Ref: LPGCL-RA/CERC/2023/18 **Date: 25.07.2023**

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

Subject: Suggestions/Comments of Bajaj Group- Power Business on "Approach paper on Terms and Conditions of Tariff Regulations for Tariff Period from 01.04.2024 to 31.03.2029" dated 26.05.2023 and its addendum dated 03.07.2023.

Dear Sir,

Please find the enclosed herewith written suggestions/comments on behalf of Bajaj Group - Power Business (having total thermal capacity of 2430 MW in state of U.P.) on the "Approach paper on Terms and Conditions of Tariff Regulations for Tariff Period from 01.04.2024 to 31.03.2029" issued by Hon'ble CERC as **Annexure – I** to this letter.

We humbly request you to consider our submission favourably and please do let us know, if you require any further clarification.

Thanking You,
Yours Faithfully,

Amit Mittal
President – Regulatory Affairs
(Bajaj Group- Power Business)

Encl.

1. Annexure I - Comments of Bajaj Group-Power Business on "Approach paper on Terms and Conditions of Tariff Regulations for Tariff Period from 01.04.2024 to 31.03.2029" dated 26.05.2023 and its addendum dated 03.07.2023.

Annexure -I

A. Comments of Bajaj Group – Power Business on Approach Paper on "Terms and Conditions of Tariff Regulations for Tariff Period from 01.04.2024 to 31.03.2029"

Sl. No.	Clause No.	Issue	Approach Adopted in Paper	Suggestions and Rationale
1.	1.0	Introduction	• CERC has invited suggestion in respect to other relevant issues that are not covered in paper.	• In the later section of this note the additional issues are addressed for consideration.
2.	2.0	Review of Past and emerging need for simplification of Tariff process	• The core idea of this approach paper is to simplify the Tariff determination process. Additionally, approach paper focuses on: ➢ Efficient and Performance based Norms ➢ Maximising the utilisation of efficient generating stations. ➢ De-risking Generation and Transmission Business • Further given to the degradation of operation norms on account of variability of Demands this approach paper also acknowledges the need of Regulatory certainty in the sector,	• In respect to suggestions made by CERC it is submitted that any major changes in established regulatory approaches create considerable risk for regulated entities. This is particularly so for existing assets which have been set up based on the prevailing regulations and tariff principles applicable at the time of the assets being planned. Any change in basic regulatory approach will adversely impact revenues and cash flow projections and thus jeopardize the availability of the projects. • Any major departure in the fundamental approach from established principles may deter funding by lenders. It is therefore important to maintain regulatory stability, consistency in approach and minimize recovery risk which are also identified as the objectives of the Tariff Policy issued by GoI. The National Electricity Policy also stresses the need to have regulatory certainty to promote investors' confidence. • Detailed study for analysing the impact of the proposed normative approach needs to be conducted by the Hon'ble CERC. Hence for this control period, it would be appropriate to not to consider such approach for existing stations as well as new generating stations. • It is understood for the approach paper that instead of simplification/reduction of efforts involved in tariff determination under normative proposed approach will actually increase the efforts and complication in the tariff determination process reality of current location applicability as applicability of delegations.
3.	3.0	Tariff determination – General Approach (Category A)	• Suggestions are sought as to how present system of hybrid mechanism of tariff setting under cost plus approach can be made more efficient by moving closer to normative or performance-based approach so that the same shall positively impact interest of consumers as well as utilities. • Approach 1 – Shift to Normative Tariff wherein, once capital cost is approved on actual basis after prudence check, all other AFC components are determined on normative basis for the entire useful life of the Asset.	• For accommodating the changes in cost, the revision in tariff should be done annually and the impact of True-up to be adjusted on annual basis. This will ease out the burden on Generating Company or Transmission Licensee as well as on beneficiaries. • If capacity charges are determined on normative basis, it will require annual true up of various parameter to ensure revenue neutrality. Timey truing up of approved cost is also important for adjustment of revenue gaps. • Whether the proposed normative tariff stipulated in 2024-29 regulations would be made applicable for a period of 25 years. How applicability of

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			Comments sought on Normative Tariff mechanism, wherein AFC components are determined on normative basis for Control Period. AFC components are categorised as two components under: • O&M expenses • AFC excluding O&M Expenses The following mechanism is proposed: Existing Stations (in operation for > 5 years as on 31.03.2024) – • Approved AFC for above two components for FY 2024-25 to be considered as Base AFC for Control Period to be determined by applying Indexation factor • Truing up for Indexation factor only. • Indexation factor for 2029-34 with base as FY 2024-25 to be specified with same exercise. • Specific Petition for approval of capitalisation. The impact of the same from date of capitalisation to be adjusted in Indexation factor. • Energy Charges as per present approach to be continued. • Sample calculation to be included as Annexure to Paper. New Projects: • Capital cost to be approved on actual basis. • Additional capitalisation to be approved on normative basis. • From 6th year onwards, AFC to be determined on normative basis as per above said approach. • Energy Charges as per present approach to be continued • Approach 2 – Further Simplification of Existing performance-based Hybrid Approach, wherein based on admitted capital cost, AFC components can be approved based on actuals or norms as may be specified for Control Period.	tariff regulations enforceable for only a control period of 2024-29 be made applicable next four control period? There is question of regulatory certainty in applicability of equitable normative tariff for such period. • Legality of such extended applicability of Tariff regulations for the period of 25 years would be in question, as applicability of Tariff Regulations is confined to Control period, presently specified as five (5) years. However, with proposed approach, the tariff regulation specified for tariff 2024-29 would be applicable for at least twenty-five (25) years. Hence, there is a need re-look in terms of legal applicability of this proposed change. • Considering the parameters like additional capitalisation, ROE, interest on long term loan, interest on working capital, etc. are likely to change in each of the control period, so the proposed normative tariff approach will only be a theoretical exercise whereas in practicality, the Commission will be required to intervene in every stage. • It is difficult to cater the project peculiarities in normative tariff approach. Hence, the generating company and licensee will likely seek specific relief from the Commission or from beneficiaries. Nos. of dispute will become higher compared to present approach. • It is also submitted that every project has different project specific issues and cost implications, if this approach is made applicable to all, and if a higher normative number is fixed DISCOMs will be in a loss and if its lower then GENCO would be in loss. This approach is against the principle of section 62 wherein the cost recovery with regulated return is fixed. • Also there might be some projects where the final tariff is not yet approved due to legal cases, what capital cost would be assumed in that case. • Further the proposed mechanism of categorising AFC in two is detrimental in long run. • Indexation Factor approach may lead to substantial reduction in AFC. • In view of the above, it is suggested to continue the present approach for tariff framework instead of adopting the normative tariff approach for existing generating stations as well as new generating stations. • It is understood form the workshop organized by CERC tariff fixation will be done for individual project specification. In this context, it is requested that it may be clarified in the regulations if the actual capital cost

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			• Further, additional capitalization may be allowed on certain count on normative basis. In view of the above said approaches, the suggestions invited on the following points. • Whether clustering the components of AFC based on their nature to increase/decrease in order? Possible methods to cluster the AFC components. • Methodology to be adopted to determine the increasing/decreasing factor. • Whether impact of additional capitalisation can also be allowed through the same indexation mechanism or through a separate revenue stream?	incurred for the project is more than the normative cost specified then regulation should specifically enable the Commission to look into the prudence check of increased cost and if found in order it should be allowed. It is important that regulation curtail the plenary powers of Hon'ble Commission as enshrined under the Electricity Act, 2003.
4.	4.2.1	Capital Cost	• CERC has been approving the capital cost of the projects on case-to-case basis based on actual expenses incurred after due prudence check. • Also, CERC Tariff Regulations, 2009 for first time allowed utilities to seek approval of capital cost on projected basis, which helped utilities to minimise the gap between projected vs actual. • Hence, suggestion are invited on whether provision for interim-tariff for approval of capital cost for Tariff determination as per present regime should be continued for next tariff period?	• The cost of the project depends on various factors such as capacity, technology, location, site specific conditions, resources availability, etc. These variables are peculiar for each project. In such case, the normative approval of cost of project would not be possible. • **Hence, the present approach of approval of cost of project on case-to-case basis subject to due prudence check shall be continued.** • The mechanism for approval of Interim/Provisional tariff to be continued as it ensures the cash flow to the company and arrangement of funds for Loan Repayment. • **Also, the approval of capital cost as well as additional capitalisation as specified in Regulation 19 and 24 of Tariff Regulations shall be continued.** This really helps utilities to reduce the gap between projected expenditure and actual expenditure. Also, recovery of cost based on projected basis eases the commissioning of the project because of availability of fund. • **In addition to this, the provisions related to in-principle approval of the capital expenditure on projected basis shall be explicit for having better clarity.**
5.	4.2.2	Procurement of Equipment and Service	• In the interest of consumers, work contracts are required to be awarded on the basis of competitive bidding, which shall form basis of approval of such costs. • Comments invited on need to mandatorily award work and services contracts for developing projects under the regulated tariff mechanism through a transparent	• Developers are following least cost approach for execution of the projects. The majority of work contracts are being awarded for section 62 projects based on competitive bidding as the same are liable for prudence check. • However, in some special cases, because of limited participation from vendors or limited vendors for such special works, the competitive

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			process of competitive bidding, duly complying with the policy/guidelines issued by the Government of India as applicable from time to time	bidding is not feasible. In such cases, the contracts have been awarded based on one-to-one negotiations. • Hence, award of contracts based on competitive bidding mandatorily will increase the difficulties of the developer and more Petitions/cases may pile up before CERC for special exclusion on case-to-case basis. • **In view of the above, it is suggested that developer should be provided enough liberty for execution of the project and award of contract based on competitive bidding shall not be made mandatorily. Moreover, any contracts is liable for prudence check and developer shall follow the least cost approach for such work execution.**
6.	4.2.3	Reference cost for approval of Capital cost-Benchmark cost v/s Investment approval	• As per existing methodology, investment approval cost is considered as reference cost while approving the capital cost. • Suggestion sought of efficient reference cost other than Investment Approval costs that can be considered for prudence check.	• The cost approved in Investment approval is the most appropriate cost to be considered as reference cost for approval. The project peculiarities have already been considered at time of investment approval. • Further, it is also suggested that, in case of substantial delay in execution of project from Investment approval, the revised investment approval shall be considered as reference cost. • Alternatively, it is also suggested that, CERC benchmark cost shall be considered for hard cost approval. If hard cost of the project is within the CERC benchmark cost then such hard cost shall be allowed without any reduction in cost. The prudence check shall only be carried out for Hard cost over and above the CERC benchmark cost. • CERC Benchmark cost shall also be taken into account at time of investment approval.
7.	4.3	Capital cost for projects acquired post NCLT proceedings	• For Section 62 projects, acquisition value may need to be considered for determination of tariff of the projects acquired post NCLT proceedings. • Further, in case of acquisition price is higher than historical value then the same may be capped at the historical value of such assets as consumers cannot be allowed to bear the asset premium quoted. • In view of the above, the comments are invited on the following: o What capital cost (Historical cost or Acquisition value) should be considered for determination of Tariff post approval of Resolution plan. o Tariff Provisions to be included to address the issue of cost of debt servicing including repayment that were allowed as a part of tariff	• For the projects acquired post NCLT proceedings, the historical cost shall be considered for the determination of tariff. • Historical cost would represent the actual cost incurred at the project site and the same should be reflective in tariff. • In fact, NCLT proceedings is the arrangement to make the project active and recovery of lenders money. Any acquisitions value shall be kept out of regulatory regime. • If such approach is adopted, then generating company and licensee will endeavour for consideration of acquisition value in regulatory regime, in case of usual mergers and acquisition transactions.

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			during the Corporate insolvency resolution plan (CIRP) process.	
8.	4.4.1	Computation IDC- Post Scheduled COD	• The existing provisions may be modified so that IDC can be spread till actual COD instead of SCOD and IDC up to the SCOD or till the date delay has been condoned may be allowed. • In view of the above, the comments are invited on the following options for allowing IDC: o Option 1 - Existing mechanism wherein the pro-rata computation is done on excess IDC pertaining to delay period beyond SCOD. Option 2 - Pro-rata IDC may be allowed considering the total implementation period wherein the actual IDC till implementation of the project is pro-rated considering the period upto the SCOD and period of delay condoned over total implementation period. o Option -3 - IDC approved in the original Investment Approval to be considered while allowing actual IDC in case of delay.	• It has been observed that, the actual IDC payment during the construction period varies from project to project and depends on loan infused. • Option 1 would be detrimental to Developer in case of higher IDC payment made between the period from SCOD to Actual COD. Hence, this would not be considerate approach. • Also, Option 3 would not give correct picture as IDC in investment approval may not be indicative to the delay scenario on account of uncontrollable factors. Further, if delay is condoned the actual IDC must be considered as pass through. • **Hence, Option 2 is suggested wherein total IDC paid during total implementation period/ construction period is to be pro-rated based on condonation of delay.**
9.	4.4.2	Treatment of Liquidated Damages	• Suggestions are sought on necessary changes required in Tariff forms and Regulations regarding the treatment adjustment of LD and IDC on account of delay in the project, and for improvement in current methodology for accounting the delay.	• For treatment of controllable and uncontrollable delay, the APTEL Judgment in Appeal No. 72 of 2010 may be followed. Moreover, the scope of the APTEL Judgment is limited to delay on account of Generating company or Transmission licensee. The same shall also be clarified. • In case of delay by upstream or down-stream elements of Projects, then treatment of such delay shall be explicitly mentioned and be made separate than the principles decided in APTEL Judgment in Appeal No. 72 of 2010. • CERC (Inter-State Transmission Losses and Charges) Regulations, 2020 already provided the treatment regarding the delay of upstream or downstream element and recovery of charges in such case. The similar principles may be adopted in these Regulations and should be clearly mentioned in the Regulations for providing absolute clarity. • As per Delhi High Court Order [Indian Oil Corporation Vs. Messrs Lloyds Steel Industries Limited; 2007 (144) DLT 659)] it is established that Liquidated Damages cannot be claimed if it is proved that no actual damages were caused Hence in cases where delay is on account of

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				non- commissioning of upstream /downstream or where the obligation of COD is on another party, the case of charging of LD from the contractor does not arise. CERC must bring more clarity on such cases in Tariff Regulations.
10.	4.5	Price variation	• Suggestions invited for allowing price variation, the utilities may be mandated to submit the statutory auditor certificate along with the petition duly certifying the price variation corresponding to delay and the same may be allowed on pro-rata basis corresponding to the delay condoned. Further, a separate form may also be specified to submit the relevant information pertaining to price variation.	• In the event of delay in the Commissioning of the project, the cost of the machines and equipment changes as compared to envisaged cost in the investment approval conceptualized at the initial stage of the project. Such price variations are on account of inflation, foreign risk, change in cost of raw material, manpower cost, etc. over the time of project delay. • In such cases, where the delay in project commissioning is condoned, then corresponding price variation for such delay period should also be allowed. This will provide an equitable approach. • A separate Tariff form will only increase paperwork. Existing Tariff form 5B is already catering the purpose.
11.	4,6	Renovation and modernization	• Comment invited on continuation of existing R&M mechanism considering R&M is cost effective investment as against fresh capital investment. • Comments and suggestions are also sought on the suggestion of continuing with Special Allowance for the rest of the tariff period, if opted at the beginning of the tariff period to avoid abrupt changes and ensure proper planning.	• R&M is majorly adopted by plants which are old and are not in good health. Provision for R&M will ensure availability of well-maintained generating stations to the beneficiaries at reduced cost as compared to replacement with new generating stations. R&M is a cost-effective mechanism and should be continued. • On other hand CERC also has provision for Special allowance for well-maintained plant not willing to opt for R&M. Special Allowance is exclusively for meeting the capital expenditure towards R&M. The present norm of Rs. 9.5 lakhs per MW per year works out to Rs. 1.42 crores / MW over a period of 15 years, which is barely sufficient to meet capex requirement of R&M. Therefore, other necessary expenditure related to ash dyke and those to comply with Change in Law events for units of more than 25 years may be allowed separately. • Currently, R&M works are done by plants which have completed their useful life. It is suggested that a special provision be made for undertaking R&M works for projects, which have completed 10-15 years. The benefit of R&M works in terms of improvement in performance parameters shall be passed on to the beneficiary by reducing the Energy Charge Rate,
12.	4.7	Initial Spares	• Suggestion invited on approach and alternative options to standardize and simplify the process of approval of initial spares.	• Initial Spares are crucial part of capital investment. Capitalization of spares like other additional capitalization also dependent on many uncertainties such as spares availability, vendor negotiation, funding, delivery time etc.

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				• It is suggested that initial spares may be allowed based on actual expenditure after prudence check, rather putting a ceiling limit. • As the technology is changing availability of spares are becoming more important and cannot be avoided. • It is further submitted that CEA vide advisory dated 07.02.2020 has mandated the availability of spares inventory for thermal power plants. • **Hence, as an alternative approach, if the ceiling limit is put, then there should not limit for capitalisation upto cut-off date. The relaxation of cut-off date should be allowed for initial spares and capitalisation of spares should be considered beyond cut-off date as well.**
13.	4.8.1	Delay toward obtaining forest clearance	• Comment sought on whether delay on account of forest clearance should be included as uncontrollable factor, provided such delays are not attributable to generating company or transmission licensee.	• In most of the cases major part of the project delay is attributable to the forest clearance. Forest clearance comprises of two stages viz. Stage 1- In principal approval of the process Stage 2- Finalization of land acquisition. • During Stage 2, the most of the project get stuck due to non- availability of alternate land for Compensatory afforestation, which further delays the project execution. It would be a welcome move that delay on account of forest clearance is included as uncontrollable factor. • In addition to this, some other factor such as, o Delay due to clearance approval for Railway line crossing, any other statutory approval, Delay in taking approval for tree cutting, etc. o Any stay on work by any judiciary body (DM, High court order) should also be considered as uncontrollable factors. • Further, the clarity should be provided in this Tariff Regulations, in case of delay from the upstream or downstream elements. Although, CERC (Sharing of Inter-State Transmission Charges and Losses) Regulations, 2020 provides the clarity in such treatment, moreover, the applicability of those provisions should be clarified in the Tariff Regulations. Further, it is suggested that, o In case of delay of transmission evacuation system, the generating station should be allowed for deemed COD and charging its tariff. o Further, wherein the bilateral charges are levied on entity which got delayed in commissioning, such bilateral charges are to be passed through to end consumers or to be waived off, if the delay of such entity is condoned by the Appropriate Commission.

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14.	4.9	Differential norms- Servicing impact of delay	• To encourage rigorous pursuit of such approvals from statutory authorities, even if delay beyond SCOD on account of clearances and approvals that are condoned, some part of the cost impact (Say 20%) corresponding to the delay condoned may be disallowed. • Should ROE on equity corresponding to cost and time overrun allowed over and above project cost as per investment approval may be allowed at the weighted average rate of interest on loan. • The current mechanism of treating time overrun may be continued, considering that utilities are automatically disincentivised if the project gets delayed.	• ROE for any project covers the risk investor has put in the project. For any delay not attributable to the developer is considered as the capital investment toward the project. Investor must be assured of return on such risk taken up by him to complete the project despite any hurdles. • Additionally, ROE is the sole the financial motivation of the investor to execute the project. Not giving ROE on the delay period expenditure may not attract investment in the sector as infra project is having uncertainties during the construction period. • Hence, weighted average rate of interest of loan shall not be allowed for such capital expenditure. The allowance at rate of return on equity would be an appropriate approach. • As also evident from the approach paper any delay in the project itself reduces the IRR of the project. Hence disallowing some part of the cost may again impact the cash flow and reduce IRR further. **The present mechanism of treating the time over run should be continued without deduction in cost for which the period delay is condoned.**
15.	4.10	Additional capitalization	• Comment invited on: - • For having an enabling provision under which costs resulting in better operational management leading to reduction in operation costs or resulting in other tangible benefits, can be allowed. A provision may be introduced which acts as an enabler to allow such capital expenses which shall be considered only if it is established by the Utility through a cost benefit analysis report that such expenses shall result in reduction in operational costs, increase in efficiency of operations.	• It is submitted that Tariff Regulations have been specifying the norms of operation, expecting improvement in performance of generating stations. In 2019-24 for 250 MW capacity normative SHR is revised as 2430 kCal/kWh against 2450 Kcal/kWh allowed in 2014-19. Similarly, Y-O-Y O&M escalation has also been reduced to 3.50% from 6.31%. Also, it cannot be ignored that the coal quality is constantly deteriorating. The actual operating conditions in future are expected to deteriorate further as compared to the existing situation due to constant deterioration in coal quality, shortages in coal supply, low PLF, etc. • However, on the other hand, no deterioration in norms is considered. Keeping the improvement in norms is aggressive trajectory for performance. • For achieving such performance and technological improvement in terms of digital systems, additional capitalisation should be considered beyond original scope towards such efficient and smooth operation. • Hence, the provision should be incorporated as under: "*Any additional capital expenditure which has become necessary for efficient and smooth operation of generating stations or transmission system as the case may be. The claim shall be substantiated with the technical justification duly supported by the documentary evidences;*" • Further, it is submitted that, for additional capitalization like ash disposal, it may not give cost benefit analysis being intangible benefits. However,

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				such additional capitalization is essential for smooth operation of plant. Hence, such additional capitalisation should be allowed without providing any cost benefit analysis and clarity to be provided in the Regulations in this regard.
16.	4.10.1	Normative Add-cap Generating Station	Suggestions are invited on following approaches in respect to Add cap: - **For Thermal generating stations that have already crossed cut-off date as on 31.03.2024** • Thermal Generating Stations - Based on the analysis of actual additional capitalization incurred by such generating stations in the past (15-20 years) a special dispensation in the form of yearly allowance based on unit size and vintage may be allowed which shall not be subject to true up and shall not be required to be capitalized. • While allowing such dispensation, work covered under Force Majeure, change in law, arbitration award etc, may not be included and should be allowed separately. • Items (tools/tackles/Capital spares) costing below Rs. 20 lakhs may be allowed as part of O&M and should not be considered as add cap. • Discharge of liability already admitted by Commission as on 31.03.2024 shall be allowed when discharged. **For Thermal generating stations whose cut off date is falling in next Tariff block (2024-29) and are expected to achieve COD by 31.03.2024** • Cut off date is to be extent to 5 yrs to allow more time to close contracts and discharge liabilities and to eliminate the need to allow additional capitalization post cut off date unless in case of Change in law and Force majeure • However, if there is a need to allow additional capitalization which may be legitimately required post cut off dated other than those presently allowed under force majeure, change in law etc, same may be allowed as special- I compensation as proposed in case of existing station who have crossed cut-off date.	**For Thermal generating stations that have already crossed cut-off date as on 31.03.2024** • Yearly allowance may not be able be cater each plant in the same manner. A general Benchmarking may not serve the purpose with plant having peculiar requirements. • For capital spares less than 20 lakh additional O&M head to be included under O&M of per/MW/year basis. • **It is rather suggested to move ahead with present regime for allowing additional capitalisation on actual basis, subject to prudence check by the Commission.** **For Thermal generating stations whose cut off date is falling in next Tariff block (2024-29) and are expected to achieve COD by 31.03.2024.** • Relaxing cut off is a welcome move and should be incorporated. • Additional capitalisation necessary for plant operation not covered in original scope to be allowed.

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			• While allowing special compensation work covered under Force Majeure, change in law, arbitration award etc, may not be included and should be allowed separately. • Items (tools/tackles/Capital spares) costing below Rs. 20 lakhs may be allowed as part of O&M and should not be considered as add cap. • Any major capital spares costing above Rs. 20 Lakh may form part of special compensation. • Discharge of liability already admitted by Commission as on 31.03.2024 shall be allowed when discharged.	
17.	4.11	GFA/NFA/Modified GFA approach	• Suggestion invited on alternate approaches, i.e. GFA/ NFA/ Modified GFA approach.	• **The present GFA approach to be continued as the utilities are more familiar with the approach. Also, the audited accounts are also aligned with the regulatory framework of GFA approach.** • Since, all past implemented projects achieved financial closure assuming returns on GFA basis and not NFA approach. Tinkering with the methodology will increase the perceived risk and banks will charge a higher interest rate which will be passed on to beneficiaries and thereby negating the gains achieved by basing the returns on modified Gross Fixed Assets. • The transition of approach would lead to regulatory uncertainty for recovery of cost. • Power Sector is going through critical phase and private investment has died down in generation and transmission projects. Also, existing projects, when conceptualized, were evaluated considering RoE till the supply/service continues. • Tariff Policy mandates regulatory certainty and any such move will demotivate the prospective investors.
18.	4.12.1	Normative O&M expenses	Whether O&M expenses may be categorized: - • Employee expenses • Other O&M expenses (R&M and A&G) Suggestion may be given considering that the automated system would require less manpower and less automated system would require more manpower. Segregation may increase complications.	• It is suggested to allow additional head for contingent O&M. • **It is suggested to take cognizance of the O&M incurred on actual basis rather than relying on same norms for all. True up of O&M should also be practised.** • Equal treatment should be given to IPP and JVs as compared to Central Government Utilities in respect to pay revision. • It is further suggested that insurance cost must be treated and allowed separately, as from lenders' perspective insurance is must for loan disbursement. Unlike group companies, keeping insurance corpus is

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			Alternatively, to give effect to the impact of pay/wage revision, 50% of the actual wage revision can be allowed on a normative basis, suggestions are sought.	not possible for a single plant generator company. The insurance cost available in the market are expensive and has huge share in O&M expenses. • Insurance is hedge towards risks a generator faces while running the project. The present Tariff Regulations does not shield generators against emerging risks in changing market scenario. Buyers of electricity are changing their behavior looking for more renewable energy supplies and on the other hand electricity consumption is still growing. Climate change also has an impact on the electricity prices as e.g. during dry seasons with lack of rain electricity generation from hydro power has to be replaced by conventional energies like coal or gas. • It has to be stated that many electricity markets today are in a state of considerable change and suffer new challenges. Existing conventional power plants are now required to operate with much more flexibility and thus are deviating from original design features. Innovative power purchase agreements are expected to govern the market. Future power purchase agreements will be more complex with complicated adjustment and settlement especially with the involvement of electricity and carbon emissions trading. • In light of rapid changes expected in the market and thermal power plant are facing lot of uncertainties both at operation and contractual end. Needless to say although these risks exist they need to be insured in respect of value and their influence on the PPA and regulatory policy coverage. • At present, insurance cost allowed to generator is subsumed in the O&M expenses. The insurance cost is necessary for the projects covering all risks including market risks and risks on account of natural calamities. It is to be appreciated that insurance cost depends upon market risk of the business, which is now continuously increasing for coal generating plant and burdening the generator. • It is pertinent to mention that even lenders also do not provide additional loan in absence of insurance which affects the plant operation and capex investment. • **Given to above factor it is requested that Commission may allow the petitioner to recover the insurance cost as on actual basis over and above normative O&M expenditure.**

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19.	4.12.4	Inclusion of capital spares	Suggestion invited on whether capital spares: - • Can be allowed on normative basis along with O&M or • Low value capital spares i.e., below Rs. 20 lakhs may be made part of normative O&M and capital spares above Rs 20 lakhs can be allowed separately on case-to-case basis.	• To include capital spares (below Rs. 20 lakh) in O&M, the Commission should provide enough margin in the O&M norms to include such expenditures or should make additional head under O&M on per year/MW basis. • However, it is advisable to continue with present regime to allow capital spares as and when it is capitalized on actual basis.
20.	4.12.5	Impact on account of change in law	• Suggestions are invited in respect to increase in additional O&M expenses on account of change in law.	• The adjustment for impact of change in law to be done between Generating company or licensee and beneficiaries. In case of any dispute, the Commission should be approached for adjudication of dispute and approval of change in law impact. • The impact of change in law must be taken into consideration on actual basis and should be trued up on quarterly or annual basis. • It is submitted that, at present, the impact of Change in law is allowed only in capital cost. In case of project specific change in law wherein new assets is capitalised like FGD, etc, the present mechanism allows only capital expenditure. Since, the present O&M norms are linked to capacity and there would be no change in capacity in such case, O&M expenses on account of this additional capitalisation is unrecovered. Hence, there is requirement for allowing O&M expenditure on such new capitalised asset on account of change in law. Hence, it is further suggested , the Commission should specify additional O&M for maintaining and operating that new assets, which is capitalised on account of change in law duly approved by the Commission. The additional norm may also be specified in this regard.
21.	4.13	Depreciation	• Comments are invited on the depreciation rates to be specified if loan tenure is considered for 15 years instead of current practice of 12 years. • Further, additional provisions may also be specified that allow lower rate of depreciation to be charged by the generator in the initial years if mutually agreed upon with the beneficiary(ies)	• Under the present Regulatory mechanism, the repayment for long tenor loan for repayment period of 12 years has been considered equivalent to depreciation. Accordingly, depreciation has been allowed by considering the annual depreciation equivalent to repayment amount considered for loan tenor of 12 years. This enables the Generating company to have an adequate cash flow available to meet its debt service obligation. However, the Approach paper has proposed to increase the repayment period from 12 years to 15 years, with an assumption that there is availability of long tenor of 15-18 years. • With the increase in the repayment period to 15 years, it is assumed in the Approach Paper to lower the tariff because of decrease in depreciation, which is not reflecting in the computations. On the contrary,

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				it is noted that there would be net increase in Annual Fixed Charges by more than 7-8% over the useful life of the project, on account of increase in Interest amount for such longer period of normative loan. Increasing repayment period will increase the burden on beneficiaries (at the last mile- end consumers) over project lifecycle as well as reduce the cash flow for Generating Company. The proposed approach is also not aligned with the principles and objectives enshrined in the Electricity Act, 2003 and Tariff Policy to protect the interest of consumers as well as developer. In this case, it is evident that it is helping none of the stakeholders. • Further, it is noted that, the long-tenor loans are disbursed by Banks after considering their Asset-liability position and risks associated with loans. Majority of Bank's liabilities (Deposits, etc.) are in the bucket of lower age tenor (8-10 years). The repayment period of 12 years is being allowed by considering the average period of Bank's liabilities and risks of infrastructure projects. The longer time would be required to Banks for recovery of its long tenor loans, and this will increase their risk. Hence, there is strong aversion by Banks to lend the long tenor loans to infrastructure project. Accordingly, for long tenor loans, higher interest rates are being charged by Banks. If such long tenor loans are availed by Generating Company(ies), this will put additional burden on Beneficiary over project lifecycle as interest rates are pass through. Hence, it would not be a feasible option for Generating company to avail such long tenor loans because of higher interest rates and its subsequent impact on cash flows. In view of this, it would not be appropriate to consider the repayment period of 15-18 years as the long tenor loans are not feasible option. • Now even in case External Commercial Borrowings (ECB), Reserve Bank of India (RBI) has stipulated the average maturity period of three (3) years with "All-in-cost" ceiling interest cost i.e., Benchmark rate plus maximum spread. For Rupee denominated ECB, it would be Benchmark rate plus 450 basis points and for Foreign Currency denominated ECB, it would be benchmark rate plus 500 bps. Further, in case of long tenor ECBs, say 10 years, it would require the payment of higher spread over the

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				benchmark rate, which is not allowed by RBI. Hence, option for consideration of long tenor ECB would not be feasible option. In addition to this, Issue of assets liability matching will also be applicable in ECB facility. Foreign Banks, Indian Banks having branches outside face difficulty in sanctioning longer tenor foreign currency loans for projects unless they have matching assets and liabilities. • Further, it may be noted that because of current climate change scenario and Environmental, Social and Governance (ESG) constraints, Foreign Banks/Financing Institutions are not readily willing to lend for financing fossil fuel-based projects. With changing scenario and energy mix, the availability of loans to Thermal Generating Stations is expected to be constrained or it would be at higher rate of interest. This is primarily because of higher risk perception of Fossil fuel generation due to transition to RE and higher exposure of domestic loans to power sector considering large fund requirement for Thermal generating stations. Therefore, the situation for taking longer term loans from foreign banks/ financial Institutions will further aggravate on increase in tenor of term loans. • **In view of the above, it is noted that there is lot of uncertainty in terms of interest rates for fossil based plants especially for long tenor loans and for cost plus projects, primary reason for considering Interest rates on actual is to insulate the both beneficiaries and generating company from the associated risks. The proposed approach of consideration of repayment period of 15 years would lead to major liquidity issues for Generating Stations as well as it would burden the beneficiary with additional cost. Hence, it is suggested that the present approach of consideration of repayment period of 12 years may be continued.**
22.	4.14	Interest on Loan	• Suggestion is welcomed on consideration of WAROI of the generating company may be considered instead of project specific interest on loans. • Further, the cost of hedging related to foreign loans be allowed on an actual basis, without allowing any actual FERV.	• The present approach is more considerate approach for computation of weighted average rate of interest. Also, it provides the mechanism for consideration of rates in case of SPVs with no actual loan. • The option to claim either hedging cost or FERV should be available to generator for loan. • Further, Tariff Regulation should also introduce the provision with respect to hedging /FERV against the Project contracts as most of project contracts are exposed to Foreign Exchange risks.

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				• It is further suggested that in respect to refinancing of loan, the Commission should provide a detailed mechanism as more and more projects are opting for refinancing. At present, the computation of re-financing is left at discretion of Generating company and its beneficiary. It is suggested that NPV based one-time settlement of the refinancing benefit should be allowed. In NPV based settlement, the NPV of Interest on loan based on difference of actual and revised WAROI is calculated and shared between the parties in as suggested in the regulations.
23.	4.15	Return on Equity (ROE) Vs Return on Capital employed (ROCE)	• Comments are sought from stakeholders on the continuation of the RoE approach.	• **The present approach of ROE to be continued as it is more familiar with the stakeholders.** • The sudden change in return approach will create regulatory uncertainty amongst the developers as well as lenders. • RoE approach takes into account the fact that there is no legal provision for taking out the equity invested in a company other than liquidating the company generally after the useful life. Thus, equity remains locked in the company for its entire life and hence, RoE approach throughout life is justified.
24.	4.16.4	Rate of Return on Equity	• Suggestion invited on consideration of Capital Assets pricing Model for estimation of ROE. Any alternate mechanism may be suggested.	• Capital Asset Pricing Method may be continued for arriving at rate of return on equity. However, it is advisable that the market indices of COVID period may be omitted as it would not be correct representation of a healthy market scenario. • Further, it is also submitted that the sudden change in rate of return will create regulatory uncertainty amongst the developers as well as lenders.
25.	4.16.4	Return on Equity	Comments and suggestions are sought • Rate of RoE to be allowed including that to be allowed on additional capitalization that are carried out on account of Change in Law and Force Majeure. • Whether revised rate of RoE to be made applicable to only new projects or to both existing and new projects? • Whether incentivizing timely completion of hydro generating station attract investments? • Merit behind approving different Rate of RoE to Thermal, Hydro Generation and Transmission Projects with further incentives to Dam/reservoir-based projects including PSP.	• ROE on additional capitalisation on account of change in law and force majeure should be allowed at the same rate. • Any expenditure admitted by the Commission after prudence check has the same applicability of ROE as capital investment. It is submitted that each cost incurred after the cut-off date is approved by the Hon'ble Commission after adequate prudence check. Therefore, the current provision of denying adequate return on equity portion towards such additional capitalization is arbitrary and defies all financial reasoning. • Return on equity is the return allowed to the ordinary shareholders on their equity investment in generation/transmission projects. To ensure that, it is fair to both the investors and the consumers, the return allowed should be comparable with the returns available from alternate investment opportunities having comparable risk.

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			• Merit in allowing RoE by linking the rate of return with market interest rates such as G-SEC rates/MCLR/RBI Base Rate.	• Rate of ROE should reflect the market situation and must yield reasonable benefit to the investors. For this Commission has deployed CAPM model for arriving at RoE during previous tariff periods. G-sec trend for 10 year yield and market return trends are considered to arrive at normative rate of ROE. It is submitted that during 2019-20 and 2020-21 economy has toppled worldwide due to COVID -19 pandemic. Post covid economy has geared up and still in improvement stage. Hence**, the impact of COVID -19 regarding lowering of G-Sec rates should be omitted as outliers while computing the rate of return.** • As not all the companies are listed in stock market. CAPM may not reflect the risk prevailing in the thermal generation market due to uncertainties and all-time high proportion of stressed assets. Unlike transmission or hydro assets, thermal generating asset is posed with the risks of fuel shortage, paucity of demand, etc. • Therefore, there is a need to consider for increasing the rate of RoE for generation. • In addition to above providing the regulatory certainty for the investment made in generating station, rate of return should be applicable for the control period in which such project has achieved COD. • Also, ROE may also be considered for construction period compensating Thermal generator for long gestation period.
26.	4.16.5	Rate of Return -Old Thermal Generating Station	Suggestions are sought on various possible alternatives to incentivizes generation from efficient old generating stations. • Alternatively, additional incentive in the form of paise/kWh may be allowed to such generating stations against generation beyond target PLF.	• The plant which had already completed their useful life do not recover depreciation and Interest on Loan in AFC. Such efficient plants are required to be incentivized for their performance. • PLF based incentive may or may not be realized by such plant and will depend on despatch of plant by Beneficiaries. • It is advised if any incentive is to be provided shall be given in AFC as an additional component.
27.	4.17	Tax Rate	• Suggestion invited whether tax shall be allowed in cases where the company has actually paid the taxes and should not be allowed in any other circumstances.	• **The present approach for allowing of pre-tax ROE shall be continued.** • The regulatory business to be treated as watertight compartment. The tariff is approved with PAT equivalent to ROE. Hence, tax is payable on such regulatory tariff. • The tax is not paid on account of higher expenditure in P&L accounts. These higher expenditures are not allowed by the Commission while

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				approving the AFC e.g., O&M expenses are allowed on normative basis, Working capital is limited to receivables of 2 months, etc. Hence, as resultant of higher expenditure, generating company should not be penalised by not allowing the income tax. • The regulatory accounting and actual accounting for tax purpose to be treated separately. • It is submitted that, for amalgamated entities / zero tax companies, RoE should be allowed to be grossed up with at least MAT rate despite there being no actual tax liability for company as a whole if the project on standalone basis is profitable.
28.	4.18.1	Working Capital	• Whether any changes required in working capital norms.	• The present mechanism is prudent approach adopted by CERC. The same shall be continued.
29.	4.18.2	Rate of interest on working capital	• Suggestion invited on consideration of Rate for working capital which is presently one-year MCLR plus 350 bps	• The present mechanism is prudent approach adopted by CERC. The same shall be continued.
30.	4.18.3	Normative working capital and Interest thereon.	• Comments and suggestions are sought from stakeholders on the ways to determine IoWC along with any other alternatives, if any, so that the same may not require periodic truing up.	• The present approach is prudent approach as receivables also include the energy charges based on fuel prices, which is not part of AFC approved by the Commission. • Computation of working capital as % of AFC would not be prudent approach as it would not reflect the receivables correctly. Any other approach would not give correct reflection as IOWC depends on many other variables. • Hence, the present approach for computation of interest on working capital shall be continued.
31.	4.19	Useful life	• Whether the useful life of Thermal power plant may be increased to 35 years given that the current dispensation of allowing a special allowance or provision of R&M may be continued after 25 years?	• **The useful life of thermal plant is to be kept as 25 years.** • Increasing useful life would delay the recovery of the cash flow, which may further impact the loan repayment and effective ROE. • The gestation period is already high for thermal plant with huge investment. Increasing the useful life will delay incoming cash flow of Investor. This may impact future investment in thermal power business.
32.	4.20	Input price of Coal-Integrated mine	• Suggestion invited on modification in current tariff provision regarding determination of input price of integrated mine.	• The present provisions are to be continued.
33.	4.21	Sharing of gains	Comments are invited on • Modification required to increase non-core revenues by better utilization of available resources	• **Any gain due to variation from the normative parameters shall be to the account of generating company and not to be shared with beneficiaries.** This will be the true reflection of the spirit of defining normative

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			• Any modification in sharing mechanism that may be required	parameters and the Commission will also be saved from the task of scrutinising the accounts, year after year. • All the risk here is taken by the generation company. There are many challenges like unavailability of fuel, maintaining operation norms, etc. Also, no risk is being shared by Beneficiary and all risks are with the Developer only. • Therefore, the generating companies should be rewarded for efficient performance and all gains are to be retained by the generating company. • In line with "Principle of Equity", as there is no sharing of losses in case of Efficiency loss, there should be no sharing of Efficiency gains earned by a generating company/Licensee. Moreover, such parameters are normative in nature, hence, there should not be any sharing of either gain or losses should be allowed. Whole purpose of giving normative target is defeated by sharing of gains. • It is further mentioned that, in CERC Tariff Regulation 2009-14, there was no sharing of gain, appreciating the same principle stated above. It is requested same may be followed in upcoming Regulations as well.
34.	4.22	Arbitration award - servicing of principal and interest payment	• Comments are invited in respect to treatment of carrying cost to be levied to ascertain the outcome of financial implication of court arbitrations. • Enabling provisions may be made wherein only the principal amount pertaining to capital expenses is capitalised and interest expenses can be recovered in instalments.	• In order to avoid the Tariff shock for either party, the interest payment may be segregated and recovered over a fixed period of time as agreed between the parties.
35.	4.23	Treatment of interest on differential tariff after truing up	Suggestions are sought on given views - • To streamline the rate of interest on the differential amount, the current practice of allowing a simple interest rate as per Regulation 10(7) in the 2024-29 tariff block may be continued. • Interest may be allowed to be charged on the differential amount by the utility only until the issuance of the order, and no interest may be allowed during the recovery in six equal monthly instalments.	• The present approach may be continued. • Also, the interest during the period of payment of six-monthly instalment should also be allowed in order to ensure the timely payment of the over-recovery and under recovery.
36.	5.2	Peak and Off-Peak Tariff	Suggestions are also sought on the following: - • Whether it would be advisable to limit the recovery based on daily peak and off-peak periods.	• It is advisable to consider the Peak of the state of beneficiary, instead of considering at national level, for recovery of the fixed cost as it will relate

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			• Suggestions on National versus Regional Peak as a reference point for recovery of fixed charges.	more to the requirement of the Beneficiary and facilitate better fuel planning.
37.	5.3	Operational norms	• Because of de-gradation impact due to low load operations of thermal power plants, suggestions are invited on the norms to be fixed for considering ideal loading of generating station.	• At present, the operational norms are provided based on ideal loading condition of generating station i.e., PLF of 85%. The same approach may be continued. • In addition to this, the incremental norms to be specified as part of compensation mechanism, depending on loading conditions. This will cater the impact of low loading condition separately.
38.	5.4	Operational norms inefficient generating stations	• **For generating stations have not being operating efficiently** - Suggestions are sought on the option to do away with the relaxed norms currently being allowed based on actual performance for various efficiency norms of generating stations.	• Such plant may be given some grace time to improve efficiency. Post that relaxed norms may be linked to actual performance. • Also, in accordance with Clause 5.11 (h)(2) of Tariff Policy 2016 for the plant operation below the norms the improvement trajectory for the plant must be set at “relaxed level’ and not ‘desired levels’. Separate study/ benchmarking must be undertaken to set operational norms at ‘desired level’.
39.	5.5	Operational Norms for Washery Rejects based Plants	• Comments and suggestions are sought from stakeholders on the above proposal of continuing the with the existing norms for such plants in next tariff period. • CERC Tariff Regulations, 2019, has specified the following operational norms for washery reject-based power plants: 1. Station Heat Rate – To be approved on a case-to-case basis. 2. Auxiliary Energy Consumption – 10% 3. Secondary Fuel Oil Consumption – 2ml/kWh 4. NAPAF – 75% (First three years from COD) and 80% thereafter.	• The present norms may be continued.
40.	5.6	Operational norms-Emission control system	Suggestions are invited on :- • Impact of emission control system on actual operational performance of the plant and consideration of the same in the tariff. • Ways to incentivise proper operation of emission control system so that very purpose of incurring such huge expenses can be achieved and accounted for. • Whether current mechanism to exclude impact of emission control expenses from merit order may	• The expenses on Emission control system are to be recovered as fixed and energy charges. However, the actual data may only be available after successful running of plant for at least 3 years. Such data may be incorporated in O&M and energy charges. Till that time in principal approval of cost may continue. • To incentivise the EMS cost of EMS equipment may be subsidized by Government so that the final benefit can be pass through on customers.

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			continue till all generating station equip themselves with emission control system as per timeline specified in the MOEF&C notification dated 31.03. 2021.	
41.	5.7	Addendum to Tariff Regulation issued on 03.07.2023- Compensation for part load operation	• Comments are sought on the earlier norms and any changes that may be required to compensate the generators to operate the plant in a flexible manner to support the grid.	• As of now there is no provision in Tariff Regulations, 2019. • Also, CEA (Flexible Operation of Coal based Thermal power generating units) Regulations, 2022 specifies for flexible operation capability with minimum power level of 40%. • CERC Tariff Regulation must identify compensation mechanism in Tariff Regulation itself considering CEA's directions. • The generating stations are running at low PLF has high energy cost so they will be out of MOD (Merit order Dispatch). So, to bring level playing field energy cost of these plants, MOD needs to be considered based Energy Charge Rate without considering the compensation charges. Further, the compensation charges to be billed separately based on actual dispatch of the plant. • It is further suggested that flexible operation of thermal generating station is inevitable in view of the increasing generation from RE sources and requirement of integration of such RE generation for efficient operation of Grid. Hence, in order to provide better clarity and regularize the flexible operation of thermal plants, the compensation charges to be made as part of Tariff. Hence, there would be three-part Tariff viz. Annual Fixed Charges, Energy Charges and Compensation Charges, paid by Discoms to Generating Company. • Similar mechanism for compensation charges may be considered to other Thermal generators as part of Ancillary services who would be participating in providing the support to RE generation. • Since, the compensation charges would be arriving out of flexible operation of the plant used for integration of RE generation. Hence, Discom may recover the part of the compensation charges from RE generators or Green Open Access users to ease out its burden of charges. This will encourage Thermal Generator to opt for Flexible generation and provide necessary support for RE integration. This will also ease out burden on DISCOMs.
42.		Addendum to Tariff Regulation issued on 03.07.2023	The approach paper suggests the methodology for compensation for part load operation. Fixed cost compensation –	• Regulation 7 of CEA (Flexible Operation of Coal based Thermal Power Generating Units) Regulations, 2023 dated 25.01.2023 specifies as under: *"7. The coal "based thermal power generating units shall have ramp rate capability of minimum three percent per minute for their*

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			Capital cost investment and O&M expenses - CEA has suggested Rs. 30 Crore/plant unit capital cost investment for the units commissioned before 01.01.2004 and Rs. 10 Crore/plant unit for the Units commissioned on or after 01.01.2004 to operate at 40% load. For O&M expenses CEA has suggested increase of 9%, 14% and 20% for part load operation of 50%, 45% and 40% respectively. Variable Cost Compensation – Increase in Station heat rate and Increase in oil consumption due to force outages. Based on pit head and non-pithead plants, CEA has derived compensation in respect to increase in SHR and increase in oil consumption. CEA has calculated compensation charges (Fixed and variable) for Thermal capacity of 200 MW , 500 MW, 660 MW and 800 MW, under 3 categories of part load operation :- 1. < 50%-55% 2. < 45%-50% 3. < 40%-45%	*operation between seventy percent to hundred percent of maximum continuous power rating and shall have ramp rate capability of minimum two percent per minute for their operation between fifty-five percent to seventy percent of maximum continuous power rating."* • According to the current actual operating conditions of the majority of the generating stations, achieving a ramp rate of 3% is not possible without making modifications to the boiler and turbine design. The addendum does not mention any compensation mechanism for the modifications required to comply with the ramp rate and recovery of the same as part of fixed cost recovery mechanism. • As there is currently no available long-term continuous operation data for the supercritical unit at a load lower than 55% with a 3% ramp rate, it is advisable to include provisions for compensation of Capital costs on a case-by-case basis, specifically for supercritical units capacity greater than 660 MW. • During flexible operation, the generator will undergo frequent) ramping up and ramping down, resulting in deviations in operating parameters. This change in frequent parameter during transient state results in very high heat rate. All the Station Heat rate degradation are mentioned for steady stated not for dynamic condition. To address this issue, it is imperative to incorporate additional compensation for the ramp rate . • Further, the compensation mechanism provides the compensation for operation below 55%. However, it is silent on the operation of the plant between normative level at 85% and 55% level. • In view of the above, it is suggested to include comprehensive compensation mechanism for the operation of the thermal plants from the normative level of 85% to 40% level.
43.	5.8	Gross Calorific Value (GCV) of fuel	• Suggestions are invited on ways to reduce the gap between billed and received GCV.	• We appreciate the concern of the Hon'ble Commission and intention to curb losses. However, losses between billed and received GCV are majorly due to coal supplier or railways, and beyond the control of the generating company. • Any such suggestion for consideration of billed GCV for tariff purpose would be substantive loss to the generating company only. • It is noted that the part of the gap between "Billed" GCV and "As Received" GCV is inherent in nature because "Billed" GCV is arrived at by considering the Equilibrated moisture (At 60% Relative humidity and 40 degree centigrade temperature) whereas "As Received" GCV is calculated based on the total moisture in coal at ambient condition.

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				• The generating stations initially pays to Coal India Limited (CIL) Subsidiaries for the coal based on the GCV ”As billed” on equilibrated basis and final payment settlements is being done (through issuance of debit/credit notes) on the “Equilibrated” GCV analysed by Third Party Sampling Agency at loading end as per the Tripartite Agreement signed between coal company, generating company and Sampling agency. • Introduction of Third Party Sampling and testing of coal at loading point to ascertain the coal quality has been a joint effort of Generators, MoP/CEA and MoC/CIL to reduce the quality gap at loading and generator end as far as possible. • Since Generator has no control over the GCV at loading point and coal mining, inter-carting, coal loading and Railway transportation are carried out by external agencies, therefore GCV “As received at Generator end may be considered. • Further, it is not possible to determine normative losses for GCV and quantity for each mode of transport and distance between the mine as there will be different challenges at different geographical location in India. • Hence, it is suggested that GCV should be "as received" basis at plant end for domestic and international coal as generator have no control over moisture content till coal reaches its boundary. • Further, it is also suggested to consider the normative stacking losses over and above GCV “as received” basis as it is not practically possible to reduce stacking losses to “Nil”.
44.	5.9	Blending of coal	• Comments are invited in respect to linking consent of beneficiaries with % blending of imported coal by weight as notified by Central Government instead of increasing in ECR. • Procurement of such coal (other than linkage coal) has to be done through transparent competitive bidding process.	• Since blending of coal is based on the statuary directions issued by Government or appropriate authority from time to time, it may be passed through without taking further consent from beneficiary. • In situation of exigency restricting the procurement through bidding may leave generator in lurch and in such a situation the generator shall be allowed to recover it full capacity charges.
45.	5.10	Incentive	• Suggestions are invited on incentive linked to generation in excess of target PLF/ NAPF in case of old generating station that are pithead in order to encourage higher generation from such plants.	• The comments are already covered at Sl. No. 26.

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46.	6.2	Tariff structure for Cost recovery for Emission Control System	• Suggestions are invited on alternatives to the existing tariff structure for recovery of impact of installation of emission control system as all the plants have not installed the emission control system yet.	• Till all the generators are equipped with ECS, ECS charges should not be made part of MOD and should be recovered separately.
47.	6.3	De-commissioning of generating station	• Comments are sought on possible approaches to recover/refund the impact of de- commissioning cost in case the generating station is de-commissioned before the completion of useful life, if such decommissioning is done to comply with any statutory order or due to technological obsolescence duly approved by RPC.	• It is suggested that In the event of unforeseen decommissioning of Thermal power plants, the revenue on balance depreciable value for remaining useful life of the project minus scrap value of the plant should be recoverable by the generating company as one time settlement or as agreed between the parties.
48.	6.4	Simplification of Tariff Formats	• Comments and suggestions are invited from stakeholders for simplifying the existing tariff formats.	• It is advisable that for prudence check CERC may develop a portal on which most of financial details of the plant is filled at the time of filing. Only necessary forms are to be submitted with petition. The rest of the details could be filled on portal.
49.	6.6	Up-gradation of Asset/Replacement of asset	• In view of the above, comments and suggestions are invited from stakeholders regarding the treatment of unrecovered depreciation for decapitalization of assets.	• It is suggested that the balance depreciable value may be spread based on balance useful life after completion of 12 year. This practise must be done every year. This will ensure full recovery of depreciation for any additional capital expenditure of De-capitalisation.
50.	6.7	Assumed Deletions	• Stakeholders may comment on whether to continue to consider the gross value of the asset being de-capitalized, by de-escalating the gross value of the new asset @ 5% per annum until the year of capitalization of the old asset or may suggest any other methodology to compute assumed deletions.	• Further, it is noted that the replacement of asset takes place only when such asset is not useful. Capital cost of new asset is based on prevailing market prices and cannot be simply subtracted with the old assets. • The de-capitalization of the assets to be treated separately. Only salvage value to be adjusted with GFA of new asset. Any sale proceeds on account of such scrap of replaced assets will be taken care through 50% sharing of Non-tariff income. • Accordingly, the following proviso to be incorporated in Regulations. *"Provided that in case of any replacement of the assets, the additional capitalization shall be worked out after adjusting the gross fixed assets and salvage value of the assets replaced on account of de-capitalization"*
51.	6.8	Necessity to review/retain Regulation 17(2)	• As per regulation 17(2) for generating station (who has completed 25 year operation) and beneficiary shall have the first right of refusal and upon its refusal to enter into an mutual arrangement as per 17(1), the generating company shall be free to sell the electricity	• To continue or wriggle out of any PPA after 25 years of useful life must be mutual decision of beneficiary and generator based on T&C agreed between the parties.

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			generated from such station in a manner as it deems fit.”. Considering number of generating stations, at times, operate beyond the tenure of the PPA. It is observed that regulatory intervention in PPA may result in further complication as it is inequitable for generator and therefore it may be reviewed. Suggestions are invited.	• It is advisable to not to continue with 17(2) as it is not providing same level playing field to the generators and is one sided.

B. Additional Suggestions / Inputs to be included in CERC Tariff Regulation 2024-29

Sl. No.	Particulars /Regulations	Existing Provisions	Proposed Provisions	Remarks
1.	Capacity Expansion		• The existing generating stations shall be allowed to expand their capacity up to 100% of existing capacity for meeting the future requirement of power and tariff for such expansion of the capacity shall be determined by the Commission as per the norms specified in these Regulations: • Provided that, the execution of projects shall be undertaken with least cost approach and award of works and services for execution of such project shall be based on International Competitive Bidding	• The increase in power demand is to be met by addition of capacity of thermal generating stations. Instead of the going for new competitive bidding, the addition of capacity at the existing project shall be encouraged in order to have ease of execution. The existing projects are well acquainted with additional land, evacuation infrastructure and skilled manpower requirement. The cost competitiveness for such projects under Regulated Tariff Mechanism can be achieved by following International Competitive Bidding for awarding works and services for execution of the projects.
2.	Notional IDC on Additional capitalization		• The Notional IDC on Additional capitalization should be allowed on the equity infused in excess to 30%, at the interest rate of prevailing WAROI admitted for the respective year.	• The present approach for allowing Notional IDC shall be continued. During the funding of Add cap internal accrual is being infused by utilities in most of the cases due to delay in disbursement of loan. • The cost of equity infused over and above 30% is never recovered by the developer. Normative IDC would enable the generator to recover cost of excess equity.

<table>
<tr><th>Sl. No.</th><th>Particulars /Regulations</th><th>Existing Provisions</th><th>Proposed Provisions</th><th>Remarks</th></tr>
<tr><td>3.</td><td>35 (1) - Operation and Maintenance Expenses</td><td>35. Operation and Maintenance Expenses:
(1) Thermal Generating Station: Normative Operation and Maintenance expenses of thermal generating stations shall be as follows: … … …
Rs Lakh/MW
<table>
<tr><th>Year</th><th>200/210/ 250 MW Series</th><th>300/330/ 350 MW Series</th><th>500 MW Series</th><th>600 MW Series</th><th>800 MW Series and above</th></tr>
<tr><td>FY 20</td><td>32.96</td><td>27.74</td><td>22.51</td><td>20.26</td><td>18.23</td></tr>
<tr><td>FY 21</td><td>34.12</td><td>28.71</td><td>23.30</td><td>20.97</td><td>18.87</td></tr>
<tr><td>FY 22</td><td>35.31</td><td>29.72</td><td>24.12</td><td>21.71</td><td>19.54</td></tr>
<tr><td>FY 23</td><td>36.56</td><td>30.76</td><td>24.97</td><td>22.47</td><td>20.22</td></tr>
<tr><td>FY 24</td><td>37.84</td><td>31.84</td><td>25.84</td><td>23.26</td><td>20.93</td></tr>
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<tr><td>FY 25</td><td>56.76</td><td>47.76</td><td>38.76</td><td>34.89</td><td>31.40</td></tr>
<tr><td>FY 26</td><td>60.98</td><td>51.31</td><td>41.64</td><td>37.48</td><td>33.73</td></tr>
<tr><td>FY 27</td><td>65.51</td><td>55.12</td><td>44.74</td><td>40.27</td><td>36.23</td></tr>
<tr><td>FY 28</td><td>70.38</td><td>59.22</td><td>48.06</td><td>43.26</td><td>38.93</td></tr>
<tr><td>FY 29</td><td>75.61</td><td>63.62</td><td>51.63</td><td>46.48</td><td>41.82</td></tr>
</table></td><td>
There is significant increase in Employee salaries and wages, which constitute major portion of O&M expenses, over a period of last 10 years, and annual increase in salaries of employees is in range of 10-15% per annum, which is required to be factored in revision of O&M expenses norms for 2024-29 period.
Further, there is a significant increase in the cost towards contracts awarded for carrying out housekeeping, specific O&M works, transportation for O&M related activities, etc, which needs to be factored in while revising the O&M norms.
Also, there is significant increase in steel and cement prices for 2017 to 2023. The cement prices have increased to 20% and steel around 55% for the past five years during 2017-2023. In view of this, it is noted that the escalation for O&M norms to be considered in such way that this increase in prices shall be met. In past years, the Commission has considered the nominal increase in O&M norms while shifting from one control period to other control period.
Hence, considering all the reasons cited above, one time increase after considering 10% increase for each year of last control period is to be considered. Accordingly, the norm for FY 2024-25 is to be considered.
A weighted average of 7.43% increase is to be provided year on year basis to counter inflation and soaring commodity prices.
</td></tr>
<tr><td>4.</td><td>30(2) - Return on Equity</td><td>30. Return on Equity: … … …
(2) Return on equity shall be computed at the base rate of 15.50% for thermal generating station, transmission system including communication system and run-of river hydro generating station, and at the base rate of 16.50% for the storage type hydro generating stations including pumped</td><td>30. Return on Equity: … … …
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It is submitted that each cost incurred after the cut-off date is approved by the Hon'ble Commission after adequate prudence check. Therefore, the current provision of denying adequate return on equity portion towards such additional capitalization is arbitrary and
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		storage hydro generating stations and run-of river generating station with pondage: *Provided that return on equity in respect of additional capitalization after cut-off date beyond the original scope excluding additional capitalization due to Change in Law, shall be computed at the weighted average rate of interest on actual loan portfolio of the generating station or the transmission system;*	storage hydro generating stations and run-of river generating station with pondage: ~~*Provided that return on equity in respect of additional capitalization after cut-off date beyond the original scope excluding additional capitalization due to Change in Law, shall be computed at the weighted average rate of interest on actual loan portfolio of the generating station or the transmission system;*~~ (3) In case of projects commissioned on or after 1st April, 2024, an additional return of 0.50 % shall be allowed, if such projects are completed within the timeline specified. Also the additional rate of ROE allowed to the project in previous MYT for early commissioning would be applicable for the useful life of the project.	defies all financial reasoning. CERC nor through its explanatory memorandum neither by SOR has explained its intention for introducing such law. • It is to be noted that in Regulation 25 & 26 additional capitalization beyond cut off and beyond the original scope of work is duly acknowledged, which may be admitted by after prudence check. • The capital expenditure is legitimate and the Hon'ble Commission recognizes that such expenditure may be required to be incurred by the generator even after the cut-off date. Regulator after recognizing the need of such expenditure cannot penalize the developer for incurring such expenditure. Return on the equity should be allowed at the same rate (i.e., 15.5%) on such additional capital expenditure after prudence check by Hon'ble Commission. Allowing return at the weighted-average rate of interest to the equity holders who bear the entire construction and operation risk does not appear to be equitable/logical. There is no option for generating company to avoid any additional capitalisation required in compliance of order or directions of any statutory authority, or order or decree of any court of law. The additional capitalisation is required to be incurred for such compliance. It would not be appropriate to negate return on such investment which are necessary for operation of the plant. • All such expenditure would require equity contribution by the generator and many cases such equity ratio may be higher than the

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				normative of 30% specified under the regulations. The generating company would not be in a position to undertake such expenditure if return on equity is denied on their contribution and the same would be treated as debt. The resultant loss to generating company would be higher as apart from denial on equity on such additional capital, it leads to higher taxable liability on the generators. • Accordingly, we would request to delete above highlighted clause from upcoming Tariff Regulations 2024-29. • It is further suggested the CERC reinstate providing additional ROE for early commissioning of the project to encourage the investment in the sector. • It is also requested that in the present regulation CERC must clarify the applicability of the addition ROE provided in the earlier regulation for the plant achieve COD in earlier MYT. Additional rate of ROE provided to any generator for its early commission may be made applicable for the life time as it involve huge investment and compensate. the risk and effort taken by the generator for early commission
5.	**Transit and Handling Losses**	Transit and Handling Losses: For coal and lignite, the transit and handling losses shall be as per the following norms:- Thermal Generating Station Transit and Handling Loss (%) Pit head 0.20% Non-pit head 0.80%	Transit and Handling Losses: For coal and lignite, the transit and handling losses shall be as per the following norms:- Thermal Generating Station Transit and Handling Loss (%) Pit head 0.20% Non-pit head 1.2% to 1.4% Non-Pit head with RCR mode 3%	• Getting coal through RCR mode is not in control of the generating station. In case of RCR coal, coal is lifted from coal mines and stacked in Railway good shed, the losses in RCR coal are much more than Rail mode coal because of multiple handling of the coal. Hence, the transit loss in case of RCR mode would be more compared to Rail mode. In view

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				of this, it is suggested that the transit loss should be considered as 3% for coal sourced through RCR mode. • As regards the existing norms, it is noted that transit Loss in case of rail-fed stations is beyond the control of power generators due to the following reasons: - • For many Railway rakes, where the standard tare (empty wagon) weight is considered based on the design weight of empty wagon, significant loss is being observed in coal received vis-à-vis coal quantity billed by coal company. – ✓ Coal is loaded at different sidings of the colliery and after loading, the same is weighed at weighbridges installed at or near various sidings. The Railway Receipt (RR) is generated based upon this weight. The coal rake, when reaches stations, are being weighed again. Ideally, for the determination of quantity at station end, difference in weight of loaded rake and empty rake on weighbridge should be considered. In case empty rake is not weighed in the weighbridge, difference in loaded rake weight and stencil tare weight should be considered for quantity at station end. ✓ Theft and Pilferage during transit. ✓ Weighbridge accuracy ✓ Also the handling cost is distance sensitive. • Non-pit head based power plants procure coal from different subsidiaries of Coal India Ltd. through FSAs. Owing to the different weighing conditions at the collieries and reasons as cited above that are not under the control of the non-pit head generating station, there are significantly higher variations in the transit loss than as proposed by the Commission.

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				• Also tare weight of railway wagon increases over the time due to repair and maintenance (welding, retrofit) work but it doesn't get reflected in the tare weight table. This causes loss in coal weight in monetary terms to the generator. Because of this coal shortage of around 1 to 1.2% is encountered by Power plant in general. To substantiate the same it is pertinent to mention report issued by Ministry of coal dated 11.05.2020 identifying systemic deficiencies in coal shortage on the way after its loading from points of Northern Coalfields Limited and its receipt in power plants. In this report ministry of coal identified the need of calibration of wagon weight on regular basis a regular coal shortage is observed by NTPC power plants • In view of above Commission may consider revising the norms in respect to transit loss as proposed above.
6.	**43(3) - Computation and Payment of Energy Charge for Thermal Generating Stations**	(3) In case of part or full use of alternative source of fuel supply by coal based thermal generating stations other than as agreed by the generating company and beneficiaries in their power purchase agreement for supply of contracted power **on account of shortage of fuel or optimization of economical operation through blending, the use of alternative source of fuel supply shall be permitted to generating station:** Provided that in such case, prior permission from beneficiaries shall not be a precondition, unless otherwise agreed specifically in the power purchase agreement: Provided further that the weighted average price of alternative source of fuel shall not exceed 30% of base price of fuel computed as per clause (5) of this Regulation: Provided also that where the energy charge rate based on weighted average price of fuel upon use of alternative source	(3) In case of part or full use of alternative source of fuel supply by coal based thermal generating stations other than as agreed by the generating company and beneficiaries in their power purchase agreement for supply of contracted power on account of shortage of fuel or optimization of economical operation through blending, the use of alternative source of fuel supply shall be permitted to generating station: Provided that in such case, prior permission from beneficiaries shall not be a precondition, unless otherwise agreed specifically in the power purchase agreement: Provided further that the weighted average price of alternative source of fuel shall not exceed 30% of base	• In many cases, the beneficiary delays/deny the consent for alternate coal usage in case of shortage of coal. In such case, the generating company would end up in losing capacity charges on account of lower availability, in spite of taking efforts for procurement of additional coal. In such cases, the generating company shall not be penalized and allowed for recovery of full capacity charges. • Further, Ministry of Power has recently mandated 6% blending of the imported coal for all TPP. In such cases, the consent of beneficiary would take additional time for implementation or compliance of directives.

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		of fuel supply exceeds 30% of base energy charge rate as approved by the Commission for that year or exceeds 20% of energy charge rate for the previous month, **whichever is lower shall be considered and in that event, prior consultation with beneficiary shall be made at least three days in advance.**	price of fuel computed as per clause (5) of this Regulation: Provided also that where the energy charge rate based on weighted average price of fuel upon use of alternative source of fuel supply exceeds 30% of base energy charge rate as approved by the Commission for that year or exceeds 20% of energy charge rate for the previous month, whichever is lower shall be considered and in that event, prior consultation with beneficiary shall be made at least three days in advance: **Provided also that, in case of shortage of coal, if the beneficiary does not provide its consent to the Generating Company in writing within 7 days, the Generating Company is entitled for full capacity charges for such period, considering the deemed availability at 85%.** **Provided also that, in the case where the blending of fuel is mandated by Government Authorities in order to avoid power shortage in country, no prior approval form beneficiaries would be required.**	
7.	49(C)(a) - Gross Station Heat Rate	Gross Station Heat Rate … … Note 3 The normative gross station heat rate above is exclusive of the compensation specified in Regulation 6.3 B of the Grid Code. The generating company shall, based on unit loading factor, consider the compensation in addition to the normative gross heat rate above. **(b) Thermal Generating Station achieving COD on or after 1.4.2009:** (i) For Coal based and lignite-fired Thermal Generating Stations: 1.05 x Design Heat Rate (kCal/kWh)	**Provided that the Generating Company shall, based on unit loading factor for a period, consider the compensation in addition to norms of operations specified above:** **Provided further that such compensation shall be computed in accordance with Indian Electricity Grid Code or Order of the Commission applicable from time to time:** **Provided also that such compensation shall be billed by the Generating Company to the beneficiary along with the monthly bill with detailed computation and supporting documents.**	• Indian Electricity Grid Code (Regulation 6.3 B) specifies the compensation mechanism on account of reduction in Plant load factor towards performance parameters viz. SHR, Auxiliary Consumption and SFOC. • Present Tariff Regulations, 2019 covers only for SHR in this regulations. • In Draft IEGC, 2022, the similar provisos are not considered with intent to cover in other regulations. • CEA (Flexible Operation of Coal based Thermal power generating units) Regulations,

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			(b) Thermal Generating Station achieving COD on or after 1.4.2009: (i) For Coal based and lignite-fired Thermal Generating Stations: 1.065 x Design Heat Rate (kCal/kWh)	2022 specifies for flexible operation capability with minimum power level of 40%. • In order to comply the same, adequate compensation mechanism in terms of norms of operation to be provided in Regulations. • For Gross Station Heat Rate 26 (ii)(B) of 2009 -14 Tariff Regulation provides:- ***"(B) Thermal Generating Station achieving COD on or after 1.4.2009:*** *(i) For Coal based and lignite-fired Thermal Generating Stations:* ***1.065 x Design Heat Rate (kCal/kWh)"*** However in 2019-24 49 (C) (b) provides ***" (b) Thermal Generating Station achieving COD on or after 1.4.2009:*** *(i) For Coal based and lignite-fired Thermal Generating Stations:* *1.05 x Design Heat Rate (kCal/kWh)"* • There is clear contradiction in the norms specified for the TPP achieving COD in 2009-14 in both the Regulations. For the plants commissioned under 2009-14 period, the same multiplying factor i.e., 1.065 is required to be continued as provide in Tariff Regulation 2009.
8.	59 Late payment surcharge	59. Late payment surcharge: In case the payment of any bill for charges payable under these regulations is delayed by a beneficiary or long term customers as the case may be, beyond a period of **45 days from the date of presentation of bills, a late payment surcharge at the rate of 1.50% per month** shall be levied by the generating company or the transmission licensee, as the case may be.	59. Late payment surcharge: In case the payment of any bill for charges payable under these regulations is delayed by a beneficiary or long term customers as the case may be, beyond a period of 45 days from the date of presentation of bills, a late payment surcharge at the rate of 1.50% per month shall be levied by the generating company or the transmission licensee, as the case may be:	• Late payment surcharge should be reflecting ageing of receivables. The default for longer period shall be more punitive and surcharge shall be levied at higher rate. • This will encourage the payment of long due bills prior to short due bills.

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			Provided that the rate of Late Payment Surcharge for the successive months of default upto six months shall increase by 0.5 per cent for every month of delay: Provided also that, for default beyond six months, the rate of Late Payment Surcharge of 2% per month shall be levied by the generating company or the transmission licensee, as the case may be.	
9.	3(14) – Cut-off date	14) 'Cut-off Date' means the last day of the calendar month after thirty six months from the date of commercial operation of the project;	14) 'Cut-off Date' means the last day of the calendar month after thirty-six months from the date of commercial operation of the project; <u>Provided that the cut-off date may be extended by the Commission if the Generating Company or transmission licensee is able to provide the documentary evidence that the capitalisation could not have been made within the cut-off date for reasons beyond the control of the project developer</u>	• As per general trend out of total expenditure of 85% of expenditure is done prior to cut off date. • At present, extension of cut-off date is required to be done using general powers Power to relax. • The enabling proviso to be added for extension of cut-off date for the reasons beyond the control of the developer of generating station.
10.	PAF based Incentive	NA		• At present, there is not availability-based incentive available to Generating companies. The generating stations are required to maintain a normative PAF of 85%. Also, the normative working capital also considers the coal stock at PAF of 85%. There is a disincentive for generators for maintaining coal stock for more than 85% PAF on account of Working capital • The PAF based incentive would be in the range of 2 paise per unit (for 86% PAF) to around 40 paise per unit (for 100% PAF), which means that Discoms can avail additional electricity beyond 85% by incurring marginal cost of 2 paise per unit to 40 paise per unit over and above variable charge and avoid the high cost of power purchase of around Rs 8-10 per unit from external sources.

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				• The PAF based incentive was specified in Tariff Regulations 2009-14. However, at present, there is no incentive for achieving PAF more than 85%. This means to consider the PAF of 86% and 99% at same level, however, in actual, there are considerable different in the efficient practices adopted for such PAF achieved. • Further, the additional power availability will enable Discoms to manage and absorb the infirmity of Renewable sources in grid and enhance the Grid Stability. • Hence, it is suggested to incorporate PAF based incentive for Generating stations for achieving PAF more than 85% to encourage the efficient performance of the plants and optimize the power purchase cost of Discoms.