill amount, since the set-off amount has been paid by DIC in the previous month

2. <u>TPCIL Comments:</u>

- Request to adjust all the transactions (including exchange transactions), which were approved by the RLDC for accessing the corridor to be adjusted against the peak injection.

- This will ensure, double charges are not levied for collective (exchange) transactions.

Illustrative:

Say a generator peak injection is 1200MW out of which 200MW they are selling in exchange by self or though some trader. In such conditions as per peak injection, transmission charges to be paid for 1200MW.

If adjustment are not considered, the generator ends up paying transmission charges for 1400MW (1200 + 200 MW), thus resulting in double payment for 200MW scheduled through the exchange as a collective transaction.

3. **<u>TPCIL Comments:</u>**

We request Honorable commission, above regulation second para may be substituted as below to ensure alignment with concept of Peak injection:

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 ***based on the peak injection*** *after offsetting the quantum of Medium-term Open Access and Short-term Open Access* **against Peak injection.**

4. **<u>Torrent Power Ltd</u>**

- It is possible that the beneficiary may need to draw power from other sources than the identified generator due to various reasons (also mentioned in the Explanatory Memorandum of the proposed amendment). In such situation, the beneficiary would be drawing power from other sources under MTOA/STOA using the same drawl network. However, the proposed amendment is not clear whether such beneficiary/DIC would get offset for the MTOA/STOA.

- We sincerely request that the Hon'ble CERC may like to provide better clarity on such situation as PoC charges are now proposed to be payable based on peak injection or drawl for the applicable period (i.e. inclusive of drawl under LTOA, MTOA, STOA & Deviation (if any)). The same would ensure avoiding burden of double recovery transmission charges from DIC.

Also, such off-set to be provided against LTA charges irrespective of whether the MTOA/STOA is applied by the generator or beneficiary for a particular generating station

In view of above, we would like to submit that the proposed amendment in Clause (9) of Regulation 11 of the Principal Regulations may be modified as given below:

*Provided that the DICs 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 access based on Peak Injection****<u>/Withdrawal</u>****:*

*Provided further that a **DIC generator** who has been granted Long-term Access **to a target region without identified beneficiaries**, shall be required to pay **applicable** 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:*

In addition to the above, we also like to submit that short term charges of collective transaction may also be adjusted against Injection/Drawl PoC charges (as applicable).

6. **Regulation 17**:

6.1. GRIDCO Ltd.:

In addition to the stipulated availability of Data in the websites such as Basic Network, Nodal Generation/Demand and Load Flow results, following data should also be made available:-

1) Marginal Participation Details
2) Avg. Participation Details for withdrawl and injection nodes
3) Zone-wise injection and withdrawl PoC
4) Computation of Schedule Charges payable by the DICs
5) % of Scaling
6) % Participation
7) Any other Data, as necessary

Accordingly, Sub-Cl. (i) of Cl. No. 3 (Amendment in Regulation 7) of Draft 3rd Amendment be modified

6.2. **POWERGRID**:

The computation tool (Webnet) results needs to be more transparent with query based approach like

- which DIC is receiving power from which generators and what quantum
- Similarly given generator is serving which DICs and for what quantum ,

Which DIC is using which lines and in what percentage

Amendment to Annexure of the Principal Regulation

7.1. TRUNCATION / NON-TRUNCATION

7.1.1. Comments by Stakeholders:

7.2. Existing: Proviso under Step 4 under Para 2.7.2 of Annexure of the Principal Regulations

7.2.1. Comments by Stakeholders:

2. POSOCO

Issue:

- Controlled power flow through HVDC for overall optimization
- Substantial impact of set point of HVDC considered in base case on nodal charges

View: Existing provision may be retained

Support:

- Upcoming HVDC systems in the country
- Every entity will derive benefit out of HVDC systems

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

Additional Comments:

4. Himachal Small Hydro Power Association:

The Preferential Tariff should be calculated on the basis of Present realistic project cost which is not less than Rs.10 Crore / MW.

To make the REC Mechanism equitable, a National Average Power Procurement Cost needs to be calculated and the projects in all those states which have APPC lower than the National Average must be compensated by giving Multiplier of more than 1 for 1 MWH so that they are at level playing field vis-à-vis those states having APPC higher than the National Average.

The definition of APPC needs to be amended to include Average Procurement Cost of Power for the Conventional Projects commissioned in last 10 years.

5. **GRIDCO Ltd.**

Sub-Clause (o) of Clause No. 3(7) be modified confirming the mid-date (Normally be omitted) with specific peak hours for each application period

Sub-Clause (o) of Clause No. 3(7) be modified taking into account the revision necessary in case of any mistake, inadvertent error etc. in addition to revision of YTC

Sub-Clause (6) of Clause No. 7 be modified as:-

"* Approved injection/ Approved withdrawl (MW) shall be based on Peak Scenario as per Sub-Clause No. 7(o) of Cl.No. 3 of Third Amendment"

GRIDCO proposes that, if there is variation of 5% in TC or more between two consecutive quarters with more or less same prevailing conditions, IA to justify such variation, failing which the differential amount not to be claimed on concerned DIC(s). The above provision be incorporated in the amendment

6. **POWERGRID:**

Payment Security Mechanism :

Payment security mechanism has been a serious concern since some time in the past . We propose the provision be made in amendment to Sharing Regulation on the lines of the CERC open access Regulation 2008 ,

On the request from CTU, National Load Despatch Centre or the Regional Load Despatch Centre, as the case may be, shall not grant short-term open access to the entities and associates of such entities who have defaulted in payment of transmission charges.