

“Terms and Conditions for Determination of Generation Tariff Regulations, 2024” [Draft]

The OERC notified "Terms and Conditions for Determination of Generation Tariff Regulations, 2024". The key highlights of this draft is mentioned below:

Objective: The draft regulation, will guide the determination of generation tariffs for existing and future generating stations, excluding those with tariffs set through competitive bidding or by the 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. The aim is to encourage competition, efficiency, and optimal investment in the electricity generation sector in Odisha.

The document can be accessed [here](#)

- 1. Suggestion on 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:*

GCV X (1-TM)

(1-IM)

Where: GCV = Gross Calorific Value of coal on as “billed basis”

TM = Total Moisture

IM = Inherent Moisture”

According to the Order in **Petition No: 152/MP/2018¹**, “*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

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)

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 be archived and made available in the public domain through the Commission's or other suitable website.**

2. **'Change in Law' Definition: 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).

3. **'Date of Operation' Definition: 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 technical and environmental standards, certified through the management certificate duly signed by an authorised 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 authorised person, not below the level of Direction of the generating company. **Provided that ODe is greater than or equal to the COD of the thermal generating station or its unit**"* (emphasis added).

4. **'Force Majeure' Definition - Statistical Measures of adverse weather conditions and, inclusion of System-Wide Cyber-Attack: Clause 3(bb)(i)** of 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 **Clause 3(bb)(ii)** of the draft document states

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.

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 localised 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 Clause 3(22)(ii). Input from the Indian Computer Emergency Response Team (CERT-In) should be required to ascertain severity of such cyber attack.

- 5. Definition of Useful Life: 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.

- 6. Determination of Energy Charge Component for Integrated Mines: 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”.

7. **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”.

8. **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”**.

9. **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).

10. **“Arrangement” for Provisions of Tariff of Generating Stations beyond 25 years of Operation from COD: 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.

11. Sharing of benefits accrued under PAT scheme: 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 Clause 15(2)(n) and Clause 15(3)(f) of the proposed draft, 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 determination³.

12. 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

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.

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 time⁴ 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.

- 13. Capital Costs for the determination of tariff for Projects acquired through NCLT proceedings under 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 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 depreciation allowed should be lower of the restructured loan repayment amount or the applicable depreciation under the tariff framework.

Case 2: When the acquisition value post NCLT proceedings is greater than the actual project capital cost – In such cases, the historical value of the project, at the

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

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).

- 14. Prudence Check Criteria for Thermal Generating Stations: 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 over-run 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”.

- 15. Sharing of Impact of Condoned Delay Between Generating Company and Beneficiary: Clause 17(5)** of the draft document states that *“If the delay in achieving the COD is attributable either in entirety or in part to the generating company or its contractor or supplier or agency, in such cases, IDC and 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.

- 16. Additional Capitalization Criteria Within Original Scope and Up to the Cut-Off Date: 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)

17. 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 exceeding **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”.

18. Passing on Benefits of Railway Infrastructure Augmentation to Consumers and Adjusting Capital Costs Based on Tangible Benefits: **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.

19. Special Allowance and Additional Capitalization for 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 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 O&M expenses should be recoverable.

20. Fixing RoE for generating stations: 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 IIT Kanpur*⁵, the CAPM method used to estimate the cost of equity provides a post-tax figure analyzing 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 1 below. This is lower than the sector's regulated return.

Figure 2 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>

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.

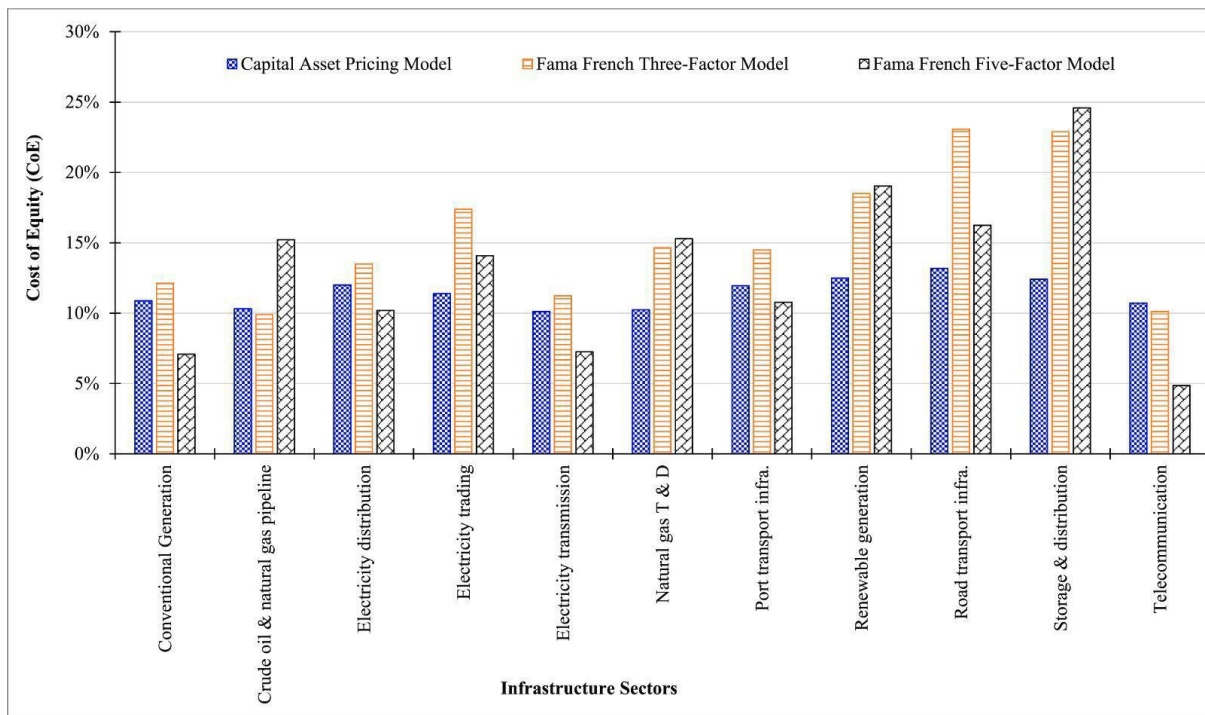


Figure 1: Cost of equity for different infrastructure sectors

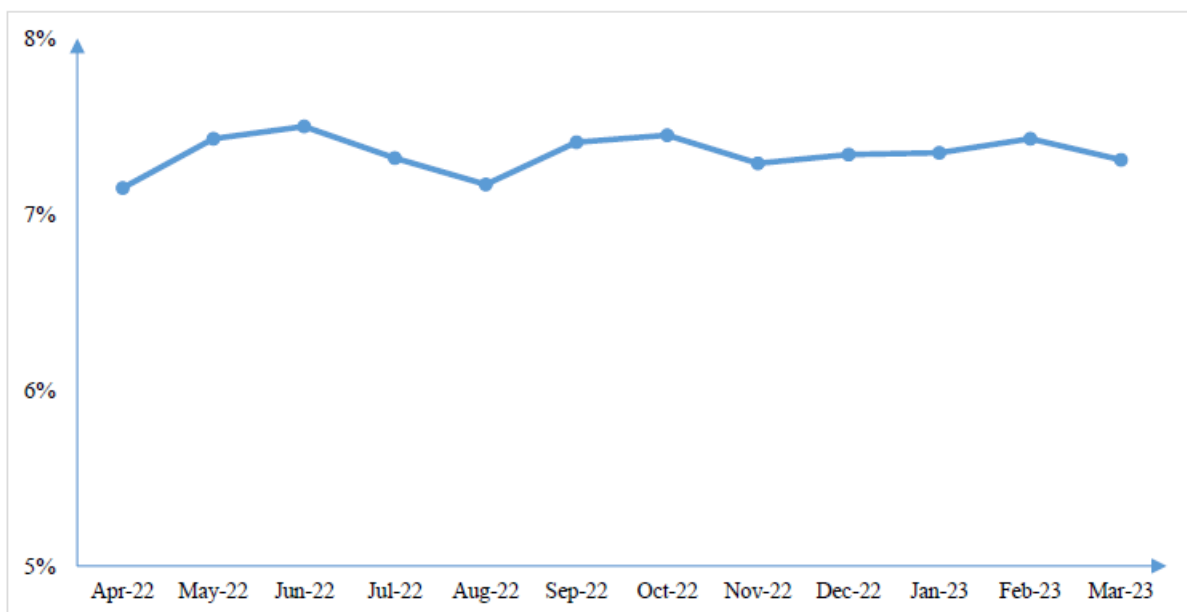


Figure 2: G-Sec 10-year Bond Yield over One year horizon

- 21. Inclusion of Procedure for Block-wise Verification of Ramp Rate and Associated Incentives/Disincentives in Draft Clause: 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.*
(iii) 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).

- 22. Clarification on Financing Charges and Calculation of WAROI on Actual Loan Portfolio: 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).

- 23. 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.

- 24. 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?

- 25. Estimation of Working Capital Based on Actual Blending Ratio of Coal: 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.

- 26. Calculation of Coal Cost and Working Capital for Captive Mine-based Generating Stations: Proviso to 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.

27. Clarification on Allowance for Changes in O&M Expenses Due to Change in Law or Force Majeure: 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.

28. Operation and Maintenance Expenses for Emission Control Systems in Coal/Lignite-Based Thermal Stations: 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 operation and maintenance expenses on account of emission control systems in coal or lignite based thermal generating stations shall be 2% of the admitted capital expenditure **of the respective emission control system** (excluding IDC and IEDC) as on its date of operation, which shall be escalated annually @ 5.25% during the tariff period ending on 31st March 2029 emission control system”.

29. Incentive for Frequency Response Performance: 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.*”

$$\text{Incentive} = (1.00\% \times \beta \times \text{CCy})/12$$

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 D:E 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.

30. Incentive for Scheduled generation beyond NAPLF:- Clause 42(6) states that “In addition to the capacity charge, an incentive shall be payable to a generating station or unit thereof @ fifty (55) paise/ kWh for ex-bus scheduled energy during Peak Hours and @ forty (40) paise/ 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 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.