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REGULATORY INSIGHTS

Regulatory Outlook

CERC (Terms and Conditions of Tariff) Regulations, 2024 2

CERC (Terms and Conditions for Tariff determination from Renewable Energy Sources) Regulations, 2024 17

CERC (Connectivity and General Network Access to the inter-State Transmission System) (Second Amendment) Regulations, 2024 20

JSERC (Terms and Conditions for Green Energy Open-access) Regulations, 2024 ... 22

APSERC (Grid Interactive Distributed Renewable Energy System with Net Metering, Net Billing, Net Feed In, Gross Metering and Its Related Matters) Regulations, 2024 25

ERC Tracker

Regulatory Updates *(available online)*....... 27

Tariff Orders……….................................. 30

Regulations *(available online)*…………..... 30

CER News

Regulatory Certification Programme on "Power Sector Regulation: Theory and Practice" 31

Centre for Energy Regulation Spearheads Dialogue on "Power Market Derivatives".. 31

Regulatory Certification Programme on "Renewable Energy: Economics, Policy and Regulation" 32

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Editorial

The regulatory framework for the tariff determination for generation plants and the transmission licensees has evolved in terms of approach to tariff as well as parametric benchmarks to implement the same. The regulatory process for tariff determination has also grown in scale with the growth in generation and transmission capacity. In contrast, the capacity of the Electricity Regulatory Commissions have not been able to keep pace with the same. This requires adaptation of a novel approach that embodies the principles of light-handed regulation. The ERCs may adopt the suggested approach allowing certain degree of 'autonomy' to the regulatory process, subject to regulatory jurisprudence and subsequent truing up.

The normative cost of service approach continues to benchmark operational parameters based on historical performance with limited targets for efficiency improvement and cost reduction. While this builds up into the tariff to be paid by the consumers, additional components of tariff have been introduced as a form of incentive. Incentives for improved performance are an important component of a regulatory framework, the Electricity Act 2003 as well as the tariff policy provide for the same. However, design of incentives itself has not received due attention in term of economic principles and benefit to final consumer. For example, incentives for generation beyond NAPAF during peak and off-peak hours, and higher ramping can be justified to achieve desirable performance, but gains on that account are not accounted for to justify the level of incentives. The existing regulatory and policy framework does not provide for an impact assessment of the proposed regulations or changes thereof. It is suggested to adopt an approach for Regulatory Impact Assessment (RIA), wherein appropriate commission would be able to evaluate the impact of proposed regulations or changes thereof on various stakeholders specially in terms of tariff to be paid by the beneficiaries and hence the final consumers, thus justifying the adopted benchmarks and incentives. This would be in line with the spirit of the Act as well.

Lack of adequate capacity in the regulatory matters, especially due to inadequate and insufficiently trained manpower on regulatory matters is often reflected in limited participation of the government owned Discoms during public hearing based on detailed analysis. This necessitates setting up and strengthening of the Regulatory Cells in the respective Discoms.

The admitted capital cost for conventional as well as renewable energy plants has far reaching impact on a variety of components of tariff including depreciation, O&M cost, interest on loan, interest on working capital as well as ROE. This highlights the urgency and importance of a framework for capital cost benchmarking. The existing approach often depends on the 'market prices, which are to be derived from the manufacturers/project developers both have their interest aligned with approval of a higher capital cost.

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CERC (Terms and Conditions of Tariff) Regulations, 2024

CERC notified draft Terms and Conditions of Tariff Regulations, 2024 for the tariff period from 01.04.2024 to 31.03.2029 on 4th January, 2024. The key highlights of this draft is mentioned below:

Objective: The proposed draft regulations lay the provisions for the determination of tariff components i.e. IoL, RoE, Depreciation, Interest on working capital, O&M expenses (normative), energy charge rate for the thermal generating stations (coal/lignite based and gas based) including that of the emission control system, hydro generating stations, transmission system or element thereof. The regulations provide for computation of the input price of coal and lignite from integrated mine and the recovery mechanism thereof including the mine closure expenses, adjustment due to shortfall of overburden removal and non-tariff income. The draft also proposes the methodology for computation and recovery of capacity and energy charges (supplementary capacity and energy charges for emission control system) applicable for the above-mentioned entities.

The proposed regulations also provide the incentive mechanism applicable for recovery of the capacity charges for demonstration of frequency response performance as per the methodology prescribed by NLDC and the energy supplied during peak and off-peak hours in excess of the ex-bus energy corresponding to NAPLF.

CER Opinion

- **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.**

- **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 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.**

- **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.

[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

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

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

Where,

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

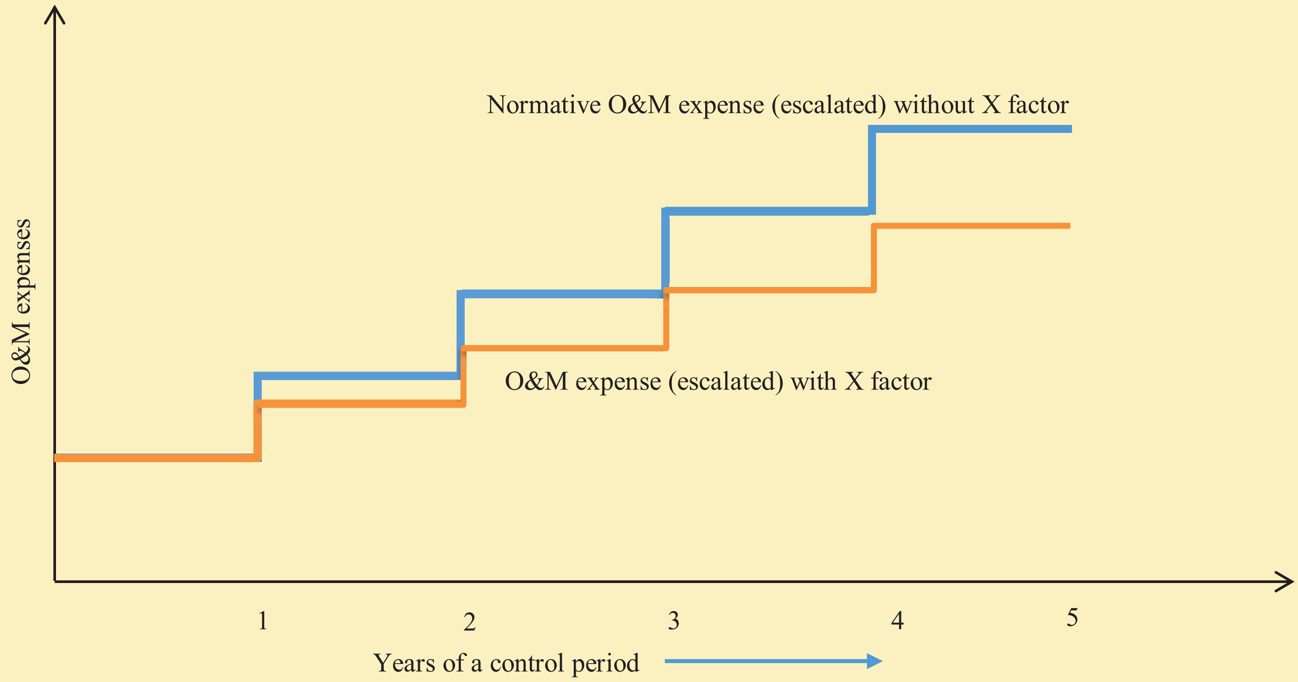


***Figure 1:** Representation of O&M expenses with efficiency factor "X"*

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 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 $CPI_{\text{urban \& clerical workers}}$. 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.

- **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.

- **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

[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

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 considers 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	11	56
800 MW series	9	7	5	21	-

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.

- **Defnition 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 **of any existing agreement 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"

- **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.**

- **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 that 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.

- **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).

- **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 **as approved by the Commission**" (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?**

- **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".

- **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, mines etc. identification thereof.

- **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).

- **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."**

- **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"*.

- ***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."

- **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.

- **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.

- **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 <u>meeting</u> 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) **<u>and payable only on account of meeting the revised emission standards</u>** (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.

- **"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 **<u>an arrangement,</u>** 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 –

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

- **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.

- **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.**

  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.

  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.

- **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)).

- **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 determining 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 components 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 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).

- **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.

[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

- **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.

- **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"

- **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.

- **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 two 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.

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 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).

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.

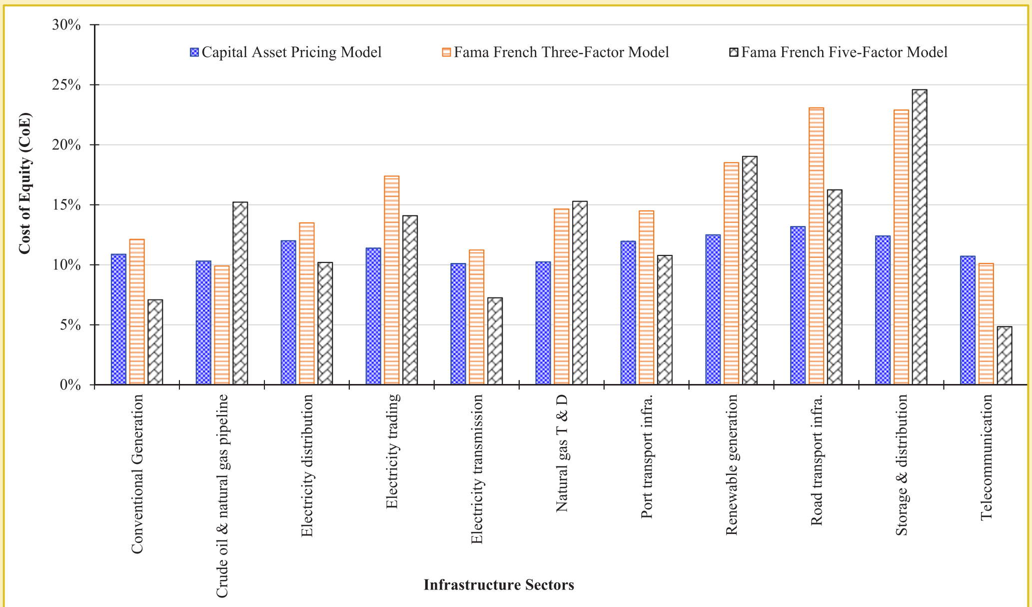


***Figure 2:** Cost of equity for different infrastructure sectors*

[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

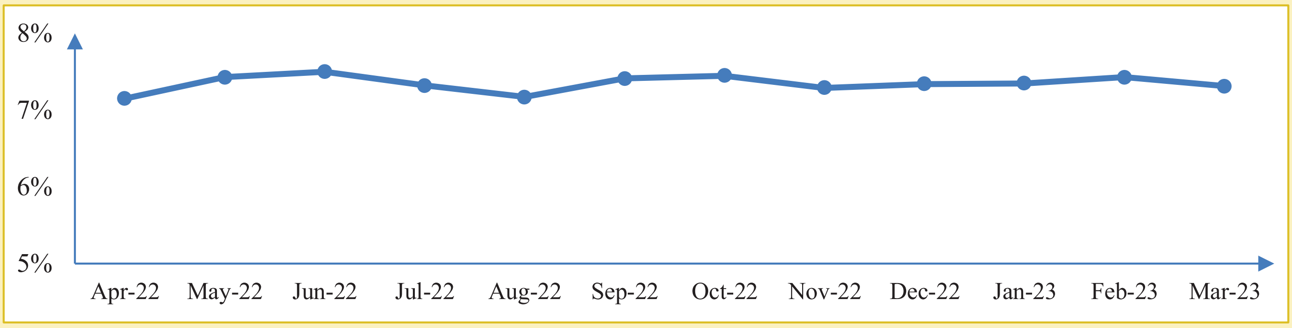


Figure 3: *G-Sec 10-year Bond Yield over One year horizon*

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.

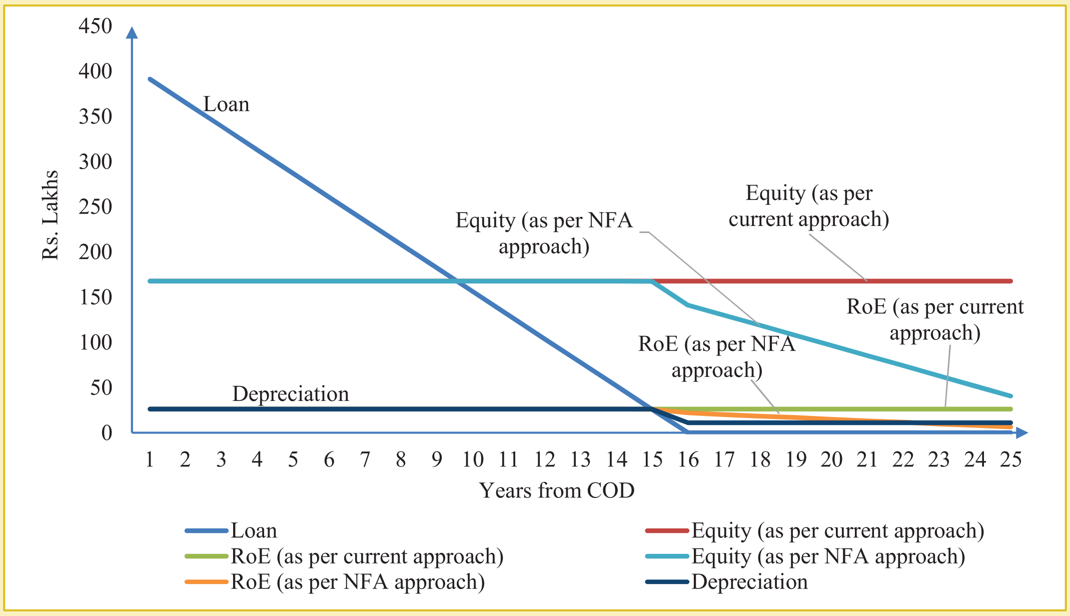


Figure 4: *Modified GFA approach vs NFA approach*

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: 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. 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.

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;"

- **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"

- **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".***

- **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).

- **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.

- **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.

- **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?

Working capital requirements:

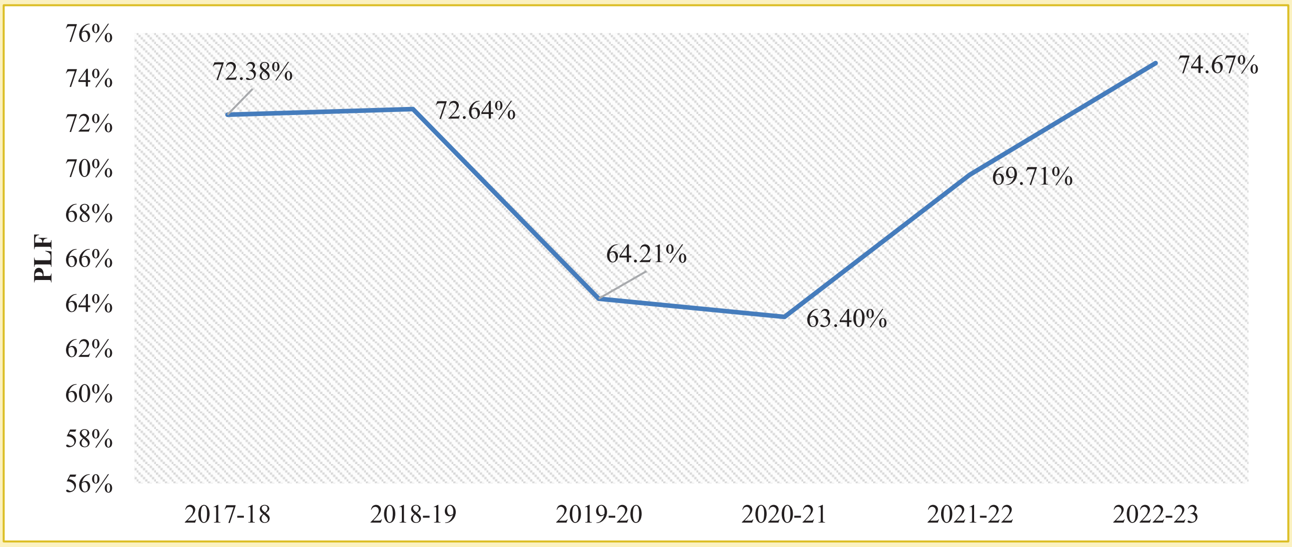


Figure 5: *Average PLF of the central sector thermal station*

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%.

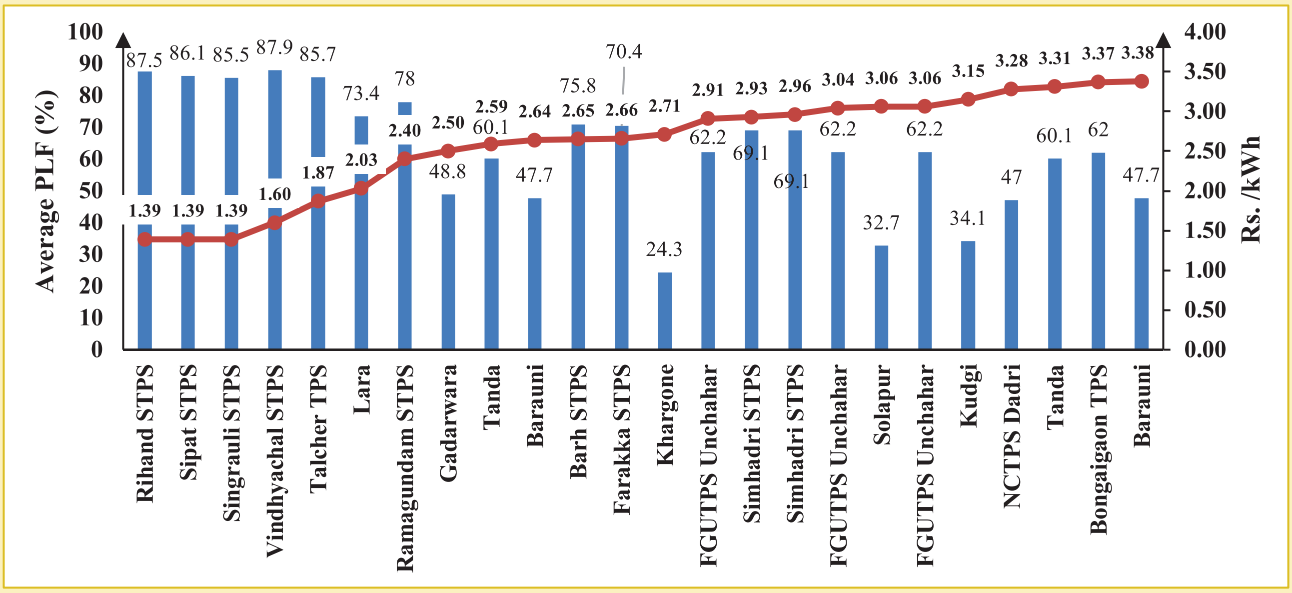


Figure 6: *Average PLF of central coal-based generating stations and respective VC*

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.

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
- 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.

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.

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.

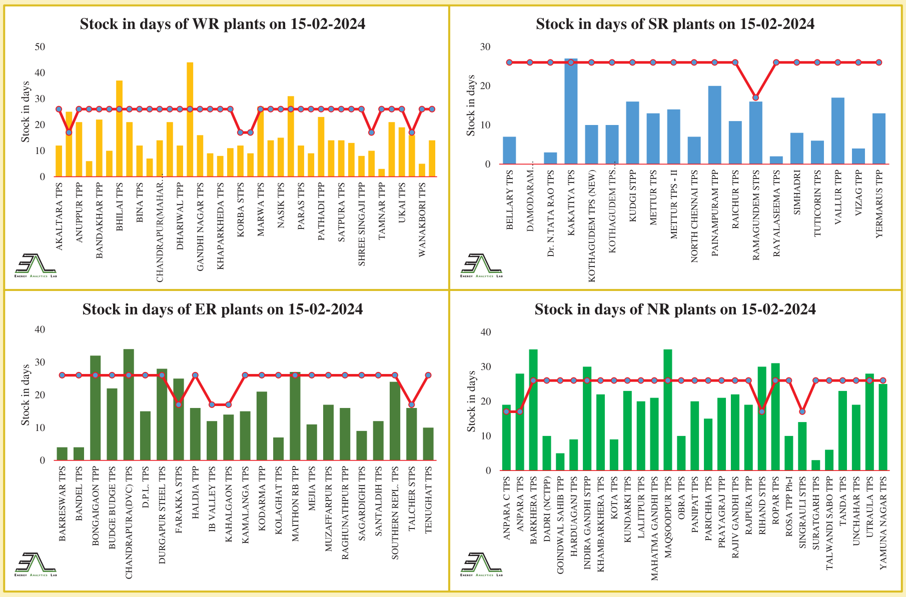


***Figure 7:** Normative vs actual coal stocks for thermal generating stations*

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.

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).

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.

- **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.

- **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:

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 2 below.

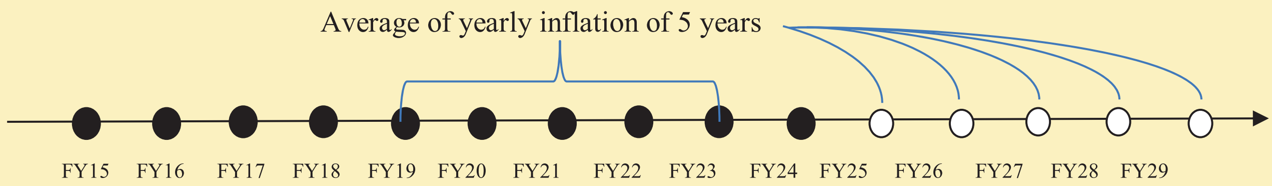


***Figure 8:** Calculation of escalation rate as per prevailing approach*

***Table 2:** Index Calculation – Normal Average vs CAGR*

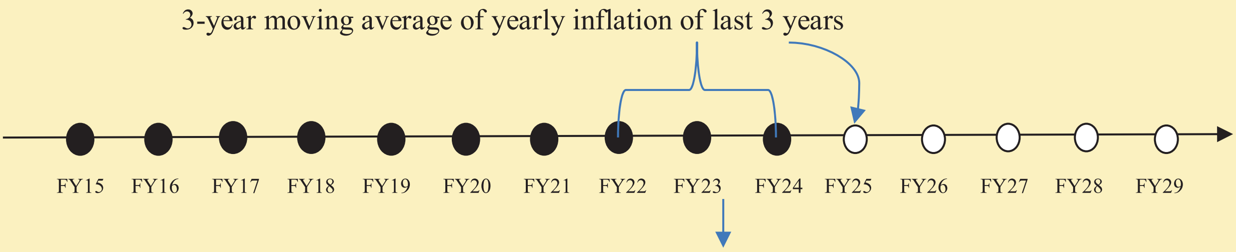
Index	Growth Rate	CAGR	Recalculated Values using	
			Average Gr.	CAGR
100			100	100
105	5.00%		107.21	107.19
116	10.48%	7.19%	114.94	114.89
125	7.76%		123.22	123.15
132	5.60%		**132.11**	**132.00**
Average/CAGR	7.21%	7.19%		

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:

- 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!
- 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.



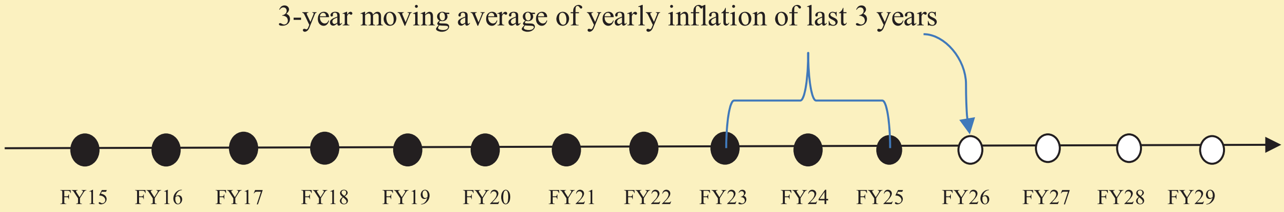


Figure 9: *CER's approach for calculation of escalation rate - 3-year rolling average method*

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

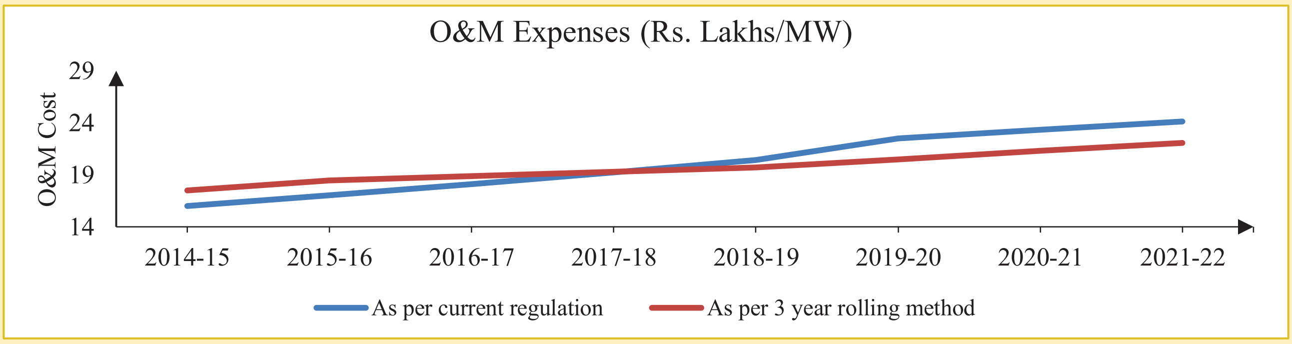


Figure 10: *O&M expenses as per prevailing method and proposed approach (done for the current control period FY (2019-24)*

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 raes: 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

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

- **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.**

- **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).**

- **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).

- **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.

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

- **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**

[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.

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.

- **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).
- **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.

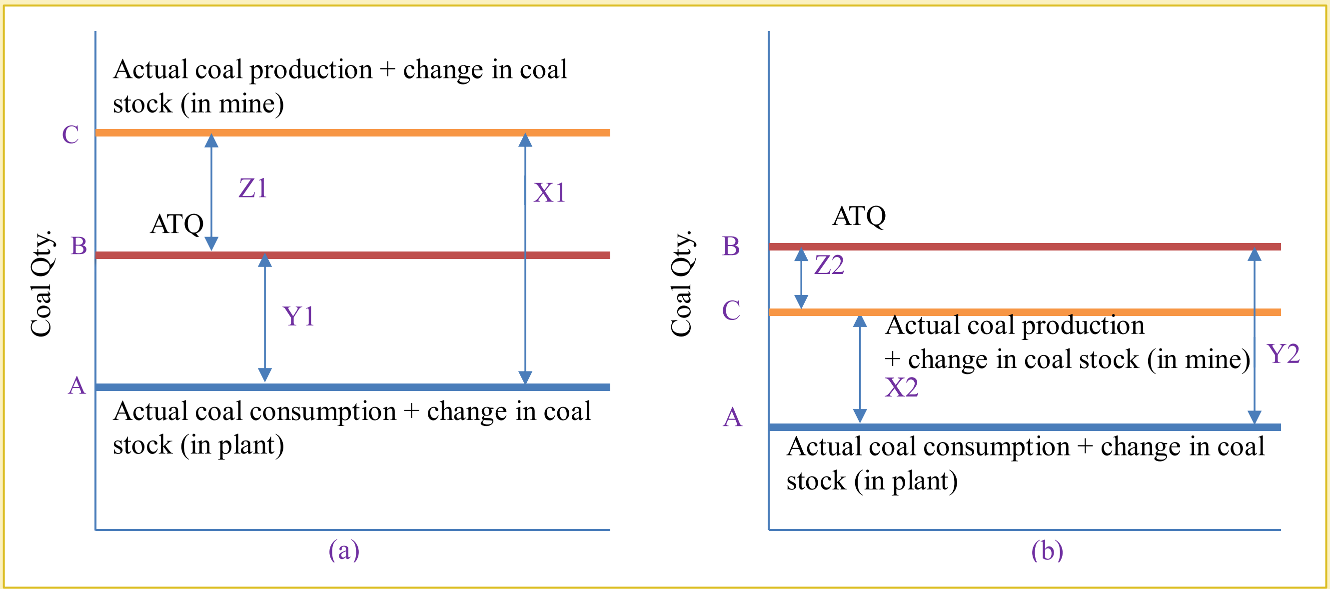


***Figure 11:** Approach to estimate 'Merchant' Coal*

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.

CERC (Terms and Conditions for Tariff determination from Renewable Energy Sources) Regulations, 2024

CERC notified draft Terms and Conditions for Tariff determination from Renewable Energy Sources Regulations, 2024 for the control period 2024-25 to 2026-2027. Highlights of the proposed regulations are given below.

Objective: 'Municipal Solid Waste (MSW)' and 'Refused derived fuel (RDF)' have been provided special emphasis and regulation changes to promote growth in the sector. The useful life have been reduce to 20 years. Station heat rate and Gross calorific value clauses have been omitted from for MSW/ RDF projects. Regulation have categorise MSW/ RDF based power project under generic tariff but project developer can opt for project specific tariff.

- The regulation that provides compensation for the 'Treatment for Over-generation' have set price for excess energy as 100% of tariff applicable for that year.
- The time period for loan tenure is 15 years and normative interest is 200 basis points above SBI MCLR.
- Depreciation rate of 4.67% per annum for first 15 years and rest to divided equally for rest of useful life of project.
- The normative Return on Equity for renewable project is 14% while for small hydro power project it is 14.5%.

- RoE to be grossed up by latest MAT for first 20 years of tariff period and by latest corporate tax rate for rest of tariff period.
- Late payment surcharges will be according to specification provided in Ministry of Power - Electricity (Late Payment Surcharges and Related Matters) Rules, 2022.
- Efficiency of RE with storage project based on solid state batteries is 80% while for storage based pumped storage is 75%.

CER Opinion

Prevailing market trends to Efficient 'Capital Cost Benchmarks': It is suggested that Commission should provide clarification for the term **prevailing market trends mentioned in clause (23), (26), (46), (48), (68), (69), (71) and (73).**

Given that capital cost influences various components particularly depreciation, interest cost and RoE, a **capital cost benchmarking methodology** should be evolved. This may also include 'market trends' covering efficient cost benchmarks in the international context. Higher weightage should be given to capital equipment procurement on competitive tendering basis. There may be inherent data bias as 'market trends' may be reported from limited set of deals. **The Commission may propose a methodology for gauging market trends.** This should give higher weightage to recent deals.

Prevailing market trends got Interest on Loan and Interest on Working Capital: The SERCs may also follow up with a Capital Cost Benchmarking approach. The existing approach sets interest rate at certain basis points above the SBI MCLR. The Commission may develop **a methodology to capture 'market trends' for interest for term loans and working capital loans.** Such data may be captured through RBI or other means for companies with PPAs, which have lower risk as compared to those facing market risk. This should appropriately adjust for leverage and other aspects affecting risk of the projects.

Definitions of excess energy/ Over-Generation: Clause 11 of the proposed draft Regulation states *'In case a renewable energy project, in a given year, generates energy in excess of the capacity utilization factor or plant load factor, as the case may be specified under these Regulations, the renewable energy project may sell such excess energy to any entity, provided that the first right of refusal for such excess energy shall vest with the concerned beneficiary. In case the concerned beneficiary purchases the excess energy, the tariff for such excess energy shall be equal to the tariff applicable for that year.'* There is need to clarify if the excess energy is on account of excess capacity of the plant (than that for which tariff is determined) or excess energy generation (due to better resource e.g. solar or wind). The later can only be known on a day ahead or few hours ahead basis. The regulation seems to refer to the former case. It is suggested that draft Regulation should include a **definition of excess generation/ Over-generation.**

If excess generation is on account of excess design capacity planned by the generator, then the generator will have benefit of economies scale for creation of that excess capacity. The additional cost of incremental capacity won't be same as designated capacity. Thus, tariff 'determination' for such excess energy should not be based on pro-rated capital, operational and other costs. **Such excess generation would not require a compensation rate at 100% of the RE tariff for the capacity considered for tariff determination.**

It may be further be clarified whether excess energy injected is to be considered on a **rolling monthly basis or on trued up on yearly basis.** Otherwise, the RE generator would have lower revenue realization.

Excess energy injected at the end of a month in a FY (say April), would then need to be paid as per the tariff approved for such excess energy. However, on an annual basis this energy may not be excess due to shortfall in generation in later months. Thus, **billing and settlement for excess energy should be done on an annual basis only.**

Tariff for excess energy: In case of excess energy due to better resource availability but for the same capacity - Section 62 of the Electricity Act 2003 mandates 'determination' of tariff for original capacity. Since the tariff for original capacity already accounts for full cost recovery, the costs cannot be replicated. Proposal for 100 % of the determined tariff translates to over recovery of cost and thus is not in line with the prudential cost recovery.

In case of tariff for excess energy generation from biomass fuel based generators, the excess energy may be purchased at the 100% of the **approved variable charge.** In case of solar, wind, small hydro and MSW/ RDF power plants, the excess energy above the normative CUF, should be purchased at 30% of the determined tariff. Note that capital cost in case of MSW/RDF are very high, even 30% tariff for excess energy would translate into a significantly higher tariff for excess energy.

- **Efficient Benchmarks to Address High Capital Cost for MSW based Plants:** While it is important to note that MSW are now included under generic tariff, the regulation should adopt efficient benchmarks for capital cost as well as operational parameters. The proposed capital cost now incorporates costs associated with waste segregation/fuel preparation. To ensure that environmental goals for 'utilisation' of municipal solid waste are achieved in a cost competitive manner, either competitive bidding based approach should be adopted for MSW based projects, or cost benchmarks should reflect cost efficiencies and encourage further cost reduction. Very high capital cost would translate to a very high tariff for MSW based projects.

  The proposed generic tariff framework adjust any capital subsidy or other benefits available to the generating projects through support from the central or the respective state government or the local authorities.

- **Removal of Station Heat Rate and Gross Calorific Value:** It is noted that in "Chapter 11. Parameters for municipal solid waste based power projects and refuse derived fuel based power projets" in order to promote the Municipal Solid Waste (MSW)/Refuse Derived Fuel (RDF) based power project few incentive have been added. The Energy charge component in fuel cost is nil, the station heat rate (SHR) and Gross Calorific Value (GCV) are omitted from proposed draft regulation.

  As mentioned in Explanatory Memorandum Page 75 *"In the view of the above, the Commission decides not to allow any fuel costs in the case of MSW based projects on RDF; instead, the Commission prefers to include the cost of fuel preparation (process equipment) in the overall capital cost of the project, which will address both Capacity Charge and Fuel preparation costs and other incidentals. Hence, the related norms like Station Heat Rate, Fuel cost escalation, Gross Calorific Value, etc. are not applicable to them"*

  It is proposed that Commission must direct all MSW/RDF based power plant under this proposed draft regulation to monitor and record the GCV of MSW/RDF used, SHR and PLF on a monthly bases. This information would be valuable for the Commission to set standard benchmark under the regulation in future.

- **Definition of CUF, Minimum CUF and Capacity Share:** In proposed clause 68 (1) proviso 2 states that *"Provided that the **minimum capacity utilization factor for renewable hybrid energy projects shall be 30%** when measured at the inter-connection point, where the energy injected into the grid." (emphasis added). Reading along with Eligibility criteria clause 4 (f) "Renewable hybrid energy project- The rated capacity of generation from one renewable energy source is at least 33% of the total installed capacity of the renewable hybrid energy project, which operates at the same point of interconnection: Provided that energy is injected into the grid at the same interconnection point and metering is done at such a common interconnection point accordingly"*

  Clause 68 of the draft regulation states the Capacity Utilisation Factor to be *"(1) The Commission shall determine only project specific capacity utilisation factor in respect of renewable hybrid energy projects, taking into consideration the proportion of **rated capacity of each renewable energy source,** as the case may be, and applicable capacity utilisation factor for such renewable energy sources, as the case may be:"* (emphasis added)

  Capacity Utilisation Factor (CUF) would thus consider the rated capacity of individual technologies. The capacity under consideration, for the purpose of tariff determination, is the rated capacity of the plant. The tariff determination would consider capital and other cost associated with such a capacity. Thus, minimum stipulated CUF of 33% cannot materialize unless it is calculated with respect to the contractual capacity.

  The stipulation of minimum 33% CUF seems to have been adopted from the competitive bidding document for hybrid projects, which entail installation of excess capacity. The tariff determination process would calculate CUF on the basis of the rated capacity being considered for the tariff. Using such an approach for the defined capacity, CUF for a hybrid power plant cannot be above the CUF of the technology exhibiting highest CUF. The Tables above explicitly demonstrates the same. A hybrid project with solar and wind technology (with or without storage) would not have a CUF at 33% under the prevailing resource availability conditions in the country. Thus, the CUF stipulation of 33% of the rated capacity, as 'adopted' from the competitive bidding document would not be applicable in the context of tariff regulations and should be modified. One possible way is to define contractual capacity as distinct from the rated capacity. Thus regulatory approach for tariff determination would differ from that adopted for the standalone technologies.

  Specification of minimum CUF, in its current form, for the overall hybrid project and minimum capacity share by technology indirectly places a minimum capacity limit for higher CUF technologies like biomass (See Tables above). Inclusion of storage would not enhance CUF of the combination of RES technologies embedded in a RE project as an ESS would store energy generated from the hybrid project only.

Furthermore, CUF for hybrid project needs to be defined by excluding 'energy generation' (discharged) by the storage capacity either by storing the energy generated by the hybrid project or that stored from other sources of generation/procurement. This should be explicitly mentioned to avoid grey areas for interpretation and potential legal disputes in future.

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

	Cap MW	CUF %	Energy Gen MWh
Solar	33	21	60706.8
Wind	67	30	176076
Biomass	0	0	0
Total	100	27.03	236782.8

	Cap MW	CUF %	Energy Gen MWh
Solar	67	21	123253.2
Wind	33	30	86724
Biomass	0	0	0
Total	100	23.97	209977.2

	Cap MW	CUF %	Energy Gen MWh
Solar	33	21	60706.8
Wind	33	30	86724
Biomass	34	75	223380
Total	100	42.33	370810.8

	Cap MW	CUF %	Energy Gen MWh
Solar	33	21	60706.8
Wind	33	30	86724
Biomass	34	75	223380
Total	100	42.33	370810.8

Optimal Combination of the Rated Capacity for the Hybrid RE Plants: Numerous combinations of individual technology wise capacity can be used to create a hybrid capacity with a desirable CUF. Different combinations would entail different capital cost and other associated costs. Two projects with same overall capacity but same CUF will thus have different tariffs. How would the Commission decide if an optimal capacity combination has been used for the hybrid RE project? One possible approach would be to introduce an 'optimality test' wherein a range of capacity for the individual technologies can be defined, wherein the project developer should demonstrate that it has applied the principle of cost minimization to arrive at the capacity combination.

CERC (Connectivity and General Network Access to the inter-State Transmission System) (Second Amendment) Regulations, 2024

The CERC notified "CERC (Connectivity and General Network Access to the inter-State Transmission System) Regulations, 2024" on 16th February, 2024 applicable for interstate entities for transmission of power. The key highlights of this draft is mentioned below:

Objective: The draft notification from the Central Electricity Regulatory Commission proposes amendments to the Central Electricity Regulatory Commission (Connectivity and General Network Access to the inter-State Transmission System) Regulations, 2022, focusing on changes related to the selection and purchase of power from renewable energy generating stations, application processing timelines, financial closure requirements, possession of land, and bank guarantees.

The amendment proposes the eligibility criteria of minimum installed capacity of 25 MW in North-Eastern region to apply for grant of connectivity.

The amendment has laid the provisions for a renewable energy generating station other than hydro of pump storage plants to seek the grant of connectivity and general network access.

The regulations have also proposed approval of grant of connectivity after receipt of complete application within eighteen days instead of seven days.

CER Opinion

Definition of Renewable Energy Implementing Agency: The proposed new Clause 2.1.(ag-i) states that *"Renewable Energy Implementing Agency" means and includes an entity designated by the Central Government or the State Government to act as Intermediary Procurer to select and buy power from Renewable energy generating station(s) and sell the same* ***to one or more distribution licensees or any other entity*** *in accordance with the Guidelines issued from time to time by the Ministry of Power, Government of India or the Ministry of New and Renewable Energy, Government of India or the State Government"* (emphasis added). It is suggested that it may be clarified that whether the "Renewable Energy Implementing Agency" can participate in market for selling part capacity as a merchant power plant? It may also be clarified that whether these regulations will be applicable if such entity is supplying power to more than one DISCOM within a (single) State.

It is further suggested that proposed Clause may be rephrased as "Renewable Energy Implementing Agency" means and includes an entity designated by the Central Government or the State Government to act as Intermediary Procurer to select and buy power from renewable energy generating station(s) and sell the same **to one or more distribution licensees or any other entity across different States** in accordance with the guidelines issued from time to time by the Ministry of Power, Government of India or the Ministry of New and Renewable Energy, Government of India or the State Government" (emphasis added).

- **Document submission for bank guarantee:** It is suggested that the sub-clause (c) clause (vii) of the principal regulations *"Clause (vii) of Regulation 5.8 of the Principal Regulations shall be substituted as under: (vii) In case of Renewable Power Park Developer, the documents shall be submitted in combination of clauses (a) and (b) or combination of clauses (a) and (c) as specified hereunder:"* may be rephrased as "(vii) In case of Renewable Power Park Developer, the documents shall be submitted in combination of clauses (a), (b) and (d) or combination of clauses (a), (b) and (c) or clauses (a), (c) and (d) as specified hereunder" to incorporate the proposed amendment.

- **Clarification of connectivity for Hybrid System:** The proposed regulation 5.8 clause (xi) sub-clause (c) states that *"For a capacity up to 1000MW - Bank Guarantee of Rs. 10 lakh/ MW and for a capacity more than 1000MW - Bank Guarantee of Rs. 100 Crore plus Rs. 5 lakh/MW for capacity over and above 1000MW, in lieu of ownership or lease rights or land use rights of land for 50% of the land required for the capacity for which Connectivity is sought subject to provisions of Regulations 11A and 11B of these regulations;"*. It is suggested that the proposed Clause may further be clarified to include hybrid systems (REGS plus ESS) for grant of connectivity or GNA.

- **Documents related to land:** The proposed sub-clause (d) clause 5.8 states that *"Government Order issued by the concerned Government for allotment of the land along with possession **documents** for 100% of the land required for the Capacity for which Connectivity is sought"* (emphasis added). It is suggested that the "documents" may be further elaborated to include the exact list of land related documents to be submitted for submission of bank guarantee.

- **The bank guarantee:** The proposed sub-Clause (c) of Clause (vii) states that ***"The Bank Guarantee** submitted under sub-clause (c) of Clause (vii) of Regulation 5.8 of these regulations shall be returned within 7 days of submission of stipulated Documents as proof of Ownership or lease rights or land use rights"* (emphasis added). It is suggested that the term "Bank Guarantee" may be substituted with **"irrevocable bank guarantee"**. It is further suggested that the bank guarantee to be released post submission of documents related to land subjected to the verification for the documents by the Nodal Agency.

- **Equity Infusion:** The proposed sub-clause (a) of Clause (vii) of Regulation 11A states *"Provided that in case of REGS (other than Hydro generating station) or ESS (excluding PSP) who have been granted Connectivity under sub-clause (a) of Clause (xi) of Regulation 5.8 or are subsequently covered under sub-clause (a) of Clause (xi) of Regulation 5.8, the scheduled date of commercial operation for the purpose of Clause (2) of Regulation 11A shall be considered as SCOD, as extended by REIA or a distribution licensee or an authorized agency on behalf of distribution licensee from time to time, subject to the condition that any extension in the timeline to release **10% equity infusion** due to extension in SCOD shall not be allowed more than **12 months** from the original timeline as per initial SCOD"* (emphasis added).

  It is suggested that proposed release of 10% equity infusion is very less and the REIA may not be affected from the same. This will expose to the transmission utilities to significant risk. (For e.g., for a project cost of Rs. 1000 Cr., the equity of the developer/ REIA will be 30% i.e. Rs. 300 Cr. 10% of the equity infusion will be Rs. 30 Cr. to be released in (up to) 12 months, which is very less.) Thus, it is suggested that the equity infusion to be released in the event of extension in timeline of the project implementation should be expressed in terms of the overall project cost and should be **minimum 15-20% of the project cost** and should be maintained throughout the period.

  It is further suggested that following proviso may be added to the proposed Clause (xi) to the Regulation 5.8 -

  "Provided that at this stage the equity diluted after 10 Months the particular GNA may be revoked. Amount of equity infused in such project should exceed or should be equal to the total equity contribution in a project or at least 20% of project or land cost and it has to be maintained that level also post project completion."

- **Land use rights:** Sub-clause (c) of Clause (xi) of Regulation 5.8 states *"Bank Guarantee of Rs. 10 lakh/MW in lieu of ownership or lease rights or land use rights of land for 50% of the land required for the capacity for which Connectivity is sought subject to provisions of Regulations 11A and 11B of these regulations"*. It is suggested that the equity in the Regulations 11A and 11B should be maintained **throughout the project period.**

It is further suggested the minimum equity may be expressed in terms of the overall project cost and be kept as 15-20% of the total project cost and to be maintained throughout the project period.

Also, the financial closure should be achieved at earliest, otherwise the transmission sector may witness significant rise in stranded asset. To safeguard the transmission licensee from the above mentioned risk of stranded assets, financial closure of the project may be mandated to be achieved within the **first three months of the signing of CGNA.** Alternatively, a mechanism may be developed for recovery of the fixed charges of stranded assets from such transmission users rather than the same being borne by rest of the beneficiaries.

JSERC (Terms and Conditions for Green Energy Open-access) Regulations, 2024

JSERC notified a draft (Terms and Conditions for Green Energy Open-access) Regulations, 2024 on 11th January, 2024.

Objective: The objective of GEOA, is to promote the use and accessibility of renewable energy sources. It aims to facilitate the sharing and distribution of clean and sustainable energy, allowing consumers and businesses to choose environmentally friendly options.

Definitions: Green Energy Open Access Consumer (GEOA) shall mean any person who has contract demand or sanctioned load of 100 kW and above, either through single connection or through multiple connections aggregating 100 kW or more located in same electricity division of a distribution licensee, (captive consumers shall not have any load limit) who is supplied with electricity from RE sources for his own use by a licensee or the Government or by any other person engaged in the business of supplying electricity to the public under this Act or any other law for the time being in force and includes any person whose premises are for the time being connected for the purpose of receiving renewable energy with the works of a licensee, the Government or such other entity, as the case may be;

Categorization of Green Energy Open-access:

- Long-term Open-access consumers: The intra-state transmission and/or distribution system for a period exceeding 12 years but not exceeding useful life of the Plant, whichever is earlier;
- Medium-term Open-access consumers: The intra-state Transmission and/or distribution system for a period exceeding 3 months but not exceeding 3 years;
- Short-term Open-access consumers: Open-access for a period up to one (1) month at a time;
- Provided that short-term Green Energy Open-access consumers shall be eligible & re-eligible to obtain a fresh reservation on the filing of an application after the expiry of his term and subject to availability. Such eligibility shall be on priority fixed on the basis of the date of application.

CER Opinion

Quantum of green energy: As per the draft Clause 4.C (iv), *"Any requisition for green energy from a distribution licensee shall be for a minimum period of one year;"* & Clause 4.C (v.) *"The quantum of green energy shall be pre-specified for at least one year".*

The above provision would demotivate Green energy open access consumers to opt for the same. The option for a consumer to seek green energy from a distribution licensee should be in line with consumers' ability to secure non-green electricity, which does not come with such limitations. To ensure greater acceptability of green energy by final consumers, such limitations should be avoided at the very outset and may be reviewed later, if required.

Given that the RE sources like solar and wind are subject to variation in generation across months, it may not be possible to pre-specify a quantum for a year. **Under such circumstances, appropriate provisions to address cases of such a variation should be added. As a step towards encouraging renewables, a 10-15% variation (or as deemed fit by the Commission) in quantum and duration of green open access should be allowed.** This may be reviewed later based on experience. Over and above this variation, exceptions should **include force majeure conditions, and curtailment of the transmission capacity, both at the inter-state as well as intra-state level.**

Furthermore, the regulation should provide for part or full surrender of load by the consumers. Such reduction in load should be translated to reduction in the quantum of power as well as duration of green Open Access.

- **Guarantee of origin of energy used for producing Green Hydrogen or Green Ammonia:** As per the draft Clause 4.F, *"The obligated entity can also meet their Renewable Purchase Obligation by purchasing green hydrogen or green ammonia and the quantum of such* ***green hydrogen or green ammonia*** *would be computed by considering the equivalence to the green hydrogen or green ammonia produced from one MWh of electricity from the renewable sources or its multiples and norms in this regard shall be notified by the Central Commission."* emphasis added

  A mechanism would be required to ensure the origin of source of energy use for generation of green hydrogen or green ammonia. Similarly, mechanism to verify the purchase and use of green hydrogen or green ammonia by the obligated entity would also be required for considering them for meeting the RPO. The existing REC registry may be empowered to certify the same. Relevant procedures, protocols and accounting framework would be required to be specified for the same under the relevant CERC regulations.

- **Eligibility Criteria for applying GEOA:** As per the draft Clause 6.i *"Subject to the provisions of these Regulations and system availability, consumers shall be eligible for Green Open-access to the intra-state transmission system of the State Transmission utility or any other transmission licensee(s) and distribution system of the distribution licensee(s) within the State. Provided that notwithstanding anything contained in these Regulations, any renewable energy (RE) generation company that currently has a valid Power Purchase Agreement (PPA) with the Distribution Licensee will not be allowed to use open access for the RE capacity specified in the PPA except in accordance with the terms of such PPA. Provided further that, such Open-access shall be available on payment of such charges as may be determined by the Commission from time to time."*

  The regulation excludes the green energy open access for the RE capacity that has been already been tied up with the distribution licensee under a valid PPA. However, it is not clear how this particular clause be implemented on the ground as this needs to be uncertain whether this said RE generator has enhanced the capacity on the ground of the existing RE power plants or has installed additional capacity on the ground which would be transacted through the same pooling meter. Such lack of clarity on this aspect may lead to legal dispute and hence should be clarified upfront.

- **Contradiction in two statements:** As per the Clause 9.3, *"The State Nodal Agency shall ensure that* ***non-refundable processing fee*** *of ten thousand rupees for long-term/ medium-term Green Energy Open-access and three thousand rupees for short term Green Energy Open-access is paid by applicant to the nodal agency and the nodal agency shall intimate the same through electronic mode of communication, immediately on receipt of the application form from Central Agency. The applicant shall pay the processing fees within one working day." & Clause 9.7, "Where any application is rejected for any deficiency or defect, the* ***processing fees and BG, if submitted, shall be returned*** *to the applicant and in such cases a fresh application to the Central Nodal portal shall be made by the applicant after curing the deficiency or defect."* emphasis added.

  The first statement states the 'Processing fee is non-refundable', while the second one suggests it is 'refundable to the applicant. There is a contradiction between the two clauses. Hence, it is recommended to address and correct the inconsistency.

- **Digitalisation and Green Energy Open-access status:** As per the draft Clause 10.4.,*"Where Open-access is denied, the State Nodal Agency shall furnish reasons thereof to the applicant."*

  The details of the application process as well as the status of the grant of GEOA and quantum of thereof should be reported for easy access at the SLDC portal and be archived thereof.

- **Define Power Utilization:** As per the draft Clause11.1, *"In the event of inability of the short-term Green Open-access consumer to utilize for more than four hours, full or substantial part of the capacity allocated to him, such a short-term Open-access consumer shall inform the respective SLDC of his inability to utilise the capacity, along with reasons therefore and may surrender the use of capacity allocated to him. However, such short-term consumer shall bear full transmission and /or wheeling charges based on the original reserved capacity and the period for which such capacity was reserved."*

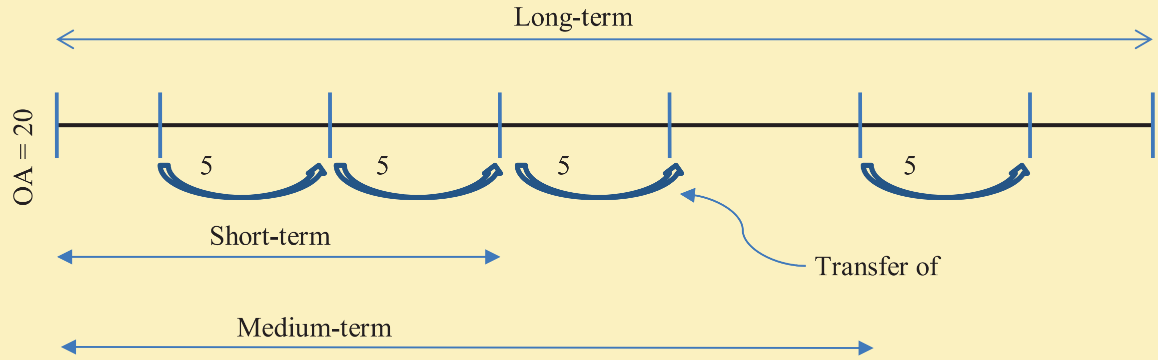
  As per the draft Clause 11.3, *"The SLDC may cancel or reduce the capacity allocated to a short term Open-access consumer to the extent it is underutilized, when such a short-term Open-access consumer under-utilizes the allocated capacity more than 2 times in a month with duration of underutilization exceeding 2 hours each time or fails to inform the distribution licensee of his inability to utilize the allocated capacity such cancellation shall be resorted to after giving due notice."*

  The definition of underutilization of power is not clear should be specified with respect to the point of injection or drawl.

  It is advisable to calculate the power utilization from the injection point of the RE generator.

Also, there is a contradiction in the above two clauses, as in the first statement the underutilization is defined as the inability to utilize the power for more than four hours whereas, it suggests two hours in the second Clause. This inconsistency requires clarification to ensure better understanding.

- **Clarification on transfer of rights for long-term/medium-term:** As per the draft Clause 11.2, *"A medium-term/ long-term consumer shall not relinquish or transfer his rights and obligations specified in the Open-access agreement without prior approval of the nodal agency. The relinquishment or transfer of such rights and obligations by a long term consumer shall be subject to payment of compensation, as per the terms of the Open-access agreement."*



In the case of medium-term/ long-term consumer having GEOA, the transfer of such rights should be clarified as to whether it takes place for the part of capacity of such open access on a long-terms basis or such transfer can be done for short-term open access also.

- **Web Portal for the Surplus Availability:** As per the draft Clause 11.4, *"The surplus capacity available as a result of its surrender by the short-term Open-access consumer under clause (1) above or reduction or cancellation of capacity by the SLDC under clause (3) above, may be allocated to any other short-term Open-access consumer in the order of pending applications based on the point of injection and drawal."*

The availability of the surplus capacity (across time blocks) should be made available in advance at least on a day ahead basis as well as on a real time basis at a separate webpage of the web portal to be created for GEOA.

- **Definition for the peak, off peak and normal hour:** As per the draft Clause 12.F.vi., *"The withdrawal of banked energy shall be allowed on a slot to slot basis during the financial year only as per the following system,*

Peak hour banking with peak hour withdrawal;

Peak hour banking with Off peak hour withdrawal; and

Off peak hour banking with Off peak hour withdrawal;

Provided that the withdrawal of power in peak hours shall not be allowed against power banked in Off peak hours."

The GEOA draft does not define the peak and off peak hour, neither such a definition exists in the state grid code. However peak, off peak and normal hour are defined in the Tariff Order while defining ToD tariff. The definition of the above mentioned hours should be clarified upfront.

- **Applicability for Exemption with Storage System:** As per the draft Clause 12.1.a.(ii), *"With Storage System Grid connected solar projects with storage systems selling power within the state shall 100% exemption from transmission charges for a period of 10 years from the date of commissioning of the project. The details of the exemption shall be specified in the bidding document. Provided that the transmission losses are fully applicable for both third parties as well as captive solar project within the state."*

The above mentioned clause does not specify minimum storage capacity with reference to the capacity of the overall solar project. For instance, can a 100 MW Solar project with just 1 MWh storage system would also qualify for full exemption. The minimum capacity of storage system should be mentioned in the draft regulation for 100% exemption to be valid.

Alternatively, a prorated exemption can be specified, wherein it is linked with the proportion of storage to the total capacity of the solar project.

The above should also provide for projects selling part of the electricity generated outside the state. In such cases, only the power consumed within the state may quality for the exemption. This would enable higher investment in the state, wherein economies of scale can benefit the projects with larger capacity.

APSERC (Grid Interactive Distributed Renewable Energy System with Net Metering, Net Billing, Net Feed In, Gross Metering and Its Related Matters) Regulations, 2024

This draft aims at renewable energy adoption in the state of Arunachal Pradesh and provide a structured approach to integrate distributed renewable energy system. The scope covers aspects such as definitions, general principles, capacity targets, metering arrangements and billing and settlement procedures.

Objective: The Distribution licensees have a specified capacity target of 50 MW allowed under various metering arrangements.

- Provisions are made for third-party owned renewable energy systems, including the conditions for leasing premises, exemption from open access restrictions and the role of distribution licensee.
- The Regulations enforce standards for the interconnection of renewable energy systems with grid, ensuring safety and compliance with existing technical standards.

CER Opinion

Determination of Capital Cost on the basis of prevailing market trends: The draft Regulations proposed to use market trends to arrive at a capital cost for determining the tariff for various RE technologies. It is important to mention that the data on capital cost is maybe of private nature and may be treated as commercial information by a number of RE Generators. Specifically, those who have selling power through the process of competitive bidding. Capital cost should be ascertained on the basis of those projects which have been ascertained from competitive bid tariff. In case of RE Projects for which tariff is going to be determine under section 62 and 63, there is perverse incentive for potential over invoicing for providing a higher capital cost.

The commission should spell out the mechanism through which such capital cost should be recovered, data for such capital cost should be based on quote-unquote market trends. Furthermore, care should be taken to ensure that the market prices obtained from different points of time are appropriately adjusted from the value of money i.e. they are converted to the current prices using appropriate price indexation.

The capital cost may vary across depending upon different projects, transportation charges, maintenance contracts of utilities etc. Thus, while compiling the additional information related to such aspects, should be included. Various SERCs/ JERCs have spelled out the similar approach to obtain market prices. It would be advisable that database for such capital cost is to be done through the coordinated effort of forum of regulators.

Rated Capacity of Energy Storage System (ESS): The draft regulations does not specify a minimum storage capacity requirement for the overall project, leaving it open-ended and potentially subject to varying interpretations or requirements (example – varying sizes). In the absence of any specific requirement, any minimal capacity would redefine the RE Project with energy storage services and would redefine such additional incentives.

CUF for Renewable Hybrid Energy Projects: As per the Draft Clause 53, *"……Provided that the minimum capacity utilization factor for renewable hybrid energy project shall be 30% when measured at the inter-connection point, where the energy is injected into the grid."*

The clause defines the eligibility criteria for RE hybrid energy project is minimum 30% CUF. This criteria mentioned in the document seems to be applicable only for the definitional purpose of RE hybrid projects, since 'minimum CUF' and 'normative CUF' are two different concepts, whereas the first is applicable only in case of definitional purpose and the second is applicable for the purpose of determination of tariff. It is important that the regulation should clearly specify separate number, for normative and minimum CUF unless these are numerically same.

Plants With Multiple PPAs Connected to a Single Injection Point: In case of a single injection point for sale of power under multiple contracts, estimation of CUF for hybrid RE projects should also ensure that the single injection point have the metering capability which are able to separately measure the electricity supply which are supplied to DISCOMs under the tariff determined for the same. In certain instances, if single metering point is used for injecting electricity for more than one PPA that makes it difficult to identify the portion of energy injected and deviations thereof.

Determination of O&M for Renewable Energy with Hybrid Energy Project: As per the Draft Clause 54, *"The Commission shall determine only project specific O&M expenses considering the prevailing market trends."*

The O&M services for RE projects / RE hybrid projects are often not there, it is difficult to evaluate the market trends/market rate of O&M cost for standalone or hybrid tariff. In the absence of lack of data, the commission should specify the appropriate manner in which such data would be determined. It is suggested that the Commission may use a benchmarking approach utilizing data on O&M expenses across the number of projects under private as well as public ownership across the country. Since such data could be utilized by multiple ERCs, it is suggested that Forum of Regulators may develop an approach to regularly compile such data for its utilization by ERCs.

- **Treatment of Levelised Tariff:** As per the Draft Clause 55, *"The tariff for a renewable hybrid energy project shall be a composite levelised tariff for the project as a whole by factoring in the tariff components up to the minimum of the useful life of the RE technologies combined for such RE hybrid Project:"*

  The draft clause should clarify that the levelised tariff represents a discounted present value of average tariff for each year of the contract in future. It should be clarified if the applicable levelised tariff will remain fixed or to be allowed to be escalated. In that case, escalation factor to be used should also be identified.

- **Storage of Energy:** It should be clarified if such projects can only store energy produced from the renewable energy project itself or can arbitrage on value of energy across different times of the day(s). Further, storage of energy should be technology agnostic. Framework for monitoring of energy stored and utilization thereof should be defined. Adoption of storage technology should be on the basis of value that brings to the stability to the operation of the grid.

- **Energy Banking:** The energy banking provisions should also be outlined in the draft regulations for both existing and new renewable energy based plants.

- **Eligibility Criteria for Wind Power Project:** As per the Draft Clause 4.1, *"using new wind turbine generators, located at the sites approved by State Nodal Agency/State Government with capacity equal to 25 MW"*

  The Clause may be rephrased as "using new wind turbine generators, located at the sites approved by State Nodal Agency/State Government with capacity lower than or equal to 25 MW" (emphasis added).

- **Calculation of Capacity Utilization Factor and Plant Load Factor:** As per the Draft Clause 20, *"The number of hours in a year for calculation of capacity utilization factor and plant load factor, as the case may be, shall be considered as 8760"*.

  The clause so assumed that each year has 365 days in a year but considering the leap year, number of hours in the additional day should be redistributed in the calculation of average. Thus, number of hours in the calculation shall be considered 8766.

- **Project specific tariff determination:** The regulation may identify the financial principles/framework for the generic tariff that would also apply for project-specific tariff and which one would be defined separately for specific cases. For example, capital cost may be project specific, but Debt-Equity ratio, working capital, auxiliary consumption etc. would be the same for project specific tariff.

Tariff

TERC concluded that creating a separate slab for defence establishment at par domestic consumers was not required and maintaining current arrangements was fair to both parties due to transparent tariffs and compliance with regulations. Further, granting deemed licensee status wasn't cost-effective as it requires setting up a separate structure.

JSERC directed to pay JBVNL, a notional fine of Rs.10 lakhs for the aforementioned non-compliances to BEE within three months from the date of order issue. Failure to comply will result in an additional interest of 9% per annum being applicable for the delayed payment.

JSERC intended to revise the computation of Incentive for Achievement of Transmission Availability Factor (TAF) of DVC T&D system in accordance to CERC issues of True up Order for the Control Period FY 2019–20 to 2023-2024 for DVC.

BERC has reviewed the methodology of levying cross subsidy surcharge and other surcharges on a monthly basis to M/s Ultara Tech Cement Ltd. and finds no fault in the approach adopted by the South Bihar Power Distribution Company Ltd.. They determine that if the petitioners meet the conditions specified in Rule 3(1)(i) and (ii) by the end of the year, the charges collected will be refunded to them.

BERC allowed M/s Harinagar Sugar Mills Ltd. & M/s Bihar Sugar Mills Associations request regarding the determination of bagasse prices for FY 2020-21 and 2021-22, in line with their relevant provisions of the Power Purchase Agreements (PPAs) and other applicable rules, while the interest on the payable amount due to bagasse price differences (escalation) is deemed unjustifiable.

GERC directed that the awarded tariff be accepted, and GUVNL was advised to issue the Letter of Award to the L1 bidder for the tie-up of 293 MW at the specified tariff and that GUVNL to secure long-term power procurement. The order details the procedural adjustments made to encourage competition and the eventual negotiation to a tariff that balances cost efficiency and power supply reliability for the state.

GERC decided to amend the RGP Tariff category provisions for the remaining period of FY 2023-24 to include small-scale animal husbandry activities involving not more than 30 milking animals. Consumers wishing to avail of this tariff benefit must produce a certificate issued by the competent authority concerned at the sub-division office of the Distribution Licensee. The discoms DGVCL, PGVCL, UGVCL, and MGVCL were directed to issue a public advertisement regarding this amendment and file an affidavit in compliance with the Commission's directive.

MSERC approved the generic tariff for Ganol SHP applicable from FY 2024-25 and valid till 40 years of project life. The construction of the project started in 2014 and commissioning date of project is 01.08.2023. This delay in project commissioning have resulted in increase of capital cost of project from Rs. 177.52 Cr. in 2008 to estimated Rs. 602 Cr. in current petition. After due consideration the Commission have approved following Annual fixed charges as shown in table below:

Particulars	Filled by Petitioner (in Rs. Cr.)	Approved for RE tariff (in Rs. Cr.)
Interest on Loan Capital	16.81	15.39
Depreciation	15.74	13.92
O&M Expenses	7.76	7.76
Interest on Working Capital	0.95	0.85
Return on Equity	12.96	8.74
Total Annual Fixed Cost	54.22	46.66

UPERC approved NIDP Developers Pvt. Ltd. filed a petition for the adoption of a tariff and approval of a Power Purchase Agreement (PPA) for the procurement of up to 6.00 MW power for a period of 7 months, from April 1, 2024, to October 31, 2024. The tariff of Rs. 6.56/kWh was discovered through a competitive bidding for procurement of power from 4.00 MW to 6.00 MW for the period from April 1, 2024, to October 31, 2024 and allowed to sell surplus power up to 10% of the contracted quantum from June 2024 onwards in the power exchange through a Trading Licensee.

HERC decided that the determination of tariff to be for the 25 years useful life of the project and the tariff payable to Greenyana Solar Pvt Ltd. shall be fixed on levelized tariff, for the entire life of the 10.72 MWp solar power project .

KSERC allowed the petition of Kerala State Electricity Board Ltd. to permit the developer M/s Nippon Infra Projects Pvt

Ltd to avail Single Point Supply from KSEB Ltd. to their commercial project "Nippon Infra QI projects", Ernakulam and to provide electricity to the individual beneficiaries within the building on under Section 86(1)(f) of the Electricity Act, 2003 for resolution of the disputes between GRIDCO Ltd., M/s. TPWODL with the Petitioner M/s. SAIL, Rourkela Steel Plant, Rourkela.

OERC Directed M/s. TPWODL and M/s. SAIL to initiate action in co-ordination with OPTCL and provide power supply to M/s. LIL and M/s. SER directly from the Grid at the earliest. In this regard, it is directed to constitute a Committee under the Chairmanship of the CMD, OPTCL, comprising of the Senior Officials representing concerned parties, namely OPTCL, TPWODL, M/s. SAIL (RSP), M/s. LIL and M/s. SER, to discuss the matter for providing power supply to M/s. LIL & M/s. SER directly from the Grid as suggested by the OPTCL in its submissions. The report of the Committee along with the suggested remedial action with defined timeline for execution of the same shall be submitted to the Commission by the OPTCL within two months of issuance of this order.

Power Procurement

WBERC approved the Power Purchase Agreement executed on November 30, 2022 between Indian Railways and IPCL for purchase of 13 MW power from IPCL at 132 KV at Pandabeswar TSS drawl point at the mutually agreed tariff and associated conditions.

WBERC approved the arrangement to determine the tariff through ARR with applicable levellized discount of 7 paisa per unit under linkages received in 2nd round and 19 paise per unit under linkage in 6th round of SHAKTI scheme. The discount shall be computed with reference to the scheduled generation from linkage coal to the extent supplied through both the SHAKTI Schemes and the benefits shall be passed on to the end consumers through tariff. Such discount shall also be passed on to the consumers through the Monthly Variable Cost Adjustment.

GERC approved on MPSEZ Utilities Limited's petition to procure 2077 MW of power on a long-term basis for its licensed area and also approved the deviations from the Model Bidding Documents issued by the Ministry of Power for wider participation and competitive bidding.

GERC has approved GUVNL's petition for short-term power procurement of 700 MW of round-the-clock (RTC) at the specified rate of Rs. 6.48 to Rs. 9.00 per kWh. to ensure a reliable power supply during the specified period, with the tariffs determined through a transparent bidding process while keeping the names of successful bidders public and the tariffs quoted by other bidders anonymous.

GERC allowed the Torrent Power Ltd. petition for a short-term power purchase arrangement for July 1, 2024, to August 31, 2024. The approval is based on the transparent bidding process conducted by the company and the recommendations of the Standing Committee. The company is directed to submit copies of duly executed Power Purchase Agreements (PPAs) to the Commission and make the bids public for transparency, in line with the MoP guidelines and GERC regulations.

HERC considered the power deficit scenario projected by HPPC for the period from May, 2024 to October, 2024 and hereby approved power procurement at a tariff up to Rs. 7.75/kWh for the month of June, 2024. However, in the months of July to October, 2024, the power proposed to be procured is approved at a tariff up to Rs. 7/kWh. The Commission approved 1640 MW (July), 1590 MW (August), 1740 MW (September) and restrict the quantum of power during October month to 479 MW i.e. in line with the deficit projected by the Haryana Power Purchase Centre, Panchkula (HPPC).

KSERC decided to approve the proposal of CIAL Infra Ltd to extent validity of the PPA dated December 16, 2022 for a further period of two years from April 01, 2023 to March 31, 2025, at the tariff @Rs 2.37/unit and also electricity generated and injected into the grid from November 13, 2021 to June 14, 2022 shall be settled at the approved tariff of Rs. 2.37 /kWh.

KSERC approved the petition of M/s KSEB Ltd for entering in the banking transaction with M/s Shubheksha Advisors Private Limited for supply period from March 15, 2024 to March 31, 2024 with return period from June 01, 2024 to June 30, 2024. The details of the banking transaction is mentioned below:

Trader	Source	Offered Quantum (MW)
Shubheksha Advisors Private Limited (SAPL)	NR Utilities	200 MW RTC power on firm basis

Supply Period	Return Period	Return (%)	Trade Margin
15th to 31st March 2024	1st to 30th June 2024, RTC on firm basis	105	4 ps/ unit

Regulatory Updates

Renewable Energy, RPO and REC

TERC granted permission to Airport Director, Agartala Airport to establish a 2.0 MWp Solar Power plant under special circumstances, with a 12 month deadline from the date of the order for installation and commissioning.

GERC approved the tariffs the Gujarat Urja Vikas Nigam Limited (GUVNL) seeking the adoption of tariffs discovered under a competitive bidding process for procuring 800 MW of grid-connected solar photovoltaic power from projects located in GSECL's Solar Park at Khavda, with an option for an additional capacity of up to 800 MW and it further, emphasized on the need for transparency and compliance in executing the PPAs.

GERC has approved GUVNL petition for adoption of tariffs discovered through a competitive bidding process for procuring power from solar projects to be set up in Dholera Solar Park in Gujarat for the 400 MW capacity based on the merits of the case, without being influenced by previous observations. The decision will take into account the need to balance consumer interests with the economic viability of the procurement.

UERC directs UPCL and APPCPL to accommodate the changes suggested by both the parties in draft energy banking agreement. The new amended agreement must be submitted within 15 days from the date of issuance of this order.

OERC allowed OPTCL to charge for reactive energy at 3 paise/kVARh, subject to OPTCL submitting justifications in next filing. The tariff for transmission over OPTCL's lines and substations is fixed at Rs. 24 paisa/ kWh. The net transmission cost approved is Rs. 913.70 Cr, to be recovered from an estimated energy transmission of 38,073.49 MU, with open access charges set at Rs. 5760/MW/day or Rs. 240/MWh. Transmission loss for wheeling is approved at 3.00% for the year. Payment security mechanisms include a letter of credit arrangement. Exemptions on STU charges are provided for consumption from renewable energy projects. The approved transmission tariff comes into effect from April 1, 2024, until further orders.

JERC (Goa & UTs) disapprove the petition of VE commercial vehicle Ltd. regarding the use of electricity at their captive charging station aligns with the tariff category of EV charging station. Hence they should be charged a tariff of Rs. 3.60/kWh instead of Rs. 4.50/kWh, which is the tariff for the HT commercial category. The petitioner was ruled in favor of the EWEDC. The Commission clarified that the tariff category of Electric Vehicle Charging Station in the tariff order dated 30th March, 2023, applies only to public charging stations and does not include captive charging stations.

KSERC approved the proposal of Kerala State Electricity Board Ltd. dated 12.03.2024 for Procurement of hydropower on short term basis at Rs.7/unit from 60 MW Naitwar Mori project of SJVN Limited for period from 10.03.2024 to 15.06.2024. KSEBL and SJVNL shall sign an undertaking to the effect that, the benefit shall be passed on to KSEB Ltd in case the CERC determined tariff is lower than the ceiling tariff @ Rs. 7.00/kWh.

Others

WBERC decides to consider the proposal of WBSEDCL to amend the State Grid Code Regulation under provision of Section 86(1)(h) of the Electricity Act, 2003 and take suggestions / objections and comments from the stakeholders.

UERC instructed UJVN to install a protection device (SPS) to shut down the small hydro plant if voltage limits are exceeded. The Commission also noted that this measure would not impact the plant since power evacuation is permitted only during dry and lean seasons. Additionally, it instructed UPCL to allow the connection to UJVN until March 15, 2024, and to submit a technical report by the same date.

UERC approved UJVN request for an extension to continue evacuating power until May 31, 2023, due to a clerical error in a previous order. HHPL accused UJVN causing mislead and prompting the Commission to criticize UJVN for attempting to exploit a typographical error to undermine its authority. The Commission emphasized adherence to the timelines outlined in previous order.

OERC approved a total of Rs. 1,596.078 Lakhs for SLDC, Orissa operation during FY 2024-25. The charges are divided into System Operation Charges (SOC) at 80% and Market Operation Charges (MOC) at 20% of the Annual Fixed Charges (AFC). The SOC and MOC are further apportioned among the Intra-State Transmission Licensee, Generating Stations & Sellers, and Distribution Licensees & Buyers based on specific percentages and energy consumption.

Note: *'Other Notifications' can be accessed through the online version of this issue.*

Tariff Orders

SERC/ JERC	Licensee/ Utility	True-up	APR	ARR	Tariff
JERC (M&M)	Power & Electricity Department Government of Mizoram	FY 2022-23	FY 2023-24	FY 2024-25	FY 2024-25
TNERC	TANGEDCO	FY 2021-22	-	-	-
BERC	BSPTCL, NBPDCL, SBPDCL	FY 2022-23	FY 2023-24	FY 2024-25	FY 2024-25
JSERC	JBVNL	FY 2021-22	FY 2022-23	FY 2023-24	FY 2023-24
PSERC	PSPCL, PSTCL	FY 2021-22	FY 2022-23	FY 2025-26	FY 2023-24
KERC	KPTCL	-	FY 2022-23	FY 2024-25	FY 2024-25
KERC	BESCOM, MESCOM, HESCOM, GESCOM, CESC	-	FY 2022-23	FY 2024-25	FY 2024-25
HERC	HVPNL, DHBVNL	FY 2022-23	FY 2023-24	FY 2024-25	-
MSERC	MePGCL, MePDCL, MePTCL	-	-	FY 2024-25	-
OERC	OHPC, OPGC, GRIDCO, OPTCL, SLDC, TPCODL, TPNODL, TPSODL, TPWODL,	-	-	FY 2024-25	FY 2024-25

Regulations

Title	Date of Approval/Notification
TNERC (Forecasting, Scheduling and Deviation Settlement and Related Matters for Wind and Solar generation) Regulations, 2024	14/02/2024
TNERC (DSOP amendment, 2023 embodying consumer rules 2020 and CRP recommendations) Regulations, 2024	21/02/2024
TNERC (Re-nomination of SAC Members)	21/02/2024
KSERC (Terms and Conditions for Determination of Tariff) (Second Amendment) Regulations, 2024	27/02/2024
KERC (Pre-paid Smart Metering) Regulations, 2024	06/03/2024
HPERC (Terms and Conditions for Determination of Transmission Tariff) Regulations, 2023	14/03/2024
JSERC (Electricity Supply Code) (Second Amendment) Regulations, 2024	15/03/2024
JSERC (Renewable Energy Purchase Obligation and its compliance) Regulations, 2024	15/03/2024
DERC (Group Net Metering and Virtual Net Metering for Renewable Energy) (Fifth Amendment) Guidelines, 2024	15/03/2024

Regulatory Certification Programme on “Power Sector Regulation: Theory and Practice”

CER, in collaboration with EAL, conducted the Regulatory Certification Program titled **"Power Sector Regulation: Theory and Practice"** from February 17, 2024 to March 3, 2024. The program aimed to delve into the evolution, economic dynamics, and regulatory frameworks governing the power market within India. Hosted under the umbrella of the Centre for Continuing Education at IIT Kanpur, the inaugural session on February 17, 2024, was honored by the presence of Shri P.W. Ingty, Former Chairman of the Meghalaya State Electricity Regulatory Commission.

Distinguished speakers such as Mr. S. C. Srivastava (Former Chief (Engg.) CERC), Mr. H.T. Gandhi (Advisor, CERC), Prof. Anoop Singh (Founder and Coordinator, CER, IITK), and Ms. Shilpa Agarwal (Jt. Chief (Engg.), CERC) among others, facilitated enlightening lectures throughout the program.

The valedictory session, under the auspices of Shri Mr. Arvind Kumar, IAS (Chairman, UPERC) marked the conclusion of the program, bringing together insights and reflections from the extensive discourse on power sector regulation.

Centre for Energy Regulation Spearheads Dialogue on “Power Market Derivatives”

In a pivotal step towards addressing the evolving dynamics of the Indian Power Sector, the Centre for Energy Regulation (CER) at the Indian Institute of Technology Kanpur organized a Stakeholder Consultation Workshop on **"Developing Power Market Derivatives for the Indian Power Sector."** The event on 1st March 2024, held at the India Habitat Centre in New Delhi, brought together key stakeholders to explore innovative solutions and develop risk mitigation strategies amidst the growing share of renewables and market volatility.

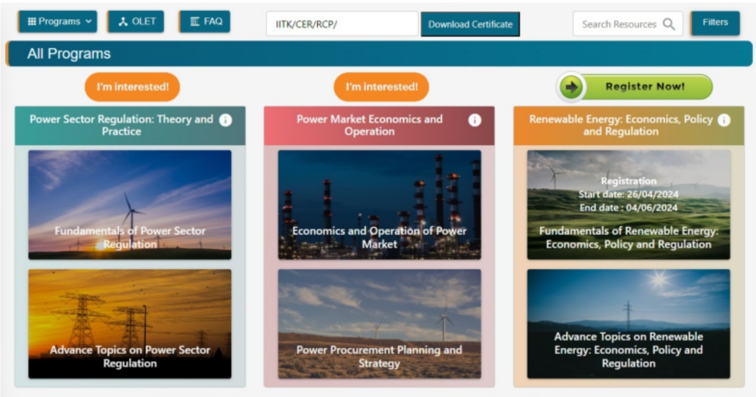
Professor Anoop Singh, Department of Management Sciences, IIT Kanpur, a leading authority in the field, presented the key outcomes of an ongoing study conducted by CER (for more details of CER activities and studies please visit https://cer.iitk.ac.in) with support from the Shakti Sustainable Energy Foundation. Through his presentation, Professor Singh shared insights into derivative product design, regulatory frameworks, and policy implications vital for successful implementation of power market derivatives in the country. He proposed an innovative approach to facilitate sector-wide participation in financially settled and physically delivered derivatives, aimed at mitigating risks encountered by DISCOMs, Open Access Consumers, and Thermal/RE generators.

Dr. Srikant Nagulapalli, Additional Secretary of the Ministry of Power, delivered the Keynote Address, acknowledging CER's accomplishments in the study and highlighting the government's initiatives for Renewable Energy (RE) integration and market development. He emphasised on the workshop's importance in shaping the power sector's future.

The event featured two insightful panel discussions and deliberations among esteemed industry professionals. The first panel, comprising representatives from the Central Electricity Authority, PTC India Ltd, Indian Energy Exchange, and EY Parthenon, explored the theme **"Identifying Risks and Hedging Avenues in the Indian Power Market: Role of Derivatives".** The second panel delved into the **"Regulatory Framework for Power Market Derivatives"** with Professor Singh setting the stage through a presentation. Eminent panelists from the Punjab State Electricity Regulatory Commission, Central Electricity Regulatory Commission, Grid India, Securities and Exchange Board of India, and The Lantau Group offered valuable insights and perspectives on this critical aspect. The discussions highlighted the pivotal role of derivatives in power market development and the need to enhance understanding among key stakeholders, particularly distribution companies. These entities could leverage such instruments to effectively hedge their exposure to short-term power market volatility, ensuring greater stability and risk mitigation.

The workshop concluded with a consensus on the potential of power derivatives to enhance market efficiency and manage risks in the Indian power sector. CER's pioneering initiative garnered appreciation from attendees for its timely and comprehensive approach to addressing the sector's evolving challenges, encouraging dialogue, and exploring innovative solutions for a sustainable and resilient power ecosystem.

Regulatory Certification Programme on “Renewable Energy: Economics, Policy and Regulation”



CER in association with EAL, is pleased to announce the Regulatory Certification Program on **“Renewable Energy: Economics, Policy and Regulation”** commencing from **07th June to 23rd June, 2024.** The program on Renewable Energy Regulation focuses on regulatory and policy framework for Renewable Energy (RE). The program would be conducted under the aegis of Centre for Continuing Education, IIT Kanpur. The last date for registration is **04th June, 2024.** For further program details including program duration, key topics, schedule, admission process and fee, please visit: https://cer.iitk.ac.in/re_reg/?id=3.

We invite readers to register at CER's web portal to access CER's publications and resource material. This would also help us design CER's activities and deliver a more relevant output by engaging with stakeholders. We also request your inputs on the periodical and the activities of the Centre.

Regulatory Insights Team

Other Initiatives

Energy Analytics Lab

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Note: *Additional information can be accessed through the hyperlinks provided in the online version of this periodical.*