

No. L-1/44/2010/CERC
CENTRAL ELECTRICITY REGULATORY COMMISSION
NEW DELHI

Coram: Dr. Pramod Deo, Chairperson
Shri S.Jayaraman, Member
Shri V. S. Verma, Member
Shri M. Deena Dayalan, Member

Date: 11th June 2010

In the matter of

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

STATEMENT OF REASONS

1. Introduction:

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

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

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

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

- (c) *the factors which would encourage competition, efficiency, economical use of the resources, good performance and optimum investments;*
- (d) *safeguarding of consumers' interest and at the same time, recovery of the cost of electricity in a reasonable manner;*
- (e) *the principles rewarding efficiency in performance;*
- (f) *multi year tariff principles;*
- (g) *that the tariff progressively reflects the cost of supply of electricity and also, reduces and eliminates cross-subsidies within the period to be specified by the Appropriate Commission;*
- (h) *the promotion of co-generation and generation of electricity from renewable sources of energy;*
- (i) *the National Electricity Policy and tariff policy:”*

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

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

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

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

- 1.2 The above statutory provisions and policy guidelines enjoin upon the Central Commission to develop and implement a national transmission tariff framework sensitive to distance and directions and quantum of flow. In compliance with the said mandate, the Commission has undertaken this exercise to frame regulations on sharing of transmission charges and losses.
- 1.3 The Commission has followed a detailed process of public consultation in the finalization of these regulations. The first staff paper on the subject was put on the Commission's website on 15.5.2009. Thereafter the Commission conducted workshops in Delhi, Kolkatta, Guwahati and Bangalore to explain the methodology to various stakeholders. This was followed by public hearing on 29.7.2009 on the subject. The Commission deliberated on the suggestions received and directed the staff to incorporate the accepted suggestions. Re-computation of the methodology was done by considering (i) the Basic Network of 2008-09 and 2011-12 for NEW grid and SR grid separately (ii) the pricing mechanism was based on AC load Flow analysis instead of DC load flow (iii) loss allocation was done using the same methodology (iv) Average Historical YTC was considered for lines at each voltage level instead of Benchmark YTC, and (v) by considering slack buses based on the Average Participation Method. Based on the above, revised paper and draft regulations were posted on the CERC website for public comments. The Commission conducted a workshop in New Delhi on 5.4.2010 to explain the methodology to various stakeholders, which was attended by more than 100 participants from across India and from CEA, STUs, SEBs, private sector players, NLDC / SLDCs, RPCs and PSUs. Subsequently, public hearing was conducted on 13.4.2010. Finally detailed discussions were held with NLDC which has been designated as the Implementing Agency. Various implementation issues were further discussed with representatives from RPCs, SLDCs, CTU and NLDC before finalization of these regulations.
- 1.4 The Point of Connection (PoC) transmission pricing mechanism lends itself to the requirements of the Tariff Policy and also fits the requirements of a competitive market. PoC mechanism has already been used in the power exchange based transactions in India – the difference being just that the existing transmission

charges applicable to exchange based transactions are not locationally differentiated. Further, such charges need to be applied across all types of transactions – long term, medium term and short term (including those that materialize on the power exchange). Transmission charges computed based on the location of various generators and demand customers in the grid capture utilization of the underlying resources and hence meet the requirements 61(c), 61(g) and 61(i) of the Act.

1.5 The PoC based transmission mechanism will benefit the transmission network development and the designated ISTS Customers (DICs) of the transmission system in the following ways.

1.5.1 At present the transmission investments are faced with the uncertainty in generation and also the cumbersome process of getting the Bulk Power Transmission Agreements (BPTAs) signed by all the expected beneficiaries of the transmission system. Under the new proposed mechanism all the Designated ISTS Customers (DICs) are default signatories to the Transmission Service Agreement (TSA), which also requires these DICs to pay the point of connection charge, which covers the revenue of transmission licensees. This commercial arrangement would also facilitate financial closure of transmission investments.

1.5.2 The PoC based transmission pricing mechanism would facilitate integration of electricity markets and enhance open access and competition by obviating the need for pancaking of transmission charges.

1.5.3 The National Electricity Policy requires the transmission charges to reflect network utilization. The Point of Connection tariffs are based on load flow analysis and capture utilization of each network element by the customers.

1.5.4 The distinction between generation and demand customers would provide siting signals to the DICs, through accurate transmission charges. The current decision of generators is based on just the fuel transportation costs. With the implementation of the new transmission pricing mechanism – where transmission

charges are locationally differentiated – the generators will have to take a view both on transmission costs of electricity and transportation costs of fuel.

- 1.5.5 The new framework will greatly facilitate fair and transparent competition for case-1 bids. Under the current methodology, the case-1 bid processes are severely distorted because of pan-caking, and this results in pit head / hydro plants not being competitive for inter-regional bids. The impact of pan-caking is further amplified in such bid processes because of application of escalation factors to transmission charges over a 25 year period. The proposed methodology will remove such difficulty.
- 1.5.6 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 14-18 / 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.
- 1.6 These regulations describe the methodology and the mechanisms, in line with the above stipulations of the National Electricity Policy and the Tariff Policy, for sharing of transmission charges and losses amongst the DICs. The transmission charges and losses shall be based on the Yearly Transmission Charge (YTC) and transmission losses of the ISTS Transmission Licensees and other transmission owners /licensees whose specific lines, as certified by the RPC, form a part of the

ISTS for a particular TSA/transaction of interstate transmission. This regulation does not seek to determine the Yearly Transmission Charges, which shall continue to be determined in accordance with the Tariff Regulations of the Commission in force.

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

2.1 The Commission considered the comments of the stakeholders on the draft regulations, views of the participants in the public hearing as well as their written submissions received during and after the public hearing. The regulations have been finalized after detailed analysis and due consideration of the various issues raised. The analysis of the important issues and findings of the Commission thereon are discussed in the subsequent paragraphs. While an attempt has been made to consider all the comments, the names of all the stakeholders may not appear here. However, the names of all the stakeholders from whom the comments were received are enclosed as Annexure-I.

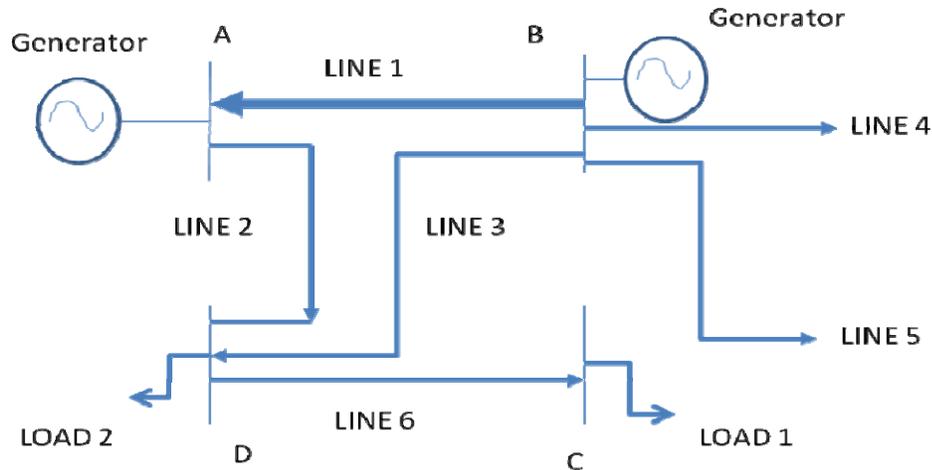
3. Preliminary Objections to the Regulations and Findings of the Commission

3.1 Philosophy of the Methodology:

3.1.1 Comments: Professor SA Khaparde, IIT Bombay, Mumbai et. al. questioned the rationale for using the Marginal Participation Method, when PoC transmission charges could be computed by directly using the Average Participation Method – which is being used in the Hybrid Method for selection of slack buses.

3.1.2 Order / Analysis: The Commission has carefully considered this comment. The Commission is aware of the on-going academic debate between the Marginal Participation and the Average Participation Method. Both the methods have their

strengths and weaknesses. The Average Participation Method is based on proportionate tracing of electricity from generator node to demand node(s) or vice-versa. Though the method requires the results of Load Flow Analysis as its input, the mechanism of proportionate tracing does not follow the Laws of Physics (Kirchoff's voltage law). This has implications for determination of utilization of the transmission lines by each node. This is illustrated below:



Under Average Participation Method, tracing from generator at Node-A would lead to the consideration of utilization of Line 2 for load 2 and Line 2 and Line 6 for load 1. However, it can be seen from the above network diagram, that keeping the generation at Node B constant, an increase in generation at Node A is expected to lead to an increase in flow in Line 2, Line 6, Line 4, Line 5 and Line 3 (Flow in Line 1 will be from Node B to Node A, as in the base case, but with an increase in generation at Node A, the magnitude of flow will reduce). While the AP Method captures utilization of Line 2 and Line 6, it fails to consider the impact of generation at Node A on Line 4, Line 5 and Line 3. Application of the AP method, in this case, would lead to very low nodal charges at Node A and high Nodal Charges at Node B and hence an inaccurate estimation of line utilization. Application of the MP method, on the other hand, would capture utilization better by attributing some percentage of utilization of not only Line 2 and Line 6 but also Line 3, Line 4 and Line 5 to Node A.

Hybrid Method – a combination of the Average Participation and the Marginal Participation Method, while considering the absorption of power generated at Node A by Load 1 and Load 2 only (as determined using AP method), considers the utilization of Line 3, Line 4 and Line 5 also, as opposed to the consideration of only Line 2 and Line 6, as in the pure AP method.

This weakness of the AP method has been recognized by European Transmission System Operator (ETSO) also when it states that “The AP method is based on an arbitrary assumption that contradicts the laws of physics. AP is based on the arbitrary assumption that the power flow arriving at one node must be shared between the local load and the exiting flows in the other lines at that node. Moreover, AP assumes that the sharing is in proportion of local loads and exiting flows. This assumption is not physical: many other solutions are possible and would lead to different responsibilities of generators and loads and to different compensations. In particular, according to physical laws, an increment in the flow in a line entering one node would be distributed among all other lines at that node and not only those with exiting flows.”

Further the Average Participation Method (Tracing Method) produces results with a higher variance in nodal charges. This interestingly has been reported by Professor Khaparde , Dr. Abhyankar and Professor Soman in their paper (Min-Max Fairness Criteria for Transmission Fixed Cost Allocation, IEEE Transactions on Power Systems, Vol. 22, No. 4, November 2007) They state “It is observed that postage stamp and conventional proportionate tracing methods produce skewed results which can lead to debate. The other two methods allocate costs in a more amicable manner by containing them in a narrower band.”

In another paper, Optimization Approach to Real Power Tracing: An Application to Transmission Fixed Cost Allocation, IEEE Transactions on Power Systems, Vol. 21, No. 3, August 2006, the Dr. Abhyankar, Professor Khaparde et. al. claim that:

“The easy-to-implement postage stamp method tends to favor heavy users at the cost of light users of the transmission system. Under certain circumstances where equitable cost distribution gains more importance over providing price signals, the conventional proportional tracing can come under question by the heavy users, raising some pertinent points about socioeconomic unbalance. This can be particularly

observed in developing countries like India. This is not to say that a versatile conventional method of tracing is unable to handle the situation, but one can explore larger solution space to strike the balance of seemingly conflicting requirements. The proposed methodology attempts to trade off and take a balanced and fair view within the framework of tracing algorithms meeting all technical and socioeconomic constraints...”

The above quote illustrates that proportionate tracing solution is one of the many feasible solutions and may not be the most equitable also. Clearly, lower variance in the results of the Hybrid Method indicates a more equitable solution.

In another recent paper M. S. S. Rao, S. A. Soman, P. Chitkara, Rajeev K Gajbhiye, N. Hemachandra, and B. L. Menezes, “Minmax Fair Power Flow Tracing for Transmission System Usage Cost Allocation: A Large System Perspective,” In Press – IEEE Transactions on Power Systems, 2010., a comparison of MP method and AP method on all India network shows higher variance in the nodal charges obtained using the AP method.

Further, simulations conducted by the consultants in the course of this assignment also revealed that the nodal transmission charges in the AP method have a higher variance. As compared to the range of transmission access charges in the Hybrid method (Rs 2.98 – 17.75 lakh / MW), the range in the AP method (Rs. 2.79 – 53.61 lakh / MW) is much higher.

Finally the Commission is convinced that the academic literature does not establish a definitive superiority of any of the two methods – the Marginal participation Method or the Average Participation Method over the other, but Hybrid Method combines the strengths of both the Marginal Participation Method and the Average Participation Method and also produces results which are explainable (based on the network configuration and underlying network flows) and also politically more acceptable.

3.1.3 Comments: It has been pointed out by several petitioners that transparency and simplicity is an important consideration in any pricing methodology.

3.1.4 Order / Analysis: The Commission surveyed the definitions of Transparency and Simplicity in the context of transmission pricing. Richard Green, a renowned power sector economist in his paper “Electricity transmission pricing: An international comparison” published in *Utility Policy*, 6(3):177–184, 1997, explains how transparency, in this context, is defined in other power systems. For the purposes of transmission pricing, National Grid Company interprets 'transparency', to imply the use of a very simple model when calculating the load flows on which its prices are based, and made the data involved available to interested parties. New Zealand system is transparent in the sense that it is based on a specific, auditable, model; although that does not mean that every market participant understands it. In this context the Hybrid method involves selection of “slack bus(es)” based on the Average Participation Method (tracing method) and then applies Marginal Participation Method – which involves running a sequence of load flows and is described in great detail in the literature and in the draft paper circulated by the Commission on May 15 2009. The algorithm is perfectly auditable and is therefore transparent. There are many standard load flow software – which are extensively used in power sector for power system analysis. The results of the Hybrid method can be validated by any other software. In fact, the Commission has decided to institute an unbiased, non-commercial and competent “Validation Committee” to validate the software which has been developed at the Power Anser Laboratory in the Department of Electrical Engineering at IIT Bombay, Powai, Mumbai.

The Commission is further convinced, and the conviction is supported in the paper by Richard Green, that “it can also be helpful (not least in political terms) for users to know how price differentials are calculated, and why. At the same time, if prices are to reflect marginal costs, which are complicated, they cannot be overly simple. Some countries have chosen to send more accurate cost messages, and accepted that their price system must be relatively complex, while others have deliberately simplified things.”

The Commission is further convinced that accuracy cannot be compromised beyond acceptable limits for the sake of simplicity. This is borne by the following argument of Green:

“The 'contract path' pricing used in New England (and other systems) until the recent past is an extreme case of simplicity. Each transmission-owning utility has a 'postage stamp' wheeling charge per kW year. This might be obtained by dividing its costs of transmission by its peak demand. Utilities which wished to exchange power would have to negotiate a contract path across any intervening systems, and pay each of those systems its wheeling charge. In practice, the transaction would usually affect power flows on other utilities' systems, but these would neither receive payments nor make them (in the event that their costs were reduced by the transaction).”

There have been numerous examples of such “other utilities’ systems” in the Indian context also, where such utilities’ systems were neither identified as being used for interstate transmission nor paid for.

Traits of simplicity such as determination of charges based on ‘zoning’ instead of their being charged on the basis of ‘nodal charges’ and ex-ante determination of charges have been incorporated in the new transmission pricing mechanism. Green also points out that ‘The use of zones rather than nodes for pricing purposes is a common simplification.’ Further if users do not know how much they are paying for transmission, they cannot change their actions in response to the charges. Hence ex-ante determination of charges also introduces simplicity. From the understanding point of view, the Hybrid Methodology is based on Load Flow Analysis – which is taught at the under-graduate level in any B.E. / B.Tech. Program in Electrical Engineering as a part of the Power Systems course and should be well known to power system engineers.

3.1.5 Comments: Some stakeholders have observed that the transmission charges computed using the hybrid method may lack distance and direction sensitivity. These stakeholders have cited some examples to illustrate their concern.

3.1.6 Order / Analysis: The Commission considered these concerns in detail. As illustrated below, most of these are in fact examples of counter-flows and hence

strengthen the argument that the new transmission pricing mechanism is sensitive to direction of flow. It was pointed out that sale of electricity from a generator in Orissa to demand in Maharashtra is cheaper as compared to the sale from Chattisgarh to Maharashtra. This is a classic case of counter-flow. These days ER imports power from WR under most grid conditions, therefore any generation in Orissa will most likely get absorbed in Orissa itself, thereby using very less transmission network (and hence lower transmission charges). This will further lead to reduction in the utilization of the transmission network (reduced flow on the ER-WR links) and hence invite lower transmission charges for the generator. A generator in Chattisgarh, on the other hand will use Raipur–Bhadravati, Bhilai-Bhadravati and Bhilai-Koradi lines along the direction of the main flow along these lines, thereby leading to the use of these inter-state transmission lines and higher transmission charges. A similar explanation holds for the instance of a contract for sale of power from UP-West to Maharashtra. WR usually feeds into NR and hence such a transaction would be counter to the direction of the bulk flow and hence invite lower charges.

On the demand side, some stakeholders pointed out that the demand charges for Punjab are higher than other similarly placed states like Haryana and Rajasthan. Punjab draws power from Chamara (400 kV D/C line) during seasons when hydro stations are generating and hence the charges for this corridor are loaded almost entirely on Jullundur and Amritsar sub-stations. Further, Punjab draws power from Dadri region throughout the year. Power from Dadri flows into Punjab via Delhi and Haryana. Rajasthan, on the other hand uses the link between Agra-Bassi (Jaipur) and Samaypur-Bhiwadi and hence the use of ISTS is minimal. It can be shown through load flow analysis that Punjab uses more ISTS assets as compared to Haryana and Rajasthan. In fact, the results of the Hybrid Methodology, applied to 2011-12 network indicates that the demand charges in Punjab reduce significantly. This is because of new generation expected to come in Delhi (Bawana) and Haryana.

The Commission is convinced that the ‘seeming’ counter-intuitive results pointed out by some stakeholders can be explained in the light of the network topology and

the underlying flows. As the new transmission pricing mechanism is implemented, the Commission is required by the regulations to set-up a “Validation Committee” that will validate the Basic Network, the levels of generation and demand at various nodes and the load flow results before the application of the Hybrid Methodology.

3.1.7 Comments: NLDC proposed that to start with, the proposed mechanism for sharing of transmission charges and loss allocation may be applied to only one segment of the market i.e.; Short Term Open Access market. Application of this in short-term market will ensure that the existing mechanism does not get disturbed as we already have point of connection method for collective transaction through Power Exchange. Based on the experience gathered during a reasonable period the methodology may be applied to long-term and medium term transactions as well.

3.1.8 Order / Analysis: Commission has already considered the alternative transition mechanism, wherein 50% of the transmission charges are computed based on the Hybrid Methodology and the balance 50% is based on the Uniform Charge Sharing Mechanism. This would lend uniformity across all classes of transactions, without creating incentives for users to prefer a particular transaction over the other. In the past, because of lower transmission charges, certain generators have preferred seeking short term open access over long term open access. This has caused problems in transmission system planning.

3.1.9 Comments: The priority allocation for the Available Transfer Capability (ATC) in the Day Ahead market is currently such that Power Exchanges receive a lower priority as compared to other Short Term Open Access Transactions under the Open Access guidelines. This lower priority allocation is unjustified since Power Exchange transactions have been incorporated in the forecasted demand/injection supplied in advance of the period. (PXIL).

3.1.10 Order / Analysis: This issue has been dealt by the Commission in the regulations pertaining to short term access and is not a subject of these regulations.

3.1.11 Comments: In the proposed mechanism, in case of any transaction, the Generator or the Distribution Company will have to bear the same PoC charge per unit of

power drawn or injected for their respective zones. For any short term transaction, it would not matter where they procure this power from or to where they are selling their power either. This would incentivize any participant to potentially procure power in the short term market solely on the basis of energy charge without the consideration for buying across multiple regions resulting in a more efficient operation of the national merit order.

Based on the new arrangement, bidding behavior could change causing greater inter-regional exchange and greater instances of congestion as each transaction is not being penalized for crossing regions. This may lead to overutilization of transmission capacity causing greater congestion in the Day Ahead Spot market further aggravating issues faced at the Power Exchanges if adequate measures to allocate Available Transfer Capability are not made. For example, all Southern Region want to buy from NE Region as they shall pay same PoC charge & losses for their zone without worrying about where in India they procure power from. This could also lead to greater congestion in Real Time due to inter-regional flow through the Short Term Open Access transactions. (PXIL)

3.1.12 Order / Analysis: Given the demand charge in a zone, power would be sought from zones where the generation charges are less. Such transactions would cause counter-flows to the base flows, e.g., States in ER seeking to purchase power from Delhi / Punjab etc. Such transactions would in fact relieve congestion. Now, in the instance of all the states in SR seeking to purchase power from NER – this of course would be limited by the capacity of the inter-regional links that SR has with WR and ER – which is the case even today. As pointed by PXIL, utilization of the inter-state and inter-regional network will improve because of more inter-regional transactions.

3.1.13 Comments: Point of Connection charging is dynamic in nature and may not be appropriate as siting signals for DICs considering the gestation period and thereafter of any generation plant. (PGCIL)

The transmission charges in the context of long term contracts are finally paid by the customers. Why transmission charges should then be computed separately for demand DICs and generating DICs? (MPPTCL)

3.1.14 Order / Analysis: The staff of the Commission has computed PoC charges for both 2008-09 and 2011-12. A comparison of the results are therefore indicated to provide a signal.

3.1.14.1 If demand charges are high in a zone – it would be advantageous to add generation there (after considering the trade-off between cost of fuel transportation and transmission of electricity).

3.1.14.2 If the generation charges are high in a particular region and there is adequate transmission capability, adding generation there will reduce transmission charges.

3.1.14.3 If the generation charges are high in a particular region and transmission system is operating close to capability, adding generation there may increase transmission charges.

3.1.14.4 Demand access charges in the vicinity of a generation hub are low (provided the demand nodes are connected directly with the generation hubs).

3.1.14.5 A commercial contract which is against the direction of physical flow of power will invite lower transmission charges – e.g. commercial contract between a plant in UP-West and Maharashtra would invite 11.11 paise/kWh whereas, a commercial contract between a plant in Chattisgarh and Maharashtra would invite 19.30 paise/kWh. In this example, the former contract will be against the direction of flow (which is generally from WR to NR), while in the latter case the power will flow along the direction of dominant flows in inter-state lines between Chattisgarh and Maharashtra.

3.1.15 Comments: Siting of generation is not guided by signals inherent in the transmission pricing mechanism. (MPPTCL and others).

3.1.16 Order / Analysis: Cost-reflective charges provide signals which allow the economic costs of transmission to be factored into decisions about where to locate new generation and about when to close existing generation. This is not the same as saying that we should not have generation that is a long distance from demand (or vice versa) because generators will be able to weigh the costs of transmission against other costs and operating efficiencies which are likely to vary by location. Generators will need to consider a number of factors when they decide where to site new generation facilities. Depending on their location, they will face:

- different land costs,
- different labour costs
- potential load factors
- different fuel costs, and
- they will also face different electricity transmission costs.

Cost-reflective transmission charging allows generators to trade off higher transmission charges in one area of the country (e.g. the Pithead coal fired power station in Chattisgrah) against other cost considerations (e.g. lower land, labour and fuel costs). This allows them to make informed decisions. Thus, even though it is more expensive to transport the electricity over long distances, it may still be economic to locate generation in remote locations.

In UK, where a similar transmission pricing mechanism is used, the principle of cost-reflective charging was endorsed by a report on “The Economics of Renewables” produced by the House of Lords Select Committee on Economic Affairs. The Select Committee observed that, “Ofgem has successfully defended a judicial review on the basis that “it was absolutely right that people who were at the extremities of the system should pay very high charges that reflected the economic costs of transmitting electricity a long way from where it is produced to where it is used’ ... We agree with this position. We consider that the current system of Transmission Use of System charges sends broadly appropriate signals of the costs of locating generators at different points on the system”.

3.1.17 Comments: It is felt that the time has not yet come for making sweeping changes in the present mechanism of interstate transmission charges, majority of inter regional flows will commence after commissioning of UMPP and thereafter change in the methodology could be considered. (MPPTCL)

3.1.18 Order / Analysis: It has been reported that certain 220 kV network of Madhya Pradesh gets over-loaded when the states in the NR overdraw. Power (300-700 MW) flows from WR to ER in most of the hours. ER feeds between 1000 MW to 1400 MW into NR in most of the hours. There is considerable flow from WR to NR on the Gwalior-Agra link. SR is fed by both ER and WR in almost all the hours. Almost all large traders trade inter-regional power in the short term markets. Given the generation capacity expected in Chattisgarh, Orissa, Madhya Pradesh, Uttarakhand, Himachal Pradesh, NER etc, and the associated transmission corridors (including the nine High Capacity Transmission Corridors), such transactions will probably only increase in the future. The time is therefore appropriate for introduction of a transmission pricing mechanism which is compatible with the developments in the power markets and the growth of the Indian Power System – where 4 regions have been integrated and SR is expected to be integrated with the NEW grid during the 12th Plan Period.

3.1.19 Comments: Reasons for the difference between the zonal charges reported in the approach Paper on the subject released by the Commission on May 15 2009 and the zonal charges reported along with the draft regulations needs to be explained.(MPPTCL)

3.1.20 Order / Analysis: The results reported in the Approach Paper were based on (1) the planning data obtained from CEA for 2011-12 where the NEW grid and SR grid were considered integrated (2) The line-wise ARR was based on benchmark costs of assets (3) DC load flow was used instead of AC load flow (4) the Slack buses were dispersed all over India, as opposed to slack bus selection based on AP method adopted now, and (5) All voltage levels were considered, viz, from 765 kV to 132 kV, as opposed to the truncated network considered now. The results are therefore not comparable.

3.2 Definitions:

- 3.2.1 Comments: Some stakeholders (like NLDC etc.) have observed that the definition of Annual Transmission Charge has an acronym ATC, which is generally understood as Available Transmission Capability. Hence this should be changed to Yearly Transmission Charge (YTC).
- 3.2.2 Order / Analysis: The Commission has accepted the above observation.
- 3.2.3 Comments: NLDC felt that the definition of Application Period may be modified by adding including the words “peak and off-peak conditions” in the end.
- 3.2.4 Order / Analysis: The Commission has accepted the above observation.
- 3.2.5 Comments: NLDC recommended that the term ‘Approved demand’ may be renamed as ‘Approved withdrawal’ and Approved Short term Demand may be renamed as ‘Approved Short- term Withdrawal’. As per the common understanding the demand of a control area includes generation from own resources plus drawal from the ISTS on account of approved long-term/medium term/Short-term schedules plus any unscheduled interchanges.
- 3.2.6 Order / Analysis: The Commission has accepted the above observation.
- 3.2.7 Comments: NLDC suggested that the DICs may withdraw/ inject reactive power from ISTS. These MVAR flow in the system has a significant impact on the losses. The MVAR withdrawal/injection needs to be modelled during formulation of base case. Hence DICs may be asked to declare the maximum and minimum MVAR withdrawal also. The definition of approved withdrawal and approved short term withdrawal may be amended as

“Approved Withdrawal means the simultaneous maximum withdrawal in MW and MVAR approved by NLDC for all Designated ISTS Customers in a control area put together aggregated from all nodes of ISTS for each representative block of months, peak and off-peak scenarios at the interface point with ISTS.”

“Approved short term Withdrawal means additional withdrawal approved by RLDC over and above approved withdrawal for all Designated ISTS Customers in a control area put together aggregated from all nodes of ISTS for each representative block of months, peak and off-peak scenarios at the interface point with the ISTS.”

3.2.8 Order / Analysis: The Commission has accepted the above observation.

3.2.9 Comments: NLDC suggested that the definition of Approved injection may be modified as “Approved Injection means the maximum injection approved by NLDC for the designated ISTS customer for each representative block of months, peak and off-peak scenarios at the ex-bus of the generator.”

3.2.10 Order / Analysis: The Commission has accepted the above observation.

3.2.11 Comments: NLDC suggested that the definition of Approved Short term injection may be modified as “Approved Short Term Injection means the additional injection approved by RLDC over and above the Approved Injection for the Designated ISTS customer for each representative block of months, peak and off-peak scenarios at the ex-bus of the generator.”

3.2.12 Order / Analysis: The Commission has accepted the above observation.

3.2.13 Comments: NLDC, GETCO and certain other stakeholders suggested that the Definition of Power System should be as per the Act and accordingly it would be preferable to delete the definition of Entire power System to avoid contradiction.

3.2.14 Order / Analysis: In the context of these Regulations, the network to be considered for determination of transmission tariffs is required to be defined. The same has defined as Basic Network to avoid contradiction with the Act.

- 3.2.15 Comments: NLDC and certain other stakeholders suggested that Uniform National Postage stamp charge should not be linked to actual generation or withdrawal and therefore the definition of Uniform charge may be modified.
- 3.2.16 Order / Analysis: The recommendation is accepted and the Uniform Charge component shall now be determined based on the Approved Withdrawal / Approved Injection. The definition has been modified accordingly.
- 3.2.17 Comments: NLDC and certain other stakeholders suggested that the definition of Uniform Loss be modified and terms 'demand customers' and 'uniform allocation mechanism' be defined.
- 3.2.18 Order / Analysis: The recommendation is accepted. The definition of Uniform Loss has been clarified and Uniform Loss Allocation Mechanism has been clearly defined.
- 3.2.19 Comments: NLDC recommended that ISTS be clearly defined in these Regulations.
- 3.2.20 Order / Analysis: The Commission feels that ISTS is very clearly defined in the Act and the same definition shall hold in the case of these regulations also. The Regulation deals with allocation of YTC of ISTS transmission licensees and other non-ISTS transmission licensees whose assets have been certified as being used for interstate transmission of electricity by RPCs. All such assets would fall within the purview of the definition of ISTS in the Act.
- 3.2.21 Comments: Some stakeholders (NLDC and others) have sought clarity on whether all generators connected to ISTS, DICs? If yes, separate Agreements (TSA) will have to be signed with such DICs.
- 3.2.22 Order / Analysis: All such generators, including those owned by the state government or IPPs supplying solely to one state, which are connected directly with ISTS, are required to sign TSA and shall be covered by these Regulations.

3.3 Computation of Transmission Charges and Loss Allocators:

3.3.1 Comments: Some stakeholders have sought clarity in the regulations on (1) what data shall be used for computation of PoC based transmission charges, (2) how will uniform charge be computed? In fact GETCO has proposed that “In absence of projection of short term demand/injection, the participating factor derived by implementing agency distorts results of transmission pricing significantly. Therefore, impact of short term demand/injection cannot be ignored and same is to be considered suitably while deciding pricing methodology”.

3.3.2 Order / Analysis: The basis of billing shall be the forecast generation and demand data. Cost-reflective pricing should be based on the assets that have been planned for. System planning is done after considering peak conditions, other than peak conditions which might require high loading of certain network elements which may not be loaded to the same extent during system peak conditions and network contingency conditions. For pricing based on such network conditions, ideally forecast data on long term, medium term and short term requirements of all the players is required. However, in the course of discussions with various stakeholders (including NLDC) it was felt that while there could be reasonable certainty about long term and medium term contracts at the time of computation of PoC charges, requirements of various players during short term would be based on their forecasts and is therefore subject to both errors and strategic gaming. Further, it would be difficult for the system operator to give “short term access rights” in the beginning of the year.

Therefore each DIC shall be required to submit injection data at various nodes in its jurisdiction (or at the node(s) where it is connected, as the case may be) such that the sum of injection at all the nodes is equal to the long term / medium term agreements on the date of submission of such information. Likewise, each DIC shall also submit demand data at various nodes in its jurisdiction (or at the node(s) where it is connected, as the case may be) such that the sum of demand at all the nodes is equal to the long term / medium term agreements on the date of

submission of such information. Further, where ever applicable and as specified in Attachment-I or the procedure for data collection prepared by IA and approved by the Commission, each DIC shall also provide technical data related to the power system in its jurisdiction.

Hybrid method, as described in Attachment-I shall be used for computation of transmission charges and loss allocation factors. The zonal charges computed based on the nodal charges obtained using Hybrid Method shall be so adjusted that 50% of the Monthly Transmission Charge of the ISTS Transmission Licensees is recovered from such charges. The balance 50% of the Monthly Transmission Charge shall be recovered using the Uniform Charge Sharing Mechanism.

50% of the Monthly Transmission Charge attributed to the peak / other than peak period shall be divided by the sum of the Approved Injection and Approved Withdrawal for that grid condition (peak / other than peak) and charged as a uniform Rs / MW charge for that month and peak and other than peak condition to all DICs.

Short Term Open Access transactions would continue to be governed by the CERC (Open Access Regulations) in force except that the PoC charges for such access will be determined by these Regulations. Further, post-facto, open access provided on account of short term open access would be considered in the computation of deviations.

3.3.3 Comments: Some stakeholders have sought clarity on the requirement of network truncation.

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.

3.3.5 Comments: NLDC has sought clarity on how the ISGS embedded in the state network be treated?

3.3.6 Order / Analysis: Such ISGS are a part of the state network. The charges for the state network are approved by the SERCs and applied to the beneficiaries of such ISGS after due approval by RPCs.

3.3.7 Comments: NLDC requires that the process of truncation be clearly explained in the regulations. Whether network truncation is to be done based on certain equivalencing method. The approach to be adopted for matching the voltage and angles at generation and demand buses in the truncated case AC load flow with the voltage and angles at generation and demand buses in the full network AC load flow may be suitably elaborated.

3.3.8 Order / Analysis: The Regulations require that the Basic Network be reduced such that most of the power system that features on such reduced network includes the ISTS transmission system. Truncation is one of the methods of network reduction. Other mechanisms like creating an equivalent network, if found to be technically superior alternatives, may be employed by the IA after due approval from the

Commission. The process of truncation has been explained in the Attachment-I of the regulations. Based on these generic principles a code for truncation was developed by the CTU for truncation of the 2011-12 network. The experience of the Commission staff with truncation of the 2008-09 network and 2011-12 network based on these principles shows that it is possible to obtain a truncated network wherein the slack bus generation matches very closely with the complete Basic Network. The voltage magnitude (and their angles) at all the buses was also very close to the full Basic Network.

3.3.9 Comments: NLDC desired clarity on the treatment of states which would be net injector of power in some seasons and net loads in others. There could be certain States that could be net injectors of power (say Himachal Pradesh during peak hydro). The treatment of such nodes during “zoning” may be specified in the Regulation. Alternatively the methodology used during the exercise for formulating pricing methodology for ISTS may be elaborated.

3.3.10 Order / Analysis: Each state has both generation zone(s) and demand zone, except NER where entire NER is considered as a generation zone and a demand zone. For net withdrawal (injection) on various inter-state tie lines the demand zone charge (generation zone charge) is applicable. For injection into the grid at the nodes where generators are connected with ISTS, the generation zone charges are applicable. Zones do not vary by months.

3.3.11 Comments: NLDC has sought clarity on how the generators connected with 220 kV ISTS network be charged? Further, what will be the treatment of state lines being currently considered by RPC for being charged from ISTS beneficiaries.

3.3.12 Order / Analysis: ISGS connected to the 220 kV network of the ISTS will be charged at the zonal generation charge for the region where such generators are physically located. These will be charged at the zonal transmission charges computed for zones where such generator is physically located. For the ISGS connected to the state network (owned by STU/SEB/intrastate transmission licensee), the charges for the state lines will be as per the existing mechanism. Instances of such existing cases in NR are:

- (1) UPPCL LINES FOR EVACUATING NAPP GENERATION
- (2) UPPCL LINES FOR EVACUATING UNCHAHAR GENERATION
- (3) ANTA-KOTA LINE OF RRVPNL
- (4) RAPP (B) -KOTA/ RAPP (A) LINE OF RRVPNL
- (5) PAMPORE-KISHANPUR LINE OF J&K

3.3.13 Comments: While truncating, virtual generators / loads are being used based on injection / drawals. In case of injection or drawal at a node is for more than one DIC, the sharing methodology needs to be transparent. (NLDC)

3.3.14 Order / Analysis: In case the 'virtual injection' / 'virtual withdrawal' is due to multiple DICs, the MW injection / withdrawal due to each of the DICs would be known at the time of truncation of the Basic Network. In case such a node has both injection and withdrawal, the transmission charges would be computed for injection and withdrawal at this node. This node would therefore be a part of both the generation zone and the demand zone. The MWs injected and/or withdrawn would be multiplied by the respective zonal charges to determine the liability of transmission charges for each DIC. All the information – Basic Network and the flows, Truncated Network and the Flows, Nodal Transmission Charges and Zonal Transmission Charges, after validation of a "Validation Committee" would be made available on the websites of IA and CERC for the purposes of transparency.

3.3.15 Comments: The relaxation given to the solar based generation would further the cause of renewable energy in the country and is therefore welcome. However the apportionment of those charges among other DICs may be specified. Similar detailing may also required for loss allocation. It may be clarified if the methodology suggested for long term customers availing supplies from inter-state generating stations is to be used for the solar generation.(NTPC)

3.3.16 Order / Analysis: Normally Solar based power plants are connected at 132 kV and below. In such cases issue of charging ISTS charges arises if such generator leads to net injection in the 400 kV network (or 132 kV in NER). Normally this is unlikely because generation by such generators embedded in the state would

serve the local demand at lower voltage levels and reduce the loading of the high voltage transmission network. In any case, if there is net injection into the 400 kV ISTS (or 132 kV in NER) due to solar, in the implementation of the MP component of the Hybrid Methodology, perturbation shall not be done at such nodes for the computation of transmission charges or loss allocation factors based on the Hybrid Method. The charges for the line and losses would then, programmatically get allocated to other nodes.

3.3.17 Comments: The clauses have proposed that no transmission charges (and transmission losses) for use of ISTS network shall be charged to solar based generation. It is not clear whether this is only with respect to the generation end charges (and losses) or the charges (and losses) for corresponding drawal too. It is suggested that to promote solar based generation in line with the policies of the Govt., the transmission charges and losses may be waived for both injection and drawal. For, drawal, their charges may be calculated based on Approved Demand less contracted solar based power. Since tariff for solar based generation is exclusively in the nature of fixed charges and variables charges are zero, it is not apprehended that any buyer who has contracted for solar based power shall not draw the same when available. (NTPC)

3.3.18 Order / Analysis: The adjustment of transmission charges (and losses) due to solar based generation can be done programmatically. Further, in case the solar generation is not available and the DIC contracts for the shortfall from an alternative source, such an exemption would give undue advantage to such a DIC. Further, tracking of contracts to carefully allow for such an adjustment may be considered by the Commission after the base systems required for the implementation of the new transmission pricing mechanism materialize.

3.3.19 Comments: Moving from existing weekly to Annual loss is likely to create large difference between scheduled and actual loss. (NLDC)

3.3.20 Order / Analysis: The Regulations do not suggest movement from weekly to annual loss allocation mechanism. The loss allocation factors for each DIC will be

computed based on the Hybrid Method. The total losses in the system will be computed as per the existing mechanism. The attribution of these losses to various DICs shall be done using these loss allocation factors. The Regulations require the NLDC to prepare a detailed mechanism for charging the losses attributed to each DIC in kind.

3.3.21 Comments: The proportion in which the Annual Transmission Charges of the substation is to be apportioned to lines emanating from each substation may be clearly specified (Voltage level, ckt kilometres, twin/triple/quad conductor, effect of FSC & TCSC). The methodology used during the exercise for formulating pricing methodology for ISTS may be elaborated. (NLDC and Other Stakeholders)

3.3.22 Order / Analysis: The transmission charges of the sub-stations are allocated to the lines in proportion to their circuit kilometres. The charges for any sub-station are allocated to the lines connected with the sub-station such that the sub-station charges attributed to lower voltage lines are 50% of the sub-station charges attributed to higher voltage lines. This is based on the benchmark costs of bays in the benchmark model of Transmission Line and Sub-Station under consideration by the Commission. The Commission understands that this may need to be refined as more experience is gained and better suggestions are submitted by various stakeholders in this regard.

3.3.23 Comments: It is understood that the control area and boundary metering related issues would be taken care in the Indian Electricity Grid Code. However with respect to sharing of transmission charges the following may be clarified

a. Few entities may be connected with both ISTS and the State transmission system. The regulations may specify the methodology for treatment of such entities.

b. There could be some users of ISTS embedded in the State transmission system such as Feroz Gandhi Unchahar Thermal Power Plant, Narora Atomic Power Plant, Anta Gas Power Station, UT Goa, UT Daman & Diu UT Dadra & Nagar Haveli etc. The regulations may specify the methodology for treatment of such entities.

c. Further, Changing of Scheduling jurisdiction should not result in change in payment of transmission charges and loss allocation.
(NLDC and other Stakeholders)

3.3.24 Order / Analysis: The MWs injected (or withdrawn) by DICs, which are connected to both the State Network and the ISTS Network, in the ISTS network shall be determined on the basis of the Network Flows in the Truncated Network. Such DICs shall be billed based on the MWs thus determined. Goa has been considered to be in the same zone as Maharashtra. UT Daman and Diu and UT Dadra and Nagar Haveli have been considered in the same zone as Gujarat. This is based on the criteria for zoning specified in the Regulations. The transmission charges for power plants which are connected with the 220 kV (or below) grid owned by the state government, shall be determined by the state and adopted as per the recommendations of the RPC. For power plants connected with the 220 kV substations of the ISTS licensees, the zonal charges of the zones where such generators are physically located shall be applicable.

3.3.25 Comments: A single mechanism for pricing of transmission charges, losses and congestion pricing can be found in developed markets in the form of Location Marginal Price (LMP) – as in PJM, MISO etc. Congestion charge, especially if frequent, assumes the nature of a transmission capacity building charge and should be accrued such that adequate development of the transmission system can be done at the appropriate bottlenecks. Perhaps all Short Term Open Access participants need to be subject to the same uniform rules with regards to the pricing of congestion, transmission and losses in an integrated fashion. It is suggested that the Transmission Charge and Congestion Management in Short Term transactions be looked at uniformly rather than separately. (PXIL)

3.3.26 Order / Analysis: Pricing of transmission based on the “opportunity value” as identified by the differences of Energy Charges (LMPs) at various nodes is an ideal transmission pricing mechanism. However given that in India we do not have locationally differentiated energy charges, this method cannot be implemented in the current Indian context.

- 3.3.27 Comments: Clarification is required as to whether all transactions through the power exchange including the Day Ahead Spot (DAS), Day Ahead Contingency (DAC), and Week Ahead (WA) transactions are subject to the same set of zonal charges (PXIL).
- 3.3.28 Order / Analysis: All transactions through the power exchange have the same treatment as short term transactions.
- 3.3.29 Comments: Average voltage-wise ARR should further be differentiated based on the type of conductor used to further correctly reflect “utilization” of transmission assets by users. (CEA, NTPC)
- 3.3.30 Order / Analysis: The Commission has accepted this suggestion.
- 3.3.31 Comments: What is the treatment of 765 kV lines operated at 400 kV? (CEA, NTPC)
- 3.3.32 Order / Analysis: For the purposes of computation of transmission charges based on hybrid methodology, the transmission charges of 765 kV lines operated at 400 kV shall be computed by considering the average Rs/Circuit kilometre of 400 kV (quad) lines. As detailed in the Regulations, the revenue for the use of ISTS network recovered from the Hybrid Methodology shall be 50% of the transmission charges of all ISTS transmission licensees, the balance 50% is recovered through the Uniform Charge Mechanism.
- 3.3.33 Comments: Termination of dedicated lines should be treated at the injection points for generators / demand (CEA, Reliance Energy, NTPC)
- 3.3.34 Order / Analysis: The Commission has accepted this suggestion in cases where dedicated transmission lines are constructed and owned by the Generator. The treatment of such assets will be as per the Connectivity Regulations.

3.3.35 Comments: Computation of loss allocators at the Grid level separately for peak and off peak condition, though precise, would be too much of a deviation from the current practice (NLDC)

3.3.36 Order / Analysis: The Commission has accepted this suggestion. The Loss Allocation Factors shall be computed for each block of months but shall not be different for peak and other than peak conditions. NLDC shall prepare a detailed procedure of application of the loss allocation factors to loss adjustment in schedules of various DICs.

3.3.37 Comments: The provision that allows DICs to seek revision of their Approved Injection / Withdrawal up to a maximum of $\pm 15\%$ apparently allows for deviations in the demand / injection levels after the onset of the application period and also states that ordinarily this will not necessitate a re-computation of the charges. In such an event, the ATC charges may not be fully recovered. (PGCIL)

3.3.38 Order / Analysis: The Commission has accepted this suggestion partially to avoid frequent revision of PoC charges during a year and uncertainty due to such revisions. However, in case, large changes in the PoC charges are foreseen on account of the network or its usage undergoing substantial change, the IA may file a petition before the Commission, and undertake the revised computations only upon the Commission's orders in this regard;

3.3.39 Comments: It appears that only 400kV network is retained after truncation. If such is the case then the substantial 220kV and below network of POWERGRID across the country does not get captured under these provisions. Treatment of the associated losses for such network is also not addressed. The truncation and the recovery mechanisms for the uncovered portion need to be addressed. (PGCIL)

3.3.40 Order / Analysis: Generators connected to the ISTS at 220 kV systems of the ISTS transmission licensees shall pay the same charge as the zonal charge determined for the zone where such generators are physically located. In fact, it is expected that levy of such charge would lead to over-recovery and may need to be adjusted in the third part of the bill. Further, in 2008-09 the YTC to be recovered from 220

kV assets was less than Rs 260 Crore (except NER, where 220 kV and 132 kV assets have been considered) out of the total YTC of Rupees 4959 Crore. The loss allocation factors, computed using the Hybrid Method, provide the factors to be used for allocation of losses amongst various DICs. The computation of total losses shall be as per the existing mechanism. NLDC shall prepare a detailed procedure of application of the loss allocation factors to loss adjustment in schedules of various DICs.

3.3.41 Comments: PoC charges are proposed to be calculated for each of the 5 blocks (including peak and off-peak) inter-alia based on the status of transmission system in each of the block. It may be mentioned here that Transmission systems are declared for commercial operation at the beginning of a month and not at the beginning of the 5 blocks. As such PoC charges may be considered to be determined for each month of the financial year so as to appropriately incorporate the ATC of new transmission elements that are declared for commercial operation. (PGCIL)

3.3.42 Order / Analysis: Any line getting commissioned shall be considered for the computation of the PoC charges for the entire block of month. Changes in commissioning dates of the lines or other network elements may cause a mismatch between bills raised and the actual monthly transmission charges. Such adjustments, along with the adjustments for FERV and changes in interest rates, would be reflected in bi-annual bills raised by the CTU on the DICs.

3.3.43 Comments: Injection zonal charge is recovered from NER's DIC in the NEW grid however no drawal charge is accrued to NEW grid Tr. licensees. Similarly, drawal charge is incident to the SR grid's DIC from Tamil Nadu zone, however injection charge is not accrued to SR grid Tr. licensees. Treatment of injection and drawal between the grids is not addressed. (PGCIL)

3.3.44 Order / Analysis: The total YTC for a grid is recovered from generators and demand customers in any PoC mechanism. Each generator uses the grid in a certain manner and pays for it irrespective of where the power is being consumed. Similarly each demand DIC pays its zonal charge irrespective of where the power

is generated. In the instant example quoted by PGCIL, the generator in NER pays its charge. The power might be flowing into SR either through Talcher-Kolar or through Chandrapur Back-to-Back. Since the flow in most cases is into SR over these links, the charges are shared amongst the various nodes in SR which benefit from the presence of these HVDC links. This has been explained in Attachment-I to the regulations. In the instant example, the charges for these HVDC links are internalized in the demand charges of various zones in SR. Hence the concern of the stakeholder is addressed by the methodology adopted.

3.3.45 Comments: Consideration of State Transmission assets like intervening transmission facilities in the present computation may affect pricing of inter-state transmission pricing and at the same time, utilities using state network are also charged for use such state network, Therefore, the consideration of state transmission assets may cause unfair burden on those DICs using State assets. (GETCO)

3.3.46 Order / Analysis: The DICs are billed at the interface of the ISTS network and the STU network based on the SEM. The Commission considered the following alternatives – (i) Consider the revenue requirement of the intervening state assets as zero, (ii) consider the revenue requirement of such intervening assets but scale the zonal PoC charges to recover the revenue requirement of only the ISTS Transmission Licensees and (iii) consider revenue requirement of all intervening assets and charge at all the nodes. Option (i) was found to distort the PoC price signals and hence was rejected. Option (iii) would be ideal and state transmission owners / licensees would be encouraged to get their charges recovered through the transmission pricing mechanism under these Regulations. This would require approval of the State Electricity Regulatory Commissions. Option (ii) is considered appropriate since it causes minimal distortion of the PoC price signals and also recovers the YTC of the ISTS transmission licensees. Further, in option (ii), the states are billed for their use of the ISTS network only at the interface of the ISTS network and the state network.

3.3.47 Comments: The consideration of peak and off peak hours may vary from region to region and season to season. Therefore, the consideration of peak and off peak hours common for all regions may be reviewed and accordingly it is to be considered while calculating weightage. (GETCO)

3.3.48 Order / Analysis: Planning data normally forms the basis of transmission pricing because the users must pay for what has been planned. System planning considers alternative grid conditions. The Commission has therefore defined the hours as 'peak' and 'other than peak' because while 'peak' conditions are definitely critical for system planning, certain other grid conditions 'other than peak' (and not off-peak) are also critical because during such times certain crucial components of power system might be critically loaded. Since system operators monitor the grids most closely, they have been assigned the responsibility to identify such conditions (peak and other than peak) for the purposes of transmission pricing.

3.3.49 Comments: In the determination of transmission pricing, the revenue requirements of transmission assets of the same voltage class are pooled. The addition of new transmission assets will increase the tariff as the old assets have been depreciated. Therefore, the transmission tariff charged to those utilities on the basis of old assets may be affected. (GETCO)

3.3.50 Order / Analysis: Nearly all states require more generation and associated transmission assets. The loss because of having to pay more on an average of old assets gets neutralized to an extent by having to pay less for new lines.

3.3.51 Comments: As mentioned in the draft regulation the proposed methodology is a method of allocation of transmission charges and not determination of ARR, which implies that ultimate recovery by the transmission utility, should remain same and the payment by end beneficiaries may vary in narrow margin only. Based on the results of simulation for the period for 2008-09 as made available alongwith the draft regulation the transmission charges under proposed methodology for the State of MP has been worked out and results are as under:-

a) Generation access charges for the year 2008-09 Rs.183.47 Crs.

b) Demand access charges for the year 2008-09	Rs.256.28 Crs.
Total	Rs.439.75 Crs.

However, based on the billing of POWERGIRD for the period 2008-09, actual charges work out around Rs.272 Crs. only. It could be seen that there is vast difference between the present and proposed for annual transmission charges. If it is so, then there appears some flaw somewhere in the proposed methodology, which needs to be adequately addressed. (MPPTCL)

3.3.52 Order / Analysis: The staff of the Commission analyzed the detailed computations submitted by MPPTCL. The computation of the Generation access charges is correct. However the entire volume of power (in MW) has been used for the computation of Demand access charges. Instead the stakeholder should have taken the MW flowing into Madhya Pradesh only through the ISTS sub-stations. It is observed that some of the power flows into Madhya Pradesh using the state's own transmission assets. Transmission charges for power flowing into the state from its own sub-stations are not charged. Such a consideration will reduce the gap between the existing transmission charges the state has to pay and the charges payable according to the existing mechanism. The difference will further get reduced because of 50% charges being charged based on the Hybrid Method and 50% based on the Uniform Charge Mechanism.

3.3.53 Comments: The generators may have to inject beyond the 'Approved Injection' to either support the grid or as a part of the alterations in the Planned Maintenance Schedule of the RPC. The penal provisions should not be applicable to generators under such conditions. (NTPC)

The penal provision of 25% excess charge for violation of the grid access limit in more than 5% of the hours in a month is stringent and hence must be relaxed. (NTPC, other stakeholders)

3.3.54 Order / Analysis: The regulation in this regard has been revised. Therefore in case the metered MWs (ex-bus) of a power station or the aggregate demand of a DIC exceeds, in any time block

(a) In case of generators: The Approved Injection + Approved Medium Term Injection + Approved Short Term Injection or;

(b) In case of demand customers: The Approved Withdrawal + Approved Medium Term Withdrawal + Approved Short Term Demand,

Then for first 20% deviation in any time block, the DIC shall be required to pay transmission charges for excess generation or demand at the same rate and beyond this limit, the DIC shall be required to pay additional transmission charges which shall be 25% above the zonal PoC charges determined for zone where the DIC is physically located. Such additional charges shall not be charged to the generators in case of rescheduling of the planned maintenance program which is beyond the control of the generator and certified to be so by the appropriate RPC. Further, any payment on account of additional charges for deviation by the generator shall not be charged to its long term customer and shall be payable by the generator.

3.3.55 Comments: TPTCL has sought clarity on whether the Uniform Charge, under the new regulations will be computed on a regional basis, as is presently the case or will the computation be at the national level. (TPTCL)

3.3.56 Order / Analysis: The Uniform Charge, under the new regulations shall be computed separately for the NEW grid and the SR grid till such time as the grids are synchronised. The new transmission pricing is based on the philosophy of 'National Grid'.

3.3.57 Comments: The CTU should be allowed to keep a percentage of the revenues from short term open access so as to provide adequate incentive to create capacity for short term transactions. (TPTCL)

3.3.58 Order / Analysis: This issue is not a subject of these Regulations. The governance of STOA will be as per the CERC (Open Access Regulations) in force except that the PoC charges payable for such access shall be determined in accordance with these regulations.

3.3.59 Comments: It would be advisable to adopt in full the new concept at one go than rather 50% on existing principles and the balance on the revised one for next two years. The objections to the new concept if any could be addressed on merit and the model need to be adaptive to the same. (PTC)

3.3.60 Order / Analysis: This provision is a part of the transition mechanism. The Commission may reconsider this after 2 years of implementation of the new mechanism.

3.3.61 Comments: 50% charging based on POC method and 50% based on Uniform charging method would cause burden to the state because of certain lines created for use by other regions / states. (BSEB)

3.3.62 Order / Analysis: This is a transition mechanism adopted to avoid tariff shock to any beneficiary. This may be reconsidered by the Commission after two years.

3.4 Zoning

3.4.1 Comments: PoC injection tariff and loss sharing index correctly reflect its location in the grid. Therefore transmission charges / losses for generators must be specified individually and plant-wise, instead of grouping generators in geographical zones. (CEA, GETCO)

3.4.2 Order / Analysis: Generation zones where the generators are meshed within the network would be kept as per the initially proposed mechanism. Transmission charges for large generators where the pooling point is at far away locations would be determined as charges at these specific nodes (such nodes would be considered as separate generation zones) and not clubbed with other generator nodes in the area - this is consistent with the suggestion of CEA. For example, for UMPPs, the transmission access charges will not be clubbed with the transmission charges for other generators in the zone where such UMPPs are physically located. Rather the transmission charges for such UMPPs (or large generators) would be the charges applicable at their nodes (sub-stations) where these

generators inter-face with the ISTS network. Regulations provide flexibility to IA to re-zone after due regulatory approvals.

3.4.3 Comments: There are different PoC tariff zones within the same state. In case a state utility sells power, it is not clear as to which zone's charges shall apply for such transaction. For simplicity, it is proposed that each state may be considered as a single zone for both generators and demand customers. (PTC)

3.4.4 Order / Analysis: The schedules of the various generators connected with the STU network are available with the SLDC. Based on these schedules, the SLDC can determine the power plant whose power is being traded outside the state. The transmission charges for the use of the intra-state and inter-state network shall be required to be determined by the STU as per the transmission regulations of the state.

3.4.5 Comments: Hon'ble Commission may clarify that if a generator located in State A is connected to CTU point in State B through dedicated transmission lines, the generator should be deemed to be located in State B. (PTC)

3.4.6 Order / Analysis: The zonal charges are determined based on the nodal charges. The generation will be considered in state B if the dedicated line has been constructed by the generator itself, else if the dedicated line forms a part of system planning done by CEA and CTU, it will be treated as a regional asset and the nodal charge would also be determined at the generator switch yard on the HT side.

3.5 Billing

3.5.1 Comments: Any under/over recovery and true-up on account of FERV or variation in interest rate etc, may be done through the bill raised on the basis of Uniform Charge rate (postage stamp rate). This should be done monthly and the bill on the basis of the Uniform Charge component must be allowed to be raised 15 days after the bill on the basis of POC charge. Further, truing up should be based on CERCs regulations. (PGCIL)

The Treatment of over-recovery must be clarified. (GETCO)

- 3.5.2 Order / Analysis: Any over / under recovery due to FERV, Changes in interest rates, change in the commissioning schedule of lines and other such expenses approved by the Commission shall be adjusted through bi-annual bills raised by the CTU on the DICs. Such adjustments shall be shared by the DICs in proportion of their Approved Injection and/or Approved Withdrawal.
- 3.5.3 Comments: For efficient billing / collection / disbursement / reconciliation, it is felt that it will call for centralized bill generation supported by decentralized billing (to DICs) at regional level to service this activity vis-à-vis the DICs, since operationalization of LCs requires physical presentation of signed bills to the Bank. Keeping in view the large number of DICs, Regulation should encourage use of Information Technology (IT) and therefore enforce Electronic Billing and collection through RTGS on presentation. (PGCIL)
- 3.5.4 Order / Analysis: The billing function shall be performed by the CTU. CTU may perform decentralized billing operations through its various headquarters. This, however, cannot be a part of these Regulations. The CTU is required to prepare a detailed billing, collection and disbursement procedure including payment security mechanisms and mode of payment within 30 days of the notification of these Regulations, where all the detailed procedures can be set-up.
- 3.5.5 Comments: Service tax will be applicable if billing is done by CTU as an agency of other licensees. This will be an extra burden on the DICs and the consumers. Service tax may even be applicable on CTUs own portion of billing which is now exempt. (PGCIL)
- 3.5.6 Order / Analysis: The Regulation stipulates signing of a Revenue Sharing Agreement between the CTU and the Transmission Licensees. In this set-up, CTU shall only bill for transmission services which are exempted from service tax. Also CTU is required to conduct this regulatory function without charging any fee for that, this collection and disbursement would not be treated as separate service.
- 3.5.7 Comments: The entire billing will be treated as income of the CTU by the Income Tax authorities and there may be extra tax burden due to possible mismatch

between billing and collection. There is no recovery mechanism for this in the draft regulation.

TDS will be deducted by the DICs from the payments released by it and TDS certificates will be issued in the name of CTU. But CTU is entitled to a part of it. While the collection amount net of TDS will be redistributed to the other licensees, the TDS amount will remain unadjusted at the end of CTU. (PGCIL)

3.5.8 Order / Analysis: This issue has been examined in detail by the Commission in consultation with Income Tax experts. It is a fact that DICs may deduct TDS as per the provision of section 194(c) of the Income Tax Act, while making payment to the CTU. CTU may also deduct TDS on the portion of the transmission revenue to be passed on to the other Transmission Licensees. In effect there may be double TDS on the amount to be shared with other Transmission Licensees as netting off of TDS is not allowed under the Income Tax Act. But considering the materiality of the amount of TDS to be deducted from the other transmission licensees and annual tax liability of the CTU which is more than 2.5%, it may not hamper the cash flow of the CTU. Moreover, CTU can apply for TDS exemption under the provision of section 197 of the Income Tax Act.

3.5.9 Comments: Billing by a single agency will lead to complications in redistributing partial payments released by the DICs. (PGCIL)

3.5.10 Order / Analysis: Any under-payment / non-payment by DICs becomes a common liability and shall lead to pro-rata reduction in the payment to each Transmission licensee by CTU. The details of the process of disbursement of revenues to Transmission Licensees shall be detailed in the Revenue Sharing Agreement to be prepared by the CTU.

3.5.11 Comments: Under the above arrangements, it would be difficult to enforce payment security mechanism as it would not be possible to establish the default against dues of any particular Transmission licensee. (PGCIL)

3.5.12 Order / Analysis: Payment Security Mechanism shall be a part of the TSA. The TSA shall be prepared by the CTU as per these Regulations.

3.5.13 Comments: If the charges of Implementing Agency is billed through CTU, service tax will be loaded twice, once in the billing of the Implementing Agency and secondly with the billing of CTU. Therefore, the Implementing Agency should be asked to bill and collect their charges from the DICs directly. (PGCIL)

3.5.14 Order / Analysis: The IA shall be reimbursed the charges for computation of Transmission Charges based on actual costs incurred.

3.5.15 Comments: Generation access charges for long term injection are charged to the long term customers. Such charges should be applicable only after the commencement of Commercial Operation of the Generator. (CEA)

3.5.16 Order / Analysis: The clause in the regulations pertaining to direct billing of generation access charge to long term demand customers has been modified to allow the transmission charges to be charged to long term customers only after commencement of "commercial operation" of the generation. Till then, generation access charges shall be the responsibility of generator.

3.6 Metering and Collection

3.6.1 Comments: Suitable provisions may be made to ensure that in the event of under payment / payment default by the long term customer, respective generator(s) may become liable to pay the applicable transmission charges.(may be provided as part of payment security mechanism) (PGCIL)

3.6.2 Order / Analysis: This is accepted by the Commission. Such arrangements shall be a part of the TSA to be prepared by the CTU within 60 days of the notification of these Regulations.

3.7 Transmission Service Agreement and Implementation

- 3.7.1 Comments: Since signing of BPTA etc. shall no longer be mandatory, the existing Transmission Access and Connectivity Regulations would require amendment. The Commission may order accordingly. (NTPC)
- 3.7.2 Order / Analysis: The TSA and the re-alignment of the existing BPTAs to the requirements of the new transmission pricing mechanism shall be prepared by the CTU within such period as defined in these Regulations.
- 3.7.3 Comments: Any embedded customer, within a state system will be selling/ buying power through the STU network. It will be difficult to ascertain the zone (or the nearest 400 kV bus of ISTS) for the embedded customer for determining the transmission charges and losses, if the same is not kept uniform across the state. (PTC)
- 3.7.4 Order / Analysis: If a generator/demand customer is embedded in the STU network, the transmission charges for such a generator/demand customer will be determined by the STU and approved by the Appropriate Commission. These regulations determine charges for DICs physically connected with the ISTS network.
- 3.7.5 Comments: Many stakeholders commented that the system data used for determination of transmission charges and loss allocation must be validated and software audited before it is commissioned.
- 3.7.6 Order / Analysis: The System data for the present analysis was provided by NLDC, network simulation on all India grid and network truncation done by CEA (for 2008-09), data for 2011-12 was provided by CEA and CTU, load flow on all India basis and network truncation done by the CTU. In future also a data validation committee, comprising officials from CEA, CTU, NLDC, CERC and RPCs is proposed to validate the data. The regulations provide for constitution of such committee by CERC. The software shall be validated by an unbiased, non-

commercial and technically qualified person nominated by the CERC before the same is used for implementation.

3.7.7 Comments: Time lines for implementation may be extended. (NLDC)

3.7.8 Order / Analysis: The detailed timelines for implementation have been discussed with NLDC and is attached as Annexure-II to this Statement of Reasons and Objects.

3.8 In view of the above discussion, we direct that the regulations published in draft form be finalised and notified in the official Gazette after incorporating the changes as decided in the forgoing paragraphs.

Sd/-
[M DEENA DAYALAN]
MEMBER

Sd/-
[V.S.VERMA]
MEMBER

Sd/-
[S. JAYARAMAN]
MEMBER

Sd/-
[Dr. PRAMOD DEO]
CHAIRPERSON

Annexure-I

1. Central Electricity Authority
2. JSW Energy Limited
3. Tripura State Electricity Corporation Limited
4. Reliance Power Transmission
5. IIT Mumbai and IIT Delhi
6. Tamil Nadu Electricity Board
7. West Bengal Electricity Distribution company Limited
8. CESC Limited
9. MP Power Trading Company Limited
10. Transmission Corporation of Andhra Pradesh
11. BSES
12. PGCIL
13. Adani Power Limited
14. Reliance Power Transmission
15. Athena Chattisgarh Power Pvt. Limited
16. Tata Power Trading Company Limited
17. SRPC
18. RRVPN
19. Kerala SEB
20. West Bengal Electricity Transmission Company Limited
21. Shri Subodh Kumar Bhatnagar
22. IEX
23. PXIL
24. Bihar State Electricity Board
25. Maharashtra State Electricity Transmission Company Ltd.
26. SLDC Gujarat
27. PTC
28. MahaVitran
29. Reliance Energy
30. NDPL
31. NHPC
32. HP Power Transmission Corporation Limited
33. SRPC, Bangalore
34. Mr. Shanti Prasad
35. NLC
36. THDC India Limited
37. MSETCL
38. NTPC