# MINUTES OF 22ND MEETING OF CENTRAL ADVISORY COMMITTEE (CAC) OF CENTRAL ELECTRICITY REGULATORY COMMISSION (CERC) HELD ON MONDAY, THE 26TH APRIL, 2021

{ THROUGH VIDEO CONFERENCING (MS TEAM) }

The meeting was chaired by Shri P.K. Pujari, Chairperson, Central Electricity Regulatory Commission (CERC). A list of participants is enclosed at **Appendix -I**.

Shri Pujari welcomed the members of the Central Advisory Committee (CAC). In his opening remarks, he mentioned that the CAC has since been reconstituted. He acknowledged that over the years, CAC has been advising CERC on policy and regulatory matters. Some of the key issues deliberated in the past included ring-fencing of SLDCs, open access (OA), competitive bidding, financial health of DISCOMs, stranded capacity, transmission congestion, Ancillary Services (AS), Deviation Settlement Mechanism (DSM), etc. He maintained that the advice and suggestions of CAC have been extremely valuable to CERC for taking decisions and formulating regulations in these matters.

Shri Pujari, further added that heeding the current scenario in the Indian power sector, two key issues have been brought before the CAC for discussion: (i) alternative approaches to tariff determination (normative vs. detailed cost scrutiny, for the purpose of Tariff Regulations for the period of 2024-2019), and (ii) licensing vs. de-licensing (based on the Electricity Amendment Bill, 2021 proposed by Ministry of Power). With respect to the former, he iterated that while determining tariff, CERC follows a hybrid approach of cost of service and normative parameters. The tariff determination is an elaborate process involving detailed scrutiny of various cost elements. The Commission seeks to explore as to whether a normative approach to tariff determination instead of the current practice of detailed cost scrutiny could be followed to achieve the same objective but at a faster pace. As regards the second agenda item, he requested the members to give their views specially on the regulators' role in the proposed framework of delicensing of distribution business in the draft amendments to the Act that the Ministry of Power has floated.

**Agenda Item: 1- Alternative Approaches to tariff determination ( Normative Vs Detailed cost scrutiny)**

A presentation was made by Research Officer (Regulatory Affairs), CERC **( Annexure-I)** . The presentation detailed the functions of CERC in tariff determination and three alternative approaches for tariff determination: (i) determination of tariff by benchmarking capital cost, (ii) normative tariff by fixing AFC as a percentage of capital cost, and (iii) normative tariff by fixing each component of AFC as a percentage of total AFC. It was informed that a sample of 30 generating stations with varying vintage, unit size, fuel type, etc. was analysed in this context.

The following issues were posed for discussion:

i. Normative tariff by benchmarking Capital Cost
   a. Variables to be considered for determining Capital Cost on normative basis
   b. Econometric analysis or any other methodology for arriving at benchmark Capital Cost

ii. Normative tariff by fixing AFC as a percentage of Capital Cost
   a. Views on this approach
   b. Possible methodology for establishing the relation between AFC and Capital Cost to meet the interests of both buyers and sellers

iii. Normative tariff by fixing each component of AFC as a percentage of total AFC
   a. Clustering of components of AFC based on their nature of increasing/decreasing order; any other method of clustering
   b. Methodology for determining escalable (increasing) and non-escalable (decreasing) factors
   c. Same escalable (increasing) and non-escalable (decreasing) factors for all plants/transmission systems, or separate for each plant or transmission system (based on vintage, capacity, fuel type, fuel linkages, etc.)
   d. Isolation of *Additional Capitalization* as a separate stream of revenue would provide for recovery of AFC on a normative basis in realistic terms
   e. Any other methodology to treat *Additional Capitalization* for determination of AFC on normative basis
   f. Applicability of tariff principles in each control period for new plants only, for regulatory certainty to the existing plants

g. Any other methodology to minimize the impact on AFC on account of change in control period

**Discussion:**

***a) <u>General:</u>***

1. Ideally the capital costs of Section 63 projects should serve as a benchmark for capital cost for Section 62 projects. While setting the benchmark capital cost, cost of land may be excluded from the same. Cost of land may be taken at actuals, due to different costs in different States.
2. With reference to the normative approach based on benchmarking capital cost, there are constraints on account of various factors such as wide variation in technology, size, location, socio-economic factors, wind zones, seismic zone, remoteness, etc..
3. Applying an econometric approach to historical data for the purpose of benchmarking may not be advisable, given the numerous uncertainties in the sector. This might deter efficiency and competition.
4. An alternative approach could be to work backwards with comprehensive data. The price can be discovered by considering the best capital costs secured through competition, the best operational practices, and availing the best financing schemes in bidding process.
5. Benchmarking can be done using various approaches, such as data envelopment analysis and stochastic frontier analysis – primarily aimed at benchmarking, considering different technologies, circumstances, variety of controllable and uncontrollable parameters. The benchmarking techniques evolved over the last decade or so allows for incorporation of such parameters which may influence the performance or the capital cost of the plant and which might not have been in the complete control of the investors.
6. There has been a movement from cost of service approach to normative cost of service approach. Going forward, one needs to work on enhancing the efficiency component in the regulatory approach. While approving different components in tariff, an efficiency factor may be considered.
7. Changing norms once fixed at the time of COD has a detrimental effect on the profitability of a company. Hence, once commissioned and operational, the norms can be taken to be company-wide, for national companies, both on generation and

transmission sides, as long as they are in line with the Act. In this regard, efficiency parameters once fixed may only be relaxed and not tightened, going forward .

8. National Electricity Policy, 2005 and Tariff Policy, 2016 stipulate moving away from the cost plus regime, for both generation and transmission as competition in both the segments have resulted in cost (tariff) reduction. Continuing with cost plus tariff fixation would provide a wrong signal especially with competitive bidding promoting efficiency as laid down in the Electricity Act, 2003.
9. With reference to normative fixation of AFC, it would be appropriate if there are two sets of percentages fixed for normative tariff – for the first 15 years and for 15-25 years thereafter. This flows from the fact that, typically, generating stations and transmission lines have 15 years for loan repayment and what remains thereafter is depreciation. Beyond 25 years, as per MoP's recent notification, there is no need of extending PPAs when the beneficiaries are not interested. Plants older than 25 years can have a bilateral agreement with the buyers of power instead of the regulatory system of fixing a normative tariff for them.
10. The concept of control period puts pressure on CERC to revisit the tariff and notify the Tariff Regulations periodically (every 5 years). The concept of control period may be done away with. A path of say 25 years may be considered.
11. A more extensive study of a larger sample size is needed if one wishes to go further with normative approach and benchmarking.
12. Going forward, the objective should be to enhance efficiency and capability across ERCs, rather than mere reduction of regulatory burden.
13. Going ahead with any normative approach, the point of view and interests of consumers should be at the core of it, rather than costs, benefits and error margins being computed solely for the generators. Hence, while assessing the costs and benefits of the normative approach for tariff determination, one needs to ponder over the benefits that the reduction in regulatory burden would translate for consumers (financially or in terms of quality of service) and whether the correction of generation and transmission tariffs would transcend to the consumers as benefits in any form. Furthermore, this information should be made publicly available for research purposes and public knowledge (transparency).
14. Variations are bound to occur on case-to-case basis while determining benchmark norms, due to changes in market rates, land costs, etc. Hence, economic and

econometric tools may not suffice the requirements of dealing with the issues at hand, and a multidisciplinary approach might be better suited.

15. A complete shift towards a normative approach for tariff fixation of generation and transmission utilities may not be possible. While certain components of capital cost (like BTG, AHP, etc.) can be normalised, variations due to local factors need to be factored in on actual basis. An econometric approach may help lead a path that balances the interests of both consumers and utilities.
16. The idea of not changing the norms for existing projects in the control period is a good proposition. However, the thermal fleet in India is facing a crisis, operating at extremely low PLFs . Even State-owned companies face an uncertain future due to RPO compliance, etc. In the prevailing situation, the investments already made in the sector need to be well protected.
17. All future projects may be allowed on competitive basis. Cost plus approach can be reserved for variations based on case-to-case requirements, especially for transmission projects. The hybrid methodology may be continued with for the existing projects, given the extensive prudence that has already gone into the process.
18. A cut-off date beyond which additional capitalisation (Add Cap) would not be considered is essential for project developers to have accountability and complete capitalisation within time.
19. All generation projects (barring hydro but including renewables) must follow the competitive bidding route. Competitive tariff would take care of inbuilt inefficiencies and other issues. The normative approach may be followed for the existing fleet of projects as a proxy for competition.
20. Benchmarking may be difficult for capital cost, as evident from the fact that CERC had attempted it earlier through orders. If it is to be followed , benchmarking should be done for the projects, the investment approvals for which have not been done and are not under construction. Other methods on normative lines can be thought of for reducing the process of capital cost determination.
21. With decreased interest rates , it would be beneficial if the benefits of reduced rates are passed on to the DISCOMs. Similarly, reduction in the premium given in the bank rate over and above SBI MCLR may also be reduced. Reduction of the average cost of supply (ACoS) would help DISCOMs, given the stress they are in , due to the prevailing pandemic situation, with substantially reduced collections from industrial and commercial sectors.

22. Litigation in respect of Change in Law burdens the ERCs considerably. When tariff is discovered through competitive bidding, it is likely to stay. Hence, although certain claims in Change in Law may be genuine, this creates an undue window for tariff revision in TBCB projects .

***b)*** ***<u>Generation:</u>***

1. Normative approach could be a better method for new and upcoming projects. Financial norms, etc. are already in place for the existing projects.
2. The idea of national companies having a common tariff, at least in capacity charges, may be thought of. This would help in benefit sharing among all States .
3. When the benefits of efficiency are taken away, there is little incentive for utilities to improve their efficiency.
4. An appropriate indexation can be arrived at with data analysis on operating plants, for determining normative escalation factors for O&M costs, with due consideration to the vintage of plants.
5. Benchmarking may not work efficiently in the case of hydro projects as each hydro project has different characteristics and thus need to be treated individually. In case of surprises and uncertainties, CERC may take assistance of independent chartered accountant firms.
6. Forum of Regulators may arrive at a consensus regarding Tariff Regulations in order to mitigate the variance of Tariff Regulations across ERCs and to bring uniformity for generation projects across the nation.
7. Revised environmental norms are a critical consideration for capital expenditure (Capex) of projects. Going forward, with the revised environmental norms, most thermal projects would be required to undertake Capex for pollution control equipment. Adoption of benchmarking approaches which accelerate regulatory dispensation and enhance regulatory certainty, by ERCs, would aid these plants in ensuring timely compliance with environmental norms. A detailed exercise may be undertaken for the purpose of arriving at appropriate normative benchmark costs for installation of pollution control equipment by generation plants.
8. The aspect of Merit Order Despatch (MOD) needs to be reviewed – there are variations in methods at national and State levels. It has been observed that, at times,

the declaration for MOD for a particular month deviates from the bills raised in subsequent months. This aspect should be addressed to avoid distortion in MOD.

9. The idea of fixing AFC as a percentage of capital cost is very much doable. However, it should be split into two components: (i) pure capital cost servicing charges like RoE, depreciation, interest on loan, etc. (which can be determined on a year-on-year basis, with the help of formula), and (ii) component including O&M costs, working capital, special allowances, etc. (can be in terms of Rs. Lakh per MW) as already followed for O&M costs, and a study might be required in this regard . Moreover, provisions for Add Cap can be made based on historical data, and change in law with respect to water charges, transportation, etc. should also be factored in.
10. After cut-off date, there should be no Add Cap. Only normative provisions should exist, within the useful life of the plant.
11. The low PLFs and considerable ramp up and ramp down of thermal generating stations with increasing RE integration into the grid has led to an increase in the operational costs of thermal plants – an issue that needs to borne in mind.
12. In the coming years, the inefficient thermal fleet might need to be phased out completely, given the environmental obligations. Hence, any commitment of durations like 25 years faces an extremely uncertain and precarious future.

***c) <u>Transmission</u>:***

1. Variability factor is higher for transmission projects, compared to generation projects. The capital cost of the same wind zone may be different in different regions of the country; the capital cost varies even in the same hilly terrain (e.g. land cost in Sikkim is higher than in Meghalaya); time for project completion is different even in regions with same topography (e.g. it is twice in Bihar than in West Bengal due to issues like Right of Way, etc.). Hence, fixing capital cost even for similar set of terrains across the country may be difficult in the case of transmission projects. The issue may cascade onto AFC (as a percentage of capital cost), aggravated by the different interest rates on loans in different band zones.
2. With increasing number of market players in transmission business, competition may be enhanced and regulated tariff fixation on cost plus basis can be gradually done away with. In this matter, the Government should be aptly advised by CERC, and the use of discretionary provision for allocation of certain sections of transmission to certain companies should be a rarity.

3. The PoC charges ultimately burden the consumers. This is more severe in states with locational disadvantages – being located at distances from pithead plants. This should be reviewed.
4. Only a select few transmission projects are likely to require cost plus tariff determination. Nonetheless, benchmarking could be considered for certain components (such as type of technology used and cost of substations). These cases of exception should also be seriously dealt with, with a justification as to why TBCB cannot be applicable to them, and only then permitted under Section 62 of the Act.
5. Along with State-specific and region-specific factors which hinder the benchmarking of capital cost, there are issues with variation in terminal cost as well, with varying terminal equipment.

**Agenda Item: 2 : Distribution Business – Licensing Vs De-licensing ( context – proposal for amendment to Electricity Act 2003)**

The Committee took up the second agenda item with a short presentation on the issues for discussion **( Annexure II)** as under : **.**

i. In general, what should be the regulatory approach to the introduction of competition in distribution?
ii. In particular, what approach should be adopted by the regulator on allocation of PPAs, management of cross subsidy /USO fund, determination of ceiling tariff, concept of, and terms and conditions for a multi-State distribution company, etc.?

**Discussion:**

Following observations were made by the members:

***a) Competition in Distribution and multiple DISCOMs***

1. The EA 2003 provides for deepening open access, allowing and facilitating group captives, and facilitating and adopting rooftop solar. These are ways to enable retail

competition without disturbing the existing regulatory and distribution company structure. To facilitate open access regime, there should be a ceiling on open access charges i.e. in cross-subsidy surcharge and additional surcharge. There is a requirement to remove the regulatory uncertainty for open access consumers. This approach should be adopted to bring retail competition rather than experiment with an arrangement similar to Mumbai which has resulted in a lot of litigation and has not benefitted end consumers in any manner.

2. It is observed that the existing DISCOMs do not allow new entities like SEZ and townships to become licensees even under deemed licensee model. The franchise model does not provide any significant upgrades to the system. In the licensee model, there is a great opportunity for new greenfield townships and SEZ. New players need to understand the risk of the distribution business.
3. To introduce competition, regulators need to focus on improving the quality of service to consumers and efficient planning and investment in utility-scale. There should be an appropriate risk-sharing mechanism across different utilities. Presently, most of the risk is concentrated in the distribution business only. The way forward would be to go in a phased manner so that the distribution asset management company could improve its fiscal health and it should also be ensured that asset owner does not participate in the retail business.
4. Lessons need to be learned from Mumbai and Delhi distribution model. Competition will lead to relief to consumers.
5. The proposed amendment needs to bring in clarity on many issues. There is a need to bring out a white paper for international experience and Mumbai experience. Based on the white paper, a proper regulatory framework may be evaluated. Moreover, private DISCOMs should also be brought under the purview of new schemes of the government.
6. It would not be wise delicense the distribution business.
7. There should be a strong service level agreement between the incumbent wires company and the supply companies.

## b) ***Selection or eligibility criteria***

1. Selection or eligibility criteria for distribution company should be stringent and participants should have either direct experience in distribution business or a member

of the consortium. The selection of persons who do not have experience may impact the sector negatively.

2. Qualifying standards need to be designed properly so that the ultimate aim to break the monopoly and serve the customer better could be achieved.
3. Filtering of technical and financial criteria for selection of distribution company should be stringent to ensure credible and experienced participants.

***c) <u>PPA allocation and management of power purchase</u>***

1. Pro-rata allocation of PPA based on the connected load is an established process. However, the issue arises when the PPA expires. Some suppliers want to extend the PPAs while others do not want to extend it. As such, this option should be provided in the PPA. Monthly RPO obligation should also be considered in the PPA allocation and new suppliers should be given the option to procure additional quantity of renewable energy.
2. The approach for determination of tariff for new distribution companies need to be specified clearly especially on questions whether it would be cost plus mechanism or competitive regime. If a cost plus regime is decided, then how would the tariff and power purchase be regulated. If it is competitive bidding based, what should be the treatment of tariff determination for the existing DISCOMs. Whether incumbent DISCOM would also be subject to celling tariff or their cost-plus approach would continue, needs deliberations.
3. In the case of reallocation of PPAs, the frequency of reallocation needs to be mentioned. If there is a significant consumer changeover, say from DISCOM A to DISCOM B, then what would happen to the PPA of DISCOM A? In case of reverse migration after 2 years , what would happen to PPAs assigned to or signed by DISCOM B?
4. A registry may be created in every district or every State or in every DISCOM which can do the allocation based on energy or power (MW) terms.
5. There are three issues which need to be addressed. The first issue pertains to existing losses, the second pertains to debt, and the third pertains to PPAs. Bringing competition on the retail side while regulating PPA and power purchase cost at the input side might not yield the desired results.

6. It also needs to be debated as to who will bear the fixed cost of the PPA which is allocated to a new distribution company and if it goes out of business after a few months.

### d) ***Determination of ceiling tariff and cross subsidy***

1. There should be a category-wise ceiling tariff so that there is competition in the wires business.
2. As regards cross-subsidization, it needs to be ensured that the government is not burdened and a win-win model needs to be evaluated.

### e) ***Other Issues***

#### ***i) Smart Meter***

1. CERC may clarify on issues pertaining to smart meter versus prepaid smart meters.
2. Prepaid meters for all consumers may not be required if the bills of the consumers are monitored. To deploy smart meters, a digital ecosystem is required so that its benefits could be reaped.

#### ***ii) Change in law***

1. In the event of change in law during pendency before the Commission, the project developer requires additional funds for construction. However, it is observed that lenders are reluctant to fund additional expenditure in the absence of any surety regarding claims in the matter pending before the Commission. Therefore, recognition of the Change of law event in the first stage may be done in a time bound manner say, within 30 days . Similarly, the final order may also be issued in a time frame so that lenders have comfort in lending additional expenditure and money continues to flow into the project.

**iii) Reserve Bank of India’s letter of mandate as a Payment security mechanism**

The Central Commission may intervene in the matter of non-acceptance of Reserve Bank of India’s Letter of Mandate as a payment security mechanism by some ISTS agencies.

***iv) Suo motu review of DSM Regulations***

Requirement of sign change after 6-time blocks (earlier it was 12-time blocks) under DSM regulations has created a serious repercussion at the ground level. The Central Commission may undertake a Suo Motu review for the same.

Chairperson, CERC at the conclusion of the meeting thanked the members of the CAC for their valuable suggestions. He stated that a lot of clarity is required regarding amendments in the Act and a lot of work is to be done. On the issues other than agenda items, he stated that the issues are noted for suitable action. He further added that the Commission always considers suggestions and takes appropriate decisions after examining all the criteria by balancing the interest of all the stakeholders.

The meeting ended with a vote of thanks to the Chair.

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**/ APPENDIX – I /**

**LIST OF PARTICIPANTS OF THE**

**22ND MEETING OF CENTRAL ADVISORY COMMITTEE (CAC) OF**

**CENTRAL ELECTRICITY REGULATORY COMMISSION (CERC)**

**HELD ON MONDAY, THE 26TH APRIL, 2021**

{ THROUGH VIDEO CONFERENCING (MS TEAM) }

| S. No. | Name & Designation | Organization |
|---|---|---|
| 1. | Shri P.K. Pujari<br>Ex-Officio, Chairperson, CAC | CERC |
| 2. | Shri Indu Shekhar Jha<br>Ex-Officio Member, CAC | CERC |
| 3. | Shri Arun Goyal<br>Ex-Officio Member, CAC | CERC |
| 4. | Shri Pravas Kumar Singh<br>Ex-Officio Member, CAC | CERC |
| 5. | Shri Manish Gupta<br>ED/EEM, Railway Board | Railway Board |
| 6. | Shri R.V. Shahi<br>Senior Energy Advisor | World Bank |
| 7. | (i) Shri Gurdeep Singh<br>Chairman & Managing Director<br>**(ii)** Shri C.K. Mondol<br>Director (Coml.) | NTPC |
| 8. | Shri Jatindra Nath Swain<br>Chairman & Managing Director | SECI |

| S. No. | Name & Designation | Organization |
|---|---|---|
| 9. | Shri A.K. Gautam<br><br>Chairman | NVVNL |
| 10. | Shri Abhay Choudhary<br><br>Director (Project) | PGCIL |
| 11. | Shri Himanshu Shekhar<br><br>Executive Director (Coml. & Power Trading) | NHPC |
| 12. | (i) Shri Nikunja Bihari Dhal<br>Chairman<br><br>(ii) Shri Trilochan Panda<br>Managing Director | GRIDCO Ltd |
| 13. | Shri Pankaj Kumar Bansal<br>Chairman & Managing Director | TNGDCO |
| 14. | Shri A. Venu Prasad<br>Chairman-cum-Managing Director | PSPCL |
| 15. | Dr. Praveer Sinha<br><br>CEO & Managing Director | Tata Power Company Ltd.<br><br>[ ***Also represented CII*** ] |
| 16. | Shri Anil Sardana<br>Managing Director & CEO | Adani Transmission Ltd. |
| 17. | Prof. (Dr.) K. Kasthurirangaian<br>Chairman | IWPA |
| 18. | Shri Pranav R. Mehta<br>Chairman | NSEFI |
| 19. | Shri Satya Narayan Goel<br>Chairman | IEX |
| 20. | Shri Vijay Chhibber<br>Director General | EPTA |
| 21. | Shri Manish Agarwal<br><br>CEO – Infrastructure & Solutions Business | Sterlite Power Transmission Ltd. |
| 22. | Dr. (Ms.) Vibha Dhawan<br>Director General | TERI |
| 23. | Shri Shantanu Dixit<br><br>Coordinator | Prayas (Energy Group) |
| 24. | Dr. Anoop Singh<br>Centre for Energy Regulation (CER) Department of Industrial & Management Engineering (DIME) | Indian Institute of Technology Kanpur |

| S. No. | Name & Designation | Organization |
|---|---|---|
| 25. | Dr. Rahul Walawalkar<br>President & Managing Director | India Energy Storage Alliance (IESA) |
| 26. | Shri Sarthak Sukla | Representative of CUTS |
| 27. | Dr. Sushanta Kumar Chatterjee<br>Chief (RA) | CERC |
| 28. | Shri Vijay Menghani<br>Chief (Engg.) | CERC |
| 29. | Ms. Rashmi Nair<br>Deputy Chief (RA) | CERC |
| 30. | Mr Sanjeev Tinjan<br>Asst Chief (RA) | CERC |
| 31. | Mr Manavendra Pratap<br>Research Officer | CERC |
| 32. | Ms Rashmi Saurav<br>Research Associate | CERC |

Annexure I

# 22nd CAC meeting of CERC

**Alternative approach to tariff determination**

(Normative vs. Detailed cost scrutiny)

# In this presentation…..

- Role of CERC
- Normative tariff by benchmarking Capital Cost
- Normative tariff by fixing AFC as a percentage of Capital Cost
- Normative Tariff by fixing each component of AFC as a percentage of total AFC

# Introduction

- Section 61 of Electricity Act, 2003: CERC to specify the terms and conditions (T&C) for determination of tariff; CERC to be guided by National Electricity Policy and Tariff Policy

- Principles of tariff determination specified by CERC to also act as guiding principles for SERCs

- Critical challenge in framing T&C Regulations: balancing the interests of suppliers and consumers

# Normative tariff by benchmarking Capital Cost (CC) [1/2]

- Sample of 30 generating stations with varying vintage, unit size, fuel type etc. analysed
- NPV(CC)/MW during year of commissioning calculated using normalisation factor of 6.85% – ( average of WPI inflation from FY 1988-89 to FY 2013-14)
- Observations:
  - Distribution of CC/MW denser near Rs. 6.30 crore/MW
  - High standard deviation in the above distribution: ~Rs. 2.44 crore/MW
  - CC/MW variation between Rs. 3.87-8.74 crore/MW
- The above variation attributed to geographical factors, technological factors, etc.; delays in construction, taxes and duties, etc. influence the project cost

# Normative tariff by benchmarking Capital Cost (CC) [2/2]

- High variation in project cost → need for exhaustive component wise analysis for both generation and transmission projects → arrive at appropriate benchmark CC

- **Questions:**
  - Would it be advisable to undertake econometric analysis to arrive at benchmark capital cost?
  - What are the variables that should be considered for determining capital cost on normative basis?
  - Any other methodology for benchmarking the capital cost for generation and transmission projects?

# Normative tariff by fixing AFC as a percentage of Capital Cost [1/2]

- Sample of 30 generating stations examined to analyze the AFC of first year of operation as a percentage of the approved CC
- *Observations:*
  - Correlation coefficient between approved AFC (first year of operation) and approved CC: ~0.84
  - Correlation coefficient between average approved AFC/year (till FY 201617) and CC: 0.95
  - Mean of AFC as a percentage of CC: 22.55%
  - Standard deviation in the distribution: 7.17%
- Significant correlation between AFC and CC → may benchmark AFC as a percentage of CC → save time and resources otherwise deployed in rigorous prudence check

# Normative tariff by fixing AFC as a percentage of Capital Cost [2/2]

- Available data and analysis → a larger database for a bigger sample size required for a more detailed and reliable analysis to reach a decisive conclusion whether AFC should be benchmarked as a percentage of CC

- **Questions:**
  – Is it a good idea to determine AFC as percentage of capital cost on a normative basis?
  – What could be the methodology to establish the relation between AFC and capital cost so that it meets the interests of both buyers and sellers?

# Normative Tariff by fixing each component of AFC as a percentage of total AFC [1/3]

- Sample size of 30 generating stations considered to examine trends of various components of AFC as percentage of total AFC

- Trajectories of each of the five components of AFC – Return on equity (RoE), Interest on Loan (IoL), Depreciation, Operation and Maintenance (O&M), Interest on Working Capital (IoWC) – of the generating stations in the sample drawn for the period from CoD till FY 2016-17

- *Observations*:
  - Increasing trend in O&M in general
  - Constant or decreasing trends in the remaining components
  - Overall trend line was influenced by 2 major factors: i. Additional Capitalization (Add. Cap.) or De Capitalization (De Cap.), and ii. Change in Control Period

# Normative Tariff by fixing each component of AFC as a percentage of total AFC [2/3]

- Following the observations, O&M assessed separately, and the remaining components clustered into one

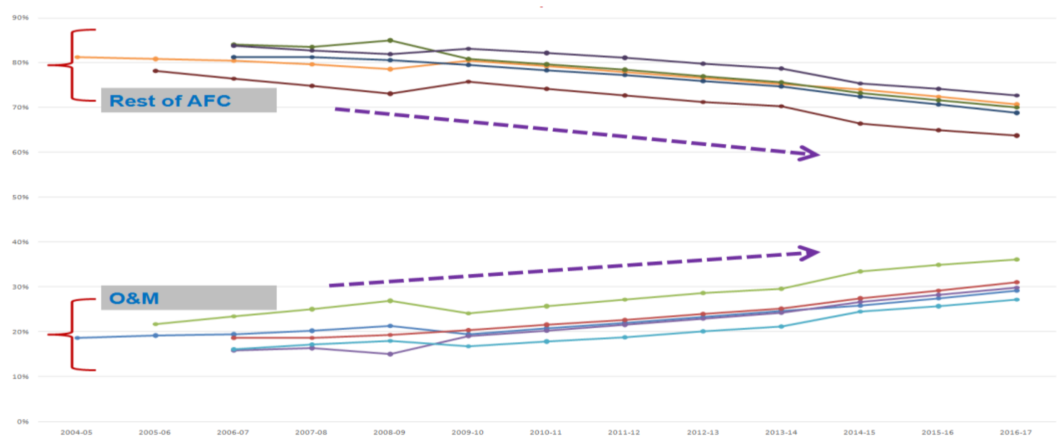


*Figure – 1: "Operation & Maintenance" and "Rest of the Components of AFC" for the generating stations with CoD from 2004 onwards.*

- The above approach of two groups to be followed for tariff determination on normative basis – i. Group of AFC components which escalate/increase over the period, and ii. Group of AFC components which de-escalate/decrease over the period

- Each group assigned with an escalation/de-escalation factor accordingly, yearly

# Normative Tariff by fixing each component of AFC as a percentage of total AFC [3/3]

- **Additional Capitalisation**
- Add Cap → change in CC
- Current regulatory provisions: Add. Cap. allowed primarily to meet the expenditure towards the leftover works from the original scope of work; permissible from CoD to Cut-off Date
- ~3 years available to generators for Add. Cap.
- Strict restriction of Add. Cap. Between CoD and Cut-off Date → regulatory certainty; no change in CC after Cut-off Date
- Any reasonable expenditure incurred in future – may be treated as a separate stream of revenue and recovery could be allowed as a separate component on annuity basis

- **Control Period(CP)**
- Current practice: for each CP, revised tariff principles applicable to new as well as existing generating stations; revision in principles → sudden surge/dip in the trend of the respective components
- Alternative: revised tariff principles of each CP restricted to new plants commissioned during that CP only, existing plants continue to be governed by the same sets of tariff principles as applicable on their CoD → regulatory certainty

# Discussion….

**Questions:**

- Whether clustering the components of AFC can be based on their nature of increasing/decreasing order? Any other possible method to cluster the AFC components?
- What methodology should be adopted to determine the escalable and the non-escalable factors?
- Whether escalable and non-escalable factors should remain same for all plants/transmission systems, or should they be separate for each plant or transmission system (based on vintage, capacity, fuel type, fuel linkages, etc.?
- Would isolation of *Additional Capitalization* as a separate stream of revenue would provide for recovery of AFC on a normative basis in realistic terms?
- Suggestions on any other methodology to treat *Additional Capitalization* for determination of AFC on normative basis?
- Would the applicability of changed tariff principles in each control period for new plants allow regulatory certainty to the existing plants?
- Any other methodology to minimize the impact on AFC on account of change in control period?

Thank you

Annexure II

# 22nd CAC meeting of CERC

## Distribution Business – Licensing Vs De-licensing

( context – Proposal for amendment to Electricity Act 2003)

# In the presentation…

- Context
- Provisions in the Act
- Salient features of proposed amendments
- Discussion

**Context**:

- Government of India in the Union Budget 2021-22 has announced the need of a framework which provides alternatives to the electricity consumers to choose from among more than one distribution company and address the issues arising out of the monopoly nature of power distribution.
- Ministry of Power has proposed amendments to the Electricity Act 2003 and proposed distribution of electricity to be a delicensed activity.

**Existing Legislative Provisions under the Electricity Act, 2003**

- **Section 12** – Authorised persons to distribute electricity, only after obtaining a distribution licence under Section 14 of the Act
- **Section 14 -** Empowers the Appropriate Commission to grant licence to any person to distribute electricity as a distribution licensee.

# Salient features of the proposed amendments (1/3)

- To provide choice to the consumer in selecting a supplier of electricity, multiple distribution companies have to operate in the same area of supply.
- Other DISCOMs can come in and compete with existing DISCOM without any change in the area of supply
- Companies meeting the prescribed eligibility criteria will register themselves with the Appropriate Commission before beginning supply of electricity
- SERCs will grant registration to any person who meets the eligibility criteria prescribed by the Government, to operate as a DISCOM for supplying electricity
- Two or more distribution companies may register to distribute electricity in the same area
- SERCs would specify terms and conditions for supply which would apply to all DISCOMs and such conditions would be deemed to be the conditions of registration

# Salient features of the proposed amendments (2/3)

- As per the rules prescribed by the Central Government, SERCs would specify the arrangements to share the power from the existing PPAs with existing DISCOMs - among all the DISCOMs in the area of supply
- SERCs would review the sharing of power from the existing power purchase agreements periodically
- A DISCOM may enter into additional PPAs, after meeting the commitments of the existing PPAs, to meet any additional requirement of power without sharing with other DISCOMs.
- SERCs would notify regulations to set up and manage USO fund. The USO fund would be managed by a Government company or entity, designated by the State Government.
- Any surplus with a DISCOM on account of cross subsidy or cross subsidy surcharge or additional surcharge would be deposited into this fund, and this fund would be utilised to finance any deficit in cross subsidy in the same or any other area of supply.

# Salient features of the proposed amendments (3/3)

- Appropriate Commission would fix the ceiling tariff while determining tariff u/s 62
- Central Commission will deal with the registration of a distribution company for supplying electricity in more than one State.
- Appropriate Commission would establish a monitoring unit with the approval of the Appropriate Government, specifically for the purpose of ascertaining the compliance of distribution companies with the provisions of the Act and the rules and regulations made thereunder, and laying down the standards of service and the rights of consumers/ prosumers as prescribed by the Central Government
- Minimum area of supply for which a distribution company may register with the Appropriate Commission to supply electricity would be equal to the area within a Municipal Council or a Municipal Corporation as defined in Article 243Q of the Constitution of India or a revenue district or a smaller area as notified by the Appropriate Government.

# Discussion

- In general, what should be the regulatory approach to introduction of competition in distribution ?

- In particular, what approach should be adopted by the regulator on allocation of PPAs, management of cross subsidy /USO fund, determination of ceiling tariff, concept of, and terms and conditions for a multi-State distribution company, etc.?

Thank you