FORMULATING PRICING METHODOLOGY FOR INTER-STATE TRANSMISSION IN INDIA

DISCUSSION PAPER (NOTE ON AVERAGE PARTICIPTION METHOD)

Prepared for:

CENTRAL ELECTRICITY REGULATORY COMMISSION

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I TRANSMISSION PRICING USING AVERAGE PARTICIPATION METHOD

1. PROCESS OF DETERMINATION OF ALLOCATION FACTORS AND TRANSMISSION USE OF SYSTEM CHARGES

Average Participation method requires as its input the complete power flow corresponding to the specific system conditions of interest. The algorithm is based on the assumption that electricity flows can be traced – or the responsibilities for causing them can be assigned – by supposing that, at any network node, the inflows are distributed proportionally between the outflows. Under these conditions the method traces the flow of electricity from individual sources to individual sinks; that is, the model identifies, for each generator injecting power into the network, physical paths starting at the generator that extend into the grid until they reach certain loads where they end. Symmetrically the paths from the loads to the generators are also identified. Then the cost of each line is allocated to different users according to how much the flows starting at a certain agent have circulated along the corresponding line.

This algorithm makes several implicit assumptions that may influence the final results heavily. In order to allow for a simple and intuitive calculation of these physical paths, a rule of distribution of power flows through the electricity network is adopted that is not fully supported by engineering principles. Considering that different options could have been used that would have lead to different results, then simplicity may not be the only reasonable design criteria.

Further, unlike the Marginal Participation method, Average Participation method requires an exogenous specification of allocation of charges between generators and demand customers. The ration used in some European countries is 27% (for generators) : 73% (for demand customers). Here, in the results presented below, the allocation of transmission charges between generators and demand customers has been assumed to be 50%:50%. Arbitrary exogenous specification of this allocation brings the sanctity of locational signals so generated into question. Further, the ratio of 50%:50% has been adopted because the ARR of transmission assets were found to be allocated in this ratio approximately in the Marginal Participation Mechanism, where these signals are endogenously generated by the model.

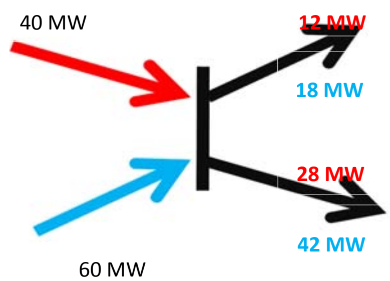
It is however, essential to test out the method through practical application for determination of the charges. The AP method (and indeed all the other methods shortlisted) relies on load flows. The inputs to this model are:

- Nodal generation information
- Nodal demand information
- Transmission circuits between these nodes
- Technical characteristics of each network branch: Resistance, Reactance, line charging and capacity of each network branch
- The associated lengths of each line

For this the data of inter-state transmission system (400 kV, 220 kV and some 132 kV branches) was procured from the Central Electricity Authority (CEA). The data reflected the expected topology of the Indian power system at the end of the XI five year plan. The data included power transmission system branch data (Resistance, Reactance and Line Charging), line capacities, transformation capacity, transformer reactances, shunt reactors and capacitors, minimum and maximum reactive generation capacities of various generators. Seasonal data for typical peak and other than peak time period during winter, summer and monsoon included generation and demand at various buses in the Indian network. The data was used by CEA for planning purposes in the preparation of the National

Electricity Plan for the XI five year plan. The data on line capacities, which was not a part of the original data set, were determined by computing the Surge Impedence Loading (SIL) of each line and the MW thermal rating of the line. Minimum of the two was taken as capacity of the line. Manual on Transmission Planning Criteria prepared by Central Electricity Authority was used as a reference for the above computations. Line length, which was not a part of the original data set, was determined based on the technical line parameters. Virtual distributed reference node is used in the above analysis.

Using this baseline network and power flow, the model traces the flow of electricity from each demand node to the source nodes of electricity using the principle illustrated in the figure below:



$$30 \times \frac{40}{(60+40)} = 12$$

The simulations were carried out jointly with Power Anser Laboratory at IIT Mumbai.

The following steps were followed:

1. AC Load flow for the entire Inter-state transmission network was run using the data provided by CEA. The results so obtained were matched with the load flow results provided by CEA. The real power flows on various lines and the voltage angles between various nodes matched closely with the data provided by CEA.

2. DC load flow analysis was done to compute the base case line flows.

3. The HVDC lines have been treated by replacing them by AC lines of same capacity and costs. Load flow analysis is first performed by replacing HVDC line with an equivalent load at the injection node and equivalent generator at the withdrawal node. Voltage angles are computed at each of the terminal buses. Given the power flow in the base case and the voltage angles, the reactance of equivalent AC line is determined. AC line with the parameters so determined is used for the determination of

4. Using DC load flow, average participation factors are computed for determination of transmission system utilization using the algorithm explained above..

5. Aggregate revenue requirement for each line is computed by assuming the capital costs of the lines as (these might change with terrain):

    a. 765 kV: Rs. 224 Lakh per km

    b. 400 kV (D/C): Rs. 159 lakh per km

    c. 400 kV (S/C): Rs. 90 Lakh per km

    d. 220 kV (D/C): Rs. 113 Lakh per km

    e. 220 kV (S/C): Rs. 70 Lakh per km

    f. 132 kV (D/C): Rs.80 Lakh per km

g. 132 kV (S/C): Rs. 50 Lakh per km

Aggregate revenue requirement (ARR) for each line is obtained by applying the CERC norms for the determination of the fixed transmission tariffs. The new and old transmission assets are thus treated in a similar manner. The ARR for each line is determined on the basis of the replacement value of assets, instead of the book value of assets. In order to avoid over-recovery by the transmission companies, the aggregate revenue determined is scaled up/down to meet the regulated aggregate revenue requirement of the transmission utility.

6. Summer months have been taken from March to June, Monsoon months from July to October and Winter months from November to February. Peak hours have been taken from 07:00 hours to 10:00 hours in the morning and from 17:00 to 22:00 hours in the evening and all the other hours have been taken as other than peak hours.

7. Annual ARR of each line is then attributed to peak and other than peak periods of each season based on the flow in that line during that period in that season. Therefore, ARR of a line to be recovered during period when the flow on that line is higher is more than that recovered during other periods.

8. The ARR (of each period in each season) of each line is attributed to the total change in flow in each line. Therefore the ARR is allocated to each agent in proportion of the change in the flow in network branch affected by that agent. Therefore, if the total changes in flow is less than the capacity of the line, full ARR of the line can still be recovered.

9. Total amount to be recovered in paise/hr from each node in each season is computed. The detailed results for each state are provided in Table A.1 in Appendix A.

10. Total amount to be recovered from generators and demand in each state is computed by aggregating the amount to be recovered from all the nodes in each state.

11. In case of over / under recovery of charges for assets attributed to transmission use of the system charges, the charges are adjusted pro-rata to ensure recovery of regulated ARR for the transmission company. The ARR for transmission projects belonging to state utilities or independent transmission service providers will have to be reimbursed to them by the appropriate entity nominated by the CERC.

2. IMPLEMENTATION OF THE AVERAGE PARTICIPATION METHODOLOGY

Inputs to the proposed model viz., Nodal generation information, Nodal demand information, Transmission circuits between these nodes, Technical characteristics of each network branch: Resistance, Reactance, line charging and capacity of each network branch, and the associated lengths of each line will be required to be obtained systematically from each user of the network and network service provider by CERC for computing the transmission use of the system charges for each season annually.

Nodal Generation Information

Nodal generation information is obtained based on the generation levels committed by each generator under specific – seasonal peak and other than peak conditions identified a-priori by the NLDC. Information received by October of the year previous to the charging year will be used in the determination of the transmission use of the system charges.

Nodal Demand Information

Nodal demand data will be based on demand that various beneficiary utilities (SEBs / distribution utilities) have forecast to occur at the specific peak and other than peak conditions identified by the NLDC. Information received by October of the year previous to the charging year will be used in the determination of the transmission use of the system charges.

Transmission Network Data

Transmission circuit data for charging year is supplied by the CTU based on transmission expansion plan data prepared in coordination with the CEA, STUs/SEBs and transmission licensees and complemented with the October updates.

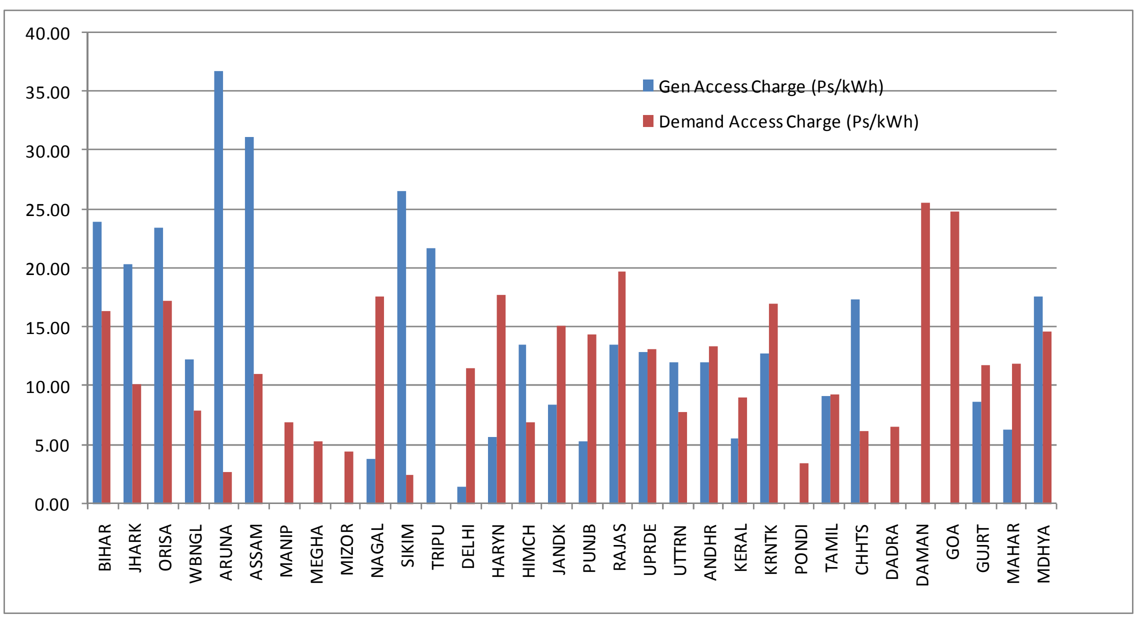
The transmission use of the system charges are determined as Rs/MW/hr in each season at each node. It is straightforward to determine the total collection in Rs/month for each node. Further collection in terms of Rs/month for all the nodes in a state for each season can be aggregated. The states would be free to either determine the charges within the state on a nodal basis or by using postage stamp method.

The transmission use of the system charges so determined are fixed for each season (and peak and other than peak periods) for a year.

3. APPLICATION OF ALLOCATION FACTORS TO SYSTEM USERS

Figure # 1 below shows annual average charges (in paise / kW/hr) to be recovered from generators and loads as transmission use of the system charges. These charges are locational charges payable by generators and loads. As a result, for instance, continuation of existing and additional new generation in regions of surplus generation would in principle be discouraged through higher network access charges to be paid by generators. Average Participation method leads to a high relative burden on demand customers in states through which electricity transits – Madhya Pradesh, Bihar, Orissa are states through which electricity moves into western regions of WR, western regions of NR and SR respectively. It is observed that the transmission network use of the system charges paid by demand customers in these states is relatively high. In turn, generation in regions of surplus consumption would be encouraged through lower access charges, which would provide the appropriate long-term locational signal. This is evident in Figure # 1 from a comparison of high generation charges in the states in NER and low generation charges in the Goa, Maharashtra, Delhi, Haryana, Punjab and Kerala.

Fig. # 1: Annual Average Charges



As displayed in the graphic above, the charges have been aggregated to the state level. This has been done by combining the data for all generation buses and load buses respectively in a state for generation and load related charges.

It is difficult to derive any meaningful conclusions from the above chart because the locational signals for generation and demand customers have been arrived at by assuming 50%:50% allocation of ARR of transmission assets between generation and demand customers.

4. TREATMENT OF LONG AND SHORT TERM TRANSACTIONS

The transmission use of system charges, for each season and peak and other other than peak conditions, are determined for a year. The charges determined above are for specific seasonal peak and off-peak periods. These are based on load flow studies, where the generators and distribution utilities specify their generation and consumption levels respectively. The total transmission use of system charges that would accrue to generation or distribution utilities would therefore depend on the proposed values of injection or withdrawal from the grid respectively. Typically, these values in most cases would be related to the installed capacity in case of generation and to the demand proposed to be met in case of loads. To the extent such requirements are identified ahead of time, there would not be any distinction between the use of the system for long term or short term transactions. Thus the current artificial distinction between long term and short term transactions that has resulted in much consternation among users would largely be avoided.

However, in spite of the greater certainty on use of the system as compared to the present, there could still be deviations as compared to the requisitions, particularly in case of load. In case, in the real time, if injection or withdrawal is found to exceed the levels forecast by the utilities, the utilities will have to bear the additional burden of transmission charges. Any injection / withdrawal by entities entering into short term energy contract would be charged transmission charges are the rates determined by the CERC (which would be basically derived from the normal use of system charges, but could include additional surcharges to disincentivise poor planning)and the recovery would reimburse the long term users from those locations. A key benefit of the above arrangement would make the players neutral to committing in long term and short term.

A critical issue in this context is that of hierarchy of system use in case of congestion in the network. The following hierarchy is proposed:

- Long term transactions (based on PPAs) would have the highest priority, since they form the backbone of the system;
- Short term transactions would be accorded the next highest priority;
- Any over-drawal or over-injection would be accorded the lowest priority in case of congestion.

However, as the following sub-section postulates, the issue of congestion could be substantially addressed under the proposed arrangements, and hence in reality the short term transactions would stand on near equal footing with long term transactions. This would be consistent with the market development objectives.

5. ARRANGING FOR NEW TRANSMISSION CAPACITY

As the Staff Paper on “Arranging Transmission for New Generating Stations, Captive Power Plants and Buyers of Electricity” has correctly analysed and argued, the issue of securing new capacity cannot be divorced from the pricing arrangements and the two aspects need to be considered in conjunction. Under the proposed method, the development of the transmission system would not be reliant on BPTA’s with beneficiaries (since in a deep network the beneficiaries cannot arguably be identified exclusively), but would depend on the approval of the capital investment plans approved by the regulator. The capital investment plans would be developed by the CTU and proposed to the CERC for approval based on the long term perspective plans and also the more immediate term plans related to generation capacity development and load growth. Once the CERC approves the plans, the lines could be built either by the CTU and/or by IPTCs, depending on the prevailing policy framework.

The CTU and IPTCs would continue to have commercial contracts with the various users of the system for arranging connection to the main transmission network and for other commercial aspects including, but not limited to, payment mechanisms and security. However there would be still a fundamental shift in the approach as compared to the present wherein a line or transmission system cannot be developed till the direct beneficiaries are identified and agree to pay for the costs involved through tariffs.

It needs to be noted that while the CTU will propose the system based on the expected load flows and likely generation siting, from a commercial standpoint (as well as for ensuring a fair deal for all others who pay for the system) there could still be a need for ensuring that a generator or load pays for the system that they desire to use. Hence the CTU (or IPTCs) should be permitted to obtain the necessary security (through bank guarantees or alternate means) related to the quantum of connection (or enhancement of existing connection) desired by the user. The specific mechanism should be determined by the CTU and regulatory approval should be obtained for implementation.

6. MECHANISM FOR RECOVERY OF TRANSMISSION CHARGES BY SERVICE PROVIDERS

The AP mechanism does not lend itself to identification of users of each transmission asset. The proportion of the use of the network by generators and demand customers needs to be exogenously specified. In this analysis, the division between generators and demand customers was assumed by be 50%:50%. The computations of transmission charges for each season can be done based on the above calculations for each user of the inter-state transmission network. The payments can be collected by the CTU and transferred to the owners of each specific transmission asset (including the CTU itself) as per the approved revenue requirement of the asset owner. Therefore, both the state utilities which make their networks available for transmission of inter-state and inter-regional power flows and Independent Transmission Power Companies can be compensated for use of their assets as per the norms of CERC. This kind of arrangement is already in place for the Tala transmission link wherein PGCIL reimburses Powerlinks Ltd., the transmission asset owner, for its approved revenue requirements.

It is germane to note that there are currently certain lines under development where the commercial contracts are directly between the IPTCs and the beneficiaries. Such arrangements would need to undergo modification to make them consistent with the proposed framework.

II IMPACT ANALYSIS

Any change in framework has inevitable impact on the various users of the system. While the rationalization of charges is in line with the requirements of the law, policy and the electricity market development in general, some of the current users paying relatively lower charges would inevitably be affected while others paying irrational charges benefit. This is particularly true since the cost recovery of the transmission service providers would not change between the current and the proposed method.

Currently the charges are paid only by the beneficiaries – typically the distribution licensees. The proposed mechanisms entail all users to pay charges for use, including the generators. While this is logical from a system perspective, the change in method would require acceptance by the various users. Hence the principles need to be adequately clarified.

The above, and several other issues of importance have been analysed in this section to identify in specific terms the impact of the proposed arrangements.

1. EXTENT TO ACCEPTABLE IMPACT ON SYSTEM USERS

The tariff impact on various users, and in particular the distribution licensees who presently pay the costs of transmission at present, is one of the foremost evaluation criteria for determining the acceptability of the framework proposed. Using the AP method, the table below illustrates the sum of transmission charges paid for transactions from generation located in one state to demand in another. Average annual transmission access charges from states (in the column) to states (in the row) are reported in Table XX. Based on the load flows and the corresponding cost computations, the maximum charge indicated at present is 62 ps/kwh on the average[1] for flows from Arunachal Pradesh to Daman if such transaction were to take place. The minimum transmission charge is charged for a transaction from Goa to Tripura. Again, the minima as per the table represents a hypothetical flow since in practice no transaction is likely from Goa to Tripura. In practical terms the range of values (based on the transactions observed in practice) from Uttar Pradesh to Delhi, Haryana, Punjab and Rajasthan is from 24.49 ps/kwh to 32.73 ps/kWh. Similarly, transactions from Chattisgarh to these states involve transmission access charges (sum of generator and demand access charges) in the range of 28.97 ps/kWh to 37.21 ps/kWh. Intra-regional transaction from Chattisgarh to Maharashtra and Madhya Pradesh involves total transmission access charges of 29.35 ps/kWh and 32.05 ps/kWh respectively. Transactions from West Bengal to these states in NR involve transmission access charges in the range of 26 ps/kWh to 32.34 ps/kWh. Transactions from Orissa to states in the SR would invite transmission access charges in the range of 23.88 ps/kWh to 32.12 ps/kWh.

Table # 1: Transmission charges for transactions from (column) to (row) sates (paise / kWh)

[1] The per kwh rate has been shown to illustrate the effective charges, In practice the transmission tariffs will be in Rs./MW/month as per the current practice. The key difference will be in the fact that generators will pay for the MW evacuation capacity contracted for injection at their location while loads will pay for the MW capacity contracted for offtake.

	BIHAR	JHARK	ORISA	WBNGL	ARUNA	ASSAM	MANIP	MEGHA	MIZOR	NAGAL	SIKIM	TRIPU	DELHI	HARYN	HIMCH	JANDK
BIHAR	40.31	34.14	41.25	31.94	26.70	34.96	30.92	29.32	28.43	41.55	26.42	23.94	35.48	41.66	30.91	39.15
JHARK	36.74	30.57	37.69	28.37	23.13	31.40	27.35	25.76	24.86	37.99	22.85	20.38	31.91	38.10	27.35	35.58
ORISA	39.89	33.72	40.84	31.52	26.29	34.55	30.50	28.91	28.01	41.14	26.00	23.53	35.07	41.25	30.50	38.73
WBNGL	28.70	22.54	29.65	20.33	15.10	23.36	19.31	17.72	16.82	29.95	14.81	12.34	23.88	30.06	19.31	27.54
ARUNA	53.09	46.92	54.03	44.72	39.48	47.74	43.70	42.10	41.21	54.33	39.20	36.72	48.26	54.44	43.69	51.93
ASSAM	47.51	41.34	48.46	39.14	33.90	42.17	38.12	36.53	35.63	48.76	33.62	31.15	42.69	48.87	38.12	46.35
MANIP	16.36	10.20	17.31	7.99	2.76	11.02	6.97	5.38	4.48	17.61	2.47	0.00	11.54	17.72	6.97	15.20
MEGHA	16.36	10.20	17.31	7.99	2.76	11.02	6.97	5.38	4.48	17.61	2.47	0.00	11.54	17.72	6.97	15.20
MIZOR	16.36	10.20	17.31	7.99	2.76	11.02	6.97	5.38	4.48	17.61	2.47	0.00	11.54	17.72	6.97	15.20
NAGAL	20.21	14.04	21.15	11.84	6.60	14.86	10.82	9.22	8.33	21.45	6.32	3.84	15.38	21.56	10.81	19.05
SIKIM	42.99	36.83	43.94	34.62	29.39	37.65	33.60	32.01	31.11	44.24	29.10	26.63	38.17	44.35	33.60	41.83
TRIPU	38.14	31.97	39.08	29.77	24.53	32.79	28.75	27.15	26.26	39.38	24.25	21.77	33.31	39.49	28.74	36.98
DELHI	17.82	11.65	18.77	9.45	4.21	12.48	8.43	6.83	5.94	19.06	3.93	1.45	12.99	19.18	8.42	16.66
HARYN	22.07	15.90	23.02	13.70	8.46	16.73	12.68	11.09	10.19	23.32	8.18	5.71	17.24	23.43	12.68	20.91
HIMCH	29.89	23.72	30.83	21.51	16.28	24.54	20.50	18.90	18.00	31.13	15.99	13.52	25.06	31.24	20.49	28.72
JANDK	24.80	18.63	25.74	16.43	11.19	19.45	15.41	13.81	12.92	26.04	10.91	8.43	19.97	26.15	15.40	23.64
PUNJB	21.69	15.52	22.64	13.32	8.08	16.35	12.30	10.71	9.81	22.94	7.80	5.33	16.86	23.05	12.30	20.53
RAJAS	29.90	23.73	30.84	21.53	16.29	24.55	20.51	18.91	18.01	31.14	16.00	13.53	25.07	31.25	20.50	28.73
UPRDE	29.31	23.15	30.26	20.94	15.71	23.97	19.93	18.33	17.43	30.56	15.42	12.95	24.49	30.67	19.92	28.15
UTTRN	28.46	22.29	29.41	20.09	14.85	23.12	19.07	17.47	16.58	29.70	14.57	12.10	23.63	29.82	19.06	27.30
ANDHR	28.44	22.27	29.39	20.07	14.83	23.10	19.05	17.46	16.56	29.69	14.55	12.08	23.61	29.80	19.05	27.28
KERAL	21.95	15.78	22.90	13.58	8.35	16.61	12.56	10.97	10.07	23.20	8.06	5.59	17.13	23.31	12.56	20.79
KRNTK	29.11	22.95	30.06	20.74	15.51	23.77	19.72	18.13	17.23	30.36	15.22	12.75	24.29	30.47	19.72	27.95
PONDI	16.36	10.20	17.31	7.99	2.76	11.02	6.97	5.38	4.48	17.61	2.47	0.00	11.54	17.72	6.97	15.20
TAMIL	25.50	19.33	26.45	17.13	11.89	20.16	16.11	14.51	13.62	26.74	11.61	9.13	20.67	26.86	16.10	24.34
CHHTS	33.79	27.62	34.74	25.42	20.18	28.45	24.40	22.81	21.91	35.04	19.90	17.43	28.97	35.15	24.40	32.63
DADRA																
DAMAN																
GOA	16.36	10.20	17.31	7.99	2.76	11.02	6.97	5.38	4.48	17.61	2.47	0.00	11.54	17.72	6.97	15.20
GUJRT	25.12	18.95	26.07	16.75	11.51	19.78	15.73	14.14	13.24	26.37	11.23	8.76	20.30	26.48	15.73	23.96
MAHAR	22.64	16.47	23.59	14.27	9.03	17.30	13.25	11.66	10.76	23.89	8.75	6.28	17.81	24.00	13.25	21.48
MDHYA	34.01	27.84	34.96	25.64	20.41	28.67	24.62	23.03	22.13	35.26	20.12	17.65	29.19	35.37	24.62	32.85

	PUNJB	RAJAS	UPRDE	UTTRN	ANDHR	KERAL	KRNTK	PONDI	TAMIL	CHHTS	DADRA	DAMAN	GOA	GUJRT	MAHAR	MDHYA
BIHAR	38.30	43.73	37.08	31.77	37.33	33.05	40.92	27.48	33.32	30.20	30.58	49.56	48.73	35.79	35.86	38.57
JHARK	34.73	40.16	33.51	28.21	33.77	29.49	37.35	23.92	29.76	26.63	27.01	45.99	45.17	32.22	32.30	35.00
ORISA	37.89	43.31	36.66	31.36	36.92	32.64	40.50	27.07	32.91	29.78	30.16	49.14	48.32	35.37	35.45	38.15
WBNGL	26.70	32.12	25.47	20.17	25.73	21.45	29.31	15.88	21.72	18.60	18.97	37.96	37.13	24.18	24.26	26.97
ARUNA	51.08	56.51	49.86	44.55	50.11	45.83	53.70	40.26	46.10	42.98	43.36	62.34	61.51	48.57	48.64	51.35
ASSAM	45.51	50.93	44.28	38.98	44.54	40.26	48.12	34.69	40.53	37.40	37.78	56.76	55.94	42.99	43.07	45.77
MANIP	14.36	19.78	13.13	7.83	13.39	9.11	16.97	3.54	9.38	6.26	6.63	25.62	24.79	11.84	11.92	14.63
MEGHA	14.36	19.78	13.13	7.83	13.39	9.11	16.97	3.54	9.38	6.26	6.63	25.62	24.79	11.84	11.92	14.63
MIZOR	14.36	19.78	13.13	7.83	13.39	9.11	16.97	3.54	9.38	6.26	6.63	25.62	24.79	11.84	11.92	14.63
NAGAL	18.20	23.63	16.98	11.67	17.23	12.95	20.82	7.38	13.22	10.10	10.48	29.46	28.63	15.69	15.76	18.47
SIKIM	40.99	46.41	39.76	34.46	40.02	35.74	43.60	30.17	36.01	32.89	33.26	52.25	51.42	38.47	38.55	41.26
TRIPU	36.13	41.56	34.91	29.60	35.16	30.88	38.75	25.31	31.15	28.03	28.41	47.39	46.56	33.62	33.69	36.40
DELHI	15.81	21.24	14.59	9.29	14.85	10.56	18.43	5.00	10.83	7.71	8.09	27.07	26.25	13.30	13.37	16.08
HARYN	20.06	25.49	18.84	13.54	19.10	14.82	22.68	9.25	15.09	11.96	12.34	31.32	30.50	17.55	17.63	20.33
HIMCH	27.88	33.30	26.65	21.35	26.91	22.63	30.50	17.06	22.90	19.78	20.15	39.14	38.31	25.36	25.44	28.15
JANDK	22.79	28.22	21.56	16.26	21.82	17.54	25.41	11.97	17.81	14.69	15.07	34.05	33.22	20.28	20.35	23.06
PUNJB	19.68	25.11	18.46	13.16	18.72	14.44	22.30	8.87	14.70	11.58	11.96	30.94	30.12	17.17	17.24	19.95
RAJAS	27.89	33.31	26.66	21.36	26.92	22.64	30.51	17.07	22.91	19.79	20.16	39.15	38.32	25.38	25.45	28.16
UPRDE	27.31	32.73	26.08	20.78	26.34	22.06	29.92	16.49	22.33	19.21	19.58	38.57	37.74	24.79	24.87	27.58
UTTRN	26.45	31.88	25.23	19.93	25.49	21.20	29.07	15.64	21.47	18.35	18.73	37.71	36.89	23.94	24.01	26.72
ANDHR	26.43	31.86	25.21	19.91	25.47	21.19	29.05	15.62	21.46	18.33	18.71	37.69	36.87	23.92	24.00	26.70
KERAL	19.95	25.37	18.72	13.42	18.98	14.70	22.56	9.13	14.97	11.84	12.22	31.20	30.38	17.43	17.51	20.21
KRNTK	27.11	32.53	25.88	20.58	26.14	21.86	29.72	16.29	22.13	19.01	19.38	38.37	37.54	24.59	24.67	27.38
PONDI	14.36	19.78	13.13	7.83	13.39	9.11	16.97	3.54	9.38	6.26	6.63	25.62	24.79	11.84	11.92	14.63
TAMIL	23.49	28.92	22.27	16.97	22.53	18.24	26.11	12.68	18.51	15.39	15.77	34.75	33.93	20.98	21.05	23.76
CHHTS	31.79	37.21	30.56	25.26	30.82	26.54	34.40	20.97	26.81	23.68	24.06	43.04	42.22	29.27	29.35	32.05
DADRA																
DAMAN																
GOA	14.36	19.78	13.13	7.83	13.39	9.11	16.97	3.54	9.38	6.26	6.63	25.62	24.79	11.84	11.92	14.63
GUJRT	23.12	28.54	21.89	16.59	22.15	17.87	25.73	12.30	18.14	15.01	15.39	34.37	33.55	20.60	20.68	23.38
MAHAR	20.63	26.06	19.41	14.11	19.67	15.39	23.25	9.82	15.65	12.53	12.91	31.89	31.07	18.12	18.19	20.90
MDHYA	32.01	37.43	30.78	25.48	31.04	26.76	34.62	21.19	27.03	23.90	24.28	43.27	42.44	29.49	29.57	32.28

Intra state transactions invite higher transmission access charges in states which are both generation rich and also form intervening states in transfer of power to other states. States like Bihar, Jharkhand and Orissa. This is because the proportionate tracing method (AP Method) allocates the costs of network created from NER/ER to NR and SR to the demand customers in these states. The transmission access charges for generators are however expected to be high and are technically justified. Higher transmission charges for intra-state transactions in Arunachal Pradesh and Assam are due to high transmission charges allocated to generators. There is an economic and technical rationale for this result. The levels of generation in these states are relatively low and this power is transmitted over HVAC lines, where the flow is largely unidirectional from NER to ER. This leads to higher charge per kW attributable to the generators in these states. Further, the demand in these states seems to be largely served by high voltage radial lines. This leads to a high access charges in these regions. However arguments based on environmental and social concerns could call for socialization of high access charges in these states. Most of the power generated in these states is from hydro resources, which are environmentally beneficial and have a positive global externality. The excess of any access charges for such generators (or a percentage, as determined by the regulator) over and above the “reasonable” levels can therefore be allocated to all the network users based on a postage stamp mechanism. It needs to be noted in this context that the transmission service providers would fully recover their revenue requirements even if there is a reduction in the charges paid by the remote generators. Also in the AP method, despite the electrical similarity in the states in NER there is a high intra-regional variance in access charges. This makes it difficult to aggregate the NER states and determine a single generation access and a demand access charge for these regions using the AP mechanism.

Inter-regional transmission access charges payable by the demand customers are indicated to be in the range of 7-43 paise / kWh, except for commercial energy contracts between states in the NER and the SR, NR, WR and ER, where the total transmission access charges payable by the demand customers would be in the range of 35-63 paise / kWh. This is expected because of the high generation access charge attributed to generators in NER as explained above. These charges would however get reduced as more generation capacity is added in NER. Till such time however, socialization of generation access charges in NER could encourage hydro generation in that region.

2. IMPACT ON SPECIFIC SYSTEM USERS

Impact on Generators – Long Term contracts

Under long term energy purchase agreements, the fixed charges of the generators are shared by the beneficiaries in proportion of their commitment in the plant capacity. The transmission charges, determined above add to the fixed charge component of the generator. The dispatch in the energy markets does not get affected because the variable charges of the generators remain unaltered.

Transmission Network Use of System Charges for each generator are different for each season. The charges payable for each generator are determined as a product of Power Station forecast Chargeable Capacity (in MW) multiplied by the zonal Rs/MW/hr tariff determined above. The total seasonal transmission use of the system charges are determined by further multiplying the above product by the number of hours in the season – for peak and other than peak periods. This seasonal Transmission Network Use of System charge is split evenly over the months of the season (for peak and other than peak periods) and charged on a monthly basis over the season.

If the actual generation increases above the forecast for the charging season, the party will be liable for the additional charge incurred for the full season, which will be recovered uniformly across the remaining chargeable months in the relevant charging season. An increase in monthly charges reflecting an increase in generation level during the charging season will result in interest being charged on the differential sum of the increased and previous generation level charge. No recalculation is to be done in the cases where the generation is below the forecast generation level.

Impact on the customers (beneficiaries): Distribution Utilities – Long Term Contracts

Currently, the customers of long term power are required to pay transmission charges based on the contract path expected to be traversed by power from the point of injection to the point of withdrawal. Therefore, if the power is injected in NER and withdrawn in NR, the beneficiary in the NR will be required to pay as transmission charges the sum of postage stamp regional charges of NER, ER and NR and also the charges for inter-regional linkages. Under the proposed mechanism, the beneficiary will have to pay the transmission use of the system charges for demand directly. Indirectly, the transmission use of the system charges for the contracted generator is also paid by the beneficiary through the fixed charge component of the generator's charge. Therefore, the total burden of transmission tariff on the beneficiary distribution utility will be the sum of the generator's charge (charged through the fixed charge of the generator) and the transmission charge paid directly by the beneficiary.

Throughout the season Users' monthly demand charges will be based on their forecasts of demand to be supplied, multiplied by the relevant zonal Rs/MW tariff. The beneficiary's seasonal Transmission Network Use of System demand charges will be based on these forecasts and are split evenly over the months of the season. Users have the opportunity to vary their demand forecasts on a seasonal basis over the course of the year, with the demand forecast requested in February relating to the next Financial Year. The beneficiary utilities will be notified of the timescales and process for each of the seasonal updates. CTU will revise the monthly Transmission Network Use of System demand charges by calculating the annual charge based on the new forecast, subtracting the amount paid to date, and splitting the remainder evenly over the remaining months.

The beneficiary utilities are expected to submit reasonable demand forecasts. The CTU shall use a methodology approved by the concerned state regulatory commission to derive a forecast to be used in determining whether a beneficiary's forecast is reasonable and this will be used as a replacement forecast if the beneficiary's total forecast is deemed unreasonable. The CTU will, at all times, use the latest available Settlement data.

Impact on the customers (beneficiaries) within the same region as generation – Long Term Contracts

There could be a particular concern of beneficiaries located within a region on the high charges incident even for consumption in proximity to generation. In particular, the licensees in the North East could be affected due to the high generation costs component which such beneficiaries would have to bear. Several relevant factors need to be noted in this context. Firstly, the allocations (except for free power) from the large projects being developed in the North East for constituents in the region are low. Secondly, the component attributable to licensees for transacting energy is low, but the generation related component (that the licensee has to eventually bear) is high. There is a strong technical justification for the high generation related component. However, if there is any residual concern regarding charges applicable when the generation and consumption is in the same region, socialization criteria can be applied to limit the charges to an "acceptable" level. Such levels would be up to regulatory judgment, and the residual amounts after applying these limits would need to be distributed over other users. However, based on review of the data, this does not appear to be a significant issue in any electrical region other than the North East. Even if such limits were to be hypothetically applied for licensees in the North East, the impact on other system users would be minimal on account of the low consumption levels in the North East from the ISTS.

Impact on Generators – Short term Bilateral contract

In short term bilateral energy markets, generators negotiate a lump-sum price per kWh with the buyer / trader. The negotiated price so determined is normally expected to include both the fixed charge component and the variable component of generation charge. The fixed charge of the generator would include the locational component of the transmission charge. It has been argued that this distorts the price signals of electrical energy in the short term market.

However, another view is that by including the signals of utilization of transmission assets in their bid, the generators, in the short term markets send signals for capacity expansion. Power is normally contracted in short term markets to satisfy the 'unanticipated' needs of the customer. The power system, therefore, operates close to its capacity limits in the short term markets. The price signal should therefore reflect the long run marginal cost of system usage under such conditions for allocative efficiency. The inclusion of access charges for transmission in the negotiated prices would therefore send the correct signal.

The inclusion of transmission access charges in negotiated prices would increase the price of electricity (for power plants in NER, West Bengal, Bihar, Jharkhand) and hence make such power plants uncompetitive with respect to power plants in Delhi, Punjab, Rajasthan, Haryana, Maharahstra, Goa, Gujarat etc. in the short term markets. This sends a signal that power plants located in NER, West Bengal, Bihar, Jharkhand should normally operate as base load power plants with most of their capacities committed in the long term markets. On the other hand, power plants close to load centers would be more competitive in the short term market. This outcome is efficient because large power plants, which operate as base load power plants need to be set up in resource rich states – NER (hydro resources), West Bengal, Bihar, Jharkhand (Coal resources). Further, power plants which can supply at short notices (have less ramp up time) should be set up close to load centers not only because supply from them over long distances during conditions when the grid is heavily loaded would entail higher losses but also because such power plants can easily be called upon to supply reactive power for dynamic voltage control and enhancing system security.

The short-term chargeable capacity for Power Stations is any approved generation level applicable to that Power Station during a valid short term period. Such generation level will need to be approved by the appropriate SLDC / RLDC for a given period. The charges in Rs/MW are the same as those applicable to generators with long term commitments. In case a generator seeks approval for a short term chargeable capacity higher than its long term chargeable capacity for more than a month in a season, the revised higher level of chargeable capacity shall be deemed to be the long term chargeable capacity and the seasonal charges will be recalculated on the basis of the revised chargeable capacity.

Impact on customers (beneficiaries): Distribution Companies – Short term Bilateral Contracts

For accessing the grid for capacity which is required in the short term, the load will need an approval of the same from SLDC and RLDC. Then beneficiary utility / load will pay the locational transmission charges applicable. The transmission access charges of the generators are paid indirectly as discussed in the section above.

The short-term chargeable capacity for demand is any approved demand level applicable to that beneficiary during a valid short term period. Such demand level will need to be approved by the appropriate SLDC / RLDC for a given period. The charges in Rs/kW are the same as those applicable to approved forecast seasonal. In case a beneficiary seeks approval for a short term chargeable demand for more than a month in a season, the revised higher level of chargeable demand shall be deemed to be the long term chargeable demand and the seasonal charges will be recalculated on the basis of the revised chargeable demand.

Impact on trades through Traders and Power Exchange

The generators that are dispatched through the power exchange internalize the transmission access charges in their price bids. Even if the trade is through a power trader, the transmission access charges will deemed to be included in the price bid on the exchange since both the generation would have to pay for the Transmission Network Use of System Charges. Separate charges would not be attracted for transmission network use for trading purposes.

The demand customers similarly quote just the price and quantity of electricity they wish to purchase from the exchange. The transmission access charges payable by the demand will be based on approved access (short term access sought by the demand customer).

Thus the AP mechanism is expected to be non-discriminatory between short term and long term trades. By obviating the incidence of separate charges for such transactions, a key issue relating to trading that has taken up much regulatory attention over the years will be obviated.

3. IMPACT ON NETWORK DEVELOPMENT

The AP mechanism requires the grid connected entities viz., the generators and the demand customers (distribution utilities, large customers) to pay transmission access charges based on their location and forecasted chargeable capacity / demand. Because of the arbitrary allocation of total transmission charges between generators and demand customers, the signals generated by charges so determined cannot be relied on.

4. IMPACT ON LOW CARBON GENERATORS

The locational signals generated by the AP method cannot be relied on. In AP mechanism, if the transmission charges are levied only on the distribution licensees (demand customers), then the mechanism does not generate any signal for location of generation because the demand customer would be indifferent between purchasing electricity from any generating source. Equal (50%) burden of transmission charges on generators and demand customers does not send a definitive locational signal.

III IMPLEMENTATION PROCESS AND WAY FORWARD

1. CHANGES IN COMMERCIAL SYSTEMS AND PROCESSES

Implementation of the proposed framework is expected to be relatively straightforward. The key inputs for implementation are stated below:

1. Revenue requirements of transmission services providers for the various lines, sub-stations or projects;

2. Load flow analysis for various seasons based on user inputs for generation and demand

3. Appropriate metering systems

4. Billing, collection and revenue distribution mechanisms

The first aspect is already determined by the CERC as per its tariff regulations. This process will remain unchanged, and the cost recovery requirements of CERC for the various projects will be aggregated. Such aggregated revenue requirements will be utilized to obtain the transmission rates per MW at the various generation or load buses (or zones).

The load flows are a critical input for determining the allocation factors and charges. As mentioned earlier in this paper, the generators and licensees (or other users) would have to specify their requirements in advance prior to the implementation period. The CEA, CTU or any other agency nominated for this purpose would conduct load flows and determine the allocation factors. The forecasting capabilities of the users could need attention to ensure that the requisitions provided for conducting the load flows and for commercial transactions are representative.

The metering systems will remain unchanged since the tariff structure will be identical to those at present (Rs. per MW per month). While there could be an element of seasonality in the tariffs, the existing SEM based metering system would be adequate for such purposes. Since the meters are already equipped with demand registers, deviations from requisitioned/contracted demand would be captured by the meters.

The billing systems could require minor changes to accommodate the seasonality requirements (if required) and over-drawal vis a vis requisitions/contracts. The billing will continue to be on monthly basis as at present. As mentioned earlier in the report, the CTU would collect the charges on behalf of all the transmission service providers (including itself) and thereafter redistribute the same. The CTU would also maintain accounts for over-recovery or under-recovery, and true up the same in the subsequent period.

The current mechanisms for payment security that the CTU has in place for distribution licensees will continue. However for generators, suitable commercial arrangements would need to be implemented. In case of long term contracts, beneficiaries may elect to continue the existing system where they are liable for the entire transmission charges and related commercial arrangements. In particular, the existing arrangements that are already in place for long term contracts/BPTAs could be continued.

2. CHANGES TO REGULATIONS

Changes are envisaged in the Open Access regulations of CERC on account of the fundamental alterations in the principles of short term open access and pricing thereof. Specific changes required would be identified separately after the finalization of the approach proposed.

The tariff regulations of CERC currently in place would need to be supplemented to reflect the changed procedure for charges for use of the ISTS. This process would follow the finalization of the framework proposed for implementation consequent to the consultation process on this discussion paper.

A key issue for consideration is the basis for allocation of losses to various users. As mentioned, CERC has already mandated IIT Mumbai to undertake a study for the same based on the "power tracing" method. The results of the same, once available, would need to be reflected in the respective regulations.

IV APPENDIX A: TRANSMISSION CHARGES DETERMINED USING AVERAGE PARTICIPATION METHOD FOR PEAK AND OFF-PEAK PERIOD DURING EACH SEASON

Table A.1: Transmission charges (Paise/kW/hr) for various seasons

	Monsson Offpeak		Monsoon Peak		Summer offpeak		Summer Peak		Winter Offpeak		Winter Peak	
	Gen Charge	Load Charge	Gen Charge	Load Charge	Gen Charge	Load Charge	Gen Charge	Load Charge	Gen Charge	Load Charge	Gen Charge	Load Charge
BIHAR	23.82	19.64	27.46	19.48	23.08	17.92	23.68	15.77	22.94	12.82	22.14	13.25
JHARK	15.69	10.97	23.75	11.65	15.90	8.48	25.81	10.68	16.17	8.78	20.60	10.06
ORISA	22.43	16.24	21.65	20.01	23.10	15.94	25.21	17.95	23.50	16.28	23.97	16.70
WBNGL	10.43	8.02	12.79	11.19	11.22	7.14	14.17	7.52	11.51	6.95	12.61	6.91
ARUNA	38.15	2.15	37.45	2.96	41.83	2.15	34.49	3.27	35.97	2.23	31.95	3.28
ASSAM	34.63	13.73	34.32	11.65	31.50	12.56	29.09	9.57	20.18	11.52	27.11	8.66
MANIP	0.00	6.64	0.00	9.55	0.00	4.37	0.00	7.66	0.00	5.68	0.00	6.94
MEGHA	0.00	2.92	0.00	2.39	0.00	2.53	0.00	3.42	0.00	11.69	0.00	9.19
MIZOR	0.00	4.91	0.00	7.21	0.00	2.56	0.00	5.04	0.00	1.99	0.00	4.28
NAGAL	8.32	0.00	0.00	22.73	8.59	0.00	0.00	33.66	6.15	0.00	0.00	33.45
SIKIM	22.80	1.72	30.38	4.61	20.18	1.11	27.45	3.58	26.56	0.54	25.50	2.31
TRIPU	28.74	0.00	26.37	0.00	24.67	0.00	18.66	0.00	18.46	0.00	11.42	0.00
DELHI	1.65	12.67	1.43	9.30	1.45	11.80	1.28	11.28	1.68	12.30	1.30	12.23
HARYN	5.29	20.64	6.46	16.01	5.50	17.76	5.93	16.37	5.25	19.93	5.61	16.95
HIMCH	12.07	7.49	15.14	6.32	12.37	7.16	14.39	6.70	12.03	7.42	13.19	6.97
JANDK	8.44	16.07	8.30	12.32	8.02	16.06	8.59	15.71	8.44	15.58	8.77	15.63
PUNJB	4.60	16.86	5.67	11.85	5.27	15.18	5.90	12.67	4.60	16.36	5.37	14.39
RAJAS	13.25	17.38	17.10	23.75	12.07	17.62	13.89	21.77	13.33	17.49	11.41	19.48
UPRDE	13.20	14.24	12.95	12.55	12.54	12.65	13.16	13.28	12.99	13.00	12.94	13.26
UTTRN	11.45	7.91	13.96	6.51	10.17	8.66	12.22	7.14	11.47	7.39	11.74	9.22
ANDHR	11.11	12.67	12.31	13.27	11.13	12.66	12.78	15.41	11.13	12.73	13.09	12.95
KERAL	4.78	9.15	6.70	9.12	4.79	9.15	5.91	9.03	4.78	9.15	6.06	9.09
KRNTK	12.68	16.36	12.20	17.02	12.62	16.06	13.90	19.50	12.65	16.07	12.31	16.09
PONDI	0.00	3.53	0.00	3.59	0.00	3.53	0.00	3.50	0.00	3.53	0.00	3.57
TAMIL	9.10	8.36	9.10	8.92	9.11	8.32	8.99	11.26	9.11	8.34	9.38	10.13
CHHTS	16.29	4.36	16.33	7.26	16.69	4.58	19.70	8.19	16.25	4.39	18.48	7.28
DADRA	0.00	5.46	0.00	8.52	0.00	5.03	0.00	7.97	0.00	5.33	0.00	6.48
DAMAN	0.00	23.41	0.00	28.13	0.00	23.31	0.00	27.73	0.00	23.31	0.00	26.06
GOA	0.00	22.06	0.00	27.74	0.00	22.84	0.00	26.25	0.00	22.20	0.00	25.83
GUJRT	8.49	9.54	8.38	14.39	8.75	9.87	9.05	13.56	8.53	9.57	9.18	12.47
MAHAR	6.63	9.84	5.95	13.35	6.62	9.95	5.99	14.06	6.64	9.84	5.95	12.82
MDHYA	16.29	13.34	17.94	14.87	17.21	13.98	19.20	15.70	16.56	13.56	18.04	15.46