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REGULATORY INSIGHTS

Regulated Tariff Framework and Competitive Bidding Guidelines for Storage

Regulatory Outlook

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Editorial

Power purchase cost accounts for approximately 70-80% of the final tariff paid by consumers. The projected quantum of energy sales, sources of supply, cost of procurement (capacity as well as variable charges) and variation in share of renewables determine the overall cost of power procurement for the distribution licensees. While the projected costs pertain to the tariff control period, the actual cost of power procurement fluctuates from month to month. Power procurement cost generally trends upwards, primarily due to rising cost of coal. This escalation places stress on the working capital requirement of the Discoms, who are entitled to working capital based on the approved cost of power procurement. Section 62 of the Electricity Act, 2003 provides for adjustment towards such cost changes within a year.

Discoms should diligently follow the process for Fuel and Power Purchase Adjustment, Surcharge (FPPAS) in a timely manner to ensure that the additional interest cost burden do not impact on their financial performance. The regulatory framework for FPPAS should account for the allowable cost increase, primarily due to cost of power purchase tied up u/s 62 or 63 of the Electricity Act, 2003. However, short-term power procurement beyond the limit imposed in terms of quantum as well as maximum/average price, should be excluded from the calculation of FPPAS. Apart from price of coal, variability in quality of coal supplied to the thermal power stations can be linked to uncertainty associated with variable cost, thus impacting the FPPAS to be paid by the consumers. Visibility of such variations to the regulators and end consumers would sensitise the two key stakeholders responsible for the approval and the payment of FPPAS respectively. Regulatory framework for tariff across the country should ensure archival and visibility of such information for all the thermal power plants by source of coal supply. This would help ascertain the concerns of the generators, and help design solutions thereof.

Competitive bidding guidelines for storage, particularly the pumped storage plant (PSP) sites, should ensure sufficient competition and a choice of public-private partnership model. Given the rising flexibility requirements of the Indian power system, the availability of PSPs and their required charging and discharging rates should be integral technical characteristics for competitive bidding.

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Founder & Coordinator, Centre for Energy Regulation

Keywords: FPPAS, Emission Control System, Flexible Operation, Auxiliary Energy Consumption, Transmission Charges, Tariff Determination, PAT Scheme, Battery Energy Storage System, Frequency Response Performance, Coal Price Caps and Storage Capacity Charge.

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Opinion on UPERC (MYT for Distribution and Transmission Tariff) (Third Amendment) Regulations, 2024 [Draft]

Cite

The UPERC notified draft on "MYT for Distribution and Transmission Tariff" (Third Amendment) Regulations, 2024 issued on 2nd September, 2024. The key objective of the draft are mentioned below:

Objective: The draft document updated methodology on "Treatment of Incremental Power Procurement Cost" under previous UPERC MYT for Distribution and Transmission Tariff Regulations, 2019. The draft document specifies that the computation of the fuel and power purchase adjustment surcharge (FPPAS) shall be automatically passed through and adjusted for monthly billing in accordance with proposed draft regulations. Additionally, the FPPAS shall not exceed a maximum duration of **two months**. In cases where the adjustment surcharge over the previous month exceeds 20% of the variable component of the approved tariff, the surcharge will be subject to review and adjustment as per the applicable regulations proposed.

CER Opinion

Clarification on FPPSA Surcharge Adjustments & Recovery : In the proposed Clause 16.1(3) *"Fuel and Power Purchase Adjustment Surcharge shall be computed and charged by the distribution licensee, in (n+2)th month, on the basis of actual variation, in cost of fuel and power purchase and Inter- state Transmission Charges for the power procured during the nth month.*

Provided that in case the distribution licensee fails to compute and charge FPPAS within this time line, except in case of any force majeure condition, its right for recovery of costs on account of FPPAS shall be forfeited and in such cases, the right to recovery the FPPAS determined during true-up shall also be forfeited."

The above Clause seems to presume that the FPPSA would always be positive. There can be circumstances leading to a decline in the power purchase cost, thus a negative surcharge necessitating downward adjustment in tariff to be charged from the consumers.

Even if the language of the Clause presumes a positive surcharge, it would have applicability in case of a negative surcharge as well. A clarification may be added to ensure that **'in case of negative surcharge' the same would be recoverable from the licensee at the time of true up.**

In case 'deemed' surcharge (calculated using the formula) is more than the limit for automatic recovery of the surcharge, would the portion of surcharge beyond this limit would also be recoverable? Clarification to that effect may also be included.

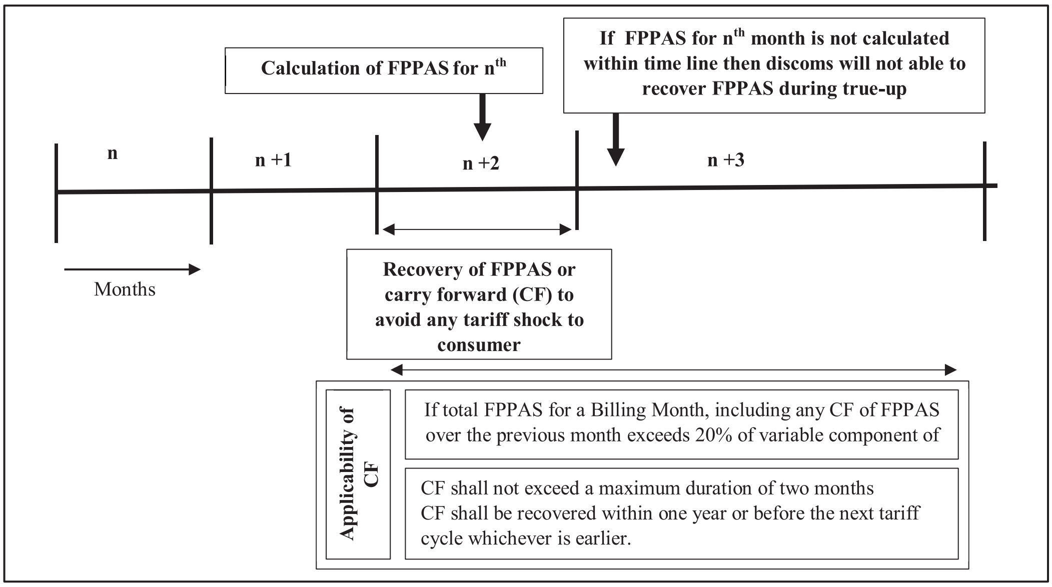


Figure 1: Timeline for recovery of FPPAS

Suggested citation: Singh, A. (ed.). (2024), Opinion on UPERC (MYT for Distribution and Transmission Tariff) (Third Amendment) Regulations, 2024 [Draft], In Regulatory Insights (Vol. 07, Issue 03, pp. 2–3), Centre for Energy Regulation (CER), Indian Institute of Technology Kanpur. https://cer.iitk.ac.in/newsletters/regulatory_insights/Volume07_Issue03.pdf

Define Baseline Value for Calculation of FPPAS: In the proposed Clause 16.1(6) *"Depending upon quantum of fuel and power purchase adjustment surcharge, the automatic pass through shall be adjusted in such a manner that, (i) If fuel and power purchase adjustment surcharge ≤5%, 100% cost recoverable of computed fuel and power purchase adjustment surcharge by distribution licensee shall be levied automatically using the formula. (ii) If fuel and power purchase adjustment surcharge >5%, 5% fuel and power adjustment surcharge shall be recoverable automatically as per 6(i) above, 90% of the balance fuel and power purchase adjustment shall be recoverable automatically using the formula and the differential claim shall be recoverable after approval by the Commission during true up."*

According to proposed Clause16.1(6), which states "If the FPPAS is less than or equal to 5%," there is a lack of clarity regarding the base value used for the calculation.

Consideration of ST Power Procurement Cost Limits in FPPSA: In the proposed Clause 16.2(1) *"A is Total units procured in (n-2)th Month (in kWh) from all Sources including Long-term, Medium-term and Short-term Power purchases (To be taken from the bills issued to distribution licensees)".*

It is suggested that any costs associated with short-term power procurement included in the calculation of the Fuel Surcharge but should exclude any procurement that exceeds the limit specified by the commission, whether in terms of quantum or associated cost. For example, if a cap is set at Rs. 8 per unit and power is procured at Rs. 10 per unit, that power should be excluded from calculation.

Actual Energy Sales Instead of Bulk Sale of Power (B): In the proposed Clause 16.2, *"B is bulk sale of power from all Sources in (n-2)th month (in kWh) = (to be taken from provisional accounts to be issued by State Load Dispatch Centre by the 10th day of each month)".*

It is suggested that 'Actual Energy Sales' would be used in the formulation instead of bulk sale of power (B) as revenue collected by discom is based on actual energy sale.

Transmission Charges: In the proposed Clause 16.2, the formulation of FPPAS includes the difference between actual and projected transmission charges i.e., additional cost due to change in transmission charges.

$$\frac{(D-E)}{\{Z*(1-Distributation\ losses\ in\ \%/100)\}*ABR} \qquad (1)$$

Where

D = Actual inter-state and intra-state Transmission Charges in the (n-2)th Month, (From the bills by Transcos to Discom) (in Rs)

E = Base Cost of Transmission Charges for (n-2)th Month. = (Approved Transmission Charges/12) (in Rs.)"

It is suggested that the transmission charges (D) on account of power purchases would be based on actual sales as per approved inter and intra transmission losses.

Energy Sale Outside the State: In the proposed Clause 16.2(1), "Computation of Fuel and Power Purchase Adjustment Surcharge:

$$Monthly\ FPPAS\ for\ nth\ Month\ (\%) = \frac{(A-B)*C+(D-E)}{\{Z*(1-Distributation\ losses\ in\%/100)\}*ABR}" \qquad (2)$$

A is total units procured in (n-2)th Month (in kWh) from all Sources including Long-term, Medium-term and Short-term Power purchases (To be taken from the bills issued to distribution licensees).

B is bulk sale of power from all Sources in (n-2)th Month. (in kWh) = (to be taken from provisional accounts to be issued by State Load Dispatch Centre by the 10th day of each month).

C is incremental Average Power Purchase Cost (including the change of fuel cost) = Actual average Power Purchase Cost (PPC) from all Sources in (n-2) month (Rs./ kWh) (computed) - Projected average Power Purchase Cost (PPC) from all Sources (Rs./ kWh)- (from tariff order)".

Is energy sale outside the states incorporated in this formation or not? For example, in case surplus energy sold from state or central generating station to another state how it is incorporate in this formulation. In the proposed Clause 16.2 doesn't explicitly define 'energy sale outside the states'. How we can interpret it.

Point of Sale-State Periphery or Distribution Licensee Area: If energy is sold outside the state by a discom, distribution losses thereof should not be considered in the formulation as this would be a sale at the discom/state periphery (Figure 2). It is suggested that the specific definition of energy sale outside the state should be outlined in the draft regulation.

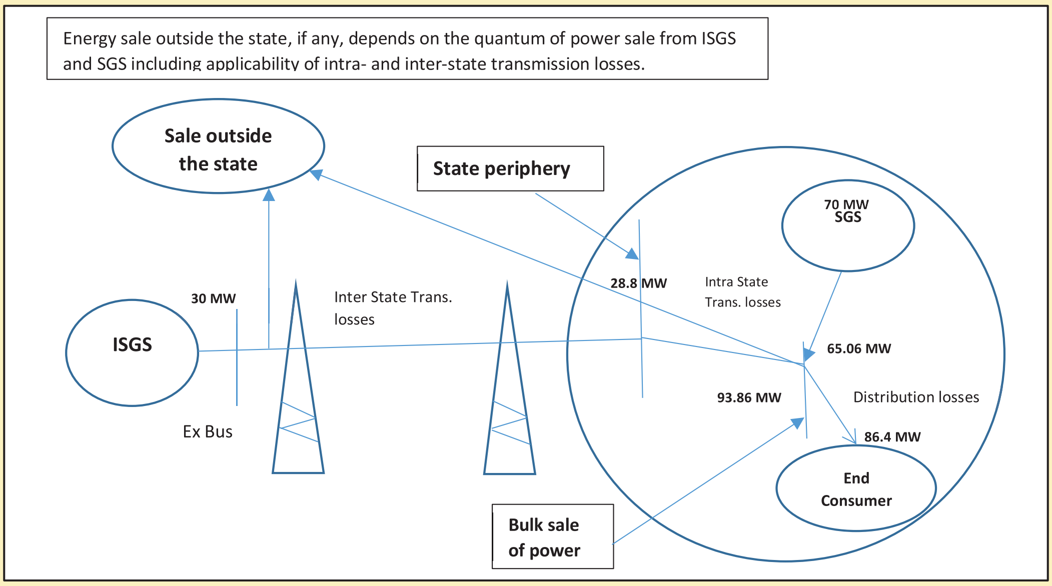


Figure 2: Power flow from inter-intra state (including transmission and distribution losses)

In the case of energy sold outside the state or to open access consumer at a higher price compared to average power procurement cost, then FPPAS should be reduced (this would allow for a fair pricing structure), and the end consumer should benefit from this (as the benefit of lower cost is passed on to end consumers).

- **Updating Merit Order with Actual VC:** Once the 'actual' variable cost of power purchase from various plants power purchase agreements is known or for the nth month, by say 10th of the month or so, the same should be reflected in the merit order for the next. This would help further optimize the power purchase cost.

Opinion on OERC (Terms and Conditions for Determination of Generation Tariff) Regulations, 2024

Cite

The OERC notified draft on “Terms and Conditions for Determination of Generation Tariff” Regulations, 2024 on 14th October, 2024. The Key highlights of the draft are mentioned below:

Objective: The draft regulations, will guide the determination of generation tariffs for existing and future generating stations, excluding those with tariffs set through competitive bidding or by the Central Electricity Regulatory Commission (CERC), and those based on renewable energy sources. The regulations cover various aspects including the determination of tariffs based on capital costs and operational efficiency, components of tariffs for thermal and hydro generating stations, norms for plant availability and efficiency, and provisions for billing, payment, and sharing of financial gains.

Key points :

1. **Tariff Determination:** The tariff will be determined based on capital costs, operational efficiency, and other factors. Applications for tariff determination must be submitted within 90 days from the date of commercial operation for new projects and by 30th November, 2024 for existing projects.
2. **Components of Tariff:** Tariffs for thermal generating stations will include capacity charges and energy charges, while hydro generating stations will have capacity and energy charges derived from annual fixed costs.
3. **Capital Cost and Additional Capital Expenditure:** The capital cost will include expenditures up to the date of commercial operation, interest during construction, and other specified costs. Additional capital expenditure will be considered for various reasons, including compliance with laws, force majeure events, and efficiency improvements.

Suggested citation: Singh, A. (ed.). (2024), Opinion on OERC (Terms and Conditions for Determination of Generation Tariff) Regulations, 2024 [Draft], In Regulatory Insights (Vol. 07, Issue 03, pp. 4–12), Centre for Energy Regulation (CER), Indian Institute of Technology Kanpur. https://cer.iitk.ac.in/newsletters/regulatory_insights/Volume07_Issue03.pdf

4. **Operational Norms:** Norms for plant availability, load factor, station heat rate, and auxiliary energy consumption are specified for different types of generating stations.
5. **Incentives and Penalties:** Incentives for achieving higher efficiency and penalties for non-compliance with operational norms are outlined.
6. **Billing and Payment:** Bills for capacity and energy charges will be raised monthly, with provisions for late payment surcharges and rebates for early payments.
7. **Sharing of Benefits:** Financial gains from improved performance, refinancing of loans, and non-tariff income will be shared between the generating company and beneficiaries.
8. **Miscellaneous Provisions:** Provisions for public procurement, relaxation of regulations, and handling of foreign exchange variations are included.

The regulations aim to encourage competition, efficiency, and optimal investment in the electricity generation sector in Odisha.

CER Opinion

Suggestion on Gross calorific Value (GCV) Calculation Methodology: 4th proviso to Clause 3(hh) of the draft document states that "Provided that GCV of as Received coal shall be found out by taking GCV of coal on as **"billed basis"** and allowing an adjustment for total moisture as per the formula given as under:

$$\frac{GCV\ X\ (1 - TM)}{(1 - IM)} \qquad (3)$$

Where: GCV = Gross Calorific Value of coal on as "billed basis"
TM = Total Moisture
IM = Inherent Moisture
According to the CERC Order in **Petition No: 152/MP/2018**[1], *"the Commission, in its various tariff orders, had provisionally determined energy charges based on the "as billed" GCV of coal, due to the unavailability of data on the "as received" GCV. This provisional determination was made with the application of a moisture correction formula and was subject to adjustment once the actual "as received" GCV data became available".*

The adjustment for moisture based approach was to be applicable on an interim basis. The Commission should ensure that GCV "as received" should be measured by an independent third party (as prescribed under the CERC regulations), on the basis of joint sampling of coal received. Furthermore, the regulation does not clarify about the basis for total moisture and inherent moisture in the coal to be used in the above formula.

Since coal cost contributes significantly to the tariff to be paid by the discoms and hence the final consumers, adequate transparency and accountability should be ensured for this exercise. **Data related to coal despatch, receipt including quantum, price, date of despatch and receipt, inventory at hand, GCV as billed and GCV as received for all generating units should archived and made available in the public domain through the Commission's or other suitable website.**

'Change in Law' Definition: In the proposed Clause 3(j)(v) of the draft document states that *"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 regulated under these Regulations."*

The definition 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[2] (emphasis added)

'Date of Operation' Definition: In the proposed Clause 3(o) of the draft document states that *"in respect of an emission control system means the date of putting the emission control system into use after meeting all applicable*

[1] Central Electricity Regulatory Commission (Conduct of Business) Regulations, 1999 seeking adjudication of dispute between the Petitioner and Respondent NTPC Ltd. regarding excess recovery of Annual Fixed Costs for various generating stations of the Respondent during FY 2014-19, Order on Petition No. 152/MP/2018, August, 2019 (152-MP-2018.pdf) https://www.cercind.gov.in/2019/orders/152-MP-2018.pdf

[2] Singh, A. (ed.). (2024), Opinion on CERC (Terms and Conditions of Tariff) Regulations, 2024 [Draft], In *Regulatory Insight* (Vol. 06, Issue 04, pp. 2-12), Centre for Energy Regulation (CER), Indian Institute of Technology (IIT) Kanpur.
https://cer.iitk.ac.in/newsletters/regulatory_insights/Volume06_Issue04.pdf
The comments provided herein are based on the detailed comments submitted to CERC, which may be referred for further clarity.

technical and environmental standards, certified through the management certificate duly signed by an authorized person, not below the level of direction of the generating company".

The above Clause seems to be applicable to the existing plants that would install an add on emission control system. Either this clarification be included, or a proviso that may be added as suggested below. "Date of operation (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 authorized person, not below the level of direction of the generating company. **Provided that ODe is greater than or equal to the Date of commercial operation (COD) of the thermal generating station or its unit."** (emphasis added)

- **'Force Majeure' Definition - Statistical Measures of Adverse Weather Conditions and, Inclusion of System-Wide Cyber-Attack:** In the proposed Clause 3(bb)(If the draft document states that *"Act of God including lightning, drought, fire and explosion, earthquake, volcanic eruption, landslide, flood, cyclone, typhoon, tornado, geological surprises,* ***or exceptionally adverse weather conditions which are in excess of the statistical measures for the last hundred years"*** **and** in the proposed **clause 3(bb)(ii)** of the draft document states that *"Any act of war, invasion, armed conflict or act of foreign enemy, blockade, embargo, revolution, riot, insurrection, terrorist or military action"* (emphasis added)

  To bring objectivity to "statistical measures for the last hundred years", **either a range of deviation from the above measure be provided or let the adversity of the weather condition be declared by the India Meteorological Department (IMD).** Such adversity of weather may need to be localized to affect a generating plant, historical statistical data may not be available at such geographical granularity. In such cases, **the weather adversity may thus be certified by the IMD based on its scientific judgement.**

  It is suggested that a **system-wide cyber-attack, which would affect the operational capability of a generating plant,** be included as a force majeure event under proposed Clause 3(22)(ii). Input from the Indian Computer Emergency Response Team (CERT-In) should be required to ascertain severity of such cyber-attack.

- **Definition of Useful Life:** In the proposed Clause 3(sss) of the draft document states that *"Useful Life in relation to a unit of a generating station from the date of Commercial Operation shall mean the following:*

  i. Coal based thermal generating station - 25 years
  ii. Hydro generating station including pumped storage hydro generating station - 40 years
  iii. AC and DC sub-station - 25 years
  iv. Gas Insulated Substation (GIS) - 25 years
  v. Transmission line (including HVAC & HVDC) - 35 years
  ***vi. Optical Ground Wire (OPGW)** - 15 years*
  vii. IT system, SCADA and Communication system excluding OPGW - 7 years (emphasis added)

  The useful life of Optical Ground Wire (OPGW), **based on the terms specified in tenders, is generally 25 years. Based on industry experience of such replacement, a higher useful life may be specified for the same.**

  It is also proposed to define useful life of Integrated Coal Mines and relate this to the mining plan.

- **Determination of Energy Charge Component for Integrated Mines:** In the proposed Clause 7(3) of the draft document states that *"Energy charge component of the tariff of generating station getting coal from the integrated mine shall be determined based on the input price of coal from such integrated mines".*

  It is suggested to add a proviso for enhanced clarity "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".

- **Application for Determination of Supplementary Tariff:** Proviso to the Clause (8)(1) of the draft document states that *"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."*

  It is suggested to add a proviso to the para as "Provided that the respective generating station or unit thereof has achieved its COD".

- **Installation of Emission Control System to meet the Revised Emission Standards:** Proviso to Clause 8(2) of the draft document states that *"Provided further that, in case of emission control system required to be installed in the existing generating station or unit thereof to meet the revised emission standards, an application shall be made for* *determination of supplementary tariff (capacity charges or energy charge or both) based on* ***the actual capital expenditure*** *duly certified by the Auditor."*(emphasis added)

It is suggested to add second proviso as **"Provided that such capital expenditure should be incurred through the process of competitive bidding".**

- **Revised Emission Standards in case of a Thermal Generating Station:** Second proviso to Clause 14(3) of the draft document states that *"Provided further that the supplementary energy charges, if any, on account of meeting the revised emission standards in case of a thermal generating station shall be determined separately by the Commission as per Regulation 44 of these Regulations".*(emphasis added)

  It is suggested that supplementary capacity charges be approved only if the generating company meets the revised emission standards and the Clause 14(2) of the proposed draft may be rephrased as *"Supplementary capacity charges shall be derived on the basis of the Annual Fixed Cost for emission control system (AFCe)* ***and payable solely upon meeting the revised emission standards*** (emphasis added).

  The Annual Fixed Cost for the emission control system shall consist of the components as listed in Sub-clauses (a) to (e) of Clause (1) of this Regulation."(emphasis added)

- **"Arrangement" for Provisions of Tariff of Generating Stations beyond 25 years of Operation from COD:** In the proposed Clause 14(4) of the draft document states that *"In respect of a thermal generating station that has completed 25 years of operation from the date of commercial operation and the power purchase agreement for supply of electricity to beneficiaries from such generating station is not extended, the generating company and the beneficiary may agree on* ***an arrangement,*** *including provisions for target availability and incentive, where in addition to the energy charge, capacity charges determined under these Regulations shall also be recovered based on scheduled generation."*(emphasis added)

  The Electricity Act, 2003 provides for the procurement of electricity under Section 62 or Section 63, and as such, the tariff for such generators shall be determined in accordance with the provisions of these Regulations. The draft clause suggests an "arrangement" between the generating company and the beneficiary, thereby excluding it from the Commission's oversight. The lack of clear guidelines or a framework for such arrangements could lead to potential legal complications. Since the beneficiaries have financed and serviced these assets, they hold the first right of refusal and should therefore benefit from the depreciated asset value.

  It is recommended that one of the following approaches be adopted:

  - The Commission may determine a separate tariff for such assets.
  - The capacity (beyond 25 years of operational life) may be pooled with the rest of the beneficiary's capacity under contract with the generating company, if any, and a combined tariff may be determined for the entire pool.

- **Sharing of Benefits Accrued under PAT Scheme:** In the proposed Clause 15(2)(n) of the draft document states that *"Capital cost incurred or projected to be incurred by a thermal generating station, on account of implementation of the norms under Perform, Achieve and Trade (PAT) scheme of Government of India shall be considered by the Commission subject to sharing of benefits accrued under the PAT scheme with the beneficiaries"* and clause 15(3)(f) of the said document 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 incurred for both new and existing projects in relation to the implementation of norms under the Perform, Achieve and Trade (PAT) scheme, as outlined in the proposed Clause 15(2)(n) and clause 15(3)(f), has been allowed. The benefits from such investments are proposed to be shared between the beneficiaries and generator. It is recommended that since the beneficiary funds and pays for the entire capital cost incurred for PAT implementation, they should have the primary right to any benefits derived from it. However, to incentivize the generator for implementing efficient operational and environmental norms, it is proposed that 20% of the benefits from the sale of ESCerts be retained by the generator, while 80% should be passed on to the beneficiaries in proportion to their share in the capacity.

  Further, it is suggested that the better of the norms for 'energy efficiency' specified under tariff regulations and that achieved the PAT scheme be used for tariff determination[3].

[3] A true-up would be required, if the generating plant achieves a target specified under the PAT scheme. This true-up would be justified as costs incurred to achieve the PAT target were passed to the beneficiaries.

Expenditure Required to Enable Flexible Operation of the Generating station at lower loads: It is recommended that for new projects, the expenditure required for enabling flexible operation of thermal plants at lower loads should be included in the original project scope, with **no additional capital expenditure permitted** later for such projects. Furthermore, **adequate justification be required ensuring economics of incremental investment for enhanced flexibility of the generating unit.**

The enhanced flexibility should be clearly identified in terms of higher ramping and/or lower technical minimum level of operation.

For existing thermal plants, a selective and staggered approach for additional investment for flexibility may be adopted. Marginal plants that operate at lower loads for the majority of the time[4] should be allowed such additional capital expenditure to achieve flexible operation at those lower loads. A strategy to approve flexibility related investment for all thermal power plants would not be cost effective and would add to the cost to be paid by final consumers.

Moreover, the recovery of these capital costs should only be permitted upon continuous demonstration of the flexible operation. The SLDC may develop a procedure to verify the low-load operation of these plants and provide monthly certification of the same.

Capital Costs for the Determination of Tariff for Projects Acquired through National Company Law Tribunal (NCLT) proceedings under Insolvency and Bankruptcy Code (IBC), 2016: As per the suggestions sought for the costs to be considered in tariff determination under Section 62 of the Act for projects acquired post-NCLT proceedings, the approach of considering the lower of the historical cost and acquisition value of the project, as proposed in draft Clause 19(5), appears to be appropriate. However, it is necessary to clarify whether the acquisition value includes only the equity component of the project cost or the entire project cost.

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 less than the actual project capital cost – In such cases, both, debt and equity component of the cost of acquired project will be restructured **(reduced).** Hence, the **RoE and IoL component of the Annual Fixed Cost (AFC) will reduce** leading to reduction in the tariff of the beneficiary. Further, the **depreciation should only be applicable on the restructured capital cost.**

Case 1: 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 allowed depreciation should be lower of the restructured loan repayment amount or the applicable depreciation under the tariff framework.

Case 2: When the acquisition value post NCLT proceedings is greater than 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).

Prudence Check Criteria for Thermal Generating Stations: In the proposed Clause 16(1) of the draft document states that *"In the case of the thermal generating station, the prudence check may include scrutiny of the reasonableness of the capital expenditure in the light of capital cost of similar projects based on past historical data, wherever available, reasonableness of financing plan, interest during construction, incidental expenditure during construction, use of efficient technology, cost overrun and time over-run, procurement of equipment and materials through competitive bidding as given in Regulation 68 and such other matters as may be considered appropriate by the Commission for determination of tariff".*

The following proviso may be added for enhanced clarity "Provided that, while carrying out the prudence check, the Commission shall also examine whether the generating company has been careful and in efficient and economical manner in its judgments and decisions in the execution of the project".

[4] Singh, A. (ed.). (2022), Opinion on CEA (Flexible Operation of Thermal Power Plants) Regulations, 2022 [Draft], In *Power Chronicle* (Vol. 05, Issue 02, pp. 6-10), Energy Analytics Lab (EAL), Indian Institute of Technology (IIT) Kanpur. https://eal.iitk.ac.in/assets/docs/power_chronicle_vol_5_issue_2.pdf

- **Sharing of Impact of Condoned Delay Between Generating Company and Beneficiary:** In the proposed Clause 17(5) of the draft document states that *"If the delay in achieving the COD is attributable either in entirety on in part to the generating company or its contractor or supplier or agency, in such cases, Interest during construction (IDC) and Incidental expenditure during Construction (IEDC) 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 in the same proportion of delay not condoned vis-à-vis total implementation period"*.

  The liquidated damages recovered may not fully offset the impact of the condoned delay, whether caused by the generating company or the contractor. In line with the Electricity Act, 2003, which mandates that the Appropriate Commission protect the interests of consumers, it is suggested that a portion of the delay's impact be borne by the generating company. Therefore, it is proposed that the **impact of the condoned delay be shared** between the generating company and the beneficiary in a ratio of **two-third and one-third,** respectively.

- **Additional Capitalization Criteria Within Original Scope and up to the Cut-Off Date:** In the proposed Clause 20(1) of the draft document states that *"The **capital expenditure** in respect of a new Project or an existing project incurred or projected to be incurred, on the following counts within the original scope of work, after the Date of Commercial Operation and up to the cut-off date may be admitted by the Commission, subject to prudence check."*(emphasis added)

  For clarity, additionality of capital expenditure be emphasised as "The **additional capital expenditure** in respect of a new Project or an existing project incurred or projected to be incurred, on the following counts within the original scope of work, after the Date of Commercial Operation and up to the cut-off date may be admitted by the Commission, subject to prudence check."(emphasis added)

- **Approval of Additional Capital Expenditure for Hydro Generating Stations:** It is suggested that for the approval of additional capital expenditure for hydro generating stations, Clause 20(1)(f) of the proposed draft be rephrased as follows:

  "For uninterrupted and timely development of Hydro projects, expenditure incurred towards developing local infrastructure in the vicinity of the power plant not exce eding a total of Rs.10 lakh/MW shall be considered as part of capital cost and in case the same work is covered under budgetary support provided by Government of India, the funding of such works shall be adjusted on receipt of such funds (emphasis added)

  Provided that such expenditure shall be allowed only if the expenditure is incurred through Indian Governmental Instrumentality".

- **Passing on Benefits of Railway Infrastructure Augmentation to Consumers and Adjusting Capital Costs Based on Tangible Benefits:** In the proposed Clause 22(1)(h) of the draft document 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 20, 21 and 23, 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 operational costs or other tangible benefits resulting from the additional capital expenditure for railway infrastructure augmentation, aimed at transporting coal to the receiving end of the generating station, **should be passed on to the consumers.** Additionally, the subsequent **norms for operation and maintenance costs may be adjusted accordingly.**

  Furthermore, if the recorded or demonstrated tangible benefits post-investment in the railway infrastructure are lower than expected, the capital expenditure allowed may be reduced on a pro-rata basis from the total capital costs.

- **Special Allowance and Additional Capitalization for Renovation and Modernisation (R&M) Expenses and Life Extension of Projects Beyond Useful Life:** According to Clause 24 of the proposed tariff framework, projects beyond their useful life have the **option** to either avail a special allowance or opt for additional capitalization to cover R&M expenses and life extension during the control period. Thus, **regulated entities can choose between these options** once the project's useful life has ended. However, after receiving the special allowance for a control period, regulated entities have the option to either continue with the special allowance or file a petition for additional capitalization for R&M expenses or life extension, as outlined in the second proviso to Regulation 24 of the proposed draft.

To ensure regulatory certainty for both the regulated entities and the beneficiaries, it is recommended that if a special allowance is granted during one control period, it should be automatically extended for the next 2 control periods. The continuation of the special allowance should be contingent upon the demonstration of specified or improved operational parameters on a pro-rata basis, with truing up every three years. Failure to demonstrate the improved parameters will result in the disallowance of further special allowances. Additionally, no depreciation should be allowed for any asset created through the special allowance.

The Commission may also set a performance trajectory for regulated entities managing projects beyond their useful life, and the approval of special allowances or additional capitalization for R&M should be subject to adherence to these performance parameters.

If regulated entities choose additional capitalization for R&M expenses for projects beyond their useful life, they should be required to submit certification from the Central Electricity Authority (CEA) confirming an extended life of at least 15 years, along with providing this information to the beneficiaries and RLDCs. These projects will not be eligible for separate R&M expenses. During system downtime for R&M activities, only interest on loan and Operation & Maintenance (O&M) expenses should be recoverable.

Fixing RoE for Generating Stations: In the proposed Clause 28(2) of the draft document states that *"Return on equity shall be computed at the base rate of 14.0% for all thermal generating stations, at the base rate of 15.5% for run-of-river hydro generating station and at the base rate of 17% for storage type hydro generation station, pumped storage hydro generating station and run-of-river generating station with pondage"*.

Because of the significantly reduced Payment Security Risk, post Electricity (Late Payment Surcharge & related matters) Rules 2022, the Return on Equity may be adjusted appropriately.

As per the study on **"Estimating the cost of equity for the regulated energy and infrastructure sectors in India" at CER[5],** the CAPM method used to estimate the cost of equity provides a post-tax figure analysing CAPM and multifactor models with extensive data from over 125 infrastructure companies, estimates the cost of equity to be approximately 10% to 12.5%, as illustrated in Figure 3 . This is lower than the sector's regulated return.

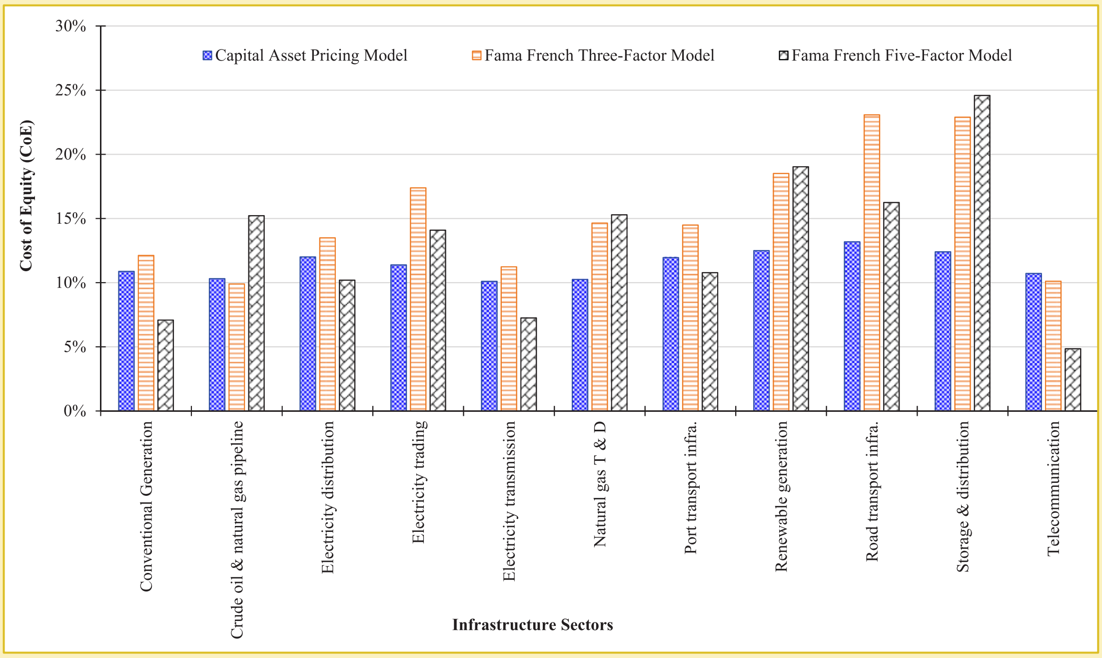


Figure 3: Cost of equity for different infrastructure sectors

Figure 4 shows the G-Sec 10-year bond yield over a one-year period, which is around 7.5%. Consequently, it is recommended that the return on equity (RoE) for generating stations, as well as the ceiling rate (14%) for additional capital due to emission control systems, changes in law, or force majeure, may be lowered. The reported RoE for major transmission companies in the regulated sector has been between 17.15% and 22.4% over the last three years. In contrast, the reported RoE for the regulated generation sector has been around 11.57% to 12.58% during the last three years. (Source: Standalone Annual Statements of the respective companies).

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

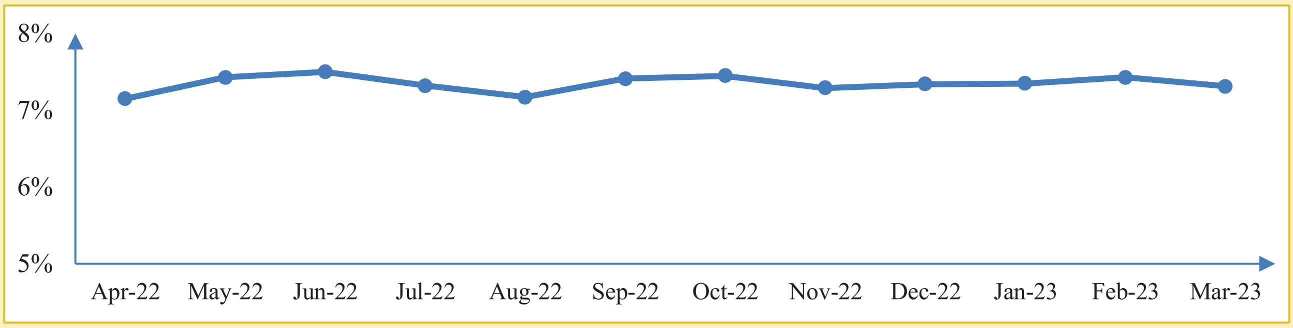


Figure 4: G-Sec 10-year Bond Yield over One year horizon

The Commission may want to apply a lower return on equity for older plants in both the thermal and hydro sectors. However, due to the long construction timelines for hydro-electric plants, which do not yield a 'return' on the invested equity during construction, the Commission might consider justifying a higher RoE for these plants, including those with pumped storage potential. This could incentivize new investments that are set to commence during the forthcoming control period.

- **Inclusion of Procedure for Block-wise Verification of Ramp Rate and Associated Incentives/Disincentives in Draft Clause:** In the proposed Clause 28(2)(c) of the draft document states that *"In case of a thermal generating station:*

  (i) 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, 2024 as amended from time to time till the OERC (GRID code) Regulations, 2015 is amended.

  (ii) An additional rate of return on equity of 0.125% shall be allowed for every incremental ramp rate of 0.50% per minute achieved over and above the ramp rate specified by Central Electricity Authority, subject to the ceiling of additional rate of return on equity of 1%".

  It is suggested that the draft clause should include a provision for developing a detailed procedure for block-wise verification of the ramp rate of generating stations (by NLDC/RLDCs), along with the corresponding incentives and disincentives (by RPCs in the Regional Energy Account).

- **Clarification on Financing Charges and Calculation of WAROI on Actual Loan Portfolio:** In the proposed Clause 30(5) of the draft document states that *"The rate of interest shall be the weighted average rate of interest calculated on the basis of the actual loan portfolio after providing appropriate accounting adjustment for interest capitalized at the beginning of each year applicable to the project".*

  It is suggested that clarification be provided on whether financing charges, if any, should be included in the calculation of WAROI on the actual loan portfolio.

  Further, it is recommended that interest on the loan be calculated on the loan amount, excluding any working capital loans or other short-term loans (with a tenure of up to one year).

- **Clarification on Disallowance of Depreciation, Methodology, and Impact of Lower Availability on Debt Repayment:** Fourth proviso to the Clause 31(3) of the draft document states that *"Provided also that any depreciation disallowed on account of lower availability of the generating station or unit, shall not be allowed to be recovered at a later stage during the useful life or the extended life".*

  It is suggested that the reference to the disallowance of depreciation be included, along with clarifications on the methodology for calculating the depreciation to be disallowed, the cut-off availability for depreciation disallowance, and other related provisions. Currently, there is no reference to the applicability of the draft clause that disallows depreciation due to lower availability, nor is the relationship between lower availability and depreciation clearly defined.

  Further, it is recommended that the debt repayment schedule should remain unchanged, even if the actual availability is lower than the normative availability.

- **Depreciation of ECS Post-Completion of Useful Life of Generating Station:** The special provision for plants that have completed their useful life, as outlined in Clause 14(4) of the proposed draft, states that *the tariff for such stations may be determined based on the "arrangement" between the generating station or the transmission licensee, depending on the situation.*

Clause 31(12) of the draft document states that *"In case the date of operation of the ECS 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 ECS based on the Straight Line Method (SLM) with a salvage value of 10% and recovered over ten (10) years or a period mutually agreed by the generating company and the beneficiaries, whichever is higher"*.

This contradicts Clause 14(4) of the proposed draft. Further, it should be clarified which provision will prevail if the "arrangement" does not allow for the recovery of depreciation?

- **Estimation of Working Capital Based on Actual Blending Ratio of Coal:** In the proposed Clause 32(2) of the draft document states that *"The cost of fuel in cases covered under Regulation 1(a) of this Regulation shall be based on the landed fuel cost incurred (taking into account normative transit and handling losses in terms of Regulation 38 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 and no fuel price escalation shall be provided during the tariff period"*.

  Working capital should be estimated based on the ratio of domestic to imported coal. Given that the mandated blending ratio (for both biomass and imported coal) has been reduced, it is recommended that the calculation of working capital be adjusted for the actual blending ratio of the last two months on a rolling basis. Relying on the previous years' actual GCV would lead to a significant (and artificial) increase in the working capital requirement in monetary terms.

- **Calculation of Coal Cost and Working Capital for Captive Mine-based Generating Stations:** In the Proposed Clause 32(2) of the draft document states that *"Provided that in case of 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 38 of these Regulations) and gross calorific value of the fuel as per actual weighted average for three (3) months,* ***as used for infirm power,*** *preceding date of commercial operation for which tariff is to be determined"* (emphasis added)

  It is recommended that the calculation of coal cost be clearly defined for generating stations with a captive mine, where in-firm power is drawn from the same.

  Further, coal costs may be higher if the initial coal is purchased at a higher rate due to short-term procurement. This could result in a higher working capital estimate for the year, even though the long-term coal purchase rate may be lower. It is suggested that the Regulations include provisions to address this situation.

- **Clarification on Allowance for Changes in O&M Expenses due to Change in Law or Force Majeure:** In the proposed Clause 34(1)(c) of the draft document states that *"Any additional O&M expenses incurred by the generating company due to any change in law 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 of the project allowed for the year."* (emphasis added)

  It should be clarified whether the total change in O&M expenses will be allowed if it exceeds 5%, or if only the incremental change beyond 5% of the normative O&M expenses will be permitted in cases where additional O&M expenses are incurred due to changes in law or force majeure events.

- **Operation and Maintenance (O&M) Expenses for Emission Control Systems in Coal/Lignite-Based Thermal Stations:** In the proposed Clause 34(1)(e) of the draft document states that *"The operation and maintenance expenses on account of emission control systems in coal 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 @ 5.25% during the tariff period ending on 31st March 2029"*. (emphasis added)

  This may be rephrased as "The O&M 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 @ 5.25% during the tariff period ending on 31st March, 2029 emission control system".

- **Incentive for Frequency Response Performance:** In the proposed Clause 42(5) of the draft document states that *"In addition to the AFC entitlement as computed above,* ***the thermal generating station shall be allowed an incentive of up to 1.00%*** *of AFC approved for a given year, which shall be billed monthly as per the following.*

  Incentive = (1.00% x ß x CCy)/12 **(4)**

Where……… Provided that the incentive shall be payable only if the Beta value is higher than 0.30. CCy = Capacity Charges for the Year."(emphasis added)

A generating station is expected to respond to frequency signals as a standard operational practice. Incentive should not be payable for a performance expected as per required operational performance in line with the operational practices and the State Grid Code. It should only be payable if there is additional effort beyond the normal expected operation of power plants. **Setting a 30% frequency response criteria a too lenient to warrant any incentive beyond this level.**

The level of incentive is also set at a very high level. Additional capacity charge of 1% of the AFC, with a Debt-Equity (DE) ratio of 70:30, this can roughly translate to an incentive equivalent to an additional RoE of up to 3.3% (330 basis points). **This is very high level of incentive and would unduly burden the end consumers.**

It is suggested that a detailed analysis of the frequency response characteristics across all generating stations is carried out to determine the level of effort and performance being achieved. Based on this, a baseline of at least 80% or more be set up for any incentive for achieving target beyond the same.

- **Incentive for Scheduled Generation beyond NAPLF:** In the Proposed Clause 42(6) states that "In addition to the capacity charge, an incentive shall be payable to a generating station or unit thereof @ Rs. 0.55/kWh for ex-bus scheduled energy during Peak Hours and @ Rs. 0.40/kWh for ex-bus scheduled energy during Off-Peak Hours corresponding to **scheduled generation in excess of ex-bus energy corresponding to Normative Annual Plant Load Factor (NAPLF)** achieved on a cumulative basis as specified in Regulation 49 of these Regulations."(emphasis added)

Payment of capacity charge is linked to normative availability of 85%. Given the relative shortages, especially during peak hours, scheduled generation would be expected to go beyond the NAPLF for most of the sub-marginal plants. The incentive may thus be 'assured' for most of the base load plants with low variable cost. There is an inherent gain for the generating plants which with higher scheduled energy if the regulated operational performance parameters, such as station heat rate (SHR), secondary fuel consumption and auxiliary consumption, are higher than the actual performance level of the plant. The commission may undertake analysis of the performance of the generating plants to determine if such performance based incentive is reasonable as to minimise impact of tariff on the discoms and hence the final consumers.

Opinion on CERC (Terms and Conditions of Tariff) (First Amendment) Regulations, 2024 [Draft]

Cite

The CERC notified draft "Terms and Conditions of Tariff (First Amendment)" Regulations, 2024 on 7th September, 2024. The key highlights of the draft are mentioned below:

Objective: The proposed draft regulations include the provisions for determination of tariff for generating station or unit thereof (excluding the renewable generators) and transmission system or element thereof whose tariff is to be determined by the Commission u/s 62 of the COD falls within the tariff period from 1st April, 2024 to 31st March, 2029 and for the projects whose final tariff has not been determined till 31st March, 2024.

The proposed draft Regulations lay the provisions for 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.

CER Opinion

- **Recommendation for Capping Coal Price:** In the Proposed Clause 50 Proviso (ii) states that *"Provided further that where such consents of beneficiaries are not available, the input price of coal from such integrated mine(s) shall be so*

Suggested citation: Singh, A. (ed.). (2024), Opinion on CERC (Terms and Conditions of Tariff) (First Amendment) Regulations, 2024 [Draft], In Regulatory Insights (Vol. 07, Issue 03, pp. 13–15), Centre for Energy Regulation (CER), Indian Institute of Technology Kanpur. https://cer.iitk.ac.in/newsletters/regulatory_insights/Volume07_Issue03.pdf

fixed that the energy charge rate based on the input price of coal from integrated mine(s) does not exceed by more than 20% of the energy charge rate based on the notified price of Coal India Limited for the commensurate grade of coal in a month".

Private participation in the coal sector was introduced with the expectation of better operational efficiency and lesser cost. Compensation at a rate more than that Coal India Limited offered by the Coal India limited would defy that philosophy at its basic core. The effective cap on the input price of coal should be limited to the price of commensurate grade coal declared by the Coal India Limited. Furthermore, this should be adjusted for any discount provided by CIL on account of timely payment, advance payment etc., if any this will avoid undue financial strain on beneficiaries, and by extension, on end consumers of electricity. Reporting of the information related to the average input coal price across all such power plants vis a vis the CIL prices for the comparable grade of coal should be part of the Annual Report of the Commission.

- **Eliminating Ambiguities in Shortfall Adjustments:** In the Proposed Clause 51 states *"Factor of **adjustment for the shortfall** of overburden removal during the year shall be computed as under:- [(Annual **Stripping ratio as per mining plan)** - (Actual Stripping ratio based on the actual quantity of coal and overburden removed during the year)]/ (1+Annual Stripping Ratio as per Mining Plan)."* (Emphasis Added)

  The regulatory approach to generation tariff determination is based on normative principles. In case of coal mining, the adopted approach is based on 'actuals' as **the provision for *'adjustment for the shortfall of overburden removal' affectively transforms the approach to 'cost plus basis'.***

  A high stripping ratio not only increases the cost of coal mining but also reduces the quantum of coal mined. A high stripping ratio would thus have double impact on the coal of coal mining operation. While each coal mine may have different geological condition, and may face varying stripping ratio across the mining areas. **The regulatory approach should be to fix a norm for the average stripping ratio for the tariff control period[6].**

  Additionally, advanced verification techniques such as satellite imaging and geological reports should be incorporated to objectively assess and validate the proposed stripping ratios. These measures will enhance transparency and accountability in mining operations while promoting efficiency and sustainability.

- **Public Hearing on Coal Mining Plan:** Cost of mined coal depends on the operational efficiency of coal mining as well as operational cost towards the same. A coal mining plan provides a glimpse of the expected coal of coal mining that would influence cost of coal and thus the final price of electricity. The coal mining plan and its amendments should thus be shared on the Commission's website along with the tariff petition and be a part of the public hearing process.

- **Lower 'Voluntary' Technical Minimum of Thermal Power Plants:** The proposed compensation for part load operation of thermal plant below normative level, provides for a technical minimum level going as low as 40%. It is noted that some of the thermal power plants are able to operate, even for longer duration, for operational level below 55%. Given the rising share of renewables, greater flexibility of thermal plants is the need of the hour. The technical minimum level for the thermal power plants be thus lowered and be brought up to 40% in a phased manner.

  From a regulatory point of view, provision for part load compensation, as per the proposed draft, effectively means that the operational level of the thermal plants stands lowered to 40% level. Since all plants may not immediately be prepared to operate at lower levels, **the part load compensation below 55% should be applicable only to plants who have declared their 'willingness' to the RLDCs for the same.** This solution would ensure that regulatory provisions are defined for plants, which can and operate at technical levels lower than the current regulatory limit of 55%.

- **Basis for Part Load Compensation for Auxiliary Energy Consumption and Station Heat:** Technical as well as operational characteristics of thermal generating plants vary depending on design features of the boiler, turbine, generator as well as the auxiliaries, as well as the fuel quality and operating conditions of the plant. **Design of a part load compensation mechanism largely on the basis of data submitted by the regulated entities suffers from information asymmetry as well as sample selection bias.** The regulatory principles, in contrast, should utilise efficient operating benchmarks with appropriate adjustment for the local conditions. While the amendment's proposal should thus be examined in light of wider operational data leading to recalibration of the compensation. **The commission should mandate submission of operational data by the regulated entities so that an in depth analysis can be conducted under a research study, thus assisting the commission to set efficient norms.**

[6] In case a coal power plant having SCoD within a control period, this may be averaged across the remaining years of the control period.

Non-linear Rate of Part Load Compensation and Period of Calculation: The compensation rate for part load operation is non-linear in nature (Figure 5) as it depicts increasing cost of operation at subsequent lower level of operation. **Payment of part-load compensation on a monthly average PLF would lead to lower level of compensation calculation than that calculated on the basis of block-level PLF. This would thus lead to financial loss for the generators.** To address the same, it is suggested that **payment for part load compensation for fuel cost including cost of secondary fuel should be based on block level calculation,** while that for auxiliary consumption may be based on a monthly average basis as it seems to follow a linear rise.

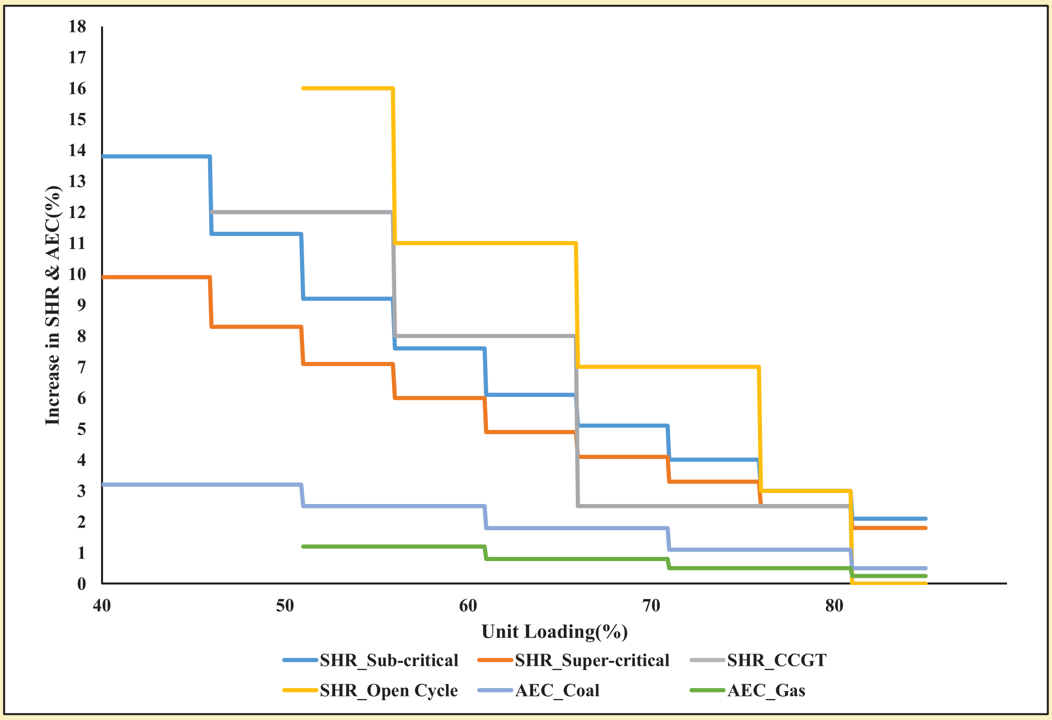


Figure 5: Incremental SHR & AEC Compensation for part load operation of thermal power plants

High Part Load Compensation for Gas based Plants: The rate of part load compensation extends up to 16% in terms of station heat rate (SHR). This would further reduce the probability of schedule for gas based power plants, except in the case of high load conditions. **As suggested above, a study based on actual operational characteristics of wider set of plants should help the Commission in setting such** norms in future. Furthermore, Auxiliary energy compensation (AEC) compensation may be differentiated for open as well as **combined cycle plants.**

Causer Pays Principle and Burden of Part Load Compensation: The approach to impose cost of part load compensation in proportion to the beneficiaries' responsible for the same due to lower schedule reflects the **basic principles of 'polluter or causer pays' principle. This would provide correct price signals for the beneficiaries as per their schedule, and would not penalize those who have given a schedule above normative level.**

Differentiating Percentage Point Change Vs Percentage Change: The table specifying compensation factor mentions the rate of change in SHR and AEC are mentioned in terms of percentage. **The table should carry a clarification if these are to be interpreted as a change in terms of percentage or percentage points.** For e.g. An absolute percentage point increase of 1% on a AEC of, say, 5% would mean 6%, whereas 1% increase on a AEC of 5% would translate to 5.05%

Reference date for MCLR Rate: It is suggested that the Commission may offer clear guidelines regarding the applicable State Bank of India Marginal Cost of Funds-Based Lending Rate (MCLR) to be used for petitions. The MCLR is generally published between the 10^{th} to 15^{th} of each month. Given the variability in the timing of its release and the fact that even small fluctuations in this rate can significantly affect the financial calculations and outcomes in petitions, it is essential for stakeholders to have clarity on which specific rate will be considered.

A clearly defined reference date for the applicable MCLR rate in each month would help minimize any ambiguity or potential discrepancies in financial models, ensuring fairness for all parties while issuing the tariff order. We suggest that **the Commission should fix a reference date of the month for capturing the MCLR rate.**

Opinion on CERC (Appointment of Consultants) (Fifth Amendment) Regulations, 2024 [Draft]

Cite

CERC notified draft on "Appointment of Consultants (Fifth Amendment)" Regulations, 2024. The key highlights of the draft are mentioned below:

Objective: The primary objective of the CERC "Appointment of Consultants (Fifth Amendment)" Regulations, 2024 is to enhance the framework for engaging consultants by introducing provisions for single-source selection, involving academic and research institutions, and implementing performance-related variable pay for staff consultants. The regulation aims to:

- Streamline the selection of consultants in exceptional cases, ensuring expertise, proprietary techniques, or specific circumstances justify such appointments.
- Leverage the specialized capabilities of academic and research institutions for regulatory research through structured procedures and panel creation.
- Incentivize high performance among individual and staff consultants by linking a portion of their remuneration to annual targets, fostering efficiency and accountability.

CER Opinion

Clarification and Mechanism for the Use of Proprietary Technology: In the proposed Clause 6B(iii) states *"in situations where execution of assignment may involve the use of proprietary techniques or only a specialized agency/institution/consultant has requisite expertise"*

There may have been historical situations wherein an appropriate technology may have been utilized. However, the Commission may avoid being locked into a single proprietary technology, which could limit its flexibility. Instead, by actively considering a variety of alternate technologies from time to time, the Commission can broaden its technological horizon, stay at the forefront of innovation, and enhance its ability to adapt to future challenges and opportunities. This approach would also encourage healthy competition among technology providers, ensuring that the Commission continually benefits from the most suitable and advanced solutions available.

Inclusion of Annual Performance Target for Staff Consultants: The proposed Clause 8B(1) "The individual consultants engaged under regulation 7 and staff consultants engaged under regulation 8A shall be entitled to performance-related variable pay of up to 40% of the Monthly fee, which will be admissible on achieving the **prespecified annual targets by the Commission for organization,** division or team and individual and released on a six monthly basis as per the procedure issued by the Commission." (emphasis added)

The targets are specified for the organization i.e. CERC, and the variable pay of the staff consultant would be linked to it. Since staff consultants represent only a subset of the human resources, they are not key to influence performance of the 'organization'. In corporate context, such a target is generally set for the sub-set of the organization's manpower who are able to take decisions for the 'performance' of the organization. The variable pay for the staff consultant should be related to the performance of the individuals (to be set by the Commission), and may partly be related to the performance of the organization.

Information about Consulting Staff and Consulting Assignments in Annual Report: The draft regulation should provide for publication of information on all staff consultants/consulting assignments issued in its Annual Report for the respective financial year. This should include the name of consultant/consulting organization appointed, basis of appointment (competitive bid, single bid, proprietary technology etc.), title of consulting assignment, date of award, duration of assignment, awarded cost etc.

The Annual Report should also include information on staff consultant on roll, including their field of expertise, date of joining, duration of appointment, salary details, and performance-linked incentives (PLI) awarded. Publishing performance ratings tied to these incentives would further promote transparency and incentives high-quality performance from consultants. Such information disclosures would also enable the Commission to evaluate the need for additional human resources from time to time.

Suggested citation: Singh, A. (ed.). (2024), Opinion on CERC (Appointment of Consultants) (First Amendment) Regulations, 2024 [Draft], In Regulatory Insights (Vol. 07, Issue 03, pp. 16), Centre for Energy Regulation (CER), Indian Institute of Technology Kanpur.
https://cer.iitk.ac.in/newsletters/regulatory_insights/Volume07_Issue03.pdf

Opinion on MoP (Tariff based Competitive Bidding Guidelines for Procurement of Storage Capacity/Stored Energy from Pumped Storage Plants), 2024 [Draft]

Cite

MoP notified draft on “Tariff based Competitive Bidding Guidelines for Procurement of Storage Capacity/Stored Energy from Pumped Storage Plants” on 22nd August, 2024. The Key highlight of the draft are mentioned below.

Objective: The draft guideline provides a framework for procurement of storage capacity for pumped storage plants (PSP). The national framework for promotion of Energy Storage Systems (ESS) 2023 aims to facilitate India's transition to renewable energy sources by addressing the challenges posed by their RE variability ESS, such as PSP and Battery Energy Storage Systems (BESS), are crucial for grid stability and peak shifting. These guidelines aim to promote the development of PSPs and provide a transparent procurement framework based on open competitive bidding to ensure their efficient integration into India's energy grid and are applicable to developers, procurers (end procurers or intermediary procurers), and for the procurement of capacity or energy by the procurers CER Opinion from existing, under-construction, or new PSP projects.

CER Opinion

- **Correction in Section Numbering:** The draft document has section numbering mistakes that need to be addressed. The comments provided below align with the existing section numbering already given in the draft document.

- **Redefining the Storage Supply with Availability of Storage Services:** In the Proposed Clause 4(b) Part A *"Actual Commencement of Supply Date (ACSD) in relation to the contracted storage capacity shall mean the date corresponding to the **actual date of commencement of storage supply** from when the storage capacity comes into regular service.*

  Part A, clause 4(v) *"Scheduled Commencement of Supply Date (SCSI))"in relation to the contracted storage capacity shall mean the date corresponding to the **date of commencement of storage supply** as indicated in the RfS.* (emphasis added)

  Both the definitions refer to ‘commencement’ of supply. Similar to the context of a generating plant, availability of the storage capacity should be important to ensure payment of capacity charges for the same. It is suggested that, in the case of Clause 4b, the term "storage supply" can be replaced by **“availability of storage services”**.

- **Appropriate Government:** In the proposed Clause 4(n) part A *"Intermediary Procurer" shall mean an agency, including a trading licensee designated by the Government of India that acts as an intermediary between the End Procurer(s) and the Developer(s)…guidelines.”* (emphasis added)

  A state government may also designate a nodal agency/intra-state trading licensee (the holding/trading company for the discoms in the state) as an intermediary procurer. The same can be provided for introducing the context of the *“Appropriate Government”* in the above clause.

- **Procurer vs End Procurer:** The draft guideline lacks consistency in the terminology used for the procurer. For example.

  Part A, Clause 4(p) states, ***"Procurer"*** shall mean the ***End Procurer or an Intermediary Procurer,*** as the context may require.

  Part B (A), (7.7.3.c), (7.7.3.d), (7.7.3.e), states, *the Procurer/intermediary Procurer may extend this period up to a maximum of 'M' months from the damages/dues recovered by the Intermediary Procurer by encashing the Performance Bank Guarantee (PBG)… the ACSD, … As an alternative to encashing the PBG/Payment on Order Instrument, the **Procurer/intermediary Procurer** may allow the Developer to furnish the requisite.”* (emphasis added)

  In multiple instances the term procurer as well as its sub-categories i.e. end procurer and intermediary procurer are referred in the same context. For example, in Part B (A), (7.7.3.c), (7.7.3.d), etc. as highlighted above. It is suggested that the term ‘Procurer/Intermediary Procurer’ be substituted with the ‘End Procurer/ Intermediary Procurer’ to enhance clarity and coherence throughout the guidelines.

Suggested citation: Singh, A. (ed.). (2024), Opinion on MoP (Tariff based competitive bidding guidelines for procurement of storage capacity/stored energy from Pumped Storage Plants) Regulations, 2024 [Draft], In Regulatory Insights (Vol. 07, Issue 03, pp. 17–18), Centre for Energy Regulation (CER), Indian Institute of Technolog Kanpur. https://cer.iitk.ac.in/newsletters/regulatory_insights/Volume07_Issue03.pdf

'Generator' to be replaced with the 'Developer': In the proposed Clause 5.2 the draft guideline Part B (A), states, *"The Tariff shall be quoted at the delivery point to be specified in the RfS… All charges and losses till the delivery point shall be borne by the* ***Generator.****"* (emphasis added)

As the entities mentioned in the guideline are the 'procurer' and the ***'developer', the word 'generator' (while referring to a storage service provider) may be replaced with 'developer'.***

'Storage Capacity Charge' in place of 'Storage Charge': In the Proposed Clause 5.1 Part B(B), *"Bidding Parameters:*

a. Storage charge (Rs/{MW/kW}/{year/month})
b. Storage charge (Rs/{MW/kW}/{year/month}) with a pre-specified VGF/ Annuity support" (emphasis added)

The bidding parameter linked to storage capacity (MW) should be termed as ***"Storage Capacity Charge"***. Term 'storage charge' suggests a charge based on stored energy i.e. MWh.

Other Model of Site Development for Mode 2: In the proposed Clause 3(b) Part B(B), *"Mode 2 - Procurement from a PSP developed on a site identified by the bidder or already commissioned (i.e., PSP developed independent of its location):-In this case the development may be on* ***Finance Own Operate (FOO)*** *basis for a period of 15 to 25 years."* (emphasis added)

In case of an existing hydro project, which has been developed under a Build Own Operate Transfer (BOOT) mechanism, the PSP development should be done using the same framework. In its reference, the PSP project at the end of expiry of the Power Purchase agreement (PPA) of such project, further hydro project, the original hydro project which would have been transferred to the procurer, the PSP project on standalone basis may have not its standalone value. Thus, it is suggested that the model of site development may also include ***Build Own Operate Transfer*** *(BOOT)"* to allow for such cases in the future.

Essential Technical Requirements: In the proposed clause 6.1(a)(iii), Part B(B) *"Technical Requirements in Bid Documents*

a. The procurer shall specify the following while defining the technical requirements for PSP:

iii Charge/ Discharge duration ***in hours*** *(Maximum number of Continuous and Non-Continuous hours in a day)"* (emphasis added)

According to the Part B(B), Clause 6.1(a)(iii) the ***charge/ discharge duration could be different due to technological characteristics of the plant, quantum of power being injected during charging or being made available on discharging***[7]***. Thus the two indicators may be specified separately.***

As per the Part B(B), Clause 6.1(b)(i) and Clause 6.1(b)(ii), *"The Procurer may choose to specify* ***additional performance*** *parameters also for bid evaluation as per its requirement:*

i. Availability (%)

ii. Switchover time between generation and pumping mode and vice versa." (emphasis added)

Similar to the context of a generating plant, ***availability of the plant, both in charging as well as discharging mode,*** is a very important performance criteria, and thus ***should be included in essential technical requirements.*** Storage capacity charge payment should be linked to this availability.

Maximum switchover time, for the storage capacity bid by the generator, between generation and pumping mode and vice versa should be specified to ensure that necessary ramping is available when required. A shorter switchover time would be desirable as the power system is to absorb greater share of variable renewable energy.

[7] Note that the PSP rating for energy to be stored, say 50 MW, and that to be injected into the grid, also 50 MW, would place different loading on the plant during pumping/generation mode respectively.

Regulatory Updates

Tariff

UERC reviewed the legal requirements for tariff petitions and assessed the issues raised by M/s UJVN Ltd. The petitioner highlighted issues such as incorrect calculation of net cash availability, non-tariff income, interest from FDRs, common expenses and RoE on additional capitalization. The Commission found merit in some of the issues raised by the petitioner and directed M/s UJVN Ltd. to raise these issues in the next tariff and true-up petition.

UERC approved the methodology proposed by UPCL for calculating the rate of the RE component based on the lowest discovered price of Renewable Energy Certificate (REC) in the Power Exchange. Rajwakti SHP was initially denied accreditation under the mechanism by UREDA, which was later overturned by the Hon'ble APTEL. UPCL and M/s Him Urja Pvt. Ltd. are directed to execute a supplementary PPA incorporating the approved methodology.

UERC determined the gross tariff for solar power plant plant as Rs. 4.43/kWh and Rs. 0.18/kWh as accelerated depreciation. The order comes into effect from 1st April, 2024 and the tariff for grid connected rooftop and small solar PV plant is given below:

Particular	Up to 10 kW	Above 10 kW < 100 kW	Above 100 kW < 500 kW	Above 500 kW >1 MW
Gross Tariff	6.08	5.52	5.14	4.93
Acc. Depreciation	0.24	0.22	0.20	0.20
Net Tariff	5.84	5.30	4.94	4.73

MPERC ruled that the additional surcharge u/s 42(4) of the Electricity Act, 2003 is not applicable to the power consumed by petitioners from its captive power plant. Consequently, the demand of additional surcharge raised by M/s MPPKVVCL on M/s. Lanxess India Pvt. Ltd. for the period from April 2017 to August 2022, along with any consequential surcharge, has been quashed.

RERC the petitioner requested the Commission to approve O&M expenses of Rs. 20.32 Crore (Rs. 19.87 Crore and Rs. 0.45 Crore already approved by the Commission) for FY 2022-23, and to approve O&M expenses of Rs. 21.29 Crore in place of Rs. 20.57 Crore for FY 2024-25.

TGERC provided judgment addressing the imposition of a surcharge for nonpayment of wheeling charges, which was delayed due to ongoing litigation and upheld the surcharge as a penalty for the loss of revenue caused by the M/s. Kakatiya Cement Sugar & Industries Ltd. The petitioner entered into a power purchase and captive wheeling agreement on 19th feburary, 2002 with the erstwhile M/s TGTRANSCO, in accordance with the Andhra Pradesh Electricity Reforms Act, 1998. The agreements valid from the commercial operation date to 30th June, 2004, stipulated that the petitioner would pay a compensation of Rs. 2 /kWh.

MERC directed the APL is eligible for Change in Law compensation on account of an increase in Transit Fee (Forest) vide SECL notice dated 27th March, 2020. Said Change in law compensation is computed as per directions. Carrying costs are also payable on the above change in law compensation at the LPS rate stipulated in the PPA on a compounding basis.

HPERC accords its approval project is set at Rs. 3.50/kWh, subject to possible subsidy adjustments. The project, located in a rural area, must apply for applicable subsidies and inform M/s HPSEBL within 15 days of receiving financial assistance. If no subsidy is applied for M/s HPSEBL will adjust the tariff benefits after two years. The Scheduled Synchronization Date is 11th June, 2025. and the SCOD is 26th June, 2025 with delays subject to the original tariff. The Petitioners must execute the PPA within 30 days as per the Commission's previous orders.

WBERC decided that the admissible net Fixed Charge for IPCL for the year 2015-16 will be Rs. 7917.44 lakh, instead of Rs. 8122.02 lakh. The reliability incentives will be Rs. 708.65 lakh, instead of Rs. 739.78 lakh

Power Procurement

UERC approved the draft PPA submitted by UPCL and APPCL, with specific modifications and conditions, such as the inclusion of T-GNA charges reimbursement and force majeure event notification requirements.

Regulatory Updates

UERC approved the draft PPA submitted by UPCL and Tata Power. The Commission directed that the agreement requires specific modifications and conditions, such as the inclusion of force majeure event notification requirements and correction of typographical error.

UERC reviewed and approved the draft Energy Banking Agreement (EBA) between UPCL and HPPC with specific modifications to typographical errors. UPCL filed the petition seeking approval of the draft EBA for advance banking of 618 MU of power from December 2024 to March 2025, to be returned during July to September 2025.

MPERC ruled that no actual difficulty has arisen in implementing the existing Green Energy Open Access regulations and rejected the proposed amendments pertaining to banking of power. The Commission also clarified that the truing-up of banking charges should be carried out at the end of each financial year, not on a monthly basis. MPPCL filed the petition highlighting that the current regulations cause operational and financial challenges for the distribution licensee, especially during high-demand periods like the rabi season.

MERC directed the respondent to comply with Section 63 of the Electricity Act, 2003, the Commission adopts Short Term Power Procurement for the period of 1st September, 2024 to 31st August, 2025 by JNPA as stated. Accordingly, JNPA is to submit a copy of the PPA to the Commission for the record.

MERC accords its approval to MSEDCL's proposal to procure 3251MW, Wind-Solar Hybrid RE Power at the tariff of Rs. 3.60-3.62/kWh. Discovered through competitive bidding for 25 years. The power procured from projects considered in this Petition shall be considered for meeting the Renewable Purchase Obligation requirement of MSEDCL. As agreed during the hearing, MSEDCL shall execute the Power Purchase Agreement within 30 days from the date of this Order, and a copy of the same shall be submitted for the records of the Commission.

MERC directed Petitioner are allowed to incur expenses for setting up of EHV network on refundable basis as per provisions of Supply Code Regulations 2021. MSEDCL and MSETCL shall coordinate and support Petitioners so that EHV network is setup and becomes available at the earliest.

MERC accords its approval to the MSEDCL's proposal for procurement of 1468 MW Firm and Dispatchable RE Power from SJVN at competitive bidding tariff of Rs. 4.38-4.39/ MW adopted by CERC vide its Order dated 1st August 2024 in Petition No. 79/AT/2024 plus the trading margin of 0.07 Rs./unit for 25 years of Power Supply Agreement. The Commission approves the Power Supply Agreement executed between MSEDCL and SJVN to procure 1468 MW from FDRE projects. The power procured from SJVN shall be considered for meeting the Renewable Purchase Obligation requirement of MSEDCL. Post signing of the Power Supply Agreement by parties, copy of the same shall be submitted for records of the Commission.

MERC accords its approval to MSEDCL's proposal for procurement of 378.67 MW nuclear Power from KAPS Units 3 & 4 at the tariff of Rs. 4.40/ kWh, Rs. 4.50/ kWh and Rs. 4.60/ kWh for the first year, second year and third year of commercial operation of these units, respectively. The Commission accords its approval to MSEDCL's proposal for extension of PPA dated 4th June, 2005 (TAPS 3 & 4), PPA dated 4th June 2005 (KAPS 1 & 2) and PPA dated 12th February, 2008 (TAPS 1 & 2) for a further period of 15 years. MSEDCL shall execute the Power Purchase Agreement, and a copy of the same shall be submitted for the records of the Commission.

HPERC has approved the Power Purchase Agreement (PPA) between the Appellant and HPSEBL, retroactive to 28th March, 2005 with terms subject to the HPERC Regulations of 2007 and the December 2007 Tariff Order. The Petitioner's project, commissioned in May 2013, will receive a tariff of Rs. 2.95/ kWh from the commissioning date. The parties must execute the SPPA within 30 days, reflecting the retroactive approval. The Petitioner's proactive approach led to this decision, but it will not set a precedent for other projects seeking enhanced tariffs without timely action.

APSERC reviewed the request for a reduction in the security deposit regulations and confirmed that the security deposit is mandatory to ensure payment of electricity bills. It observed the claim for relaxation based on "public interest" and rejected it, as the agreement terms had been accepted and applied during the last 2 years. The Commission also noted that past agreements allowed a lower deposit, but regulations must be followed. The Department of Power opposed the relaxation, confirming the deposit was based on established norms.

Regulatory Updates

WBERC has approved WBSETCL's investment proposal for three transmission projects, totaling Rs. 76,401.34 lakhs, aimed at improving power supply in Burdwan district. The projects include GIS substations at BAPL Airport, Jamuria, and Panagarh. The approval is subject to further approvals for project costs, including interest and other expenses. WBSETCL must comply with metering and data display regulations and submit a benefit analysis upon project completion. Any cost escalation requires prior approval.

WBERC has approved WBSEDCL's proposed deviations in the RFP and PSA documents for a 1600 MW plant, including changes in bidding processes, bid security, fuel cost breakups, and a 30-year supply contract. These deviations are deemed reasonable and in line with project requirements. WBSEDCL can proceed with the bidding process and must submit updated documents to the Commission within seven days. Approval for the Power Supply Agreement with the successful bidder is also required.

WBERC approved the supplementary PPA between IPCL and WBGEDCL, reducing the power purchase price to Rs. 3.40/kWh, retroactive from 1st December, 2019. This rate is lower than the original price Rs 5.00/kWh and recent average costs, benefiting IPCL and its consumers. IPCL is also directed to comply with applicable scheduling laws.

HERC requires builders and developers to deposit 50% of the External Electrical System Development Charges before the approval or reapproval of the Electrification Plan. Developers with individual loads below 15 MVA can form groups with a combined load of up to 25 MVA to avoid providing land individually. Interim connections at 11 kV are permitted due to delays in 33 kV infrastructure, which must be completed within one year or extended with proper justification.

DERC approved Purchase Cost Adjustment Charges (PPAC) for Q2 of FY 2024-25 at 5.85% as against the 8.35% claimed by the M/s BSES Yamuna Power Ltd. The variation was due to discrepancies in the short-term power sale quantum and the non-consideration of Short-term Open Access refunds. The PPAC of 5.85% is to be recovered from 21st December, 2024 to 20th March, 2025. The BSES Yamuna Power Ltd is allowed to levy the adjusted PPAC as per DERC approval. This decision is based on the verification of the power purchase bills and prudence check conducted by the DERC.

Renewable Energy, RPO and REC

TGERC decided not to extend the time for RPPO compliance, not to carry forward obligations to the next year and impose penalties for non-compliance. TGSLDC submitted a final report indicating only 19 entities fulfilled both solar and non-solar RPPO out of 67 obligated entities. The Commission also addressed discrepancies in data and allowed the purchase of Renewable Energy Certificates from the open market to cover shortfalls. Commission finalized penalties for non-compliance including a maximum of Rs. 1,00,000 and an additional Rs. 6,000 per day for continued failure.

CSERC granted permission to M/s Haryana Rolling Mills (Bhilai) to exempt from having dedicated feeder to avail open access, according to the provisions of clause 5.5 of the Open Access Regulation, 2011 and its amendments for a solar PV power generating plant (Independent Distributed Renewable Energy System-IDRES) of capacity 1.54 MW (AC) at Village-Mohbhatha, Tehsil-Berla, Bemetara, for his captive usage and such solar power is permitted to be evacuated through 33 kV dedicated feeder connected to 33/11 kV Kodwa substation.

CSERC granted permission to M/s Gravity Ferrous Pvt. Ltd. to be exempted from having a dedicated feeder to avail open access, in accordance with the provisions of Clause 5.5 of the Open Access Regulations, 2011, and its amendments, for setting up a 16 MW Waste Heat Recovery Boiler (WHRB) co-generation power plant, located at village Champa, Tehsil Tilda, Raipur.

AERC advised APDCL in the case of seeking approval for the procurement of 100 MW Wind Solar Hybrid power from NTPC under developer mode to take into consideration the difference of Rs. 0.75/ MW from the solar and wind generation, respectively, and to plot the generation curve of pure solar and wind solar hybrid generation while carrying out the cost-benefit analysis.

BERC approved the procurement of 500 MW solar power from SECI under the ISTS Tranche-I scheme at a tariff of Rs. 2.51/kWh, including a Rs. 0.07/kWh trading margin. The project is expected to be commissioned by March 2025, with no additional transmission charges. The Commission found the procurement necessary to meet the state's Renewable Purchase Obligation and contribute to India's national renewable energy targets. The proposed tariff is lower than Bihar DISCOMs' Average Power Purchase Cost, making it cost-effective.

BERC has approved the procurement of 17.68 MW solar power from six Power Sub-Stations (PSS) at tariffs ranging from Rs. 3.20 to Rs. 3.48/ kWh. The approved

PSSs are Kochas (1.5 MW), S. Nawada (2.0 MW), Cherki (6.0 MW), Wazirgunj (6.0 MW), Ekma (1.0 MW), and Raghunathpur (1.18 MW). The petition for 49 PSSs with single bids and 3 PSSs with high tariffs was rejected. The petitioners are advised to retender for the remaining PSSs following the required rules and guidelines.

KERC approved Consumers installing solar rooftop photovoltaic (SRTPV) systems with a sanctioned load of up to 10 kW in Karnataka must ensure their load is automatically increased if it is less than the SRTPV system's capacity. They are responsible for paying additional charges, providing security, and updating their power supply agreement before commissioning the system. Additionally, a 10% tolerance is allowed for the DC capacity of the SRTPV system, as long as the AC inverter capacity does not exceed the sanctioned load.

Others

UERC reviewed the submissions filed by UREDA seeking, the fixation of voltage-wise distribution loss or reduction of approved distribution loss for open access captive solar power plants. The Commission rejected UREDA's request to determine voltage-wise losses, stating that it would require an amendment to existing regulations and directed UPCL to submit a comprehensive plan for conducting an energy audit for determining voltage-wise losses within three months.

TGERC disposed off the petition with no costs and ruled in favor of the M/s Sarda Metals & Alloys Ltd. granting the requested relief. Commission rejected the TGPCC, TGSPDCL and TGNPDCL jurisdictional argument, stating that the transaction did not constitute an inter-state sale of power. The Commission directed the respondents to pay the surcharges on delayed payments and backdown compensation as per the purchase order dated 27th May, 2019.

TGERC directed TGSPDCL to pay the Hyderabad MSW Energy Solutions Pvt. Ltd. all outstanding dues along with interest for sale of energy from August 2020 to present date. Any deviations in future payments will attract Late Payment Surcharges. The core issue in this petition revolves around the payment of outstanding amounts along with interest, which have been quantified as Rs. 30,95,10,172 (principal) and Rs. 21,44,97,534 (interest) as of 8th December, 2023.

AERC has accorded approval for the purchase of gas from AGCL at a price of USD 6.31/MMBTU, subject to specific conditions. APGCL is authorized to use AGCL gas for power generation during peak hours and may also utilize it during off-peak hours, if APDCL provides a written schedule for the same. Additionally, APGCL must submit weekly updates on the supply of additional gas and the corresponding generation to both the Commission and APDCL.

HPERC has granted fresh approval to the PPA between the Petitioner and HPSEBL, effective from 28th March, 2005 as directed by APTEL. The tariff and terms are subject to HPERC Regulations, 2007. The Petitioner's project, commissioned in May 2013, is entitled to a tariff of Rs. 2.95/ kWh from the commissioning date. Both parties must execute the SPPA within 30 days. This order is specific to the Petitioner and not a precedent for other projects.

OERC directed the respondent to comply with the Ombudsman's order to reclassify their power supply from MI (HT) to MI (LT) tariff and revise bills from February, 2016 within 15 days, and to submit a compliance report to the GRF Khordha, and appear for further instructions on 5th December, 2024.

OERC referred the dispute to arbitration for non-compliance with a 3rd June, 2024 order by TPSODL's CEO and other notices regarding disconnection of their power supply, and after hearings by the Ombudsman, a report was submitted on 6th November 2024. The OERC directed the parties to comply with the arbitration report to resolve the dispute.

OERC approved a Tripartite Agreement for the power supply to M/s Tata Steel Ltd. washing and beneficiation plant at Khandbandh, 14 km from their Joda facility. Despite the plant's separate location TSL, Joda applied to enhance its contract demand from 10 MVA to 40 MVA in 2013, planning to supply power through a 33 kV line. After a six-year construction period with significant challenges, the Commission allowed the supply arrangement under a special agreement between TPNODL, TSL, Joda, and TSL, Khandbandh. The 33 kV line will be considered a deemed distribution system, and the agreement will last five years, with provisions for tariff application, Open Access transactions, and direct connection to the STU network. TPNODL will cover any revenue loss, while GRIDCO and OPTCL can address concerns of revenue loss to them. The agreement includes guidelines for billing, maintenance, and power supply terms.

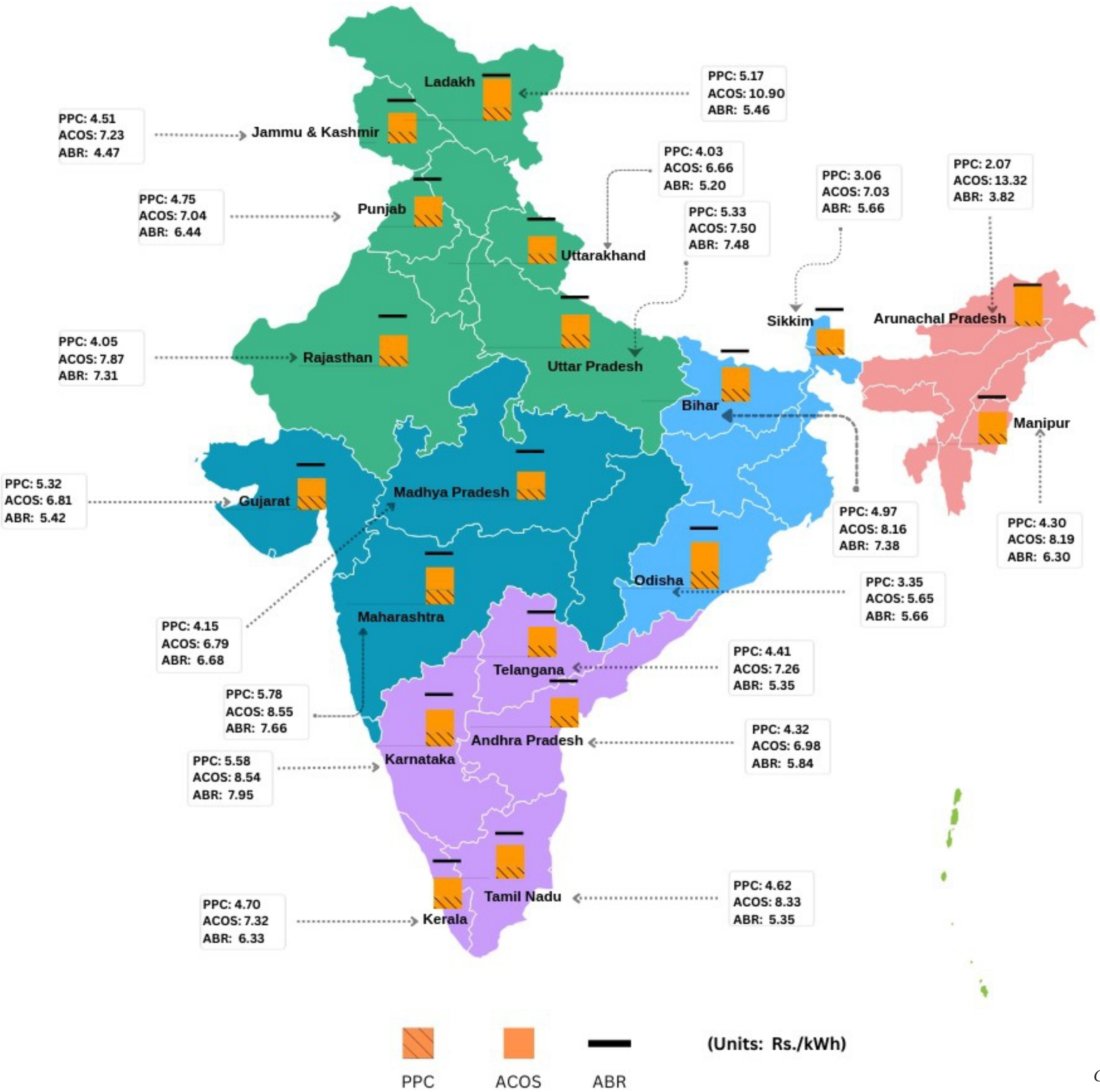
KPTCL is directed to install and maintain AMR facilities for all IPPs, recovering costs from generators. Energy bills will rely on AMR data for accuracy, with half-yearly spot inspections to verify billing. Full implementation is required within two months, and weekly progress reports must be submitted to the Commission. This Order aims to ensure transparency, efficiency, and reliability in energy billing and accounting processes.

Regulatory Updates

KSERC orders the licensee to ensure the commissioning of all other critical projects marked with priority no. 1 Listed in order (b) by 31st of March 2025, wherein the construction of 110 kV substation, Kadampuzha by 31st May 2025 and report compliance to the Commission by first week of subsequent months. The Commission further orders that, the responsible officers will be held accountable for any delays in project execution without valid justifications.

KSERC approve the deviations proposed in the Model Bidding Documents RFQ, RFP and PSA, for the procurement of 500 MW RTC Power on long term basis for 15 years on DBFOO basis through DEEP portal (DEEP e-bidding) developed by PFC Consulting Ltd.

India's Electricity Landscape: Average Cost of Supply, Average Billing Rate and Power Purchase Cost



CER Analysis

CER, IIT Kanpur for the year 2023-24 is representing a state-wise visualization delving into metrics of assessing the supply and purchase cost of electricity from the perspective of discoms. A specially designed map of India highlights three economic parameters ACOS, ABR and PPC.

Tariff Orders

State/ Union Territory (SERC)	Licensee/ Utility	True-up	APR	ARR	Tariff
UERC	UPCL, PTCUL, UJVN, SLDC	2022-23	2023-24	2024-45	2024-25
MSERC	MePDCL, MePGCL, MePTCL	2023-24	-	2024-25 to 2026-27	2024-25
TGERC	TGSPDCL, TGNPDCL, TGTransco	2022-23	2023-24	2024-25 to 2028-29	-
TGERC	CESS	-	-	2024-25	-
PSERC	PSPCL	2022-23	2022-23	2024-25	2024-25
HPERC	HPSBL	2022-23	2022-23	2024-25 to 2028-29	2024-25
RERC	RVPN, AVVNL, JVVNK, RUVITSL	2022-23	-	2024-25	2024-25
GERC	DGVCL, MGVCL, PGVCL, UGVCL, TPL-D(A), TPL-D(S), TPL-D(Dahej), MUL, GIFT PCL and AIVPL	2022-23	-	2024-25	2024-25

Regulations

Title	Date of Approval/Notification
AERC (Electricity Supply Code)(Seventh Amendment) Regulations, 2024	21st October, 2024
AERC (Payment of Fees etc.) Regulations, 2024	28th November, 2024
AERC (Terms and Conditions for determination of Multi Year Tariff) Regulations, 2024	5th November, 2024
AERC (Terms and Conditions for Open Access) Regulations, 2024	21st November, 2024
BERC (Multi Year Distribution Tariff) Regulations, 2024	1st December, 2024
BERC (Multi Year Transmission Tariff and SLDC Charges) Regulations, 2024	30th October, 2024
HERC (Framework for Resource Adequacy) Regulations, 2024	19th November, 2024
HERC (Terms and Conditions for Determination of Tariff for Generation, Transmission, Wheeling and Distribution & Retail Supply under Multi Year Tariff Framework) Regulations, 2024	22nd October, 2024
JSERC (Fees, Fines & Charges) Regulations, 2024	25th November, 2024
JSERC (Conduct of Business) Regulations, 2024	25th November, 2024
JERC Goa & UTs (Medical Facility) Regulations, 2024	20th November, 2024
JERC Goa & UTs (Terms and Conditions for Tariff determination from Renewable Energy Sources) Regulations, 2024	24th October, 2024
JERC Goa & UTs (Generation, Transmission and Distribution Multi Year Tariff) Regulations, 2024	15th October 2024
MPERC Distribution Code (Revision-1), 2024	4th October, 2024
MPERC (Ancillary Services) Regulations, 2024	4th October, 2024
MSERC (Renewable Energy Purchase Obligation & its Compliance) (Third Amendment) Regulations, 2018	26th November, 2024

Capacity Building Programme for LDCs on "Regulatory and Policy Framework in the Indian Power Sector: Load Despatchers Perspective"

CER, in collaboration with Grid-India, conducted a Capacity Building Programme for Load Despatch Center on **"Regulatory and Policy Framework in the Indian Power Sector: Load Despatchers Perspective"** from 11th to 13th December 2024. Hosted under the aegis of the Center for Energy Regulation, Department of Management Sciences, IIT Kanpur. The inaugural session was honoured by the presence of Mr. S. R. Narasimhan (Chairman and Managing Director, Grid-India). The key speakers in the program were Mr. Subhendu Mukherjee (Deputy General Manager, Grid-India), Mr. Ravi Seth (Vice President of Business Development, IEX), Mr. Rajiv Porwal (Director System Operation, Grid-India), Ms. Ammi Ruhama Toppo (Chief Engineer (IRP-I), CEA), Ms. Shilpa Agarwal (Joint Chief (Engg.), CERC), Dr. S. K. Chatterjee (Chief Regulatory Affairs, CERC), Mr. Mukesh Kumar (Assistant Chief (Engg.), CERC), Dr. Balaraman Kannan (Executive Director, Idam Infrastructure Advisory Pvt. Ltd.), and Prof. Anoop Singh (Founder and Coordinator, CER and EAL, IIT Kanpur). The program aimed to enhance participants, understanding of the evolving regulatory and policy framework in the Indian power sector from a load despatchers perspective. It also provided a platform to knowledge exchange, learning about best practices, and engagement with leading Sector experts.

Mr. Jishnu Barua (Chairperson, CERC), chief guest to the valedictory functions, handed over certificate to the participants and provided insights on regulatory and policy framework in the Indian power sector.

Regulatory Certification Programme on "Power Market Economics and Operation"

CER, in association with EAL conducted the Regulatory Certification Program titled **"Power Market Economics and Operation"** from 6th to 22nd December 2024. This program was conducted under the aegis of the Centre for Continuing Education, IIT Kanpur. The program aimed at conceptual understanding into the economic operation, regulatory structure of power market, power procurement planning and strategy of power market, ancillary services and perspectives opportunity to learn best practices from experts. The key speakers in the program were as Mr. Akhilesh Awasthy (Partner, Lantau Group India Pvt. Ltd.), Mr. Ghanshyam Prasad (Chairperson, CEA), Mr. Samir Chandra Saxena (Director Market Operation, Grid-India), Ms. Shilpa Agarwal (Joint Chief (Engg.) CERC), Prof. Anoop Singh (Founder & Coordinator, CER & EAL, IIT Kanpur), amongst many more.

Mr. Ramesh Babu Veeravalli (Member, CERC), chief guest to the valedictory functions, handed over certificate to the participants and emphasized on contribution of informed decision-making and the advancement of regulatory frameworks in the power sector.

The editor thanks Regulatory Insights team for their contribution in supporting the analysis, copy editing, compiling snippets of tariff orders, regulatory updates, and coordinating final production of this Issue.

Himanshu, Mohit, Sandeep, Keshav, Gaurav, Garima, Diksha and Muskan

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.*