Shri Harpreet Singh Pruthi
Secretary
Central Electricity Regulatory Commission
3rd & 4th Floor, Chanderlok Building
36, Janpath, New Delhi- 110001

February 19th, 2024

Subject: Comments on draft CERC (Terms and Conditions of Tariff) Regulations, 2024

Dear Shri Pruthi,

This is with reference to the Public Notice dated 26th May, 2023 for the Comments on the document, **Approach paper for Terms and Conditions of Tariff Regulations for the Tariff Period from 2024-29.**

I have gone through it and recorded some of my comments on the same. Additional suggestions are also provided for consideration of the Commission. We would be pleased to make a presentation before the commission as well.

I would be pleased to address any clarification, if required.

Thanking you,
Yours sincerely,

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Comments on

CERC (Terms and Conditions of Tariff) Regulations, 2024 [Draft]

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1. **Regulatory Impact Assessment (RIA) – Key to a Balanced Approach to Tariff Determination from the perspectives of Investors as well as the Consumers:** The approach paper outlines various options for a variety of aspects related to tariff determination for generation and transmission under Section 62 of the Electricity Act 2003. Response to the specific aspects are provided herein. Various options suggested in the context of various components of tariff can be evaluated **in terms of their impact on various components of tariff as well as overall tariff to be paid by the consumers and returns to be obtained by the investors.** This would help bring a more balanced perspective from the point of view of the consumers as well as the investors. **The CERC should thus spearhead an approach to Regulatory Impact Assessment (RIA) while approving regulations for the sector. Forum of Regulators may constitute a Working Group to take forward the discussions in a consultative manner.**

2. **Regulatory Framework to Emphasise Efficiency linked Normative Cost Recovery:**
The regulatory approach for tariff determination under the CERC framework can generally be classified as normative cost of service approach. In the spirit of the Electricity Act 2003, and Tariff Policy, the regulatory approach, while approving normative costs, should emphasise on efficiency improvement by the regulated entities both in terms of technical as well as financial costs**. While the adopted approach allows for cost recovery based on norms, the norms themselves are based on actuals of the immediate preceding control period with an escalation rate**. The norms, for example, for O & M cost in per MW term for the first year of the control period are based on actuals of the past few years, and are then escalated as per escalation factor. The regulatory framework should also provide for continuous improvement in efficiency through better norms by adding an efficiency factor. Operational efficiency norms must provide incentive for improvement for the generation companies as well as transmission licensees.
A study analysing reasons for Tariff Increase for selected states, submitted by Centre for Energy Regulation (CER), IIT Kanpur to FoR (as referred in the approach paper), pointed out various factors summing up to the tariff increase particularly that in the context of transmission tariff. This can partly be attributed to general adherence to historical performance with limited targets for efficiency

embedded in the norms for tariff. **The tariff approach to the control period 2024-29 should consider efficiency linked norms as discussed herein.**

3. **Introduction of efficiency factor for O&M expenses[1]:** The prevailing approach for determination of norms for O&M expenses is essentially a 'lagged' approach to set the O&M cost benchmarks allowing for recovery of 'the actual' O&M expenditure after inflationary adjustment for the control period. In the spirit of encouraging efficient operation, it is suggested that an efficiency factor may be incorporated for arriving at the normative O&M cost for the subsequent year. Efficiency factor may be introduced to encourage continual improvement across the cost components. For the above purpose, a framework similar to RPI-X regulation is suggested to be implemented for treatment of O&M expenses as illustrated in the following Figure 1 to encourage efficient performance.

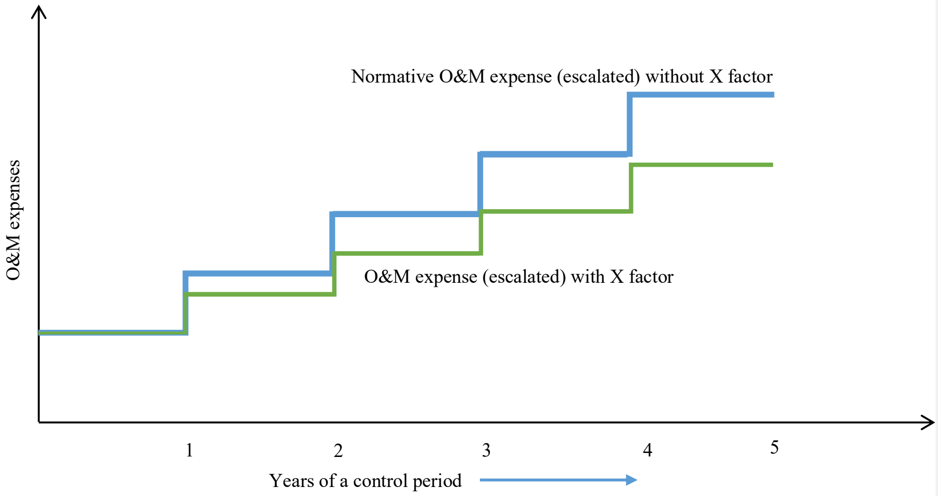

Figure 1: Representation of O&M expenses with efficiency factor "X"

Thus, the O&M expenses for a project can be expressed as per the following equation -

$$\boldsymbol{O\&M_t = O\&M_{t-1} * \left(1 + \frac{Price\ Index_t}{Price\ Index_{t-1}} - X_t^{O\&M}\right)} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ (4)$$

Where,

O&M: Normative Operation & Maintenance expenditure as approved by the Commission;

Price Index: Consumer Price Index for Industrial Workers;

$X_t^{O\&M}$: Factor representing an annual target for efficiency improvement in O&M.

The choice of the price index may be based on a single index or a weighted composite index calculated on the basis of proportion of different cost sub-components of the O&M cost i.e. wages & salary (W&S), repair & maintenance (R&M) and administrative & general (A&G) expenses. The

[1] CER's opinion on "Developing MYT Framework: Insights and Discussion on the Draft Regulations of Gujarat and Chhattisgarh" at 1st Regulatory Manthan. https://cer.iitk.ac.in/RM/rm1

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W&S component may be linked to the CPI (industrial worker), R&M to the WPI of electrical equipment or weighted sum of electrical equipment and machinery & equipment with the A&G expenses to be linked to the CPI applicable to white collar workers ($CPI_{urban\ \&\ clerical\ workers}$). Such a sub-component based application of price index could be feasible if costs under the respective heads can be apportioned reliably. This approach was earlier suggested by CER, IIT Kanpur and has been adopted by GERC in the draft GERC (Multi-Year Tariff) Regulations, 2023.

4. **Determining the Efficiency "X" factor:**
   Efficiency factor should be an integral part of the O&M cost approval process as the organisation is expected to optimise its cost of operation over time, while still providing for reasonable hedge from general price rise. Appropriate benchmarking studies such as Data Envelopment Analysis[2], etc. may be conducted to set benchmark for efficiency improvement across individual 'controllable' cost parameters across the MYT control period.

5. **Absence of efficient benchmarks – Double sample selection bias:** The O&M cost benchmarks have been arrived, as per explanatory memorandum of the proposed draft, on the basis of actual O&M cost reported by a sample of plants owned by the central generating companies for which the data has been considered for arriving at the norms for the generating stations. This exercise suffers from double sample selection bias. The first case of sample selection bias emerges due to the fact that the actual O&M cost has been reported only for the plants owned by government owned entities. It is generally reported that the private sector plants tends to be operationally more efficient than those under government ownership. The current sample of data does not include private entities whose actual performance may be better than those in the public sector.

   Furthermore, the exercise may also suffer from another instance of sample selection bias as it also does consider data across all the plants under the central generating companies. An ideal exercise would be to develop a benchmarking methodology to identify efficient frontier based on data across thermal plants across state, central as well as private sector.

Table 1: Sector-wise number of generating units present vis-a-vis data for number of units used for calculation of O&M expenses

Capacity Group	No. of Units				
	Central Sector	State Sector	Private Sector	Total (All India)	Data for analysis in EM
110 MW series	**8**	**13**	**64**	**85**	**-**
200/210/250/300/350 MW series	**65**	**149**	**67**	**281**	**35**
500 MW series	**63**	**24**	**6**	**93**	**31**
600 MW series	**22**	**26**	**67**	**115**	**6**
800 MW series	**9**	**7**	**5**	**21**	**-**

[2] Anoop Singh, B Sharma, "DEA based approach to set energy efficiency target under PAT Framework: A case of Indian cement industry", The Central European Review of Economics and Management 2 (1), 103-132

It is to be noted that the approach for determining norms for generating companies and transmission licensees issued by the Central Commission also guides the State and Joint Commissions (u/s 61) and thus influence tariff determination for about 75-80 % of the thermal capacity in the country. These should thus provide a leading beacon through a set of regulations that would take forward the spirit of the Electricity Act 2003 in terms of improvement in efficiency and cost reduction.

6. **Definition of Change in Law:** Clause 2(13)(e), "coming into force or change in any bilateral or multilateral agreement or treaty between the Government of India and any other Sovereign Government having implications for the generating station or the transmission system regulated under these regulations." may be rephrased as "coming into force **<u>of any existing agreement or</u>** change in any bilateral or multilateral agreement or treaty between the Government of India and any other Sovereign Government having implications for the generating station or the transmission system regulated under these regulations"

7. **Date of operation of emission control system or ODe:** It is suggested that a proviso to the definition of "ODe" in Clause 2(19) and the date of operation of emission control system may be defined as "Date of Operation' or 'ODe' in respect of an emission control system means the date of putting the emission control system into use after meeting all applicable technical and environmental standards, certified through the Management Certificate duly signed by an authorised person, not below the level of Director of the generating company, **provided that ODe is later than or equal to COD of the thermal generating station or unit thereof.**

8. **Force Majeure:** Clause 2(32)(a) of the proposed draft states that *"Act of God including lightning, drought, fire and explosion, earthquake, volcanic eruption, landslide, flood, cyclone, typhoon, tornado, geological surprises,* ***or exceptionally adverse weather conditions which are in excess of the statistical measures for the last hundred years****;"* (emphasis added). It is suggested that the "statistical measures for the last hundred years" may be further clarified and who should define such "statistical measures" (it should be Indian Meteorological Department).

   In case of events for which the data for last hundred year is not available, the methodology for defining such statistical measures may also be clarified.

9. **System wide cyber-attack as force majeure event:** It is suggested that the system wide cyber-attack as a force majeure event may be included in Clause 2(32)(b).

10. **Date of commercial operation for integrated mines:** It is suggested that the definition of the date of commercial operation in case of integrated mines in Clause 5(2)(b) may be rephrased as "the first of the year succeeding the year in which the value of production estimated in accordance with Regulation 7 of these regulations, exceeds total expenditure in that year **<u>as approved by the Commission</u>**" (emphasis added).

Further clarifications may be provided w.r.t the following:

a) Can the integrated mine be considered operational if it has **achieved COD** but the corresponding **generating station or unit thereof has not achieved its COD and/or is not operational**?
b) Can the integrated mine be considered operational if it is **supplying coal via purchase from a third party or swapping coal supply (linkage coal, SHAKTI policy)**?
c) In case the integrated mine achieves its COD prior to COD of the corresponding generating station or unit thereof, can the **coal be sold to another generator/ third party**?

11. **Determination of tariff for generating station with integrated mine(s):** Proviso to Clause 8(5) of the proposed draft in case of the determination of energy charge component of generating station with integrated mine(s) states that, *"Provided that the generating company shall maintain the account of the integrated mine separately and submit* ***the cost of the integrated mine****, in accordance with these regulations, duly certified by the Auditor"* (emphasis added). It is suggested that the data w.r.t. the integrated mine should be collected as much as possible for the purpose of analysis and benchmarking of costs. Hence, the proviso may be rephrased as "Provided that the generating company shall maintain the account of the integrated mine separately and submit **the detailed component-wise cost of the integrated mine**, in accordance with these regulations, duly certified by the Auditor".

12. **Joint checking of GCV of coal rejects:** 3rd proviso to Clause 8(6) of the proposed draft states that *"Provided also that the Gross Calorific Value of coal rejects shall be measured jointly by the generating company and the beneficiaries"*. It is suggested that the procedure of "joint checking" may be clarified and further elaborated. Cost towards third party assessment of GCV through joint sampling of coal should be passed through to the beneficiary. The generator as well as the beneficiaries should provide a certificate to the Commission that the sample was drawn jointly along with necessary details about order, dispatch, wagon, mine etc. identification thereof.

13. **Application for determination of supplementary tariff for an emission control system to be done post COD of the respective generating station or unit thereof:** The 5th proviso to Clause 9(1) of the proposed draft, *"Provided also that the generating company shall file an application for determination of supplementary tariff for the emission control system installed in coal or lignite based thermal generating station in accordance with these regulations not later than 90 days from the date of start of operation of such emission control system"* may be rephrased as "Provided also that the generating company shall file an application for determination of supplementary tariff for the emission control system installed in coal or lignite based thermal generating station in accordance with these regulations not later than 90 days from the date of start of operation of such emission control system, **provided that the respective generating station or unit thereof has achieved its COD**" (emphasis added).

14. **Capital expenditure for the emission control system to be done through the process of competitive bidding:** Clause 9(3) of the proposed draft states that *"In case an emission control*

system is required to be installed in the existing generating station or unit thereof to meet the revised emission standards, an application shall be made for the determination of supplementary tariff (capacity charges or energy charge or both) based on ***the actual capital expenditure*** *duly certified by the Auditor"*. It is suggested that all the capital expenditure incurred on account of emission control system should be mandated to be done through the process of competitive bidding. Thus the Clause may be rephrased as "In case an emission control system is required to be installed in the existing generating station or unit thereof to meet the revised emission standards, an application shall be made for the determination of supplementary tariff (capacity charges or energy charge or both) based on the actual capital expenditure duly certified by the Auditor, **provided that such capital expenditure should be incurred through the process of competitive bidding.**"

15. **Application of determination of tariff for integrated coal mine(s) commissioned/ started production before COD of respective generating station or unit thereof:** It may be further clarified whether the tariff of the integrated mine(s), which have started actual commercial operation, may be determined prior to COD of respective generating station or unit thereof as mentioned in the proviso to Clause 9(4), which states *"Provided that a generating company with integrated mine(s) shall file a petition for determination of the input price of coal or lignite from the integrated mine(s)* ***not later than 90 days from the date of actual commercial operation of the integrated mine(s)*** *in accordance with these regulations"*.

16. **Under-recovery of cost due to difference in interim and final tariff:** Proviso to Clause 10(3) of the proposed draft provides for return of excess amount by the generating company or the transmission licensee and stating that *"Provided that in case the final tariff determined by the Commission is lower than the interim tariff by more than 10%, the generating company or transmission licensee shall return the excess amount recovered from the beneficiaries or long term customers, as the case may be with simple interest at 1.20 times of the rate worked out on the basis of 1 year SBI MCLR plus 100 basis points prevailing"*. However, it is suggested that the provisions in case of under-recovery of costs due to difference in interim tariff and the final tariff may also be included as –

    "Provided that in case the **final tariff** determined by the Commission is **higher than the interim tariff** by more than 10%, the difference shall be recovered from the beneficiaries or the long-term customers, as the case may be, with the simple interest rate worked out on **the basis of 1-year SBI MCLR plus 100 basis points** prevailing as on 1st April of the financial year in which the under-recovery was made."

17. **Determination of interim supplementary tariff:** It may be clarified whether the interim supplementary tariff will be determined for the emission control system as specified in Clause 10(3) applicable for a generating station or integrated mine or transmission licensee.

18. **Contradiction between provisions of Clause 10(3) and Clause 10(7) for over-recovery due to difference in interim and final tariff:** Proviso to Clause 10(3) of the proposed draft states *"Provided that in case the final tariff determined by the Commission is lower than the interim tariff by more than 10%, the generating company or transmission licensee shall return the excess amount recovered from the beneficiaries or long term customers, as the case may be with* ***simple interest at 1.20 times of the rate worked out on the basis of 1 year SBI MCLR plus 100 basis***

***points** prevailing as on 1st April of the financial year in which such excess recovery was made."* Clause 10(7) of the proposed draft states *"Subject to Sub-Clause (8) below, the difference between the tariff determined in accordance with **clauses (3) and (5)** above and clauses (4) and (5) above, **shall be recovered from or refunded to**, the beneficiaries or the long term customers, as the case may be, **with simple interest at the rate equal to the 1 year SBI MCLR plus 100 basis points** prevailing as on 1st April of the respective year of the tariff period, in six equal monthly instalments.* The noted discrepancy across the two clauses need to be addressed.

19. **Recovery of cost towards emission control system only if emission below norm:** First proviso to Clause 16 states, *"Provided further that the supplementary energy charges, if any, **on account of meeting the revised emission standards** in case of a thermal generating station shall be determined separately by the Commission as per Regulation 64 of these regulations"* (emphasis added). Thus, it is suggested that the supplementary capacity charges may be approved only on meeting the revised emission standards by the generating company and the Clause 15(2) of the proposed draft may be rephrased as "Supplementary capacity charges shall be derived on the basis of the Annual Fixed Cost for emission control system (AFCe) **and payable only on account of meeting the revised emission standards** (emphasis added). The Annual Fixed Cost for the emission control system shall consist of the components as listed in Sub-clauses (a) to (e) of Clause (1) of this Regulation."

    Continuous and complete data for all the measured parameters across the plant and the neighbourhood of the plant from the Contiuous Emission Monitoring System (CEMS) as reported to the respective Pollution Control Board be also submitted to the CERC for such verification. A summarized version of the same be reported as a part of the truing up of the costs by the Commission.

20. **"Arrangement" for provisions of tariff of generating stations beyond 25 years of operation from COD:** Clause 17 of the proposed draft states *"In respect of a thermal generating station that has completed 25 years of operation from the date of commercial operation, the generating company and the beneficiary may agree on **an arrangement**, including provisions for target availability and incentive, where in addition to the energy charge, capacity charges determined under these regulations shall also be recovered based on scheduled generation"* (emphasis added). The Electricity Act, 2003 provides for procurement of electricity u/s 62 or u/s 63 and hence, the tariff of such generators shall be determined under the provisions of these Regulations. The above proposed Clause suggests "an arrangement" between the generating company and the beneficiary thus leaving it out of the purview of the Commission. Absence of any guideline or framework may lead to legal complications associated with such 'arrangements'. Since such assets have been paid and serviced by the beneficiaries, they hold the first right of refusal and should thus get the benefit of the depreciated asset. Hence, it is suggested that, one of the following approach may be adopted –

    i. A separate tariff may be determined for such assets by the Commission.

    ii. Such capacity (beyond 25 years of operational life) may be pooled with the rest of the capacity of the beneficiary and a combined tariff may be determined for the same.

21. **Capital cost allowed for implementation of PAT scheme and benefit sharing – Double accounting in favour of generator:** Clause 19(2)(o) in case of new projects states that *"Capital cost incurred or projected to be incurred by a thermal generating station, on account of implementation of the norms under the Perform, Achieve and Trade (PAT) scheme of the Government of India shall be considered by the Commission subject to sharing of benefits accrued under the PAT scheme with the beneficiaries;"*, and Clause 19(3)(f) states that *"Capital cost incurred or projected to be incurred by a thermal generating station, on account of implementation of the norms under the Perform, Achieve and Trade (PAT) scheme of the Government of India shall be considered by the Commission subject to sharing of benefits accrued under the PAT scheme with the beneficiaries;"*. The capital cost for new as well as existing projects incurred on account of implementation of norms under Perform, Achieve and Trade (PAT) scheme as per Clause 19(2)(o) and Clause 19(3)(f) of the proposed draft respectively, has been allowed and the benefits of such investments are proposed to be shared between the beneficiaries and the generator. It is suggested that as all the capital cost incurred for implementation of PAT is funded and paid by the beneficiary, the beneficiary has the first right to accrue any benefit out of it. However, to incentivize the generator for implementation of efficient operational and environmental norms, 20% of such benefits from sale of ESCerts may be allowed to retain by the generator while 80% to be passed on to the beneficiaries in the proportion of their share in the capacities.
It is further suggested that the norms specified by CERC and PAT scheme should be compared and preference to be given to more stringent target for determination of tariff.

22. **Expenditure to enable flexible operation of generating station at lower loads:** It is suggested that in case of new projects, the expenditure for flexible operation of thermal plants for operation at lower loads should be defined in the original scope of the projects and **no additional capital expenditure to be allowed** for such projects. Hence, Clause 19(2) may be deleted and the new thermal projects may be mandated to maintain the technical design specifications according to **those defined by the Commission**.

    In case of existing thermal plants, a selective and staggered approach may be adopted wherein the plants having lower schedule (for most of the time) should be allowed for additional capital expenditure for achieving flexible operation at lower loads and not for the plants having schedule more than their respective technical minimum for most of the time[3].

    Furthermore, the recovery of such capital costs should be allowed only upon continuous demonstration of the same. NLDC may design a procedure for verification of the low load operation of such plants and certify the same on monthly basis.

23. **Provision for biomass co-firing in case of new projects:** The provisions for biomass co-firing should be included/ mandated for the new generating stations as well, as mentioned in case of existing generating stations (missing from Clause 19(2)).

[3] EAL comments on draft CEA (Flexible Operation of Thermal Power Plants) Regulations, 2022. *https://eal.iitk.ac.in/assets/docs/power_chronicle_vol_5_issue_2.pdf*

24. **Acquisition value of the projects acquired post NCLT and its effect on the AFC of the project:** As per the suggestions sought for the cost to be considered while determination of tariff u/s 62 of the Act for the projects acquired post NCLT proceedings, the approach of considering the lower of the historical cost and acquisition value of the project seems appropriate as proposed in draft Clause 19(5). However, it needs to be clarified whether the acquisition value consist only of the equity component of the project cost or complete cost of the project.

The following cases illustrate the possible scenarios that may occur post NCLT proceedings and the treatment of the cost:

Case 1: When the acquisition value post NCLT proceedings are <u>less than</u> the actual project capital cost – In such cases, both, debt and equity component of the cost of acquired project will be restructured (**reduced**). Hence, the **RoE and IoL component of the AFC will reduce** leading to reduction in the tariff of the beneficiary. Further, the **depreciation should only be applicable on the restructured capital cost.**

> Case 1 scenario: For e.g. the cost of the project is Rs. 1000 Cr. Considering the debt to equity ratio as 70:30, the loan and equity will be Rs. 700 Cr. and Rs. 300 Cr. resp. When the project goes to NCLT, the entity buying the project may not be willing to pay Rs. 300 Cr. equity. At the same time the banks may restructure the loan and forego some principal amount component of project. Thus, after the NCLT proceedings, the actual loan and equity of the project will be reduced to, say 300 Cr. and 150 Cr. respectively. Thus, the interest rate on the loan component will be applicable on Rs. 300 Cr. instead of Rs. 700 Cr. and the return on equity will be applicable on Rs. 150 Cr. instead of Rs. 300 Cr. Also, the depreciation allowed should be lower of the restructured loan repayment amount or the applicable depreciation under the tariff framework.

Case 2: When the acquisition value post NCLT proceedings is <u>greater than</u> the actual project capital cost – In such cases, the historical value of the project, at the time of acquisition (after appropriate deduction of costs recovered and debt restructuring), should be considered for recovery.

It is further suggested that any premium paid over and above the book value of the asset should not be included in the capital cost of the projects acquired through NCLT (in both of the cases explained above).

25. **Details of the prudence check to be made available through Commission's website:** The details of the prudence check of the capital costs and other parameters done by the Commission may be furnished to the beneficiary and the general public through the Commission's website.

26. **Servicing the impact of delay condoned by the Commission in case of IDC and IEDC:** Clause 21(5) of the proposed draft states that *"If the delay in achieving the COD is attributable either in entirety or in part to the generating company or the transmission licensee or its contractor or supplier or agency, in such cases, IDC and IEDC due to such delay may be disallowed after prudence check either in entirety or on pro-rata basis corresponding to the period of delay not condoned vis-à-vis total implementation period and the liquidated damages, if any, recovered from the contractor or supplier or agency shall be retained by the generating company or the transmission licensee, in the same proportion of delay not condoned vis-à-vis total implementation*

period." However, the liquidated damages recovered may not be able to service the impact of the condoned delay either due to generating company or the contractor. In the spirit of the Electricity Act, 2003, that the Appropriate Commission shall protect the consumer's interest, in such cases, the part of the impact of delay should be passed on to the generating company. Hence it is suggested that the **impact of the condoned delay may be shared** between the generating company and the beneficiary in the ratio of **two third and one third** respectively.

27. **Additional capital expenditure for development of local infrastructure for hydro generating plants:** It is suggested that in case of approval additional capital expenditure for hydro generating station, the Clause 24(1)(f) of the proposed draft may be rephrased as "In the case of the hydro generating station, expenditure incurred towards developing local infrastructure in the vicinity of the power plant not exceeding **a total of** Rs. 10 lakh/MW if funding is not provided for under "Budgetary Support for Flood Moderation and for Budgetary support for enabling infrastructure"
Provided that such funds shall be allowed only if the funds are spent through Indian Governmental Instrumentality;"

28. **Operational gains due to add-cap for railway infrastructure augmentation to offset the norms for O&M expenses:** Clause 26(1)(h) of the proposed draft states that *"Works pertaining to Railway Infrastructure and its augmentation for transportation of coal up to the receiving end of the generating station (excluding any transportation cost and any other appurtenant cost paid to railways) that are not covered under Regulation 24, 25 and 27, **but shall result in better fuel management and can lead to a reduction in operation costs, or shall have other tangible benefits**: Provided that the generating company shall have to mandatorily seek prior approval of the Commission before implementing such works based on a detailed cost-benefit analysis of such schemes"*. It is suggested that any reduction in the operational costs or any other tangible benefits **should be passed on to the consumers** pertaining to the add-cap on account of railway infrastructure augmentation for transportation of coal up to the receiving end of generating station and the subsequent **norms for operation and maintenance costs may be reduced.**

    Furthermore, if lower tangible benefits have been recorded/ demonstrated post investment in the railway infrastructure, the capital expenditure allowed **may be reduced** from the capital costs on the pro-rata basis.

29. **Special Allowance and approval of add-cap on account of R&M expenses for projects beyond useful life – Regulatory Certainty:** As per the Clause 28 of the proposed tariff framework, the projects beyond the useful life have **option** to either avail special allowance or opt for additional capitalisation on account of R&M expenses and life extension of the project which is applicable for the control period. Thus, the regulated entities have **an option** for choosing either of the above mentioned options for a control period after completion of the useful life of the project. However, after availing the special allowance for a control period, the regulated entities have an option for choosing special allowance or file a petition for additional capitalisation for R&M expenses/ life extension as per second proviso to the Regulation 28 of the proposed draft. Therefore, to assure regulatory certainty to the regulated entities as well as the beneficiaries, special allowance, if allowed

during one control period, should be mandated for next 2 control periods as well.

Continuity of the special allowance should be subject to demonstration of specified/ improved operational parameters on pro-rata basis and will be trued up every 3rd year. Failure of demonstration of the improved parameters will lead to disallowance of further special allowance to be approved for the regulated entities. No depreciation to be allowed for any asset created through special allowance. The Commission may specify a trajectory of the performance parameters to be followed by the regulated entities for the projects beyond their useful life and further approval of the special allowance or additional capitalisation for R&M of the project should be subject to the same.

If the regulated entities opt additional capitalisation for R&M expenses for the projects beyond their useful life, they should be mandated to submit a certification for extended life (of at least 15 years) by CEA with information to the beneficiaries and RLDCs. Such projects will not be eligible for separate R&M expenses. During the downtime of the system for R&M activities, only recovery of interest on loan and O&M expenses should be allowed.

30. Fixing RoE for generating stations: Clause 30(2) of the proposed draft, for the existing projects, states that, *"Return on equity for* ***existing project*** *shall be computed at the base rate of* ***15.50% for thermal generating station, transmission system including communication system and run-of-river hydro generating station*** *and at the base rate of* ***16.50% for storage type hydro generating stations, pumped storage hydro generating stations and run-of- river generating station with pondage****;"* (emphasis added). For new projects, Clause 30(3) states that *"Return on equity for new project achieving COD on or after 01.04.2024 shall be computed at the base rate of* ***15.00% for the transmission system, including the communication system****, at the base rate of* ***15.50% for Thermal Generating Station and run-of-river hydro generating station*** *and at the* ***base rate of 17.00% for storage type hydro generating stations****, pumped storage hydro generating stations and run-of-river generating station with pondage;"* (emphasis added).

Further the first proviso to Clause 30(3) of the proposed draft states the provision for ceiling of base rate of RoE at 14% for any add-cap due to emission control system, change in law or force majeure, *"Provided that return on equity in respect of additional capitalization beyond the original scope, including additional capitalization on account of the emission control system, Change in Law, and Force Majeure shall be computed at the base rate of one-year marginal cost of lending rate (MCLR) of the State Bank of India plus 350 basis points as on 1st April of the year, subject to a* ***ceiling of 14%;"***(emphasis added).

The CAPM approach used for calculation of cost of equity is a post-tax estimate. A study at CER, IIT Kanpur[4] using CAPM and multifactor models using a comprehensive data for over 125 infrastructure companies estimates the cost of equity to be around 10% - 12.5% as shown in Figure 1 below which is lower than the regulated return of the sector. The following Figure 2 shows the G-Sec 10-year bond yield over one year horizon which is around **7.5%**. Thus, it is suggested that the RoE for the generating stations and the transmission licensees and hence the ceiling rate (14%) in

[4] Kewal Singh, Anoop Singh, Puneet Prakash, 2022, "Estimating the cost of equity for the regulated energy and infrastructure sectors in India" Utilities Policy, http://dx.doi.org/10.1016/j.jup.2021.101327

case of add-cap due to emission control system, change in law or force majeure **may be reduced**. Further, the transmission segment has significantly lower risk as compared with the generation and distribution segment, and thus should attract lower RoE than generation. Reported RoE of major transmission companies in regulated business has hovered around 17.15% - 22.4% over the past three reported years. In comparison, reported RoE of regulated generation business hovers around 11.57% - 12.58% over the past three reported years (So: Standalone Annual Statements of the respective companies).

Commented [MS1]: Source……

The Commission may consider lower rate of return on equity for old plants across thermal as well as hydro sector, as well as for the transmission sector. However, given the extended construction period for hydro-electric plants, which does not provide 'return' on the invested equity during constrcution, the Commission may justify higher RoE for such plants including those with PSP. This would encourage new investment that would begin during the upcoming control period.

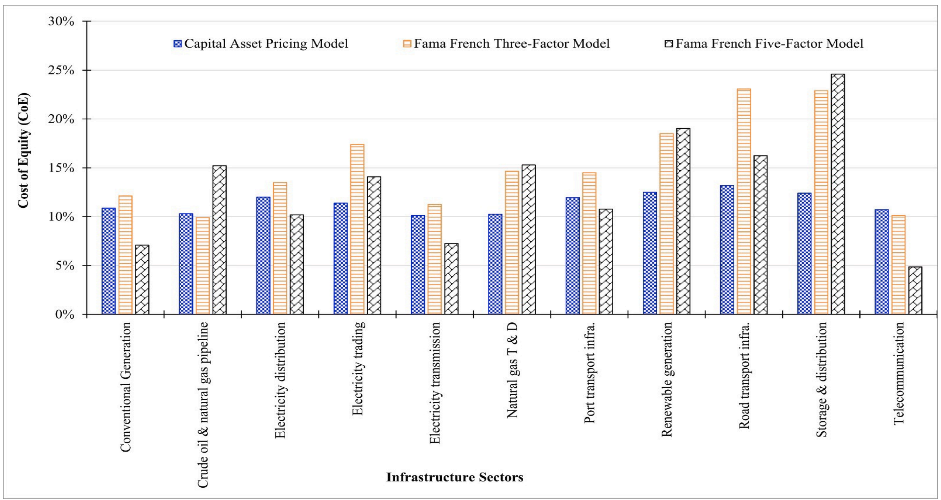

Figure 2: Cost of equity for different infrastructure sectors

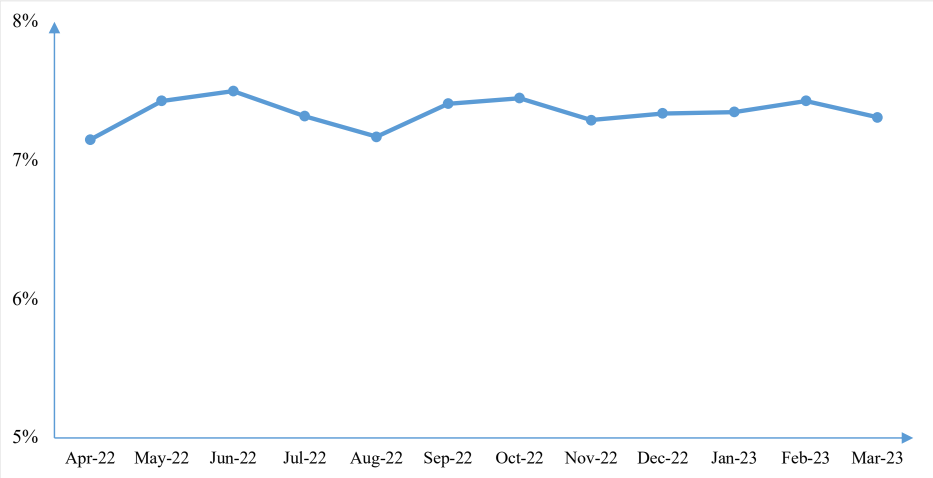

Figure 3: G-Sec 10-year Bond Yield over One year horizon

31. **Reduction of equity base post repayment of loan:** It is suggested that accumulated depreciation over and above the accumulated debt repayment (including repayment towards normative loan) should be used to reduce the equity base for allowable RoE as a portion of the risk capital of the investor is available as free cash flow and is no longer deployed in normal business operations. In its absence the consumer is charged RoE for a capital that has already been recouped through depreciation (beyond debt repayment). In case, such 'excess depreciation' is reinvested in the business, for example to finance working capital, this should attract the appropriate cost of funds as approved for such respective ARR element. The Figure 3 below illustrates the comparison between the prevailing modified GFA approach where only loan is reduced over time while, equity component, hence RoE remains constant throughout the life of the project vs the net fixed asset (NFA) approach where the depreciation beyond the repayment of loan reduces the equity base. The proposed regulatory approach for reduction of equity base should be integral part of the regulatory framework in the power sector, thus mitigating additional burden of tariff paid by the consumers.

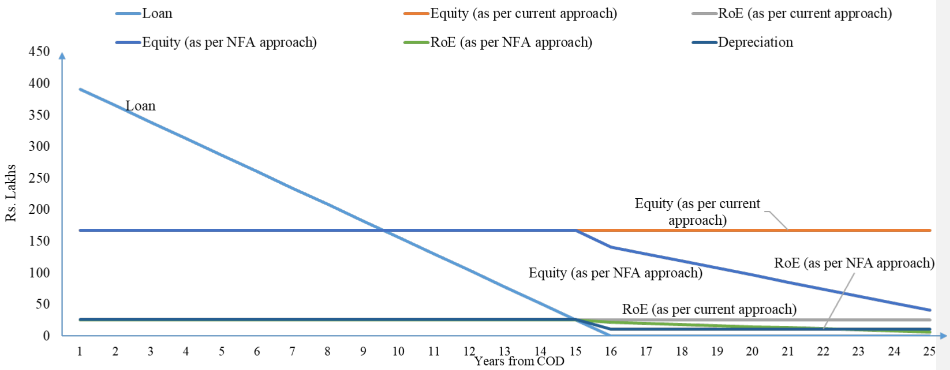

Figure 4: Modified GFA approach vs NFA approach

32. **Verification of ramp rate of a generating station and incentive thereof:** Clause 30(3)(iii) of the proposed draft states that, *"in case of thermal generating station:*

    a) rate of return on equity shall be reduced by 0.25% in case of failure to achieve the ramp rate as specified under Regulation 45(9) of IEGC Regulations, 2023.

    b) an additional rate of return on equity of 0.25% shall be allowed for every incremental ramp rate of 1% per minute achieved over and above the ramp rate specified under Regulation 45(9) of IEGC Regulations, 2023, subject to the ceiling of additional rate of return on equity of 1.00%:"

    It is further suggested that the provision for development of the detailed procedure for block-wise verification of the ramp rate of the generating stations (by NLDC/ RLDCs) and the corresponding incentives and disincentives (by RPCs in the Regional Energy Account) may be included in the draft Clause.

33. **Tax on return on equity:** It is suggested that the first proviso to the draft Clause 31(1), "*Provided that in case a generating company or transmission licensee **is paying** Minimum Alternate Tax (MAT) under Section 115JB of the Income Tax Act, 1961, the effective tax rate shall be the MAT rate, including surcharge and cess;"* may be rephrased as "Provided that in case a generating company or transmission licensee **chooses to pay** Minimum Alternate Tax (MAT) under Section 115JB of the Income Tax Act, 1961, the effective tax rate shall be the MAT rate, including surcharge and cess;"

34. **Tax on account of non-core business to be excluded while truing up of taxes:** Clause 31(3) of the proposed draft states that *"The generating company or the transmission licensee, as the case may be, shall true up the effective tax rate for every financial year based on actual tax paid together with any additional tax demand, including interest thereon, duly adjusted for any refund of tax including interest received from the income tax authorities pertaining to the tariff period 2024-29 on actual gross income of any financial year. Further, any penalty arising on account of delay in deposit or short deposit of tax amount shall not be considered while computing the actual tax paid*

for the generating company or the transmission licensee, as the case may be." It is suggested that a proviso may be included as "Provided that any tax demand including cess thereon on account of non-generation or non-transmission business of the generating company or the transmission licensee respectively shall be excluded while truing up of taxes"

35. **Provision of carrying costs to be included while truing up of taxes:** 3rd proviso to proposed draft Clause 31(3) states that *"Provided that any under-recovery or over recovery of grossed up rate on return on equity after truing up, shall be recovered or refunded to beneficiaries or the long term customers, as the case may be, on a year to year basis"*. It is suggested that the provision of carrying cost may also be included in the draft Clause and it may be rephrased as *"Provided that any under-recovery or over recovery of grossed up rate on return on equity after truing up, shall be recovered or refunded to beneficiaries or the long term customers, as the case may be, on a year to year basis* ***along with the carrying cost at the rate of SBI MCLR as applicable on April 01 of the relevant financial year plus 100 basis points or as determined by the Commission****"*.

36. **Financing charges as part of interest on loan:** Clause 32(5) of the proposed draft states *"For the Existing Project(s), the rate of interest shall be the weighted average rate of interest calculated on the basis of the actual loan portfolio or allocated loan portfolio"*. It is suggested that clarification the financing charges, if any, to be included while calculation of WAROI on actual loan portfolio.

    Further, it is suggested that the interest on loan should be calculated on loan **excluding** any working capital loan or any other loan of short-term nature (tenure up to one year).

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    Further, it is suggested that the interest on loan should be calculated on loan **excluding** any working capital loan or any other loan of short-term nature (tenure up to one year).

38. **Calculation of interest on loan for new projects:** Second proviso to Clause 31(6) of the proposed draft states, *"Provided that the rate of interest on the loan for installation of the emission control system shall be the weighted average rate of interest of the actual loan portfolio of the emission control system, and in the absence of the actual loan portfolio, the weighted average rate of interest of the generating company as a whole shall be considered subject to a* ***ceiling of 14%****"* (emphasis added). It is suggested that the interest on loan should be calculated on loan **excluding** any working capital loan or any other loan of short-term nature (tenure up to one year).

    It is further suggested that the ceiling should not be more than 10 or 11 % and may even be kept at SBI MCLR or reference rate.

39. **Disallowance of depreciation on account of lower availability:** As per the fourth proviso to Clause 33(3), *"Provided also that any depreciation disallowed on account of lower availability of*

the generating station or unit or transmission system, as the case may be, shall not be allowed to be recovered at a later stage during the useful life or the extended life." It is suggested that reference to such disallowance may be included and provisions w.r.t the methodology for calculation of the depreciation to be disallowed, provision of cut-off availability for disallowance of depreciation, etc. may further be clarified. There is no source reference to the applicability of the draft clause which disallows depreciation on account of lower availability and the relationship between the lower availability and depreciation. It is further suggested that the debt repayment schedule should remain unaltered, even if the actual availability is lower than the normative one.

40. **Recovery of depreciation if the ODe is later than the completion of useful life of the project:** Special provision for plants completing the useful life as specified in Regulation 17 of proposed draft states that for such stations, the tariff may be determined based on the "arrangement" between the generating station or the transmission licensee, as the case may be. The Clause 32(12), which states that *"In case the date of operation of the emission control system is subsequent to the date of completion of the useful life of generating station commercial operation of the generating station or unit thereof, depreciation of ECS shall be computed annually from the date of operation of such emission control system based on the straight line method, with a salvage value of 10% and recovered over ten years or a period mutually agreed by the generating company and the beneficiaries, whichever is higher."*, contradicts with the Regulation 17 of the proposed draft. Further it may also be clarified that if the "arrangement" does not allows for recovery for depreciation, which provision will prevail?

41. **Working capital requirements:**

A. Working capital to be allowed on plant load factor instead of normative plant availability factor: The following Figure 5 shows the average PLF of the central sector thermal generating stations over last 6 years, which is very less as compared to the normative availability factor of 85%.

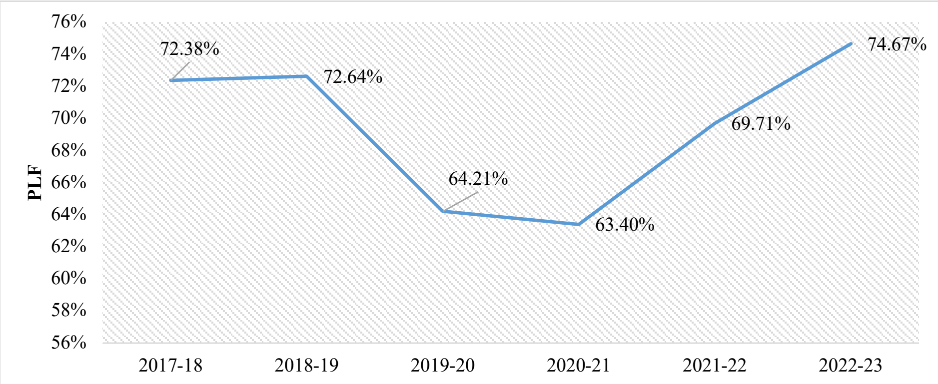

Figure 5: Average PLF of the central sector thermal stations

Figure 5 represents the average PLF of coal based thermal stations from FY-19 to FY-23 and their respective VC (FY-22). It can be observed that the average PLF of the higher variable cost power plant is further much lower than the normative plant availability factor of 85%.

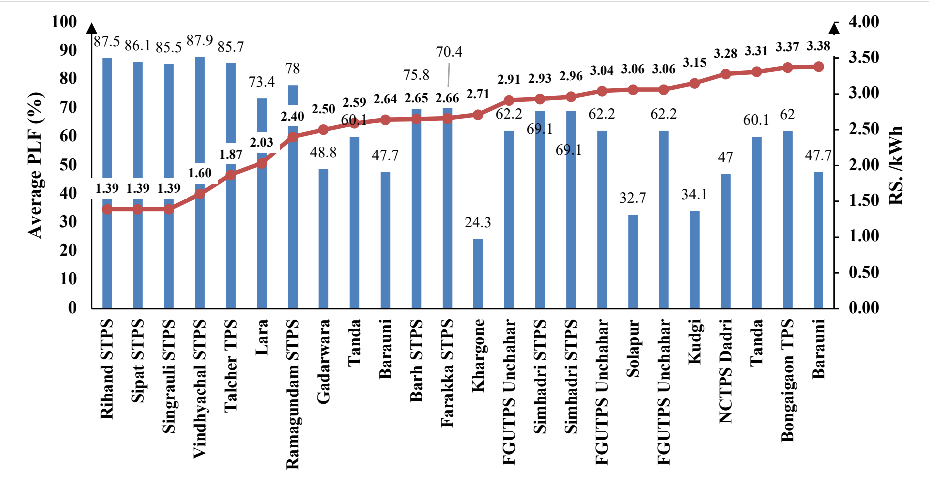

Figure 6: Average PLF of central coal-based generating stations and respective VC

Also, the calculation of working capital requirement does not take into account the actual availability of the stations. Thus, it is suggested that, for the following components of the working capital, the lower of the NAPAF, actual PAF and actual PLF of the last 6 months to be considered for calculation of working capital subject to true-up and the over-recovered amount, if any, to be adjusted along with the carrying cost.

a) In case of coal-/ lignite-fired thermal generating stations:

- Cost of coal or lignite, if applicable, for 10 days for pit-head generating stations and 20 days for non-pit-head generating stations
- Limestone towards stock for 15 days
- Advance payment for 30 days towards the cost of coal or lignite and limestone
- Cost of secondary fuel oil for two months for generation

b) For emission control system of coal or lignite based thermal generating station

- Cost of limestone or reagent towards stock for 20 days
- Advance payment for 30 days towards the cost of reagent
- Receivables equivalent to 45 days of supplementary capacity and supplementary energy charge Further, in case of emission control system, the interest on working capital may be allowed only if the actual emission parameters are within the revised emission standards and may be pro-rated as per actual achievement of the standards.

c) For open-cycle gas turbine/ combined cycle thermal generating stations:

- Fuel costs for 15 days taking into account the mode of operation of the generating station on gas fuel and liquid fuel

- Liquid fuel stock for 15 days and in case of use of more than one liquid fuel, cost of main liquid fuel taking into account mode of operation of the generating stations based on gas fuel and liquid fuel.
- Receivables equivalent to 45 days of capacity and energy charge duly taking account the mode of operation of the generating station on gas and liquid fuel.

B. Truing-up of actual fuel stock for working capital requirement: It can also be observed from the Figure 6 above that the higher VC plants (marginal plants) need not maintain the coal stock equivalent to the normative generation. Furthermore, following Figure 7 (So: EAL coal stock pics) shows that for most of the plants, the coal stock kept by the generating stations are not up to the normative level. Thus, as per the prevailing and the proposed approach, the generating stations recover the working capital for fuel costs (both primary as well as secondary) without actually keeping the normative coal stock. Hence, it is suggested that the computation of working capital with respect to the fuel costs should be based on the actual stocks trued-up and if the inventory falls below the normative inventory, it should be adjusted with the provision of carrying cost to be recovered by the beneficiary.

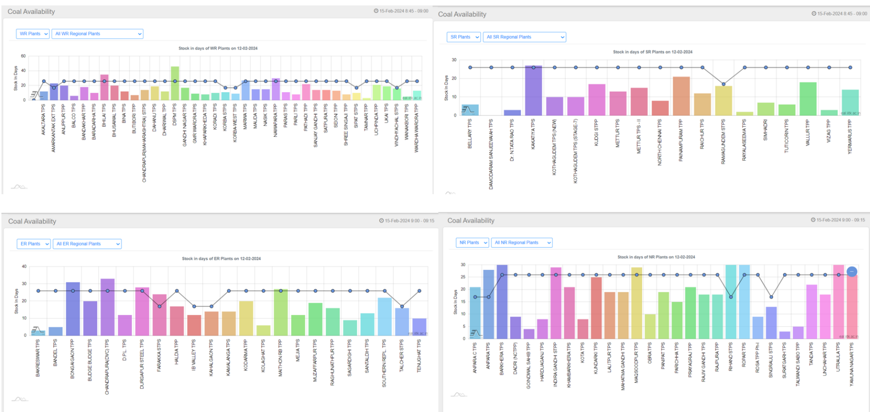

Figure 7: Normative vs actual coal stocks for thermal generating stations

C. Operation and maintenance expenses to exclude security charges: It is suggested that the O&M expenses may exclude security charges as, in most of the stations, the security personnel, being appointed from a third party, the spares may be included in the contract and need not be considered separately while calculation of O&M expenses.

42. Cost of fuel for calculation of working capital: Clause 34(2) of proposed draft states that *"The cost of fuel in cases covered under sub-clauses (a) and (c) of clause (1) of this Regulation shall be based on the landed fuel cost (taking into account normative transit and handling losses in terms of Regulation 59 of these regulations) by the generating station and gross calorific value of the fuel as* *per actual weighted average for the preceding financial year in case of each financial year for which tariff is to be determined:"* Working capital should be estimated based on ratio of domestic and imported coal. Since the 'mandate' for blending ratio (for both biomass and imported coal) has been reduced now, it is suggested that for calculation of working capital, the landed fuel cost should be adjusted for the actual blending ratio of the last two months on a rolling basis. Using previous years' actual GCV would significant (and artificially) increase the WC requirement (in monetary terms).

43. **Provision for true-up for coal cost of in-firm power:** As per proviso to Clause 34(2) of the proposed draft, *"Provided that in the case of a new generating station, the cost of fuel for the first financial year shall be considered based on landed fuel cost (taking into account normative transit and handling losses in terms of Regulation 59 of these regulations) and gross calorific value of the fuel as per actual weighted average for three months,* ***as used for infirm power****, preceding date of commercial operation for which tariff is to be determined"* (emphasis added). It is suggested that the calculation of coal cost should be specified in case of generating station with captive mine and the in-firm power is drawn from the same.

    Further, the coal cost will be higher if the initial coal may be bought at the higher rate (due to procurement of short-term nature). This will lead to higher working capital estimation for the year even though the long-term rate of the coal purchase may be of lesser cost. It is suggested that the Regulations should include the provisions to address the same.

44. **Capital cost recovery in event of early retirement of generating stations due to environmental concerns:** Recovery of capital cost in case of early retirement of the generating station due to environmental norms/ concerns and/ or commitment made by the country on its own or under any agreement between the nations – to be recovered through a per unit based charge called as………… Separate provisions/ Regulations and methodology to be developed for the same.

45. **Methodology for calculation of escalation rates:** The prevailing approach for the estimation of the escalation rate for each year of the control period 2019-24 is as shown in the Figure 8 below:

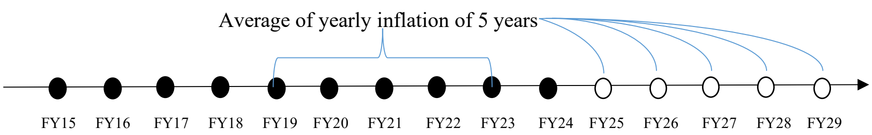

Figure 8: Calculation of escalation rate as per prevailing approach

It is suggested that instead of taking the average of the escalation rates for the last 5 years for CPI and WPI respectively as per the existing approach, the Compound Annual Growth Rate **(CAGR) of the indices** may be used as it is a mathematically correct representation of the same, as illustrated in the example in Table 1 below.

Table 2: Index Calculation – Normal Average vs CAGR

Index	Growth Rate	CAGR	Recalculated Values using	
			Average Gr.	CAGR
100		7.19%	100	100
105	5.00%		107.21	107.19
116	10.48%		114.94	114.89
125	7.76%		123.22	123.15
132	5.60%		**132.11**	**132.00**
Average/CAGR	7.21%	7.19%		

While the above error has resulted in higher normative O & M cost (due to this numerical anomaly), this should be corrected in the proposed regulation.

Furthermore, few issues with the above approach as per explanatory memorandum of the proposed draft are described below:

i. Estimation of values of future 5 years depends on the values of past 11 years with equal weightage assigned to value of each of the 5 years. In the extreme, the value in FY-18 has an impact in the projection of FY-29!
ii. Each year of the future control period has a static escalation rate, which generally do not occur in reality.

CER's Approach: To address the same, it is recommended to use the **3-year moving average escalation rate with the latest year having a weightage of 50%, mid-year having the weightage of 30% and oldest year having the weightage of 20%.** The same has been demonstrated in the Figure 9 below.

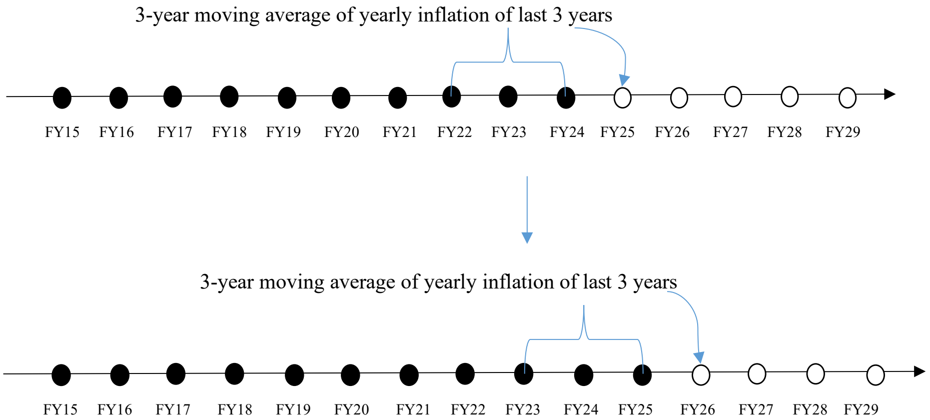

Figure 9: CER's approach for calculation of escalation rate - 3-year rolling average method

The same may also be represented as follows:

For calculation of the escalation rate for n+1 year, the weights given to escalation rates of CPI and WPI for n^{th} year, $(n-1)^{th}$ year, and $(n-2)^{th}$ year to be used in proportion of 50%, 30% and 20% respectively. These indices are to be calculated on rolling basis for each year. Further, the CPI and WPI can be used in the ratio of 60:40 for escalating the O&M expenses as per the following formula:

$$\boldsymbol{ESC_t = (0.6 * ((0.5 * ESC_{(CPI)t-1} + (0.3 * ESC_{(CPI)t-2}) + (0.2 * ESC_{(CPI)t-3}))) + (0.4 * ((0.5 * ESC_{(WPI)t-1}) + (0.3 * ESC_{(WPI)t-2}) + (0.2 * ESC_{(WPI)t-3})))}$$

Where,

ESC_t = Escalation rate for t^{th} year

$ESC_{(CPI)t-1}$ = Escalation rate of CPI for $(t-1)^{th}$ year

$ESC_{(WPI)t-1}$ = Escalation rate of WPI for $(t-1)^{th}$ year

Table 3 and Figure 10 shows the comparison of the prevailing tariff framework and the approach proposed by CER.

Table 3: O&M Expenses as per prevailing framework and proposed approach

	Average CPI (base = 2001)	CPI (% change)	WPI (2011-12 =100)	WPI (% change)	Escalation rates: CER's Approach	O&M Cost: CER's Approach (Rs. Lakh/MW)	Escalation Rates as per current reg.	O&M Cost (as per Reg.) (Rs. Lakh/MW)
2011-12	195	8.33%	100	8.94%				
2012-13	215	10.26%	106.9	6.90%				
2013-14	236	9.77%	112.5	5.24%				16.24
2014-15	251	6.36%	113.9	1.24%	7.74%	17.50	6.30%	16
2015-16	265	5.58%	109.7	-3.69%	5.41%	18.44	6.30%	17.01
2016-17	276	4.15%	111.6	1.73%	2.41%	18.89	6.30%	18.08
2017-18	284	2.90%	114.9	2.96%	2.01%	19.27	6.30%	19.22
2018-19	300	5.63%	119.8	4.26%	2.28%	19.71	6.30%	20.43
2019-20	323	7.67%	121.8	1.67%	3.83%	20.46	3.51%	22.51
2020-21	339.84	5.21%	123.4	1.31%	4.06%	21.29	3.51%	23.3
2021-22			139.4	12.97%	3.62%	22.06	3.51%	24.12

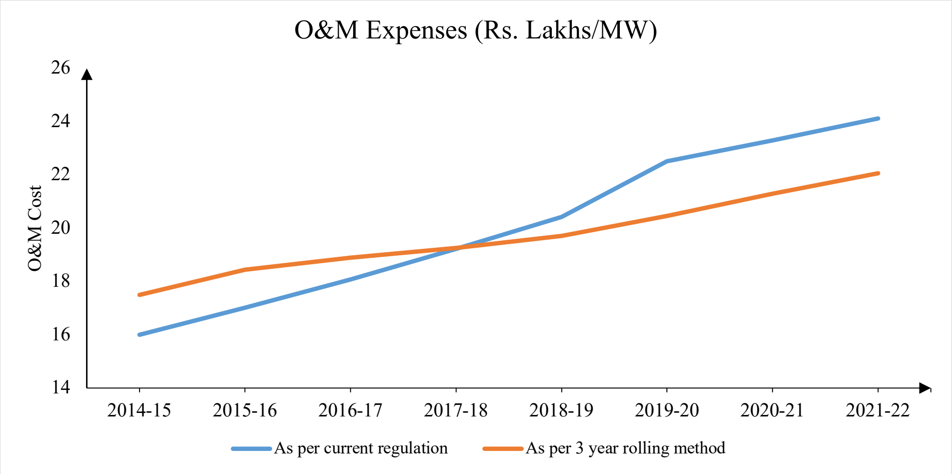

Figure 10: O&M expenses as per prevailing method and proposed approach (done for the current control period FY 2019-24)

46. Incorrect Approach to Calculate CAGR for O & M Escalation?: The CAGR to be applied for O & M expenses on per MW basis has been calculated from the absolute O & M expenses (presented in Tables 2, 3 & 4 of the Explanatory Memorandum). **This approach is incorrect as the underlying thermal capacity is not constant across the control period. The correct**

approach would be to calculate the CAGR (unadjusted, see next comment) on the basis of the O & M expenses on per MW basis only.

47. **Adjustment in O&M cost benchmark due to COVID-19:** The calculation of the past CAGR (to be applied for the upcoming control period) is arrived at after "normalizing (escalating)" actual O&M expenses for FY-21 and FY-22, which were recorded to be lower during COVID-19. While the benefit of such lower O & M costs did not accrue to the beneficiaries as this is not trued up[5], the higher (escalated) costs would be recoverable from the beneficiaries and hence the final consumers.

As per the explanatory memorandum of the proposed draft, 5.89% has been derived as escalation rate after uprating of the actual (lower O&M expenses) during COVID-19 year. **It is suggested that since the generating companies have already reaped the benefit of lower O&M expense, the advantage of same should be available to the beneficiaries and hence the final consumers while working out the benchmark O&M cost (without any adjustment).**

48. **Norms for water consumption:** Given the growing shortage of water across the country, the overall water consumption requirement for thermal power plant should be optimized with greater emphasis on recycling of water and utilization of water from the sewage treatment plant. To further ensure that the thermal power plants make optimum use of water, a normative benchmark for water consumption should be implemented as part of these regulations, and the expenses associated with the water consumption should be limited to the minimum of normative and actual consumption (in terms of volume of water used, while per unit water utilization should be passed through).

49. **Additional O&M expenses incurred due to change in law or force majeure:** Clause 36(1)(7) of the proposed draft states *"Any additional O&M expenses incurred by the generating company or transmission licensee due to any change in law or Force Majeure event shall be considered at the time of truing up of tariff.*
Provided that such impact shall be allowed only in case the overall impact of such change in law event in a year is ***more than 5% of normative O&M*** *expenses allowed for the year."* It may be further clarified whether total change in O&M will be allowed if the change is above 5% or the incremental change beyond 5% of normative O&M expenses will be allowed in case of additional O&M expenses incurred due to change in law or force majeure.

50. **Admitted capital cost on account of emission control system:** Clause 36(1)(9), which states that *"The operation and maintenance expenses on account of emission control systems in coal or lignite based thermal generating stations shall be 2% of the* ***admitted capital expenditure*** *(excluding IDC and IEDC) as on its date of operation, which shall be escalated annually @ 5.89% during the tariff period ending on 31st March 2029"* (emphasis added), may be rephrased as "The operation and maintenance expenses on account of emission control systems in coal or lignite based thermal generating stations shall be 2% of the admitted capital expenditure **of the respective emission control system** (excluding IDC and IEDC) as on its date of operation, which shall be escalated

[5] The normative costs are not trued up as per the regulation. But then the benefit of lower costs (under the lagged approach) should accrue to the consumers in the future year.

annually @ 5.89% during the tariff period ending on 31st March 2029 emission control system"

51. Downward adjustment of notified price of Coal India Limited to reflect Efficient Operations:

It has often been argued by the beneficiaries as well as the electricity generating companies that the inefficiencies of CIL are passed on the power sector as higher price of coal consumed by the thermal power plant. This is further exacerbated by the fact that CIL virtually does not face any competition, and there is no regulator for the coal sector. The operation of major coal producing entities is thus characterized by inefficient operation and institutional rigidities.

In light of above argument, the input price determined by the CIL under the Clause 37(2) the above inefficiency in the operation of the public sector coal producing entities, the power plants specially those owned by the central sector entities and those owned by the private sector are likely to be much more efficient. Hence, the input price of coal determined by CIL should be appropriately adjusted for these inefficiencies.

Clause 37(2) of the proposed draft states that *"The generating company shall, after the date of commercial operation of the integrated mine(s) till the input price of coal is determined by the Commission under these regulations****, adopt the notified price of Coal India Limited*** *commensurate with the grade of the coal from the integrated mine(s) or the estimated price available in the investment approval, whichever is lower, as the input price of coal for the generating station*" (emphasis added). **It is suggested that the input price of coal determined by the CIL (for equivalent grade of coal), should be lowered by at least 15-20% to arrive at the applicable input price of coal from the integrated mines or estimated price available in the investment approval, whichever is lower**.

52. Impact of part loading of the thermal station and different emission control system on technical and economic parameters of the generating station: It is suggested that a study must be carried out by the Commission to review the impact of different emission control system (FGD, de-NOx system, etc.) and the part loading of the station (or unit thereof) on the technical as well as the economic performance of the thermal generating station and the same may be incorporated separately in the Indian Electricity Grid Code (IEGC).

53. Gain sharing mechanism for Sale of 'Merchant' Coal : If the actual amount of coal produced is greater than the actual coal consumption plus the change in coal stock maintained by the respective generating station, **the gains corresponding to sale of such 'Merchant' coal should be passed on to the beneficiaries, after allowing for a margin of say 2-3% to the integrated mine (generator).** This approach would be similar to that applicable for the benefit sharing of the sale of energy from Un-requisitioned Surplus (URS) share of capacity not scheduled by the beneficiaries.

Further, to ensure that there is no incentive for 'leakage' of the 'Merchant' coal, the difference between the 'actual coal production plus change in coal stock at mine' and the 'actual cost consumption and change in coal stock at the power plant' be considered as sold. Any laxity in this respect may lead to significant cost impact on the beneficiaries and the final consumers who would have borne the approved cost of mine development and the associated O & M costs.

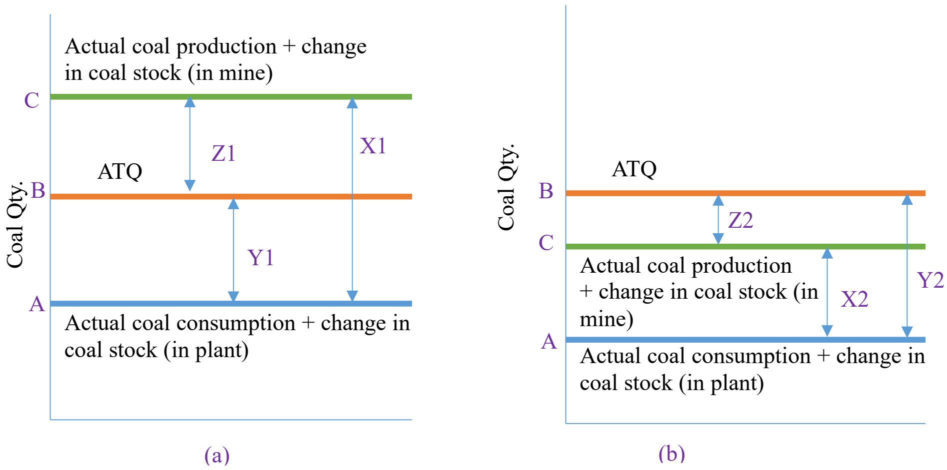

Figure 1: Approach to estimate 'Merchant' Coal