Evolution of Transmission Pricing and POC charges

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Transmission Planning

Background

- Development of transmission system in the country was traditionally the responsibility of the erstwhile State Electricity Boards (SEBs).
- The country's transmission networks were organised into five regional grids – North, West, South, East and NE.
- Grid developed as the Associated Transmission Systems (ATS) for various generation projects. Initially, CGS like NTPC, NHPC etc. too took up the construction of ATS.
- Power Grid Corporation of India (PGCIL) was created (originally NPTC) in 1988 with the objective of creating strong regional grids and subsequently a national grid.
- PGCIL was entrusted with the task of building inter-state and inter-regional transmission systems.
- Various Central GENCO transmission assets were transferred to PGCIL.
- Role of transmission system planning for harmonious development was carried out by the Power System wing of the Central Electricity Authority (CEA).

Planning Framework (Post Electricity Act 2003)

Transmission mandated as a licensed business.

- 2 statutory entities created & assigned roles of transmission system planning & development
  - Central Transmission Utility (CTU) & State Transmission Utility (STU).
  - To start with, PGCIL has been designated as the CTU
  - The transmission wing of the erstwhile SEBs designated the STUs.
- CTU and STU also deemed licensees- build own, operate and maintain transmission systems

CTU to issue Network Plans and update plans periodically (not later than annually)

- To contain details like identified new lines and substations, system strengthening projects, broad design specs, probable line lengths and substation locations etc.

New transmission planned based on

- Requests by new generators/ application for transmission access
- Identified pockets of congestions based on feedback by RLDC/ SLDC
- Demands by States to meet their load growth

CTU identifies required Transmission based on Load Flow Studies

System discussed and agreed in Regional Standing Committee Meetings

- Chaired by Member (PS), CEA
- Cost sharing for new transmission agreed in RPC- consent for signing BPTA

Differences on cost sharing have at times delayed/ held up trans. development

Planning

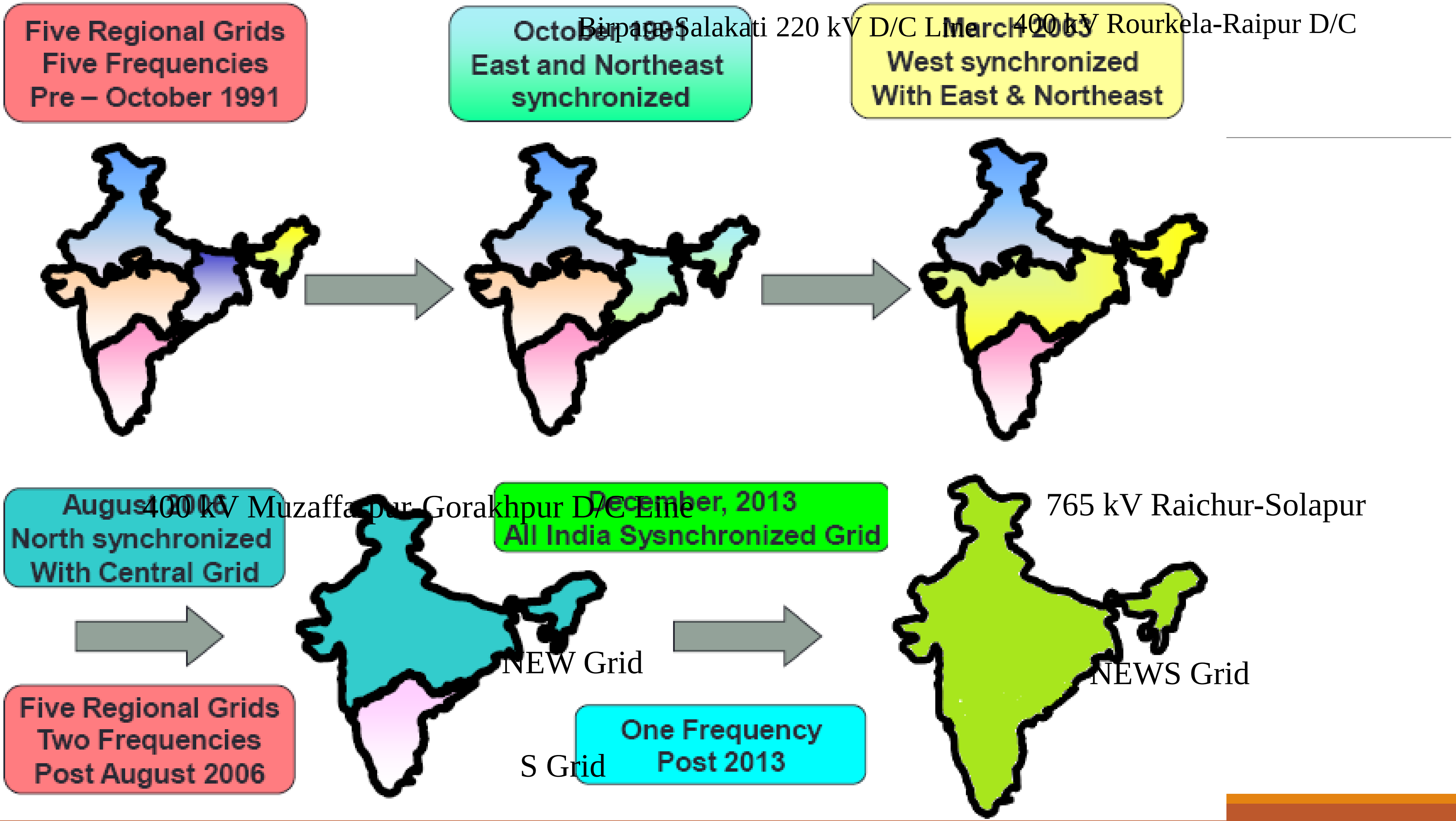
Generation delicensed with EA2003, private generators were encouraged

Evacuation ensured under Open Access Regulations 2004

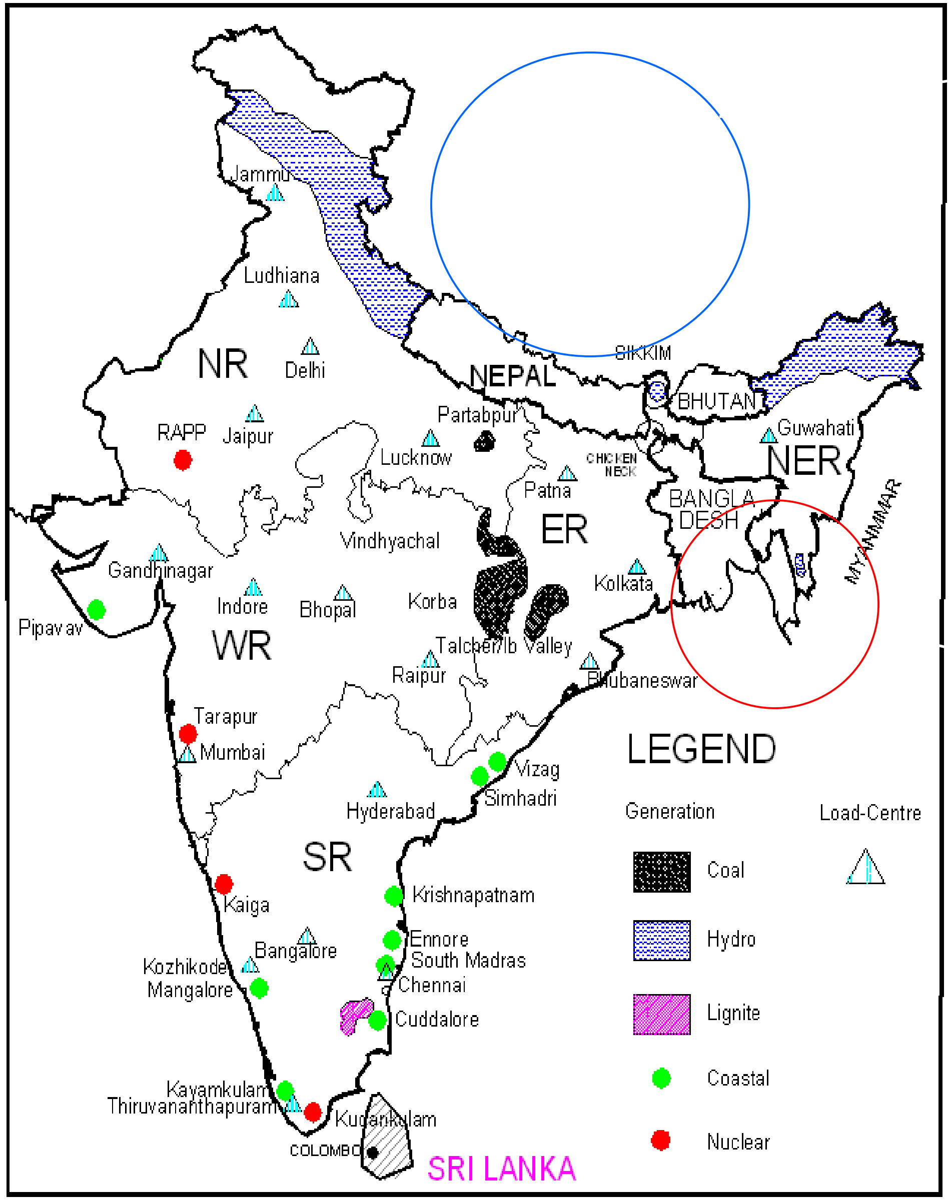
Connectivity, Long term Access, Medium term Open Access Regulations 2009, effective from 1.1.2010

2008-Power Exchange operationalised & STOA Regulations notified

Evolution of the Grid….



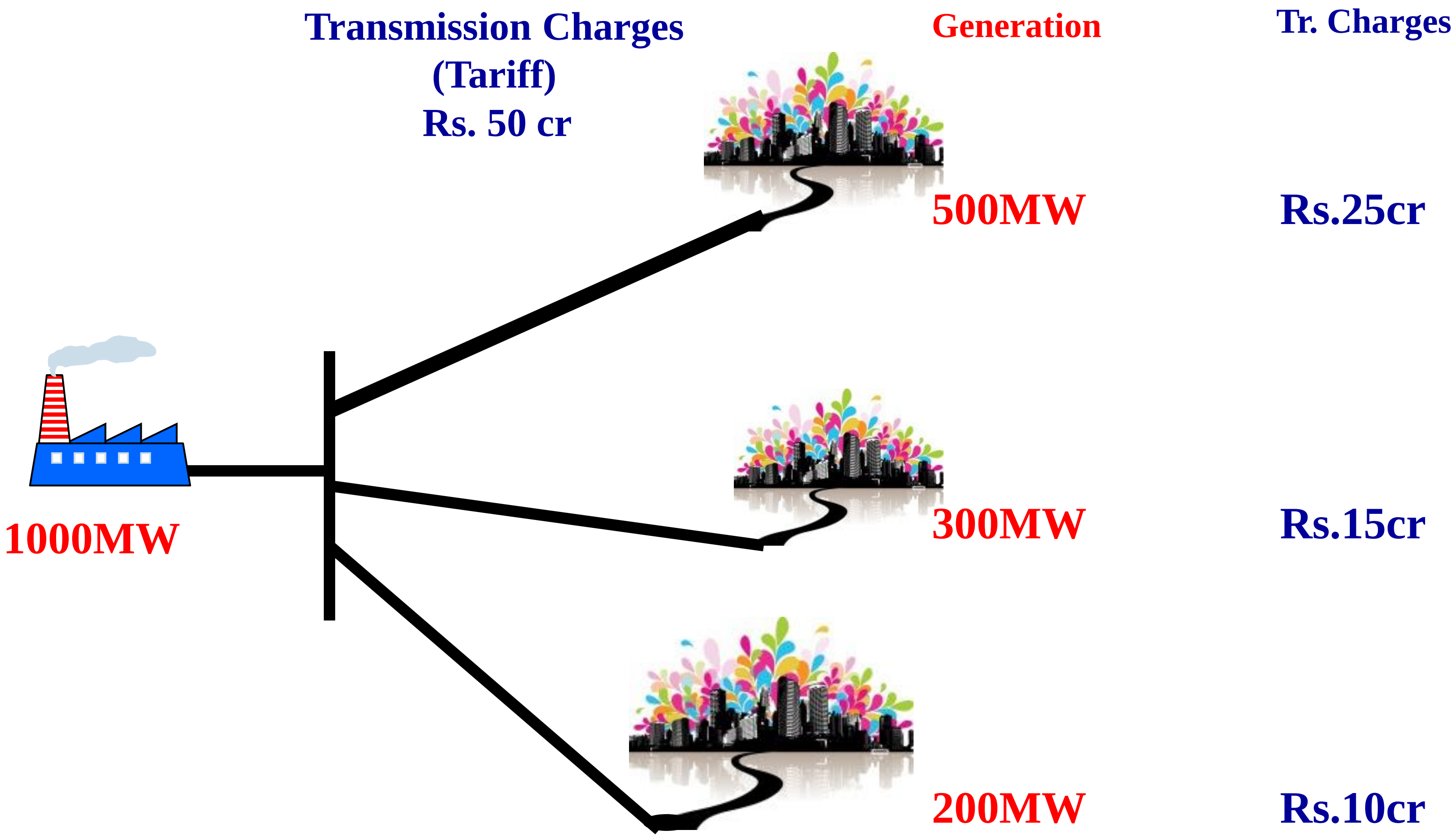
Energy Resource Map



- **Hydro potential in NER and upper part of NR**
- **Coal reserves mainly in ER/ WR**
- **For optimal utilisation of resources – strong National Grid**

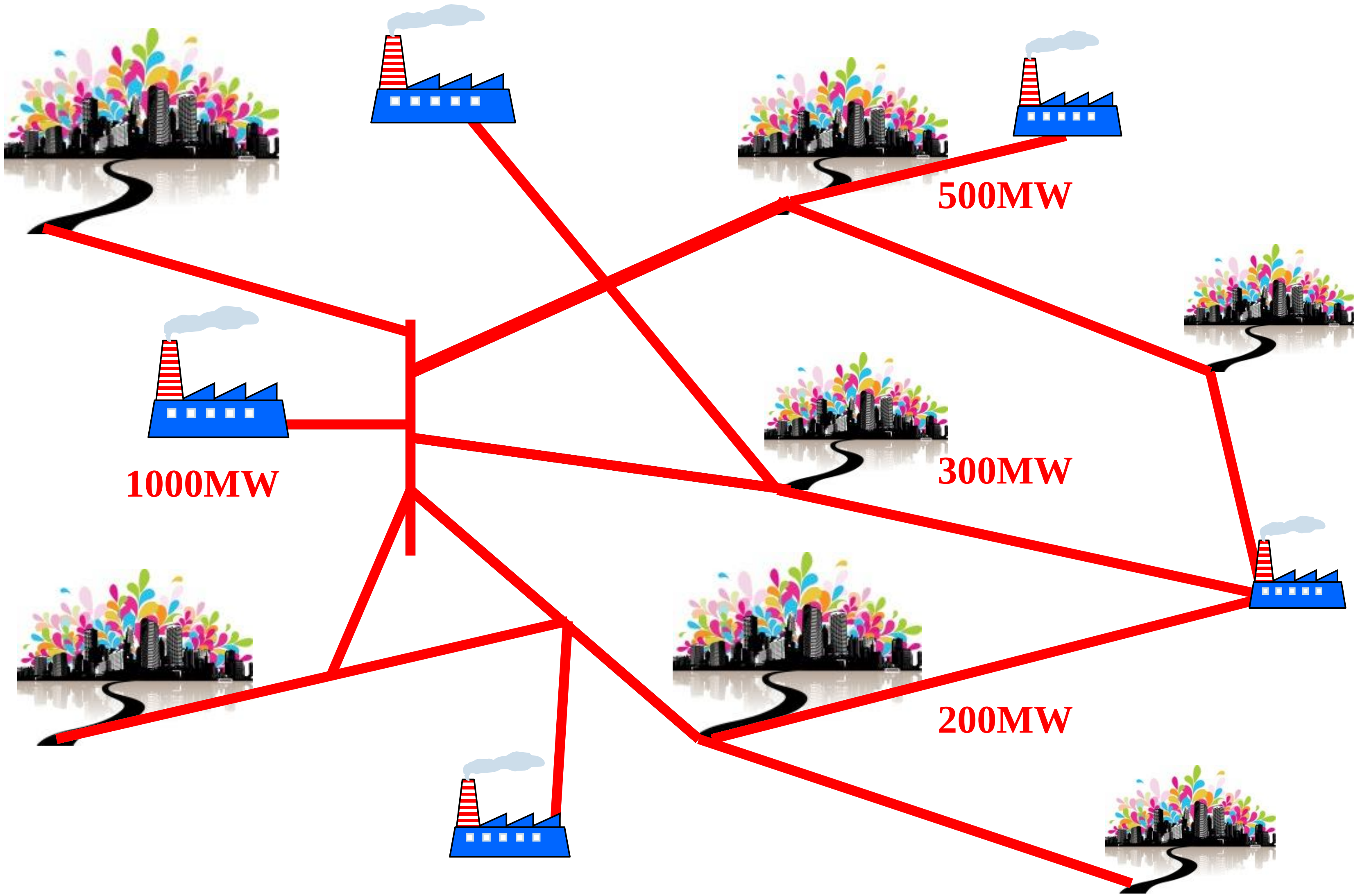
Transmission Pricing

Mechanism for Investment consent



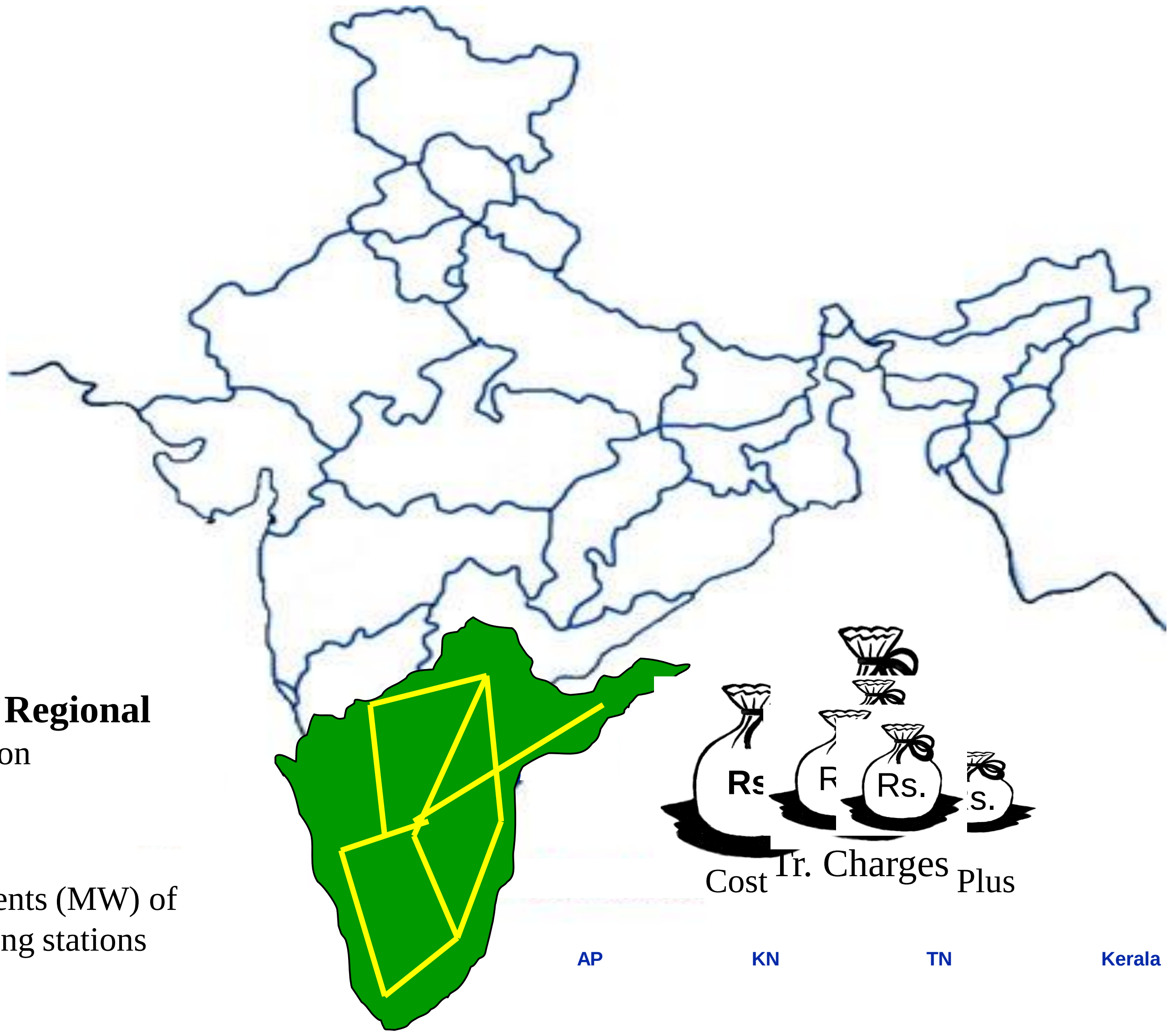
- Sharing of Tr, Charges based on Contracts
- Beneficiaries of Generation are **SYNONYMOUS** with Users of Tr. System
- Since Beneficiaries are identifiable their consent is obtainable

Mechanism for Investment consent... *in reality*



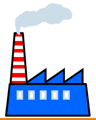
- Benefits of Tr. Systems are shared by all the stakeholders

Old mechanism for sharing Tr. charges

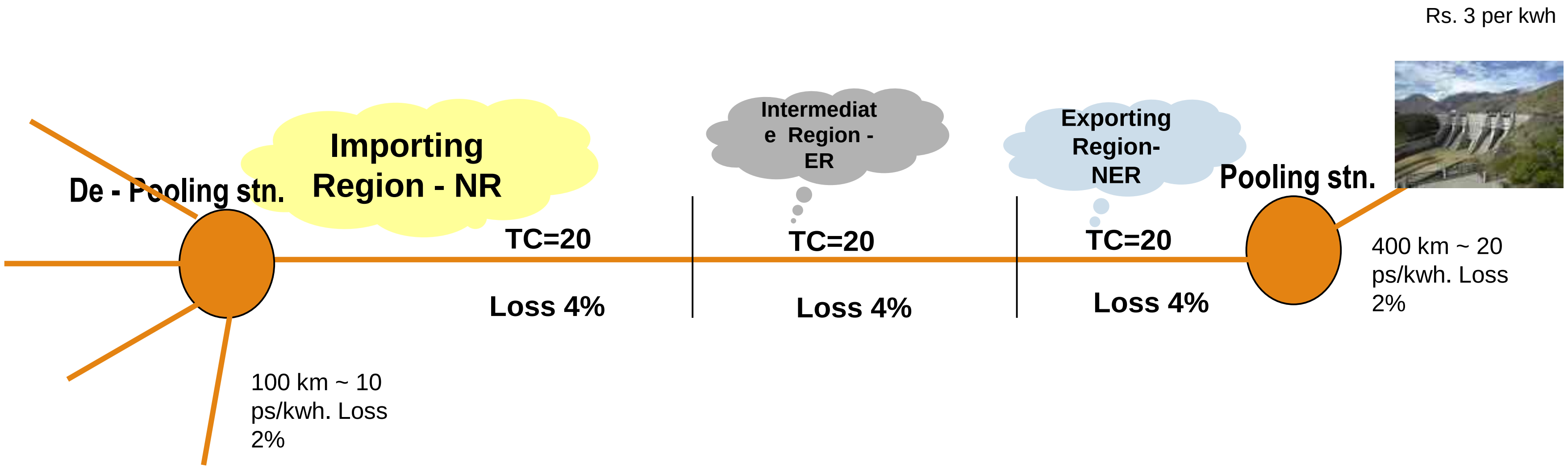


Predominantly Regional
Eg. Southern Region

Allocation
Based on entitlements (MW) of inter-state generating stations



Pricing under Postage Stamp (Long term User) – An Example



- Cost of delivery
  - Cost at Generator Terminals – 300 ps/kwh
  - Transmission costs to load centre – 90 ps/kwh
  - Cost of losses – 74.28 ps/kwh
  - Final costs – 464.28 ps/kwh
- Much of the cost levels are genuine. There could even be element of cross-subsidisation of new transmission costs by existing beneficiaries
- If new line costs are loaded on to first user(s), then the cost of delivery can be prohibitive
- There could be a tendency of over-estimation of losses
- **Hence the need to ensure a *fairer* allocation**

Evolution of Transmission Pricing

Stage I

- **Cost of Transmission clubbed with Generation Tariff**
- **Implicit**

Stage II

- **Apportioned on the basis of energy drawn**
- **(Usage Based)**

Stage III

- **Apportioned on the basis of MW entitlements**
- **(Access Based)**

Stage IV

- **Hybrid Methodology**

Upto 1991 → **1992-2002** → **2002-2011** → **2011 onwards**

… the need for revisiting the Transmission pricing

- **National Electricity Policy mandates development of a strong National Grid.**

  require transmission prices to be *distance and direction sensitive*, *independent of BPTA*

  and *reflect the utilization of the network* by each network user

- **Tariff Policy further requires that such pricing mechanism be implemented by Apr-06.**

- **Evolution of open access and competitive power markets**

  Bilateral transactions, Px

- **Pricing inefficiency in the emerging circumstances – the problem of pancaking**

- **Changing nature of use of the transmission system by various users- Merchant generators**

Individual Transmission Licensee raise the bill and maintain payment Security Mechanism.

Principles of sharing ISTS charges and losses-2010 Regulations

Factors to be calculated

- Point of connection charges – in terms of
  - RS./MW/month for LT/MT access
  - paise/kwh for STOA
- Loss allocations factors
- Load flow based methods to be used for calculating above factors

PoC charges Methodology-Hybrid method & Uniform Charge Sharing Mechanism

- Hybrid Methodology: Cost Allocation through marginal usage; Slack bus identification through Average Participation Method.
- Uniform Charge Sharing Method: Present Methodology of Regional Postage Stamp Method
- For 1st 2 years- 50% charges will be recovered through Hybrid method & 50% through Uniform charge sharing method.
- After 2 years weightage to be reviewed

Data to be provided by DIC to IA by end of Nov, each year. Else Commission may authorize IA to obtain such information from alternative sources.- as per Procedure issued by NLDC

The Yearly Transmission Charge of the ISTS Licensees shall be fully and exactly recovered. There shall be periodic truing up of YTC as per actual billing.

Solar Based Generation

- No. Tr. Charges/Tr. Losses for use of ISTS for the useful life of the projects commissioned in next 3 yrs. (July 2014)

Main components of ISTS charges-2010 Regulations

Usage based component- Hybrid method-90% of AC system

Reliability Charges- 10% of ISTS charges

HVDC charges- Billed on regions for which they were constructed- in proportion to Long term Access+ Medium term open access

Need for change

Transmission system for renewables- waiver based

Usage based component

Reliability component – quantification

HVDC – for system control

Short term open Access charges

Background

Existing Sharing Regulations- notified on 15.6.2010, effective from 1.7.2011, 6 amendments till date.

Review of framework-Taskforce under Member CERC, Sh A.S. Bakshi- Report dated March 2019.

Proposed Draft Regulations- Committee under Member CERC, Sh.I.S. Jha- Report dated August 2019

Draft Regulations – 31.10.2019, comments till 31.12.2019.

Final Regulations- 4.5.2020, w.e.f 1.11.2020

Monthly Transmission Charges

National Component (NC)

Regional Component (RC)

Transformers Component (TC)

AC System Component (ACC)

National Component-HVDC (NC-HVDC)

National Component-Renewable Energy (NC-RE)

HVDC (RC-HVDC)

STATCOM,SVC, Bus Reactors

State where located

Usage Based Component (AC-UBC)

Balance Component (AC-BC)

National Component-Renewable Energy (NC-RE)

- Transmission system built for renewables which are covered under waiver of transmission charges to be separately billed as “National Component” in the ratio of GNA of all drawee DICs across the Country.

- Linewise YTC for such transmission system shall be taken at “zero cost”
    - no cost implication shall be there under usage component for such system.

National Component-HVDC (NC-HVDC)

- 30% transmission charges for HVDC bipole
- HVDC systems such as back to back are used for control function by system operator
- Biswanath Chariali-Agra HVDC system entire Yearly Transmission Charges and for Adani Mundra –Mohindergarh HVDC System, portion of Yearly Transmission Charges.
- To be shared by DICs of all India in the ratio of GNA

Regional Component

- HVDC (RC-HVDC)- 70% of transmission charges of bipole HVDC Transmission System- to be shared by drawing DICs of receiving region & injecting DICs for LTA to target.
  - Example

- Static Compensator (STATCOM), Static VAR Compensator (SVC), Bus Reactors, and any other transmission element(s) identified by Central Transmission Utility being critical for providing stability, reliability and resilience in the grid - to be shared by DICs in the region in which these devices are located in the ratio of LTA+MTOA.
  - Drawing DICs
  - Injecting DICs- untied capacity

Transformers Component (TC)

- The transformers are planned as ISTS to cater to the drawal requirement of the State by the CTU. CTU to provide list of such transformers.
  - where the actual tariff for such transformer is not available, CTU shall provide indicative cost in such cases for billing. This cost shall be excluded from Monthly transmission charges to determine AC component transmission charges.

- If 220kV substation feeders are connected to neighbouring state such that drawal transformer is actually catering to drawl requirement of state other than the state in which transformer is located, proportionate transmission charges shall be levied to such state.

AC System Component (ACC)

- Includes AC transmission lines, AC substation, line and bus reactor and Inter-connecting transformers (excluding the drawl transformers which have been proposed to be shared by the State, SVCs, STATCOMs and such other devices which have been proposed to be shared by region in which they are located).

- Following parts:

(i) Usage Based Component (AC-UBC); and

(ii) Balance Component (AC-BC).

Usage Based Component

- Actual data –
  - injection / drawl for the month.
  - Lines in use

•“Peak block” for the month shall be considered as the block in which sum of ISTS drawl for all States is maximum to determine utilisation component of AC transmission charges. While identifying peak block, the injection into ISTS by a State shall be ignored .

Base Case file to be prepared by Implementing Agency for the Peak Block of the month comprising of the following:

- Basic Network, which shall be the network file for the power system for the peak block of the month; and.
- Actual generation and demand, in MW, at each node of the Basic Network for the Peak Block.

Apportionment of Monthly Transmission charges on per circuit kilometer basis for each voltage level and conductor configuration

Usage Based Component-Example for SIL

- Surge Impedance loading of standard transmission line at a nominal voltage to determine utilization percentage of a line .

  - A transmission line with SIL of 500 MW is carrying 300 MW in the Base case for Peak Block.
  - The transmission charges as per linewise transmission charges for such line is suppose Rs 100 Crore.
  - Then the transmission charges to be considered under AC-UBC for such a line shall be (300/500)*100= Rs. 60 Crore.
  - The balance Rs. 40 Crore shall be considered under AC-BC component

- Percentage usage of each transmission line to be multiplied by line-wise Monthly Transmission Charges to obtain modified line-wise transmission charges.

- Transmission charges at each node shall be calculated as per Hybrid Methodology, using modified line-wise transmission charges obtained as per clause (6) of this Regulation.

Usage Based Component-Aggregation

- Charges allocated to each node shall be aggregated for a State for nodes within the State

- Any other entity within the State with Long term Access or Medium Term Open Access to ISTS shall also be allocated charges under AC-UBC at their node.

- Such entity shall pay charges as allocated to its node and shall not be clubbed with other nodes. Charges for other components such as AC-BC, NC, RC are proposed to be allocated on GNA and hence shall be determined directly for such entity

Balance Component-AC-BC

The transmission charges under AC system component after allocating the charges under ”Usage based” component – AC-UBC shall be shared as balance component –AC-BC in the ratio of GNA.

Sharing of transmission losses

•All India Average Transmission losses for ISTS shall be calculated by Implementing Agency for each week, from Monday to Sunday, as follows:

{(Sum of injection into the ISTS at regional nodes for the week) minus (Sum of drawal from the ISTS at regional nodes for the week)}/ Sum of injection into the ISTS at regional nodes for the week X 100 %

•Drawal Schedule of DICs shall be worked out as per provisions of Grid Code after taking into account the transmission losses of previous week.

•No transmission loss for ISTS shall be applicable while preparing schedule for injection node including that for Collective Transactions over the Power Exchanges.

Transmission loss

•Losses are currently determined for injection nodes as well as drawl nodes. However while scheduling losses for scheduling under long term access or medium term open access is payable by drawl entities only. Currently, the losses in ISTS are calculated regionally as total loss and it is divided by 2 to determine average loss for injection and average loss for drawl which is in approximation.

For example , if total injection into ISTS is 40000 MW and total drawal from ISTS is 39500 MW, loss is 500 MW,

Average injection loss = (500/40000)*(1/2)= 0.625%

Average drawl loss = (500/40000)*(1/2)= 0.625%

T-GNA Rate (in Rs./MW/block) :

Transmission charges for GNA for entities located in the State, for the billing month, under first bill (in rupees) X 1.10 / (number of days in a month X 96 X GNA quantum, in MW, for all such entities located in the State considered for billing, for the corresponding billing period.)

Transmission Deviation

(2) Transmission Deviation Rate in Rs./MW, for a State or any other DIC located in the State, for a time block during a billing month shall be computed as under:

1.25 X (transmission charges for GNA of entities located in the State, under first bill for the billing month in Rs.)/ (GNA quantum in MW of such entities located in the State, considered for billing, for the corresponding billing period X number of days in a month X 96

Liability for DELAY

- No transmission deviation charges for injection of infirm power prior to COD of a generating station.

- Liability of transmission charges of Rs. Rs. 3000/MW/month replacing earlier provision of 10% of transmission charge per MW for connectivity grantee in case the connectivity is granted on existing margin and the generation is delayed.

- Transmission charges for Associated transmission system for period of delay by generating station

Methodology of calculation of waiver of transmission charges

(1) Waiver of a drawee DIC other than a drawee DIC which has obtained “GNA_{RE}” shall be calculated based on the following formulae:

$$\text{Waiver (\%)} = 100 \text{ X } \frac{\sum_{n=1}^{T} \frac{SDRG}{SDTG}}{T}$$

Where,

“SDRG” is the drawl schedule (in MW) through ISTS under GNA from the sources eligible for waiver under Regulation 13 of these regulations in nth block;

“SDTG” is the total drawl schedule (in MW) under GNA through ISTS from all sources in nth block;

“n” is the nth time block

“T” is number of time blocks in a month = 96 X number of days in a month

Provided that in case the “SDTG” for a time block is less than 75% of the maximum schedule corresponding to GNA, the “SDTG” shall be taken as 75% of maximum schedule corresponding to GNA for a time block.

Methodology of calculation of waiver of transmission charges

(2) Waiver of a drawee DIC which has obtained “GNA_{RE}” shall be calculated based on the following formulae:

$$\text{Waiver (\%)} = 100 \text{ X } \frac{\text{sum of SDRG for all time blocks in the month}}{\text{total number of time blocks in the month X 0.3 X GNARE}}$$

Where,

“GNA_{RE}” is the GNA to procure power only from the sources eligible for waiver under Regulation 13 of these regulations;

“SDRG” is the drawl schedule (in MW) in a time block through ISTS under GNA_{RE} from the sources eligible for waiver under Regulation 13 of these regulations;

Provided that maximum waiver shall be limited to 100%

Explanatory Memorandum –draft first amendment

“3.13 Accordingly, the proposed draft promotes consumption of power from specified RE sources. The waiver is to the extent of scheduling of power from specified RE sources since schedule corresponds to electricity generated and the Tariff policy provides waiver for ‘electricity generated’. The draft amendment has proposed to cap the denominator as 75% of maximum schedule corresponding to GNA for the following reasons:

Suppose, a drawee entity have GNA for 2000 MW, however it draws RE for only 100 MW in a block and total drawl schedule is also 100 MW, in such a case it shall get waiver for entire 2000 MW.

This condition will lead to the situation where entities may seek higher GNA and by changing their total drawl equal to RE drawl would block the transmission capacity without paying any charges and without drawing RE also.

This would defeat the policy objective behind waiver. However, there may be some variations in demand and hence a cushion of 25% has been proposed.

If total drawl schedule is less than 75% of GNA capacity, denominator shall be taken as 75% of the schedule corresponding to GNA.

………..

3.15 The abovesaid calculations are proposed for each time block and hence waiver shall be available only to the extent of RE schedule, thereby promoting drawl of power from RE.”

Trajectory for gradual increase in the transmission charges:

(1) Till 30.6.2025-100% schedule under waiver

(2) REGS or RHGS based on wind or solar sources or Hydro PSP ESS or BESS ESS:

Category	Period of COD	Number of years from COD	% of drawl Schedule from identified generating station or ESS
REGS or RHGS based on wind or solar sources or Hydro PSP ESS	1.7.2025 to 30.6.2026	25 years	75
	1.7.2026 to 30.6.2027	25 years	50
	1.7.2027 to 30.6.2028	25 years	25
	After 30.6.2028		0
Battery ESS	1.7.2025 to 30.6.2026	12 years	75
	1.7.2026 to 30.6.2027	12 years	50
	1.7.2027 to 30.6.2028	12 years	25
	After 30.6.2028		0

Trajectory for gradual increase in the transmission charges:

- Date of signing of PPA and award of construction work till **30.6.2025-100% schedule under waiver**
- **New Hydro projects:**

Date of signing of PPA and award of construction work	Number of years from COD	% of drawl Schedule from identified generating station or ESS, to be considered under Step-1 under Annexure-III
1.7.2025 to 30.6.2026	18 years	75
1.7.2026 to 30.6.2027		50
1.7.2027 to 30.6.2028		25
After 30.6.2028		0

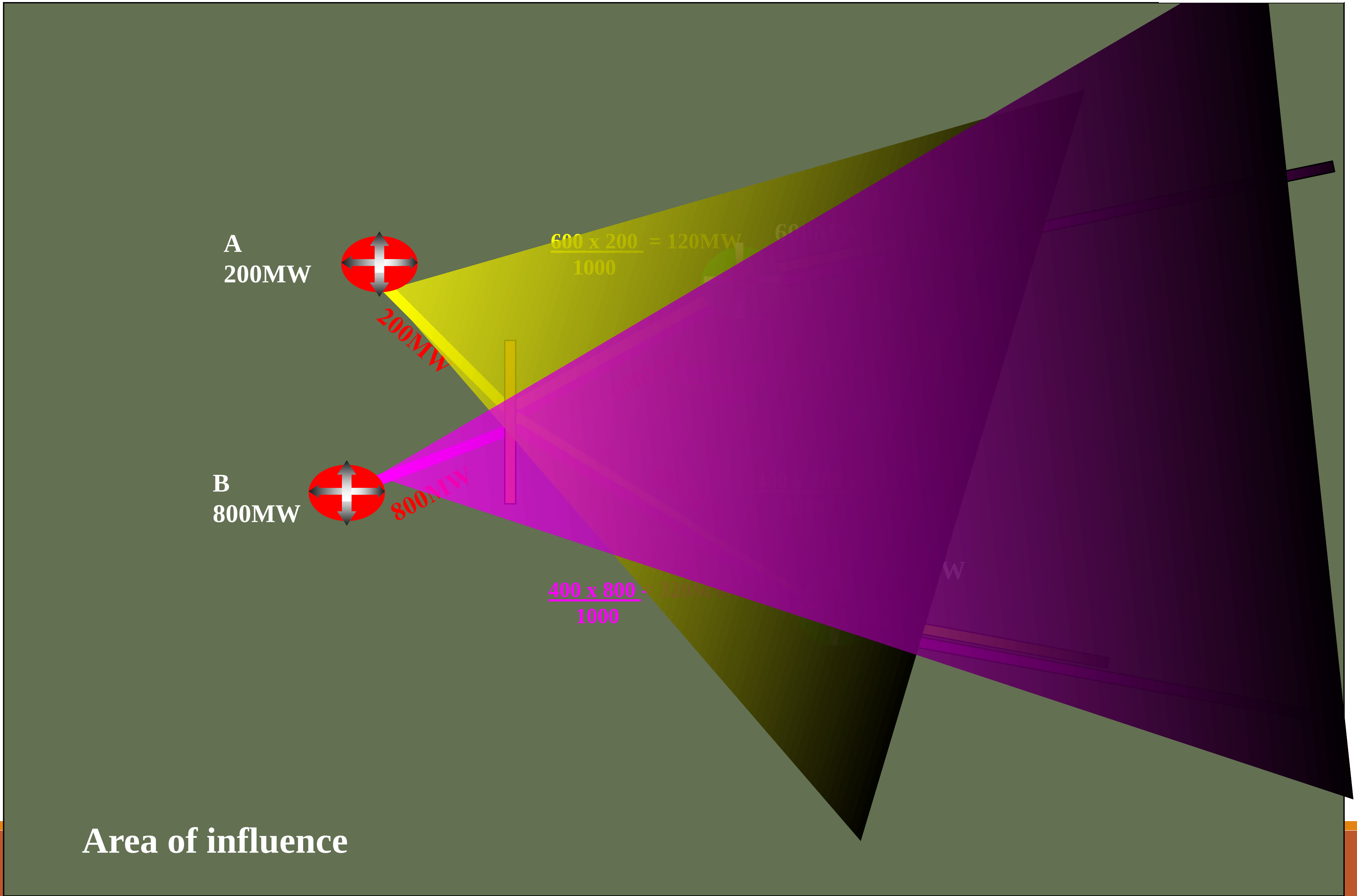
Thank You

Methods employed in arriving at Point of Connection Charges

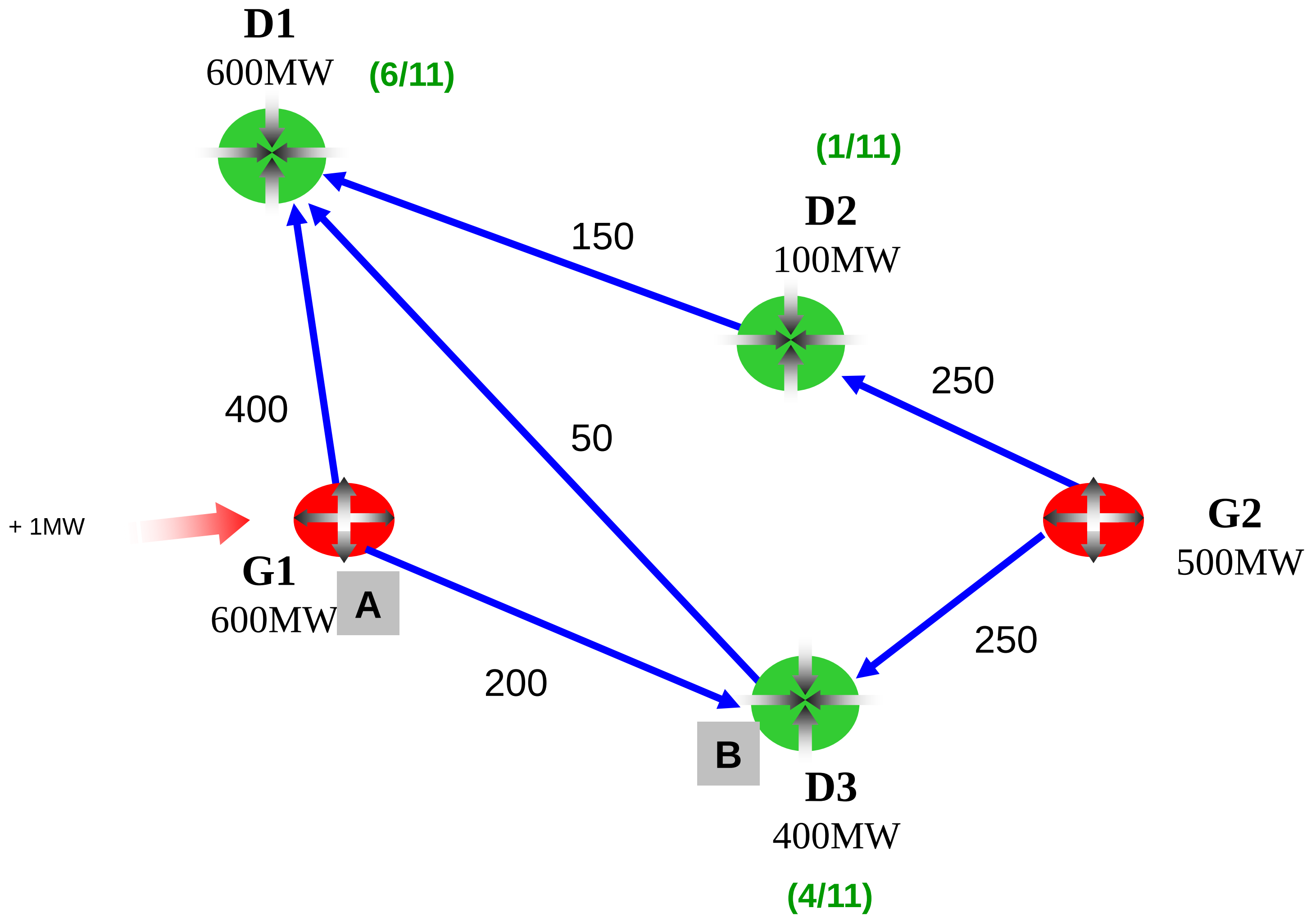
Hybrid Method

Marginal Participation + Average Participation

Average Participation

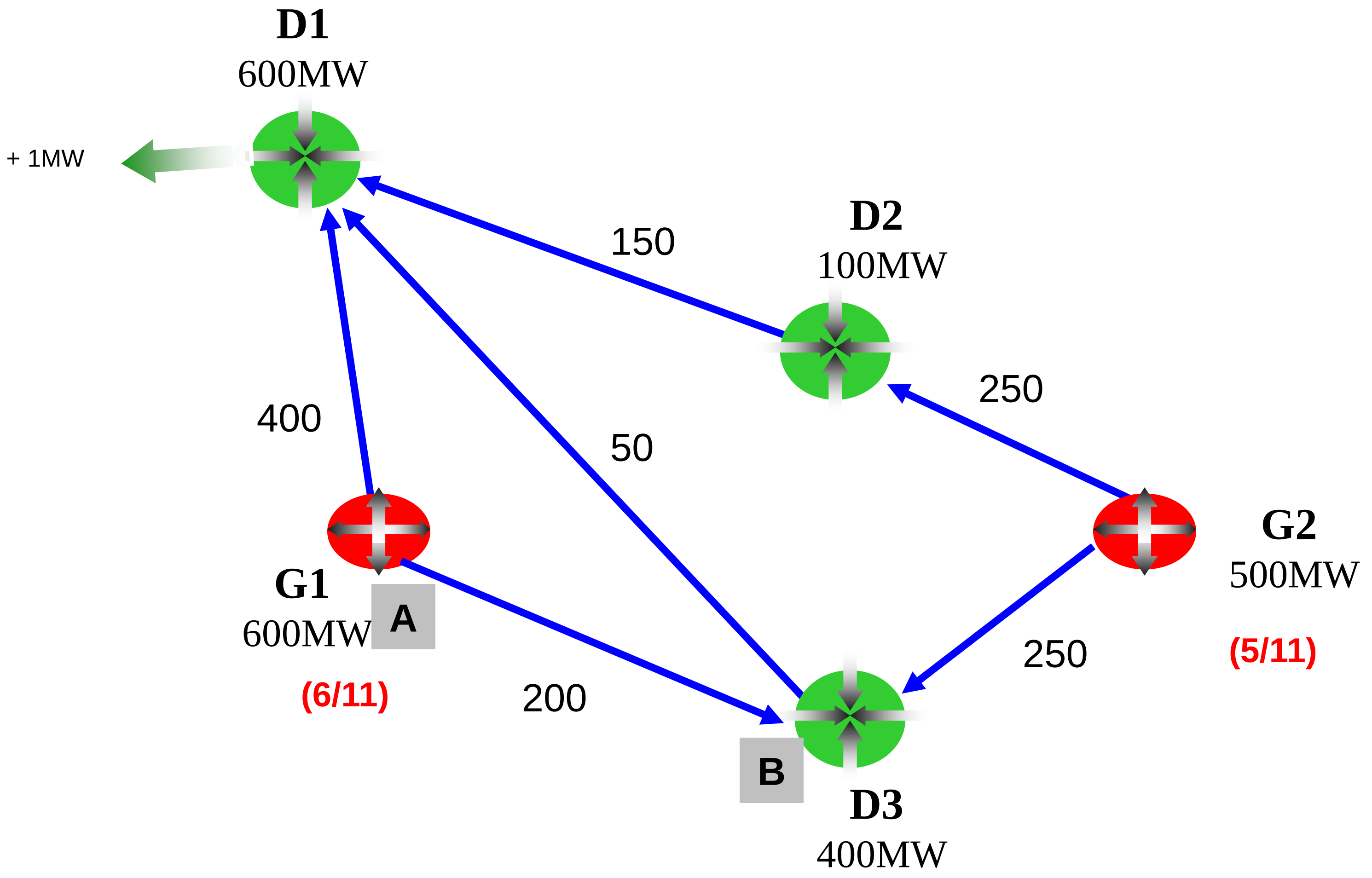


Marginal Participation



*Indicative only
Power flow in lines in MW

Marginal Participation



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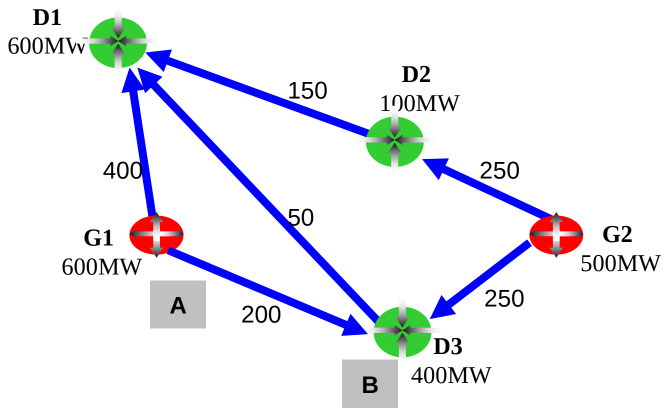

Line AB

BC + CD +EF+…

Point Tariff

Users
G1
G2
D1
D2
D3

* Identification of the slack node(s) changes the rule of the game

Transmission charges liability in case of delay of generating station

•In case of delay of generating station, it shall be liable for transmission charges of Associated Transmission System i.e Yearly Transmission charges of such transmission elements which have specifically been indicated as generator‟s ATS.

•Generating stations for whose Long term Access no additional investment is required i.e there is no Associated transmission system and the Long term Access is granted on existing margins- generating station shall pay transmission charges @10% *TDR for the period of delay of the generating station.

Transmission charges liability in case of delay of upstream or downstream system

- In case either upstream or down-stream system is not ready due to which an element cannot be put in regular service , the transmission charges for such element shall be payable by owner of upstream or downstream system which is delayed. For cases where both upstream and downstream system is delayed, transmission charges for the element shall be shared by owner of upstream and downstream system in the ratio to be decided by the Commission, Transmission licensee may approach the Commission impleading owner of upstream and downstream system.

Treatment of part operationalization of generator

•CTU identifies several transmission elements to operationalize LTA for a LTA customer, however only a few elements are commissioned, then CTU should operationalize LTA partly only when LTA Customer seeks such part operationalization upto its transmission capacity.

•CTU may operationalize LTA as per availability in transmission system even without availability of full ATS, if LTA customer seeks such operationalisation and vice versa.

•Where some of transmission elements of ATS have been commissioned and LTA customer has sought part or full operationalization of LTA, once the LTA for such LTA Customer is operationalized, the elements of ATS which have achieved COD with regular service shall be included in ISTS pool for recovery under Regulation 5 to Regulation 8 of Draft Sharing Regulations 2019 .

Event of Default

- The occurrence and continuation of the following events shall constitute a DIC Event of Default:
  - A DIC fails to comply with the prevailing regulations including the provisions of the Central Electricity Regulatory Commission (Indian Electricity Grid Code) Regulations, 2010 as amended from time to time including any subsequent re-enactment thereof or is in material breach of these Regulations and such material breach is not rectified by the said DIC within 60 (sixty) days of receipt of notice in this regard from the concerned inter-State Transmission Licensee or the Central Transmission Utility; or
  - DIC fails to make payments against bills raised by the Central Transmission Utility under these Regulations within 60 days beyond Due Date.
- Upon the occurrence and continuance of a DIC Event of Default, the Central Transmission Utility may serve notice on the concerned DIC, specifying the circumstances giving rise to such Notice.

Following the issue of such notice by the DIC, the concerned DIC shall take steps to remedy the default within 60 (sixty) days of issue of such notice.

After the expiry of 60 (sixty) days from the date of issue of notice, unless the circumstances giving rise to such notice as mentioned in clause (1) of this regulation shall have ceased to exist or have been remedied, the concerned DIC shall cease to be a DIC under these Regulations and the Central Transmission Utility shall issue a Termination Notice of 30 (thirty) days to this effect with a copy to the Commission and the Implementing Agency.

Long Term Access or Medium Term Open Access or both of such entity shall be cancelled. Such cancellation shall be treated as relinquishment

Upon termination of the status of DIC, the entity shall not be eligible for interchange of power under any form of open access unless such entity remedies the default and makes payment of all outstanding charges including relinquishment charges.

Region	I	II	III	IV	V	VI	VII	VIII	IX
NR	3.28	3.03	2.78	2.53	2.28	2.03	1.78	1.53	1.28
WR	2.45	2.2	1.95	1.7	1.45	1.2	0.95	0.7	0.45
ER	1.74	1.49	1.24	0.99	0.74	0.49	0.24	0	0
NER	2	1.75	1.5	1.25	1	0.75	0.5	0.25	0
SR	2.32	2.07	1.82	1.57	1.32	1.07	0.82	0.57	0.32

Region	Average loss for injection/drawal (%)
NR	2.28
WR	1.45
ER	0.74
NER	1
SR	1.32

SIL for different voltage levels and conductor configuration		
Voltage(KV)	Number & size of conductor	S.I.L (MW)
765	4x686	2250
765 **Op at 400**	4x686	614
400	2x520	515
400	4x420	614
400	3x420	560
400 **Op at 220**	2x520	455
220	420	432
132	200	50