Frequently Asked Questions

Section A: Principle/Methodology

1. **Why is transmission system called a shared asset?**

   It would be uneconomical and technically infeasible to build dedicated transmission system for all. Utilization of a certain transmission facility varies with quantum, location and time of injection and withdrawal. In an interconnected system, one-to-one correspondence between a user and a particular transmission asset is difficult to determine.

2. **What is Inter State Transmission System and who owns it?**

   i) Any system for the conveyance of electricity by means of a main transmission line from the territory of one State to another State

   ii) The conveyance of electricity across the territory of an intervening State as well as conveyance within the State which is incidental to such inter-state transmission of energy

   (iii) The transmission of electricity within the territory of State on a system built, owned, operated, maintained or controlled by CTU;

   ISTS may be owned by Central Transmission Utility, State Utility, Independent Power Transmission Companies

3. **Who are the users of Inter State Transmission System?**

   Generators and Load serving utilities desirous of having long term, medium term and short term contracts.

4. **How is the tariff of ISTS determined?**

   ISTS tariff is determined as per the CERC (Terms and Conditions of Tariff), Regulations, 2009. ISTS licensee submits tariff petition for approval by CERC.

5. **Presently who pays for the Inter State Transmission System and how much?**

   Beneficiaries in proportion to their long term allocations (access based) Short term customers as per usage in terms of energy (usage based) PX as adhoc charge (point of connection)

6. **What are the various methods of recovering the transmission tariff from longterm and short term customers?**

   Rolled in Paradigm: Postage stamp, Contract Path Method, MW-Mile

   Incremental Transmission Pricing Paradigm: Long/Short Run Incremental/Marginal

7. **What has been the Indian experience with various methods of transmission charge recovery**

   Access based
   Usage based contract path, pan caking
   Adhoc PoC uniform without any geographical differentiation

   Implicit or bundled (upto 1991)
   Explicit
   - Pre ABT era-Usage based (1991-2002/2003)
   - Post ABT era-Access based
     - -Regional Postage Stamp
   - Short-term Open Access, (May 2004)
     - -Rs/MW/day to Rs./MWh
   - Power Exchange (June 2008)
     - -Rs./MWh and point of connection

8. **What is the PoC Charging method?**

   It is the methodology of computation and sharing of ISTS Charges and Losses among Designated ISTS Customers (DICs) which depends on location and sensitive to distance and direction of the node in the grid. Charges would be computed for each node of DICs based on Hybrid Method as explained in the Regulations.

9. **What are the merits of PoC transmission charge over the other methods?**

   It is independent of the contract "path". It is transparent as all the data used for computing the transmission charges is shared with the users. The transmission charge payable for any contract is known ex-ante and hence it can be considered while entering into a contract.

10. **Does the PoC alter the CERC regulation on determination of transmission tariff Regulations for sharing of transmission charges/apportionment of charges on various users ?**

    No change in the CERC regulations on determination of transmission tariff.

11. What is Hybrid Method?

It is the hybrid of Marginal Participation and average participation method. Average participation method is used for determination of participation factors of slack buses. The two methods are explained below.

12. What is average participation method?

This method is based on proportionate tracing of electricity from generator node to demand node or vice versa.

13. What is marginal participation method?

This method analyzes how the flows in the grid get changed when incremental changes are introduced in generation or consumption at each node.

14. What is a slack bus?

The slack bus is the bus (es) which will respond to the incremental changes introduced at each node during marginal participation method.

15. What is the difference between slack bus and swing bus?

Slack Bus is that bus which will respond to the incremental change done at the node under consideration in Marginal Participation method. For the incremental changes at the Generator node, the slack bus is load (PQ) bus whereas for the incremental changes at the Load node, it is generator (PV) bus. A swing bus is a V-δ bus and takes care of imbalances and losses (MW & MVAR) in load flow studies.

16. Will there be only one slack bus in the basic network?

As specified in the regulation, a concept of distributed slack bus would be used. This means that for every generator there would be certain load buses acting as slack buses and for every load there would be certain generator buses acting as slack buses.

17. How is the slack bus determined using average participation method?

Power tracing is carried out to determine the slack buses. Upstream tracing (load to generator) gives slack bus for load nodes. Down stream tracing (generator to load) gives slack bus for generation nodes.

Section B: Input Data

18. What data is to be submitted to Implementing Agency?

1) Commercial Data containing Line wise YTC of ISTS / Deemed ISTS and Non-ISTS lines certified by RPCs
2) Basic Network Data for load flow
3) Nodal Injection and Withdrawal Data
4) Existing Long Term and Medium Term contracted quantum
5) List of ISTS / deemed ISTS and RPC certified non-ISTS Lines
6) Approved Additional Medium Term injection / withdrawal

19. What is commercial data?

List of transmission lines that constitute ISTS- : CTU owned regional, inter regional transmission system, STU owned interstate lines, STU owned inter regional lines, deemed ISTS (like BBMB).

Yearly transmission charges to be recovered .This is to be submitted in Format-I which has three sheets.

Format-I B: Line wise Yearly Transmission Charges (YTC)

Format-I A: Average YTC on each voltage level and conductor configuration

Format-I C: apportionment of Substation cost among the lines emanating from the S/S.

20. Who should submit commercial data and what is the timeline?

The data is to be submitted by the owners of ISTS, Deemed ISTS and RPC certified non-ISTS lines

In the first year of implementation, the data is to be submitted by the end of first fortnight of September 2010 as per the Implementation plan agreed in the first meeting of Implementation Committee

In the subsequent years the data is to be submitted before the end of fourth week of November in each financial year.

21. **Is the commercial data required to be submitted in case of the ISTS asset/deemed ISTS asset expected to be commissioned in the next financial year?**

    Benchmark figures may be submitted in such cases.

22. **What is the basic network data for load flow?**

    Basic network data shall include all network elements upto 132 Kv and 110 Kv where generators are connected, HVDC network and all generators and loads connected to it. Connectivity diagram is also desirable (preferably a geographical power map)

    Bus data comprises of the name of the substation and voltage level. In case there are three voltage levels- 400 kV, 220 kv, 132 kV then the bus data must have three entries. Shunt reactor and capacitors must form a part of bus data.

    Generator data must contain the Rated MVA, Machine reactance's (Subtransient, Transient and Steady State) on machine rated MVA , Reactive Capability limits from the capability curve, Reactance of the Generator transformer on Generator Rated MVA. Anticipated nodal injection and desired Voltage schedule for representative scenarios must also form a part of generator data.

    Branch data Pi representation of the transmission line and comprises of the transmission line length, conductor type, tower configuration, resistance, reactance, susceptance in per unit on 100 MVA base. Branch data would also include data for line reactor connected at sending or receiving end.

    Transformer data comprises of transformer MVA rating, reactance on 100 MVA base, nominal tap ratio, number of taps and tap steps

    Load data for representative scenarios nodewise also would be required for creating representative scenarios.

23. Which are the formats in which the basic network data must be submitted?

    This data is to be submitted in Format II & Format III B which has following sheets:

    Format-II A: Bus Data
    Format-II B: Generator Data
    Format-II C: Branch Data
    Format-II D: Transformer Data
    Format-II E: DC Line Data
    Format-II F: Switch Shunt Data

Format-III B: Nodal Injection and Withdrawal

24. Who should submit basic network data and what is the timeline?

All DICs (generators and load serving utilities) including STUs on behalf of embedded entities, CTU, and Transmission Licensees should submit basic network data

In the first year of implementation, the data is to be submitted by the end of first fortnight of September 2010 as per the Implementation plan agreed in the first meeting of Implementation Committee

In the subsequent years data and dates of commissioning of new transmission assets are to be submitted by fourth week of November in each financial year.

25. What is nodal injection and withdrawal data?

It is the forecasted injection and withdrawal at each node incorporating estimates of total injection and withdrawal during 5 seasons of the year for peak and other than peak conditions. This data is to be submitted in Format III-B

26. Who should submit basic nodal injection and withdrawal data and what is the timeline?

All DICs should submit the nodal injection and withdrawal data. DICs must incorporate the injection/withdrawal by embedded utilities.

In the first year of implementation, the data is to be submitted by the end of first fortnight of September 2010 as per the Implementation plan agreed in the first meeting of Implementation Committee

In the subsequent years the data is to be submitted before the end of fourth week of November in each financial year.

27. What is Long Term and Medium Term data?

Point of Connectivity with ISTS
Quantum of Long term Access (with beneficiaries)
Quantum of Long term Access (without beneficiaries)
Quantum of medium term
Period of access

This shall be submitted in Format IIIA

28. **Who should submit Long Term and Medium Term data and when?**

All DICs should submit long term and medium term contracted quantum and long term access granted.

In the first year of implementation, the data is to be submitted by the end of first fortnight of September 2010 as per the Implementation plan agreed in the first meeting of Implementation Committee.

In the subsequent years the data is to be submitted before the end of fourth week of November in each financial year.

29. **What is deemed ISTS line?**

These are those transmission lines which have regulatory approval of the Commission as being used for inter-State transmission of Power and qualified as ISTS for the purpose of these Regulations.

30. **What is RPC certified non-ISTS line?**

Any non-ISTS line which is certified by RPC as being used as ISTS will be the RPC certified non-ISTS lines.

31. **What is the timeline for submission of list of ISTS, deemed ISTS and RPC certified lines?**

This shall be submitted by the end of first week of October in each financial year as per the draft procedures prepared by IA.

32. **Who should submit additional medium term withdrawal/injection data and what is the time line?**

DICs should submit the additional medium term withdrawal/injection data by 10^{th} day of every month for the applications approved in the previous month as per the Draft Procedure for Computation of PoC Charges and Losses prepared by IA.

33. **Whether forecast injection/withdrawal should be submitted for each month or time block?**

Forecast injection/withdrawal should be submitted for five different seasons (as specified in the regulations), peak and other than peak conditions as specified by NLDC.

34. **What are the different seasons for which DICs are required to submit the data?**

April to June

July to September

October and November

December to February

March,

35. What is the significance of dates like 15th May, 31st August, 30th October, 15th January and 15th March?

A basecase is a snapshot of power flow in a network with respect to a given network topology and load-generation. Therefore the input data needs to pertain to same date and time. The dates are perceived to be representative dates for the five different blocks of month (seasons) for submission of input data. In case any of the above falls on a Weekend/Public Holiday, the data shall be submitted for working days immediately after the dates indicated.

36. In case the forecast generation of station based on the historical patterns comes out to be zero on the date mentioned above, then what figure for nodal injection should be given?

These are only representative dates, and generators should submit the most likely generation data for that season

37. Where should a DIC give its withdrawal, if the interface point is at 33 KV level.

In this case, the withdrawal should be lumped at the nearest 132 KV substation (tracing upward).

38. What figure of YTC should a transmission licensee give for certified non-ISTS lines?

A transmission licensee should give a figure which is approved by appropriate Commission. In respect of lines yet to be commissioned for which YTC is not available, the transmission licensee may consider the benchmark costs approved by CERC.

39. How the incentive/disincentive on account of transmission availability factor would be taken in arriving at Yearly Transmission Charges?

The owners of ISTS/Deemed ISTS/Non-ISTS Lines certified as being used for ISTS should consider a normative value for availability factor based on the actual availability achieved during the previous year, so that the necessary truing up is minimal for the next year.

40. Will all the non-ISTS lines which are certified by RPC as being used as ISTS be considered?

All the lines certified by RPC as being used as ISTS would be sent to CERC for final approval. The lines which are finally approved by CERC would be considered.

41. A transmission licensee is going to get its line (ISTS) commissioned in next application period. Will the cost of this line be taken in the YTC?

Yes it will be considered in the YTC of next period. It shall be included from the season in which it is scheduled to get commissioned. The anticipated date of commissioning of such assets shall be provided by the respective owner.

42. What cost should a transmission licensee give for a line for which the tariff is not yet approved?

Benchmarked cost should be given in such cases. In cases where the transmission system is based on award through competitive bidding, the YTC might be based on the tariff quoted in competitive bidding.

Section B: Basic Network

43. Is the intra state system to be included in the Basic Network Data?

The load flow studies for the purpose of this regulation require all network data upto 132 kV level no matter if it is intra state or inter state. DIC has to submit its intra state system data also upto 132 kV for preparation of basic network.

44. Whether the existing 132 KV lines charged at 33 kV shall be included in the Basic Network?

These lines shall not be included in the basic network data. These lines shall be included in basic network as and when they get charged at 132 KV level.

45. How the dedicated transmission lines would be treated in the basic network?

The dedicated transmission lines constructed, owned and operated by the ISTS Licensees shall be considered to be a part of the Basic Network. Dedicated lines constructed, owned and operated by the generator shall not be considered as a part of the Basic Network unless or otherwise it is a part of meshed network.

46. If the system has to be truncated to 400 KV level, then why do DICs have to submit data upto 132 KV level?

In order to obtain representative power flow at the 400 kV level it is desirable to start with a larger system. During truncation the net interchange at the residual 400 kV nodes (nodes that form the truncated network) would capture the effect of intrastate injection and drawal on the inter State level. The truncation would be accepted only when the Slack Bus Generation, Voltage angles at generation and demand buses closely matches with the AC load flow results on the full network.

47. How the captive power plant would be treated in the new methodology.

If the captive power plant is connected upto 110 kV, then the same shall be included in the basic network. Captive power plants are generally meant for own consumption and at time sells electricity in short term market only. Hence they would be charged as per the PoC Charge (Rs/MW/Hr) of the zone in which they are located. As these captive plants are embedded entities generally, state transmission charges and losses would also be applicable on them.

Section C: Load Flow Studies/Network Truncation

48. Whether Load Flow studies would be carried out at All India level?

Load flow studies would be carried out separately for NEW and SR Grid since these two grids are not connected synchronously. After synchronisation of SR grid with NEW grid, simulation will be done on All India Basis.

49. Upto what voltage level the basic network would be truncated?

The network would be truncated upto 400 kV level except in NER where it will be truncated upto 132 kV.

Section E: PoC Computation

50. What are the inputs to the PoC Computation software?

Converged truncated network along with average YTC (after truing up) of each line would be fed as an input to the PoC Computation software.

51. Why average YTC is used for computation of PoC Charges?

The YTC of a given line is generally based on the year when it was commissioned; therefore there is a significant difference between the cost of old and new lines. However, the transmission lines whether old or new renders almost similar service. Hence average YTC is used for computation of PoC charges. Additionally, if the actual cost of line is taken for computation, then the PoC Charges may get distorted i.e. they shall not be true representative of utilisation of grid which is sensitive to distance and direction of power flow.. Hence average YTC is taken for computation.

52. If a line is partly used for Inter-State-Transmission, then how the YTC of the line will be considered? i.e. whether on pro-rate basis, depending on the length.

If a line is certified by RPC as being used as ISTS, then its full YTC would be collected based on the PoC Charging method.

53. Is there any differentiation between PoC Charges in transactions pertaining to different time horizons?

In long term and medium term, different PoC Charge (Rs/MW/Month) would be applicable for peak and other than peak condition as compared to short term where only one PoC charge (Rs/MW/Hr) would be applicable.

54. Will the recovery be made fully through PoC Charging method?

As specified in the regulation, for the first two years, 50% recovery would be done through PoC Charging method and 50% through Uniform Charging Mechanism.

55. How would the uniform charges (UC) be calculated?

UC = Total ARR / (Sum of Approved Injection +Sum of Approved Withdrawal)

56. Will there be separate charges calculated for peak and other than peak conditions?

Yes there will be different charges calculated for peak and other than peak conditions.

57. How the cost of HVDC would be recovered through this new methodology?

As the power order of a HVDC line is fixed, the marginal participation of the HVDC line is zero. Hence the hybrid method cannot recover its cost directly. The indirect method of recovering the HVDC cost is given below:

a. Calculate charges for each node with all HVDC lines in.

b. Calculate charges for each node with HVDC out of service
c. Identify which nodes are getting benefited with its presence and the cost of HVDC would be allocated to those nodes which are getting benefited in the ratio of benefit.

58. Is their any restriction on the voltage level, above which only the ISTS line would be considered in the whole process?

There is no such restriction.

59. As per the regulation, truncation is done upto 400 kV level in NEW grid. How the cost of 220 kV assets would be recovered.

The cost of 220 kV assets would be recovered by scaling up the total recovery in pro-rata manner.

60. How the ISGS embedded in the state network would be treated?

Such ISGS are a part of the state network. The charges for the state network are approved by SERC and applied on the beneficiaries of such ISGS after due approval by RPCs. The same shall be applicable to them in addition to PoC charges of the zone in which the embedded ISTS is located for the use of ISTS network.

61. Will the Designated ISTS Customers (DICs) be charged based on nodal charges?

No, DICs will be charged based on the zonal charges. Zones will be formed based on the criteria as specified in the regulation.

Section F: Zoning

62. What are the criteria for zoning?

1. Zones shall contain relevant nodes whose costs (as determined from the output from the Hybrid method) are within the same range.
2. The nodes within zones shall be combined in a manner such that they are geographically and electrically proximate. The demand zones shall normally be the state control areas except in the case of North Eastern States, which are considered as a single demand zone. Generation zones are formed by combining the generators connected to the ISTS.
3. The same zone can act as a generation zone as well as a demand zone for the purpose of calculation of Generation and demand zonal charges respectively. Even as it is preferable to have similar zones for generation and demand, this shall be pursued only when practical, and other conditions for zoning are met

4. Transmission charges for thermal power generators either directly connected with ISTS or through pooling stations are designed to handle generation capacity of more than 1500 MW for inter-state transfer shall be determined as charges at these specific nodes (such nodes would be considered as separate generation zones) and not clubbed with other generator nodes in the area.
5. Transmission charges for hydro power generators either directly connected with ISTS or through pooling stations that are designed to handle generation capacity of more than 500 MW for inter-state transfer shall be determined as charges at these specific nodes (such nodes would be considered as separate generation zones) and not clubbed with other generator nodes in the area.

63. How would the zonal charges would be calculated?

Zonal Charges: Weighted average of nodal charges in that zone. The injection and drawal at respective node would be used as weights.

64. Will the generation zones be same as demand zones?

No, generation zone may be different than demand zone. Zones would be formed based on the criteria specified above.

65. How would the POC charges for injection for a zone be calculated in case there is no injection at any node within that zone?

In such cases the POC injection for that zone would be zero.

66. If a node is feeding more than one controls area, then how this node would be treated in zoning?

In such cases, the total cost (Pi/g * PoC Charge(Rs/MW) attributable to that node would be used in both zones, in pro-rata of power flow in these control areas.

67. A thermal generator having installed capacity of more than 2000 MW and having allocations 1400 MW outside state. Would it be considered as separate zone?

As per the regulation, a thermal generator having 1500 MW interstate transfer will be formed as a separate zone. Hence this thermal generator would not be considered as a separate zone.

68. A Hydro generator having installed capacity of 1000 MW and having allocations of less than 800 MW outside state. Would it be considered as separate zone?

As per the regulation, a hydro generator having 500 MW interstate transfer will be formed as a separate zone. Hence this hydro generator would be considered as a separate zone.

Section G: Billing/Collection/Disbursement

69. **What set of information would be passed on by the Implementing Agency / RLDC to the RPC**

    Approved PoC
    YTC to be recovered for each ISTS licensee
    Injection/Withdrawal schedule including (long term medium term, short term contracts) 15-minutes wise
    Meter data 15-min wise

70. **Who would issue the Regional Transmission and Regional Transmission Deviation account?**

    Regional Power Committee would issue the Regional Transmission and Regional Transmission Deviation account

71. **Who will responsible for raising the transmission bills, collection and disbursement of transmission charges?**

    CTU will be responsible for raising the transmission bills, collection and disbursement of transmission charges

72. **How the billing would be done?**

    1. First Part of Bill (monthly): Charges for use of Transmission assets based on PoC Methodology (50% PoC+50%UC).
    2. Second Part of Bill (monthly): Charges for Additional approved medium term open access. (50% PoC+50%UC).
    3. Third Part of Bill (Bi-annually): Adjustment due to variations in interest rates, FERV, rescheduling of commissioning of transmission assets etc.
    4. Fourth Part of Bill (Monthly): Charges for Deviation

73. **If all the power of a generating station is tied up in long term contracts, then the generator does not have to pay any transmission charges? Is it true?**

    The PoC Charges payable by generators will be billed directly to their beneficiaries. However, generators would pay additional charges for deviation only and additional charges for deviations cannot be passed on to the long term customers. Also, the charges payable by generators before commercial operation will have to be borne by them.

The PoC would be payable for Short term access also and settled among the contracting parties.

In case generator enters in PX transaction, PoC charges shall be payable by generator only.

74. How the deviations would be calculated?

Deviation = Metered MW-(Approved Injection/Withdrawal+Additional Medium term Injection/Withdrawal+ Additional Short term Injection/Withdrawal)

75. Will the billing for deviations be done separately for peak hours and separately for off peak hours?

The billing for deviation will be on time block basis. The reference for calculation of deviation will be the higher of the approved injection/withdrawal for the peak and other than peak conditions for the season under consideration.

76. Will a hydro generator end up paying charges for deviation if forecasted generation in a particular season is close to zero and actual generation is high due to sudden inflow?

The reference for computation of deviation will be approved injection. Hence there will be no deviation charge till actual injection exceeds approved injection.

77. Will there be any transmission charge for deviation in case of tripping of a unit/generating station?

In case of tripping of a unit/generating station, the actual injection would be less than approved injection. As the additional charges are levied for positive deviation only, hence no penalty would be applicable on the generating station. However in case of a generating station taking startup power from the grid, then a charge of 1.25 times the PoC demand Charge would be applicable.

78. If a generator for certain duration, starts over injecting (above approved injection) as per system requirement, then whether it would be charged for deviation or not?

Yes, as per the regulation, positive deviations would be charged as per the rates specified.

79. If the deviation is greater than 25%, then will the additional charges of 1.25 times PoC Charge be applicable on the drawal above 100%?

Case I: 0 %< Deviation < = 20%

Charges for deviation = PoC Charges of that zone

Case II: Deviation >20%

Charges for deviation:
1) For quantum of deviation upto 20%: PoC Charge of that zone
2) For quantum of deviation above 20%: 1.25 times PoC Charge

80. How would the variation in interest rates, FERV etc would be considered in billing?

This shall be considered in the third part of the bill which will be issued biannually. (First working day of September and March)

81. Will there be any over/under recovery? If yes then how the over/under recovery would be treated in the whole process?

There is a possibility of over/under recovery. The over/under recovery at the stage of computation shall be adjusted in truing up of YTC for the next application period in pro-rata manner.

82. How would the rescheduling of commissioning of transmission assets be adjusted in the billing?

This shall be considered in the third part of the bill which will be issued biannually. (First working day of September and March)

83. If a STU/SEB defaults in payment to CTU, then how will the CTU pay to other transmission licensees?

A default shall result in the pro rata reduction in the payouts.

84. If a DISCOM defaults in payment to STU, then how will the STU pay to CTU?

This is not mentioned in the regulation and in case of default by DISCOMs, the STU would have to approach respective SERC.

85. Who would collect charges from DISCOMs?

As per the regulations, STU would collect charges from DISCOMs and pay to CTU on its behalf.

Section H: Loss Sharing

86. How would the pan caking be eliminated in the new methodology of loss sharing?

Earlier in a transaction involving more than two region, losses of all the regions involved were applied on the transaction. In the new methodology, loss percentage generation zone (injection side) and loss percentage of demand zone (withdrawal side) would be applicable only. Thereby pan caking would be removed.

87. Whether losses would be applied on regional basis or on All India basis?

Losses would be applied on regional basis. Based on the actual losses of a region as computed from SEM data, study loss (%) would be moderated and applicable loss (%) would be notified for each region.

88. What is the requirement of moderation of losses?

Moderation is required for following reasons:

- Correct computation of injection and drawal schedule of various utilities.
- Scheduled losses to be closer to actual losses in the system so that there is minimum mismatch between load and generation.
- Minimizing the mismatch between UI payable and receivable.

89. How the losses would be shared among drawee and injecting entity?

Long Term Transactions: Drawee Entity would have to bear the losses for both the injection point as well as the drawal point
Medium Term Transactions: Drawee Entity (for drawal point) + Injecting Entity (for injecting point)
Short Term Transactions: Drawee Entity (for drawal point) + Injecting Entity (for injecting point)

90. Whether the losses would be known one year in advance?

The tentative losses seasonwise would be known one year in advance. But the applicable moderated losses would be calculated based on the actual losses of previous week and the timeline would remain same as it is now.

91. What is the significance of loss allocation factor?

Loss allocation factor signifies the percentage of total system loss(in MW) attributable to a particular zone/node.

92. A DIC has forecasted to be a net importer during a certain season but in real time it has started to export power? In this case whether generation zone loss % would be applied on it or demand zone loss % would be applied?

A DIC may have some transactions of exporting power and some of importing power. For transactions involving export of power, generation zone loss would be applicable and in transactions involving import of power, demand zone loss would be applicable.

93. Whether different losses would be applicable for peak and other than peak conditions?

No, there would not be different losses applicable for peak and other than peak conditions. The losses would be calculated separately for peak and other than peak conditions but would be applied as a single figure after taking the weighted average of the loss percentage of peak and other than peak conditions.

Section I: Roles and Responsibilities

94. What are the roles and responsibilities of following:

- **a. Implementing Agency**
- **b. NLDC**
- **c. RLDC**
- **d. RPC**
- **e. DICs**
- **f. CTU**
- **g. Transmission Licensee**

Implementing Agency

- Implementation of the provisions of the regulations
- Preparation of following Procedures
  - Procedure for Data collection
  - Procedure for Computation of PoC Charges
- Input Data collection
- Identification of nodes/group of nodes on which DICs would submit nodal injection/withdrawal
- Validation of input data
- Preparation of basecase for load flow studies
- Presentation of results to validation committee and CERC
- PoC Charges and Losses Computation
- Publication of necessary information on public domain

NLDC

- Preparation of Procedure for Sharing of ISTS Losses
- Declaration of Peak and Other than Peak Conditions

RLDC

- Processing of SEM readings and submission of same to RPC
- Coordination with DICs for data collection
- Validation of Input Data

RPC

- Preparation of Regional Transmission and Regional Transmission Deviation Accounts
- Coordination with DICs for data collection
- Submission of list of non-ISTS lines which are being used as ISTS

CTU

- Submission of technical and commercial details of transmission lines owned as per the formats specified by IA
- Billing , Collection and Disbursement

DICs

- Submission of technical details of the transmission assets owned as per the provisions of the regulation
- Forecast
- Submission of details of long term access, long term contracts, medium term contracts, nodal injection and withdrawal

Transmission Licensee

- Submission of commercial details of ISTS/deemed ISTS/RPC certified non-ISTS lines.

Section J: Miscellaneous

95. When would the regulations be applicable?

The regulations would be applicable from 1.1.2011

96. How the central sector generators having 100% allocation to home state would be treated. Whether that is to be treated as a DIC?

The central sector generators having 100% allocation to home state shall not be treated as separate DIC. They shall be included with the home state. Hence all necessary data for that generator would be provided by the home state.

97. Will DISCOMs be treated as DICs in states where at present CTU is collecting charges directly from them? What would be their role?

DISCOMs will not be treated as DIC. Only STU/SEB connected with ISTS would be treated as DIC for a particular state. STU/SEB would submit data and pay charges on behalf of Distribution Company.

98. What would be the criteria of certifying a non-ISTS line as being used as ISTS line?

This will be finalized by RPC only.

99. Whether the selection of non-ISTS lines certified by RPC as being used as ISTS line would be dynamic?

The selection of non-ISTS lines certified by RPC as being used as ISTS would be done every year. The list finalized by each RPC shall be forwarded to Implementing Agency which in turn would be forwarded to CERC for final approval.

100. What checks and balances would Implementing Agency perform on the data submitted by DICs?

All the DICs should own the data which they submit. Hence the data is expected to be correct. However in case of inconsistencies, IA or validation committee may modify the data with intimation to respective DIC.

101. How the approved injection/withdrawal would be determined?

Based on the details of long term and existing medium term contracted quantum, implementing agency would notify approved injection/withdrawal

102. What should be the approved injection of a generator, if the forecasted generation is close to zero in a particular season?

The approved injection would be based upon the long term and existing medium term contracts and shall not take into account the seasonal variation.
The forecast nodal injection shall take into account the seasonal variation and may be zero also in certain seasons

103. What is the difference between ISTS and certified non-ISTS line?

The lines which satisfy the definition provided in the grid code / Electricity Act 2003 shall be ISTS lines. All those non-ISTS lines which are used for inter state transmission and approved by respective RPC as being used as ISTS shall be treated as certified non ISTS lines. The list of certified ISTS lines would be provided by RPCs to IA which in turn would be forwarded to CERC for approval.The approved cost shall be provided by respective transmission licensee/DIC.

104. What is the requirement of peak and other than peak conditions?

Peak and other than peak conditions are required for setting up the base case for these conditions. This will enable DICs to submit nodal injection and withdrawal data for these identified conditions.

105. Who would notify the peak and other than peak conditions?

NLDC would notify the same on its website on or before 1st week of October.

106. The regulation provides for relaxation to the solar based generation? Is it from both sides i.e. demand side and generation side?

No the relaxation is applicable from the generation side only.

107. How would the injection from non conventional sources be treated for transmission charges, as their generation is unpredictable?

As per the regulation, no transmission Charges for solar generators. Wind generators would have to pay transmission charges.

108. If a generator has declared a capacity of 2000MW and on day ahead basis only 1500 MW is scheduled, then why it will pay for 2000 MW?

Transmission is built for peak /full capacity and not for scheduled capacity. Hence Transmission charges would be paid for full 2000 MW

109. Whether an ISGS which is connected to ISTS through state network (220 Kv) would have to pay interstate transmission charges?

Yes, it would be charged based on the PoC Charges of the zone in which it is located.

110. In this changed Scenario, Generators, have to pay transmission charges if a new generating station is not commissioned by the time ATS is ready. Thus CTU is compensated. What is the compensation mechanism for vice-versa? (Generator ready but ATS not ready). Is it now required to sign 'Indemnification Agreement' between generator and CTU since CTU is not losing on account of generators delay?

The regulation is for only sharing of inter state transmission charges and losses. This is out of the scope of the regulation

111. How the extra charges collected due to deviation would be treated? Will it go the any pool account or fund?

The extra charges collected on account of deviation would be ploughed back for truing up the YTC for next year.

112. Which information would be published on the website of IA?

a. Approved Basic Network Data and Assumptions, if any
b. Zonal or nodal transmission charges for the next financial year differentiated by block of months;
c. Zonal or nodal transmission losses data;
d. Schedule of charges payable by each DIC for the future Application Period, after undertaking necessary true-up of costs

113. Would the information available on the public domain be password protected?

Yes, some information would be password protected. The information which is to be placed in the password protected zone would be decided by the Implementation Committee. Any one who registers on the website can view the information.

114. There would be many IPPs who are not regional entities? Who would provide the basic network data, forecasted injection etc. in case of such IPPs?

STUs/SLDCs would be responsible for co-ordinating with such IPPs and furnishing the data to the implementing agency.

115. Wind generation is generally at 11 kV/33 kV level? How would it be taken into account in the basic network data as it is below 132 / 110 kV but would be a significant quantum?

STUs/SLDC would consider the wind generation suitably lumped at the nearest 132 kV node and indicate it accordingly in the forecasted nodal injection/withdrawal.

116. Would the cost per ckt km. taken for a 400 kV D/C Moose line be different for CTU and other transmission lines?

No it would be a uniform based on pooling across all ISTS licensees and CTU.

117. If a 1 MW incremental load or injection at a node leads to a reduction in the line loadings overall, would such a node be paid for using transmission?

No, the marginal participation factor for such a node would be taken as zero and it would neither pay or receive for transmission.

118. How would merit order of power stations be affected with the new regulations?

Transmission charges are in the nature of fixed charges and would therefore not affect the merit order. However transmission losses have an effect on the cost of power delivered at the state's doorstep. Hitherto merit order for each state within a region was uniform for all power stations within the region. With the zonal POC losses for this would change and each state would have its own merit order based on cost of power delivered. (worked out considering energy charge rate ex-power plant injection POC losses and state drawal POC losses).

119. What is pan caking?

Pan caking means transmission tariffs dependent of power path, where the cost of each new grid level is added together, dependent not only on the location of the seller and buyer, but on the specific path through which the parties have achieved transmission access.