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The Secretary
Hon'ble Central Electricity Regulatory Commission
3rd & 4th Floor
Chanderlok Building
36, Janpath
New Delhi – 110 001

Sir,

Comments on Terms and Conditions of Tariff for the tariff period commencing from 1 April 2024 – Approach Paper thereof

With reference to your communication No. L-1/268/2022/CERC dated 26 May 2023 read with subsequent communications dated 3 July 2023 and 13 July 2023, we furnish our submissions / suggestions on the above approach paper for your kind consideration in three copies. It is our earnest hope and humble prayer that the Hon'ble Commission will recognise our concerns and make necessary modifications.

We also crave leave to submit at a future date further materials on the subject which may be available to us in the event we are of the opinion that the same would render meaningful assistance to the Hon'ble Commission in the matter.

Yours faithfully,

Executive Director
(Regulatory Affairs & Corporate Services)

Encl.

Comments Approach Paper On Terms And Conditions Of Tariff Regulations for Tariff Period 1.4.2024 TO 31.3.2029

It is respectfully submitted that tariff for a significant part of generation, transmission and distribution assets / functions are determined by Appropriate Commissions under Section 62 of the Electricity Act, 2003. While the State Commissions and the Joint Commissions have completely separate jurisdiction, these Electricity Regulatory Commissions are guided by the Tariff Regulations framed by the Hon'ble Central Electricity Regulatory Commission ("**Hon'ble Commission**") while specifying terms and conditions for determination of tariff under Section 61 of the Electricity Act, 2003 and for determination of tariff under Section 62 of the Electricity Act, 2003. Therefore, the Tariff Regulations framed by the Hon'ble Commission hold immense importance for the entire electricity sector of the nation.

In this context, it is humbly submitted that generating companies / licensees under the superintendence of their respective State Electricity Regulatory Commissions often lack bargaining power / influence which is otherwise available to large Central Public Sector Undertakings, like NTPC Limited etc. The Hon'ble Commission is kindly aware about the ground realities which affect the generating companies, particularly in the matters of fuel supply, fuel quality, sale of un-requisitioned power, part load compensation for all set sizes and vintages for RE integration etc. The Tariff Regulations of the Hon'ble Commission, having an overarching impact on the entire power sector of the Country, may kindly be specified considering the ground realities and for units of various set-sizes and vintages.

(A) General Approaches to Tariff Determination

Under Approach 1, it has been proposed for a shift towards a normative tariff methodology wherein, once capital costs are approved on an actual basis after prudence check, all other AFC components are determined on normative basis - clubbed under Annual Fixed Costs excluding O&M expenses and O&M Expenses. It has been indicated that once such norms are determined for a station, for the rest of the tariff period, they would be determined based on specified indexation, subject to indexation pertaining to AFC excluding O&M expenses being trued up. However, it is submitted that the methodology of such indexation methodology has not been elaborated in the approach paper, without which it appears to be infructuous to comment upon the same.

Further, it is also submitted that considering that the proposed two components are being derived based on the norms being specified by CERC and effectively does not provide any additional advantage over the existing methodology of determination of individual fixed cost components on a normative basis. At best, while simplifying tariff during MYT tariff period, it may lead to unnecessary complications during true up stage. Therefore, it is submitted that unless further clarity and detailed computation methodology are specified by the Hon’ble Commission subject to detailed discussion with stakeholders, Approach 1 may not be adopted.

The proposed Approach 2 is a slightly modified take on the existing basis of tariff determination, with a scope to incorporate a normative approach for determination of interest on working capital that effectively allows consideration of fuel cost variation and interest rates on a normative basis. While the approach is more pragmatic and based on the current basis, which allows for allowance of costs on controllable and uncontrollable basis after due prudence check, it is flexible and encourages innovation from the companies.

However, the approach for normative determination of interest on working capital would further complicate the existing process of tariff determination and may be avoided. Therefore, the existing approach as per CERC Tariff Regulations 2019 may be continued. Any suggested modification in the approach for determination of tariff must go through extensive stakeholder consultations and should be both prudent to allow for efficient cost recovery by utilities as well as not burden consumers, while ensuring required response from the utilities in light of the dynamic market conditions.

(B) Capital Cost – Background (Clause 4.2.1)

The provision of interim tariff, introduced vide CERC Tariff Regulations, 2009, allows utilities to seek approval of the capital cost of new projects on an anticipated basis, which helps utilities minimise the time gap between the commissioning of the project and the generation of cash flows by means of tariff. This approach ensures financial viability of utilities, as determination of final project cost for a particular project often is an elaborate exercise that may take a significant amount of time till final approval but the utilities are mandated to start the supply of power as per relevant clauses of the PPA.

Therefore, it is prudent that the same may be allowed to be continued. Further, the provision of allowing for interim tariff based on the investment approval of project may be further extended to allow for determination of interim tariff on escalated project cost as well, as often these are on account of factors beyond the control of utilities and become part of the final project cost. However, the time gap between provisional tariff and final tariff approval needs to be minimized.

(C) Procurement of equipment or services (Clause 4.2.2)

The provision for mandatory procurement of equipment or services for developing projects through a transparent competitive bidding process, is a prudent approach considering the market dynamics driving efficiency and allowing for the lowest cost discovery for the same. However, there may be certain exigent situations, that warrant for procurement on an urgent basis (especially in force majeure or unforeseen exigencies) wherein such timeline for transparent competitive bidding may be infeasible. Considering the same, it is requested that an enabling provision for exemption of such mandate may please be provided for equipment or services of less than INR two (2) crores (a paltry amount considering the entire capital cost). This would provide for required flexibility to the utilities to handle emergency situations. Alternatively, it is suggested that the Hon’ble Commission may specify the major contracts for which competitive bidding is mandatory and for the rest, it would be optional.

Further, the mandate to procure equipment or services adhering to the policy/guidelines issued by Government of India from time to time may be restrictive for certain cases. While following of the policy/guidelines is a welcome approach, there may be cases, wherein portals such as Government e-marketplace (GeM portal) are accessible to public sector companies only, whereas private sector entities with no such advantage would be at a disadvantage towards compliance with such directives through CERC Tariff Regulations. In view of the same, this clause may be modified suitably to create a level playing field.

(D) Reference Cost for Approval of Capital Cost – Benchmark Cost V/s Investment Approval Cost (Clause 4.2.3)

The prevailing method of determination of provisional tariff based on projected capital expenditure needs to be continued as it helps to minimize the impact of retrospective revision of tariff after approval of final tariff of a project. Relying on Investment Approval costs or Escalated Project cost (as the case may be) instead of benchmarking costs on similar projects should be a prudent choice, as benchmarking often leads to non-consideration of specific demographic / situational factors that have consequent impact on the final project cost. Artificial reduction of project cost based on benchmark would be a prohibitive approach and therefore case specific considerations including due prudence checks should be adopted. Time and again, CERC had emphasised on consideration of adjustments for case specific dispensations. The Hon'ble Commission in the past has also held that capital cost benchmark has limited role in determination of project cost for tariff determination under section 62 and case specific dispensations are necessary [CERC order in case no. L-1/103/CERC/2012 dated 4 June 2012]. Accordingly, actual project cost subject to prudence check would need to be considered for capital cost rather than benchmark cost, which may not be able to factor in case specific realities.

Every project is different in terms of design, the location, the State specific economic and social situations. Use of benchmark cost at a pan India level may not be effective for approval of capital cost. The Hon'ble Commission may use hard costs of similar projects happening in the same State at the same time period approximately for reference. However, it should be used as a guideline / reference point and not be used as a strict rule. In this regard, it is submitted that the Benchmark cost mechanism was present in CERC Tariff Regulations 2009. In case the Hon'ble Commission decides to choose the benchmark cost methodology, it is submitted that a revised benchmarking cost may be ascertained for projects considering similar dispensations in terms of location, unit size, technology, configuration etc. This is owing to the fact that the process of benchmarking may therefore reflect a close to true picture if the comparison is done within the ambit of similar factors and constraints. This would require to be updated on a continuous basis with respect to any change in factors affecting the project cost.

(E) Capital Cost for Projects acquired post NCLT Proceedings (Clause 4.3)

The CERC may include Regulations stipulating the determination of Tariff of such assets under section 62, that have been acquired after completion of NCLT proceedings. Following aspect may be considered while determining the tariff for such assets:

- Lower of the Acquisition value and Historical Value of the asset should be considered for tariff purposes.
- Other relevant factors impacting the tariff such as Debt Equity Ratio, Normative O&M expenses, Normative Operational Parameters may be re-determined during the tariff setting exercise, instead of continuing allowance at previous levels

It is submitted that determination of capital cost of projects acquired after NCLT proceedings must protect the interest of the investors, the financial institutions and the consumers and no one size fits all approach would address all the concerns. Instead, a case specific dispensation, with due consultation with all relevant stakeholders may be resorted to.

(F) Computation of IDC – Post Scheduled COD (Clause 4.4.1)

Current provision of allowance of pro-rated IDC and IEDC corresponding to delay period condoned are allowed to the generating station. In this context, kind attention is sought towards the fact that entire financing for development of the project has to be seen in light of the entire construction lifecycle and not purely on the normative project schedule, which often gets delayed due to uncontrollable factors. Differentiating IDC and IEDC for the SCOD and delayed SCOD periods would artificially create a distorted view of the financing costs required for the project. Further, since the project capital cost takes cognizance of the entire capital financing irrespective of the scheduled construction period and actual delayed period, it is prudent that such differentiation of costs should not be considered. It is submitted that project construction delay and corresponding IDC and IEDC are caused by a number of factors and cannot be treated to be based on a single milestone. Moreover, debt drawal is also done judiciously by the developers, keeping in view of the project phasing to minimise the tariff impact for the consumers. Therefore, it would only be justifiable to allow the pro-rated allowance of IDC and IEDC pertaining to the condoned delay period, considering the entire implementation period. The same has been proposed through Option 2 of clause 4.4.1 and should be considered.

Further, the Hon'ble Commission has also duly recognised submissions from utilities regarding maximum IDC being towards the end of the construction cycle and any disallowance for only period of delay would disproportionately reduce the due IDC for the companies. Therefore, choice of pro-rated allowance of IDC and IEDC pertaining to the condoned delay period should be considered based on the total implementation period.

(G) Treatment of Liquidated Damages (Clause 4.4.2)

The treatment of Liquidated Damages ("LD") collected by the Implementing Agency for Generation/Transmission project have been directed as per observations of the Hon'ble Appellate Tribunal in case no. 72 of 2010 and the same has been proposed to be adopted by the Hon'ble Commission. This is a welcome step and to avoid double accounting of the LD amount collected by the Utilities.

Further, it is also prayed that existing terms and conditions of the PPA may also be factored in for actual treatment of the LD amount as there are PPAs wherein LD amount is allowable to the generator for cases wherein IDC is not allowed. A harmonious treatment of the PPA conditions along with the regulatory principles is desirable to mitigate any conflicts and protect the interest of the stakeholders.

(H) Price Variation affecting Project cost (Clause 4.5)

The approach paper has rightly contended that price variation due to delay on hard cost should be allowed to the extent of delay condoned. The price variation on hard cost due to delay may be allowed on a pro-rata basis corresponding to the delay condoned on submission of relevant audited certificates and any other supporting documents. A separate tariff form to capture the information related to price variation on account of delay as suggested would allow utilities to submit their claims accordingly.

However, in this regard, it is submitted, for the requirement of certification may be broad-based to include certification from a cost auditor or similarly placed audited submissions. Any provision stipulated through Tariff Regulations but not incorporated through the Companies Act / Existing IND-AS provisions may not be aligned with certification under the Companies Act and therefore, the same requirement may be replaced with certification from Statutory Auditor/ Cost Auditor/ Technical Auditor/ Auditor for particular environment or other aspects or through other valid documents including affidavit.

(I) Renovation and Modernisation (R&M) (Clause 4.6)

Renovation & Modernization ("R&M") should be allowed to be undertaken after specified years of service. Further, depreciation and debt servicing cost of the

Additional Capitalization should be allowed to be recovered within the balance useful life of the plant after considering the life extension, if any.

However, approval of R&M expenditure for generating companies or transmission licensees should be provided through a separate exercise by the Hon'ble Commission after specified years of operation (to be fixed by the Hon'ble Commission). Plants completing a specified number of years of operation (say 15-20 years) may opt to take up R&M evaluation based on OEM recommendation along with Residual Life Assessment before submitting the proposal before the Hon'ble Commission.

With respect to Special Allowance, it is submitted that cost incurred towards R&M is also affected by the nature of the asset and peculiarities associated with it. The current provisions provide for normative special allowance in Rs. Lakh/MW that can be claimed by a generating station at the beginning of the tariff Period as compensation for meeting the requirement of expenses including renovation and modernisation beyond the useful life of the generating station. The Generating Station may be allowed to submit a petition to recover additional cost through tariff revision in case the actual expenses incurred towards R&M is more than the accumulated Special Allowance. Such additional cost may be allowed to be added in the Gross Fixed Asset. Depreciation, Interest on Loan and Return on Equity shall be available only on such additional cost.

(J) Initial Spares (Clause 4.7)

The proposed approach directly specifies norms in 5 categories for initial spares, but it fails to consider the relevancy and risks associated with the assets. Limiting the number of categories, while it achieves simplification, is a restrictive view that may lead to under provisioning for categories/classes not specified. It is submitted that a hybrid flexible approach may be adopted that considers norms based on associated risks of the asset as well as specific dispensation related to the asset, which would amount to due prudence check for the respective tariff category.

(K) Delay towards obtaining Forest Clearance (Clause 4.8.1)

Delay on account of land acquisition may continue to be considered as an uncontrollable factor if such delays are not attributable to the generating company or the transmission licensee. Further delay on account of grant of Forest Clearance may also be added as an uncontrollable factor if such delay is not attributable to the generating company or the transmission licensee.

It is further submitted that delay in all such Regulatory/Statutory Clearances (including delay on account of land acquisition and Right of Way, as presently allowed) may be brought under the ambit of uncontrollable factor if such delay is not attributable to the generating company or the transmission licensee.

(L)Differential Norms - Servicing Impact of Delay (Clause 4.9)

At the outset, it is submitted that the observation of the Hon'ble Commission that the delay could have been avoided through rigorous pursuit is misplaced. Numerous clearances and approvals required for development of a project are under the purview of various State/Central departments, and the liability of lack of follow up being placed on the developer without any accountability of the authorities appear to be contrary to the ground realities. In case such responsibility is to be assigned, a detailed due diligence procedure to ascertain the same to be a result of failure of pursuit by the developer needs to be undertaken and therefore, may please be provided through the Regulations. Further, a third party validation mechanism may also be put into place along with the due diligence procedure, to minimise any biases towards such determination.

In the interest of the stakeholders, it is submitted that no cost should be disallowed if the delay commissioning of the generation / transmission project has been condoned. As rightly observed in the Approach Paper, if a project is delayed, even if the entire delay is condoned, the internal rate of return (IRR) for the project reduces due to deferment of future cash inflows. Therefore, there is already an inbuilt disincentive for project developers in case of delay in project commissioning. Considering that if delay has been condoned, it follows that such delay was not attributable to the generating company or the transmission licensee. Therefore, not allowing a certain portion of cost associated with such condoned delay or lowering the return to the weighted average rate of interest on loans instead of stipulated RoE is against the principles of natural justice.

Further, in cases wherein additional equity is deployed to fund the cost overrun/increase in project cost on account of uncontrollable factors, it would be unfair to restrict the recovery of expected rate of return on equity. The shareholders' return anyway suffers from the effect of prolonged gestation period on account of delay in commissioning of the Project. In any manner, developers are automatically being incentivised for completing project construction within the scheduled date and therefore, scope for penalization may not be necessary.

In any case, the delay condoned by the Hon'ble Commission is done only after due prudence check of the delay and after satisfactory demonstration of no fault from developer's side. In case the same is found attributable to the developer, it is disallowed by the Hon'ble Commission. Condoning a delay therefore clarifies that the developers are not at fault. Hence, further reduction in reasonable return to shareholders for the cost overrun allowed by the Hon'ble Commission would imply imposition of penalty for no fault of the developer and is therefore not desirable. This would in turn affect funding for future growth. In light of the above, the current mechanism of treating time overrun may be continued.

(M) Additional Capitalisation (Clause 4.10)

The existing CERC Tariff Regulations, clause 26 allow for additional capital expenditure beyond original scope of work pertaining to safety and security, change in law, force majeure, arbitration award and deferred works related to ash handling system. It has been proposed to allow capital costs related to Railway Infrastructure and its augmentation for transportation of coal up to the receiving end of the generating station and towards any works that would lead to better fuel management, reduce operating costs or have any tangible benefits. This is a welcome step, and should be allowed for existing power projects as well, considering some of them have limited infrastructure not envisaged at development stage and may lead to definitive tangible benefits. It is also submitted that such the entire capital servicing cost (including debt servicing, normative ROE etc) towards such additional capital expenditure should be allowed after due prudence check. Further, O&M norms may be reviewed and revised upwards in case such additional capital projects need additional expenses towards R&M and manpower.

(N) Normative Additional Capitalisation (Clause 4.10.1)

The proposed provision stipulates a special compensation in form of a yearly allowance, which is to be determined based on analysis of actual additional capitalization of similar generating stations (in terms of unit size and vintage) over the last 15-20 years. Further, the said allowance would not be required to be trued up and would not be required to be capitalized. Allowance of such normative additional capital expenditure in effect would lead to creation of an additional capital expenditure fund, similar in nature to power purchase fund or reserve for unforeseen exigencies, and is a welcome step towards allowance of small additional capital expense items.

However, it is humbly submitted that a shift towards such normative determination of normative additional capitalization would lead to certain challenges. There may be specific instances wherein the additional capitalization requirement of generating stations can be of significant nature, entailing substantial expenditures which were not envisaged during initial period of operation or have been triggered on account of sustaining proper operating conditions (and not covered under any conditions under clauses 25-29 of the existing CERC Tariff Regulations, 2019). These capital expenses often come in form of packages and may not be ascertainable independently on a stand alone basis. In such cases, allowing only normative additional capitalization through a normative allowance would seriously restrict the operating capability of the generating station. Therefore, it is humbly requested that such normative allowance should not restrict significant additional capitalization expenditure, which otherwise would hamper the efficient operation of the utility, the same may be allowed to be capitalized following due prudent procedure that currently exists.

Moreover, the requirement of additional capitalization for generating stations can be correlated to the age of the station. It has been observed that older generating stations, especially for those who have completed 10 years of service, significant expenditures are necessary towards critical capital spares (for eg: boiler tube bank, economiser, super heater, condenser tube bank, valves for Boiler Feed Pump, HP heater etc.) which are often recurring in nature (within a span of 2-3 years). Additionally, there are certain civil construction works related expenses that are required to be undertaken periodically for uninterrupted operation of the utility. OEMs also have certain mandated overhauls of critical plant components after a specified period (5-6 year intervals) that are vital for reliable operations of the plant, and necessitate additional capitalization. Allowing a nominal value for additional capitalization on a normative basis, derived without considering the vintage of the stations, may lead to distorted allowances and would not be sufficient for covering the recurring additional capitalization requirements for older stations.

As per Item 3 under clause 4.10.1, it has been proposed that existing provision of allowance of additional capitalization for works under Regulations 26-29 would be allowed separately. While the same is a pertinent approach, kind attention of the Hon’ble Commission is drawn towards Electricity (Timely Recovery of Costs due to Change in Law) Rules, 2021 notified by Ministry of Power, wherein provisions related to adjustments in tariff on account of change in law has been stipulated. It is prayed that the allowance of additional expenditure on account of change in law may be harmonized with the Rules accordingly.

As per subsection 2 related to generating stations who are expected to achieve COD after 01.04.2024, extension of cut-off date from 3 years to 5 years is a welcome step as it allows for all additional capitalization during the initial period of plant commissioning to get duly captured for capital cost determination. In the same spirit, it is prayed that further extension of the cut off date may be explored to minimize subsequent additional capital expenditure applications.

Furthermore, as per Item 4 under clause 4.10.1, it has been proposed that small items below Rs. 20 lakhs of nature of tools and tackles, and those pertaining to Capital Spares may be allowed only as part of O&M expenses. In this regard, it is understood that such O&M expenses would be allowed in excess to the normative O&M expenses as determined by the Hon’ble Commission.

(O) GFA/NFA/ Modified GFA approach (Clause 4.11)

The Gross Fixed Asset (GFA) approach may be continued in the interest of desired growth of the power sector. It is to be noted that under Net Fixed Asset (NFA) approach, the equity base of the project will effectively reduce which in turn will reduce the return on equity significantly. Adoption of NFA approach may severely affect the internal resource generation and further investment in the power sector will be impacted adversely alongwith debt service obligation. The investors have made investments based on the GFA approach and changing the methodology will have detrimental effects on the returns on the investments. In our humble opinion, therefore, the NFA approach will be unfair on the developers as this will deny reasonable returns to the developer as well as it will not be able to provide adequate cash to the developer to meet its debt service obligation.

In this context, it is submitted that completion of useful life is not equivalent to closure of the business. Moreover, businesses are operated under the applicable statutes as a going concern basis, and shareholders' money is not taken out from the business unless the same is wound up. Any unnecessary adjustment in the return base on completion of useful life of asset would be prejudicial to the shareholders' interest and would affect much needed investment in the sector.

It is worthwhile to mention in this context that for many of the operating generating stations and transmission systems of the country, which are nearing end of their useful lives but capable of efficient operation for a considerable period in future, cumulative depreciation surpasses the cumulative loan repayment amount. Therefore, it may be noted that computation of return for these projects on a reduced / net equity base would be detrimental for these efficient operating assets and the same may be forced to cease their operation. Therefore, such reduction of equity by accumulated depreciation may please be limited to projects that have higher equity contribution (>30%) as funded generally prior to establishment of regulatory regime under Electricity Regulatory Commissions and to the extent of 30% of Equity, rest through normative debt by whatsoever approach and not for all projects in general.

Further, it is humbly submitted that CERC Discussion Paper on Terms and Conditions of Tariff dated 12 June 2003 had acknowledged the importance of GFA based approach considering the current investments by utilities and the same may be continued as done presently.

(P) O&M Expenses (Clause 4.12)

Segregation of Normative O&M Expenses: The suggestion to treat the employee expenses separately is a required step. Under the present framework of allowing O&M expenses based on the norm, it may not be possible to capture the effect of wage revision. Segregation of the normative O&M Expenses into Employee Expenses and Other O&M Expenses would bring in clarity in the expenses allowed under the different heads.

Further, it is also submitted that Other O&M Expenses should be further segregated to Repair & Maintenance, Admin & General Expenses and other broad categories and allow normative escalation rates on each and every category based on the prevailing market scenario. The expenses under O&M Expenses like Employee Expenses, Repair & Maintenance Expenses and Administrative & General Expenses are directly related to the inflation rate and are also specific to the State where the Generating Station is located since it decides the availability of labour, spares and other administrative expenses. This would allow the Normative O&M Expenses to be closer to the actual. Exceptions, if any, are required for any year, can be allowed only to such heads which have undergone variation more than the normative escalation.

Regarding allowance of 50% of the actual wage revision on normative basis, it is submitted that wage revisions are done based on stipulated guidelines with relevant statutory authorities and therefore, should not be restricted to any amount but allowed at actuals. Further, clarification is required whether such allowance would also be provided to private developers as well.

Further, there are some other expenditures like Ash Disposal Expenses, additional expenses due to vintage, unexpected expenses on account of any event under ‘Change in Law’ which should be allowed separately.

O&M Norms for Special Cases : It has been proposed in the Approach Paper that additional O&M expenses are incurred for operating transmission lines in hilly regions in the country including North Eastern states and therefore such higher O&M expenses may be allowed. It is submitted that there are other transmission projects with special features like river crossing that are significantly deviant from standard configuration of transmission lines and actually require higher maintenance expenses on account of riverine configuration including barges and jetties required for such maintenance activities. Therefore it is prayed that such transmission lines with river crossing may also be included in the list of special cases and higher O&M norms may be allowed for these cases.

Inclusion of capital spares: For capital spares, the process of allowing on actual basis may be retained. It is a fact that the incidence of capital spare is sporadic and non-recurring. The proposal of analysing the cost for a longer duration to find correlation for norm specification may not be useful because the requirement along with technology for which it is required, may be changed. Further, it is submitted that a few of the capital spares need to be kept in the inventory as they have high lead times of procurement and are more expensive than tools/tackles or other smaller items they are proposed to be clubbed with. Considering that the capital spares support in reliable operation of major plant equipment, the same may be allowed to be serviced through additional capitalization route and not through O&M expenses.Therefore, the practice of allowing capital spare on actual basis may be continued. Maintenance spare can be continued to be a part of O&M expenses.

However, in case the Hon'ble Commission adopts the proposed methodology of inclusion of recurring and low value spares of nature tools and tackles under Rs 20 Lakhs to be included under O&M expenses, it is understood that such amount would be in excess to the normative O&M expenses as determined by the Hon'ble Commission.

Impact on account of Change in Law and Taxes: During recent times, many regulatory changes have been suggested by appropriate authority. The O&M expenses are bound to be increased in future. Reliance on the norm which has been determined based on the past data may not be effective. So, there should be a provision to include the impact of change in law. There should be a modifying mechanism for the O & M expenses norm. Further, attention of the Hon'ble Commission is drawn towards Electricity (Timely Recovery of Costs due to Change in Law) Rules, 2021 notified by the Ministry of Power. Similar provisions allowing changes in tariff on account of change in law can be aligned in the CERC Regulations, so as to avoid complications in the future.

(Q) Depreciation (Clause 4.13)

Options envisaged in this approach paper are directed towards reducing the depreciation rate by increasing the loan tenure. In this regard, it is submitted that assessment of the depreciation amount considering a loan tenure of 15 years instead of the existing 12 years, would unnecessarily increase the overall interest amount and thereby inflate the levelised tariff over the entire life cycle. An effort to shift front loading of depreciation in tariff should under no circumstances increase the tariff for the consumers. Further, it is also submitted that whatever the tenure of loan be chosen, depreciation rates under straight line method should adequately converge to recover 70% of the asset cost within the identified period and not leave any shortfall (Current CERC norms propose depreciation at 5.28% for 12 years that add up to 63.36% only, instead of stipulated 70% recovery)

Viability of a project depends on periodic cash flows during the life of the project. For assessment of project viability, cash flow estimates over a given life of the project were relied upon. Prolonging the recovery of capital cost by reducing the depreciation rate will adversely affect the cash flow from the project and consequently the reasonable return that the investor of the project had envisaged from such investment. Therefore, changes introduced during the project life will seriously affect the viability of the projects and will hurt further investments in the sector due to regulatory uncertainties. Encouraging investments and need for investments in the power sector has been a consistent and important theme in policies framed for the sector.

(R) Interest on loans- Weighted Average Rate of Interest and FERV (Clause 4.14.1)

Determination of cost of debt based on weighted average rate of the actual loan portfolio may be continued with to recognise the actual interest payment/ finance cost obligation by the generating companies. The Approach Paper rightly observed that loans are not usually availed for specific projects in general business scenario and ascertaining one to one correlation between assets and loan is a cumbersome and time and effort consuming process. Approach of deriving interest cost on the basis of overall loan portfolio of the organisation is a welcome move.

The Hon'ble Commission is kindly aware that any adverse impact on the generating companies will also affect the banking sector, which is reeling under severe pressure from bad debts / NPA. The generating companies will be seriously prejudiced if banks / lenders initiate insolvency proceedings due to problems with debt servicing.

Further, as proposed in the approach paper, hedging costs for foreign loans are to be allowed, whereas Foreign Exchange Rate Variation amount is to be disallowed. In this regard, it may be brought to the attention of the Hon'ble Commission that hedging involves de-risking foreign currency loans for a specific period (usually on a shorter term period), which entails some costs towards risk premium and margins for financial institutions. Repeated hedgings through the project life cumulatively often surpasses the overall FERV variation that would have otherwise impacted the capital cost. Considering the same, it may be prudent that defining a single option may be detrimental towards efficient financial planning and management and that both the choices may be kept for the developers. The end goal should be minimization of costs towards such variations and options may be chosen suitably by the developer to achieve the same. This would be convenient for both the utility companies as well as allow for the most efficient process to be adopted.

(S) Return on Equity v/s Return on Capital Employed (Clause 4.15)

The Hon’ble Commission may continue with the Return on Equity (“RoE”) approach for the ensuing control period, instead of RoCE. Considering the need for investment even after encouraging existing generation capacity including utilisation of vintage stations optimally as noted in the approach paper, the ROE approach provides for both fillip for investment as well as ensures regulatory certainty.

(T) Rate of Return on Equity - Methodology (Clause 4.16.4)

For determination of the appropriate rate of return for a regulated sector, the CAPM method can be used to estimate the systemic risk in the sector, as suggested in the approach paper. For such exercise, it may be prudent to study the companies in the benchmark indices for the Power and Utilities sector. Their stock returns reflect the systemic risk in the business. The same systemic risk may be applied to a regulated entity to estimate the requisite normative return on equity for the businesses.

The formula for computing the return on equity based on CAPM is as under:

$$\mathbf{R_e = R_f + \beta_e \times (R_m – R_f)}$$

Where:

R_f = risk-free rate (that can be earned by investing in a risk free security, e.g., a Government of India (GOI) bond)

β_e = equity beta (most electricity/energy regulators calculate beta using a group of companies comparable to the target utility)

$R_m – R_f$ (Market Risk Premium [**MRP**]) = equity market risk premium (the extra yield that can be earned over the risk-free rate by investing in the stock market)

β_e is an indicator of the systemic risk, which reflects the volatility of stock with respect to the market index. However, in addition to reflecting the nature of operations within an industry and the efficiency of the company in such operations, returns on a particular stock also vary according to the capital structure of the company. In this respect, $Beta_{asset}$ (β_a - Unlevered Beta) is estimated to measure the return on equity for a company, by eliminating the effect of capital structure. β_a is used to estimate the expected return on equity for a stock assuming it has zero debt.

In the context of determination of MRP, it is submitted that the existing practice of considering a 20 year period should be adopted, since consideration of a 30 year period would be too historic in nature which would fail to capture the present day trend of the market dynamics. The Electricity Act, 2003 has brought about major reforms in the power sector in light of bringing in competition through open access, introduction of competitive bidding, development of power market and trading platform, renewable power penetration etc. Moreover, it is important to determine the rate of return based on present day market trends and dynamics. Therefore, it is recommended that the Market Return should be determined based on not more than a 20 year period, considering the period after enactment of the Electricity Act, 2003.

The CAPM model may be illustrated through the following examples -

The listed companies present across the value chain of the electricity sector constituting the BSE (Power) index may be considered as the true representative of the Power sector. Accordingly, for assessment of cost of equity, the stocks considered for determination of BSE (Power) index have been considered.

$Beta_{quity}$ (β_e), Debt / Equity Ratio and Tax rate for each of the companies have been obtained from www.morningstar.in website, as presently available.

Tax rate (T_a) for the regulated entity has been considered at MAT rate (25.168%). The same has been applied for companies in the sample where the actual tax rate is not available.

Market return has been worked out on the basis of yearly average of BSE S&P Sensex movement over the last 20 years (2004-2023), which works out to **16.5%**.

Value of β_a for all the companies has been considered as the sector representative beta value and has been used to derive from the β_e for the regulated entity by applying the following formula :

$\beta_a = \beta_e$ / [1+(1-Tax rate) X (D / E)],

where, D / E is the Debt-to-Equity ratio.

Calculation of Expected Rate of Return for the listed Power companies in BSE Power Index based on Capital Asset Pricing Model (CAPM) Analysis

Sr. No.	Name of the Company	Beta Equity (β_e)	D/E	Tax Rate (T_a) [1]	Beta Asset (β_a)
1	ABB India Limited	1.02	0.01	24.9%	1.01
2	Adani Green Energy Ltd.	1.60	6.83	31.8%	0.28
3	Adani Power Ltd.	1.18	1.13	25.3%	0.64
4	Adani Transmission Ltd.	2.15	2.69	25.4%	0.72
5	BHEL	1.57	0.01	5.5%	1.56
6	CG Power	2.57	0.01	20.5%	2.55
7	JSW Energy Limited	1.07	1.04	23.8%	0.60
8	NHPC	0.54	0.72	18.6%	0.34
9	NTPC	0.74	1.29	27.9%	0.38
10	Power Grid	0.49	1.37	13.1%	0.22
11	Siemens Ltd.	0.82	0.01	26.6%	0.81
12	Tata Power	1.21	1.19	30.2%	0.66
	Average				**0.81**

Now, β_e is calculated with a normative debt to equity ratio of 70:30, with a Tax Rate of 25.168%. This yields β_e as follows:

$\beta_e = \beta_a$ x [1+(1-Tax rate) X (D / E)]

So, β_e = 0.81 x [1+(1-25.168%) x (70/30)] = 2.24

Beta	**β_e**	2.24
Risk Free Rate	**R_f**	7.3%
Market Return	**R_m**	16.5%
Market Risk Premium	**$(R_m - R_f)$**	9.2%
Expected Rate of Return	**R_e**	**27.8%**

As evident from the above exercise, the cost of equity works out to about 28% for the power sector. A similar exercise has been done for the Utilities sector as outlined below.

Listed companies of the electricity sector constituting the BSE (Utility) index, which may be considered as the true representative of the Utilities sector. Accordingly, for assessment of cost of equity, the stocks considered for determination of BSE (Utility) index have been considered.

Calculation of Expected Rate of Return for the listed Power companies in BSE Utilities Index based on Capital Asset Pricing Model (CAPM) Analysis

Sr. No.	Name of the Company	Beta Equity (B_e)	D/E	Tax Rate (T_a) [1]	Beta Asset (B_a)
1	Adani Green Energy	1.60	6.83	31.8%	0.28
2	Adani Power Limited	1.18	1.13	25.3%	0.64
3	Adani Transmission Limited	2.15	2.69	25.4%	0.72
4	Antony Waste Handling Cell Ltd	0.64	0.54	17.3%	0.44
5	CESC Ltd	0.58	0.89	19.7%	0.34
6	Gujarat Industries Power Co. Ltd	0.75	0.13	25.6%	0.68
7	Inox Green Energy Services Ltd	1.24	0.23	25.2%	1.06
8	Jaiprakash Power Ventures Ltd	1.87	0.38	75.4%	1.71

Sr. No.	Name of the Company	Beta Equity (B_e)	D/E	Tax Rate (T_a) [1]	Beta Asset (B_a)
9	JSW Energy Ltd	1.07	1.04	23.8%	0.60
10	KPI Green Energy Ltd	0.33	2.18	22.7%	0.12
11	NAVA Ltd	0.96	0.26	3.5%	0.77
12	NHPC Ltd	0.54	0.72	18.6%	0.34
13	NLC India Ltd	0.78	1.22	30.7%	0.42
14	NTPC Ltd	0.74	1.29	27.9%	0.38
15	Orient Green Power Company Ltd	0.82	1.85	22.7%	0.34
16	Power Grid Corporation of India Ltd	0.49	1.37	13.1%	0.22
17	RattanIndia Power Ltd	1.67	0.00	25.2%	1.67
18	Reliance Infrastructure Ltd	3.03	0.48	25.2%	2.23
19	Reliance Power Ltd	2.58	1.06	25.2%	1.44
20	SJVN Ltd	0.51	0.96	21.8%	0.29
21	Tata Power Company Ltd	1.21	1.19	30.2%	0.66
22	Torrent Power Ltd	0.66	0.81	28.8%	0.42
23	Va Tech Wabag Ltd	1.95	0.04	35.1%	1.90
24	Waaree Renewable Technologies Ltd	0.55	0.36	28.2%	0.44
	Average				**0.75**

Now, β_e is calculated with a normative debt to equity ratio of 70:30, with a Tax Rate of 25.168%. This yields β_e as follows:

$$\beta_e = \beta_a \times [1+(1-\text{Tax rate}) \times (D / E)]$$

$$\text{So, } \beta_e = 0.75 \times [1+(1-25.168\%) \times (70/30)] = 2.07$$

Beta	**B_e**	2.07
Risk Free Rate	**R_f**	7.3%
Market Return	**R_m**	16.5%
Market Risk Premium	**$(R_m - R_f)$**	9.2%
Expected Rate of Return	**R_E**	**26.3%**

The above exercise shows that the return on equity allowed on a normative basis should be not less than 26%.

Therefore, for the generation sector, RoE should be provided in the range of 26% to 28% considering the risk involved in the sector. The companies should be financially sustainable in this rising power demand scenario. Therefore, adequate return should be provided to attract investment in the power sector in preference to other sectors, which is also a stated policy of the Government of India, as pronounced in the Tariff Policy.

For additional capitalisation, investment related to emission control system and for investment in new projects, it is similar to infusion of capital, hence, RoE equivalent to existing projects should be made applicable both for additional capitalisation and for the new projects.

RoE should not be linked to the G-SEC rates/MCLR/RBI Base Rate, as the risk profile involved with the cost of equity is not equivalent to the cost of debt, hence CAPM based approach should be adopted for determination of RoE, as suggested.

It is submitted that for determination of the rate of return, judicious assessment of the existing market scenarios needs to be considered. Risks associated with financing are directly attributable to higher returns and the same may be considered. It may be brought to the attention of the Hon'ble Commission that the current market scenario for thermal projects has significantly become riskier owing to the multiple changes that the environment is undergoing, including policy level initiatives to high level of RE integration in the system. Although demand has picked up in the country post Covid-19, PLFs of the thermal generators continue to remain lower. Inspite of higher RE capacity addition, it is submitted that thermal power still accounts for over 70% of the electricity supplied. Therefore, considering the criticality of thermal stations providing reliable supply of electricity, it is extremely important that the investors are adequately compensated for the associated risks they are undertaking. Hence, the same risk - reward principle may be followed for ascertaining the rate of return.

(U) Rate of Return of old Thermal Generating Stations (Clause 4.16.5)

To encourage the continued operation of old plants and generation of low cost power, additional incentives, as envisaged under Clause 4.16.5 of the Approach Paper is a welcome consideration and may be provided through the Tariff Regulations.

It is good to understand that the Hon'ble Commission is considering these aspects of Old Thermal Assets. There are a number of such assets which are high on efficiency even today. However, although the O&M costs for these assets are higher, they provide advantage to consumers in terms of less AFC with low capital servicing costs. Hence, additional incentives are required to make their operation economically viable. Differential incentives are required for maintaining higher PLF/PAF, which means an older plant should earn a higher PLF/PAF based incentive than a younger plant at the same level. Also, efficiency norms for older assets should be less steep than that of younger assets. Moreover, it is also submitted that the incentives should be provided over and above the recovery of the entire capacity charge pertaining to the generating station.

In this respect, another important factor that must be considered is the guidelines and Regulations that are being published in recent times for flexible operation of thermal generating stations (Reference: Central Electricity Authority (Flexible Operation of Coal based Thermal Power Generating Units) Regulations, 2023, Central Electricity Regulatory Commission (Ancillary. Services) Regulations, 2022 etc.). Considering that the Capacity Charges of these thermal generating stations are recovered based on the achievement of higher PAF during peak and off peak periods, incentives are payable towards excess generation beyond normative PLF. Taking cognizance of the requirement to ramp down generation (even below 55% in some instances) for supporting incorporation of renewable energy in the grid, it is submitted that the normative PAF and normative PLF be kept different, the latter be kept much lower to accommodate for grid flexibilization needs while promoting generation from these older stations.

In any manner, efficient older generating stations should be encouraged to operate by providing higher returns keeping in mind that all R&M expenditures are allowed after due prudence checks. Further, the merit order stack automatically establishes the efficiency of operations. The older generation capacity will lead to reliable sourcing of power for demand servicing adequacy at a time when any new replacement assets would be much costlier for the system. Therefore, it is also submitted that the incentive amounts should be further increased to promote efficient operation of such old generating stations.

(V) Tax Rate (Clause 4.17)

The present provisions of the CERC Tariff Regulations 2019 are logical and may be continued with, as it adequately takes care of the needs of the generating companies or transmission licensees. However, such expenditure shall be trued up based on the actual tax payment at the end of tariff period and the differential amount may be adjusted for recovery / return accordingly.

(W) Interest on Working Capital (Clause 4.18)

Working Capital Requirement (4.18.1)

In the CERC Tariff Regulations, 2019, maintenance spares @ 20% of the O&M expenses including water charges and security expenses has been allowed as a component of working capital requirement. In the model tariff regulations by Forum of Regulators, such a component of Maintenance spares has been proposed @ 40% of R&M expenses for one month. Thus, 40% of R&M expenses for one month may be adopted. This approach is more rational as maintenance spare is related to R&M

expenses, whereas O&M expense not only represents R&M expenses but also includes administrative and general expenses.

While determining the component of working capital requirement, to mitigate the potential scope of significant variation on account of impact of variation of fuel prices, it is suggested that an indicative year-on-year escalation in fuel prices @ 3%-5% may be considered for the purpose of tariff determination. However, this may be trued-up at the end of the tariff period on the basis of actual fuel prices incurred by the generating company / power station and only act as a buffer to reduce the tariff shock. However, it is also prayed that under no circumstance should the utility be deprived of any impact of variation of fuel costs by off putting the true up process.

Rate of Interest on Working Capital (4.18.2) :

The Hon’ble Commission has proposed the rate of interest on working capital @ MCLR + 350 bps in this approach paper. It is humbly submitted in this context that the risk perception of the electricity business has enhanced significantly in light of the increasing uncertainties in the business and cost of finance, which calls for allowance of interest on working capital @ MCLR + 450-500 bps.

(X) Life of Generating Station and Transmission System (Clause 4.19)

There are a number of Generation and Transmission assets which are high on efficiency even today. It is always worthwhile to operate an aged asset which is efficient and high on environmental compliance. However, while O&M costs for these assets are higher, they provide advantage to consumers in terms of lower overall AFC.

Hence, the Hon'ble Commission may consider a window of evaluating assets on case to case basis based on Residual Life Assessment study followed by OEM recommendations and subsequently allow for extended life and dispensation of Special Allowance for R&M post 25 years.

(Y) Input Price of coal - Integrated Mine (Clause 4.20)

In the Current Tariff Regulations, in case of ROM cost of coal for the mines allocated through auction under Coal Mines (Special Provisions) Act, 2015, there is no provision of inclusion of mining charge charged by the Mine Developer and Operator (MDO). If a generating company engages an MDO for the purpose of crushing, transportation, handling or washing, the same cannot be recovered under the current Tariff Regulations.

Ministry of Coal vide its clarification dated 17 January 2015 in "Queries & Responses to Standard Tender Document dated 27 December 2014" had clarified that charges such as transportation cost, crushing cost, washing cost etc are allowable expenses while calculating the Energy Charge in relation to an auctioned coal mine. An extract of the Ministry of Coal's response to query no. 9 in the aforesaid clarification is given below for ready reference:

> *"……the Appropriate Commission shall, while reviewing/determining the energy charge, factor in other allowable expenses and permissible components of such energy charge and ensure that it does not lead to higher energy charge throughout the tenure of the PPA. It is expected that the Appropriate Commission, while discharging this responsibility,* ***<u>shall use appropriate benchmarks in terms of transportation costs for the relevant mode(s) of transportation and CIL's costs for washing and crushing charges</u>*** *etc. to prevent undue gain to the Successful Bidder on these counts."*

The Hon'ble Commission is requested to include mining charge, charged by the MDO including crushing, transportation, handling or washing charges in the ROM cost of coal mined from coal mines allocated through auction under Coal Mines (Special Provisions) Act, 2015. Suitable changes may be incorporated in Regulation 36 (B) and Regulation 36 (C) of the current Tariff Regulations.

Since Input Price of coal from such mines consists of cost of ROM coal + Additional Charges incurred for crushing, washing, handling and transportation, any additional capital expenditure incurred for relevant infrastructure due to reasons such as complying with directions or orders of any statutory authorities, liabilities due to Change in Law or Force Majeure events etc. needs to be taken into account while calculating input price of coal. It is requested to make appropriate changes in the

Regulations to take into account the effects of Additional Capital Expenditure incurred due to Change in Law or Force Majeure events or other similar reasons on the input price of coal from the coal mines allocated through auction under Coal Mines (Special Provision) Act, 2015. Suitable changes may be incorporated in Regulation 36 (E) of the current Tariff Regulations.

Hon'ble Commission is requested to make appropriate changes in the Regulation 36 (K) to allow recovery of mine closure expenses for the coal mines allocated through auction under Coal Mines (Special Provision) Act, 2015 in line with those allocated through the allotment route.

Successful Bidder of a coal mine allocated through auction under Coal Mines (Special Provision) Act, 2015 are required to make payment of "Upfront Amount" and "Fixed Amount" to the relevant authorities. Hon'ble Commission is requested to consider amortization of such payable amount over the life of the mine and make suitable provision in the Regulation for inclusion of the same in the input price of the coal. Other provisions for consideration of captive mine costs and revenue may be allowed to continue.

(Z) Sharing of Gains (Clause 4.21)

In the Tariff Approach paper, it has been proposed that avenues may be identified to increase non-core revenues through monetisation of existing assets including land banks etc. In this regard, it is submitted that in order to encourage any new revenue opportunity, sufficient incentivisation must be provided to the utility companies in the form of retention of 100% gains during the initial years (similar to the CDM mechanism approach), which may be progressively reduced in the future once a definitive visibility of such revenue potential has been established. Further, it is also submitted that all such non-core revenue must be shared only from monetisation of assets which come under regulatory purview and have been created/funded through the regulated tariff only and not pertaining to any other avenues of business interest of the entity.

(AA) Treatment of arbitration award – Servicing of Principal and Interest (Clause 4.22)

The proposed methodology of allowing capitalization of the principal amount of the assets on account of any arbitration award, while allowing recovery of interest in form of installments including necessary carrying cost seems to conflict with the fundamental tenet of capital servicing costs as prescribed through the existing tariff determination process. Any arbitration award with respect to capital expenditures must be treated in the same manner as other capital expenditure items and any differential treatment would unnecessarily lead to complications and create scope for further litigations.

(BB) Treatment of interest on differential tariff after truing up (Clause 4.23)

Differential tariff amounts can be often attributed to delay in timely determination of tariff and/or non-recognition of allowable cost components to the utility. Therefore, allowance of compound interest on the recoverable amount must be continued. Further, the proposed modification with respect to no carrying cost during recovery of instalments should be limited to six months of recovery only and in case the period of recovery of instalments span over multiple years, additional interest amount pertaining to carrying cost towards unrecovered amounts may please be allowed.

(CC) Normative Annual Plant Availability Factor - Review of Existing Norms (Clause 5.1.1)

Availability of thermal generation station is being considerably affected by coal shortage, integration of renewable plants, introduction of ancillary services market. Presently, the existing norm for all thermal generating stations is 85%. The present norm may be reviewed based on the recent performances along with an estimation of future scenarios.

However, it is also submitted that with rise in demand, availability of coal becomes a challenge primarily during peak season. Importing coal has its own set of challenges along with lead times & also impacts consumer tariffs. Therefore, the Hon'ble Commission is requested to carry out a study to plan for any revision of NAPAF based on the factors mentioned above.

(DD) Peak and Off Peak Tariff (Clause 5.2)

Peak and off-peak tariff was introduced to incentivise peak period availability and availability during peak demand season. The generating stations were incentivised to be available during peak period and high demand season. As correctly pointed out by the Hon'ble Commission, there is a difference between the forecast that does not match with actual period and the period of high demand and low demand is not the same for all States in the region. Moreover, with the introduction of Ancillary Services operation, the gap between demand and supply is aimed to be reduced. Besides, with the increasing percentage of renewable energy plants connected to the grid, ramp up and ramp down operation of the generating plants becomes frequent. Therefore, the recovery should not be limited based on daily peak and off peak periods. The current methodology of capacity charge recovery based on peak and off peak period availability of the generating stations, including for high and low demand season creates administrative overheads for both the generating station as well as the concerned Load Despatch Centres. Considering that the demand profile and system loading would only become more dynamic in the future on account of higher levels of Renewable Energy integration in the grid, such mapping would only get further complicated. Therefore, it is requested that in line with the overall simplification theme of the Approach Paper, the Hon'ble Commission may kindly explore reverting back to the earlier mechanism of Capacity Charge recovery linked to the overall average availability of the generator, based on the normative PAF.

(EE) Operational Norms (Clause 5.3)

It is submitted that the operating norms should be based on past performance of the units in the country including State Utilities/IPPs of relevant vintage of the units and should factor in operating constraints, like, partial loading due to erratic load pattern of the beneficiaries and lower operating load factor due to shortfall of quantity and quality of fuel which is expected to continue in future. Further, the margin in Design Heat Rate should be different for the generating stations with respect to the Control Period in which it was commissioned.

Station Heat Rate -

It is submitted that with operation of a generating unit under varying load conditions and with variations in the quality of fuel, the efficiency of the boiler and turbine tends to degrade over time. Hence, we request the Hon'ble Commission to specify the margin in the Design Heat Rate to be different for a generating station completing every block of 5-years. The margin provided to the generating stations commissioned in the Control Period FY 2014-19 should be higher than a generating station commissioned in FY 2019-24.

It is further submitted that the capability of a generating station to perform at a specified level is determined based on the date of commissioning of the units and accordingly the normative operating parameters are set. In case the EPC order is placed by the generating company based on the operating norms prevailing on that date and the unit is commissioned in the next tariff period under different Tariff Regulations with revised norms of operation, the generating company shall be constrained with operating the unit with revised norms. Hence, we request the Hon'ble Commission to determine the margin in Design Heat Rate based on date of placement of order for the BTG package in the relevant Control Period.

Further, we request the Hon'ble Commission may consider the following important criteria while specifying norms for Station Heat Rate:

- Quality of Fuel
- Operating pattern of machines (part load/full load etc.)
- Vintage of machines

- Unit size
- Climatic condition.
- Loss of Ignition

In this respect, it is also submitted that SHR norms are dependent on both the technology of the OEM as well as the quality of coal/fuel being fired. Any benchmarking based approach would not only be imprudent considering that unit configurations as well as manufacturers vary significantly across different projects, but is also detrimental to the operating and financial performance of the utilities. Further, as stipulated in the Tariff Policy, State Commissions are needed to align their norms as per the CERC Tariff Regulations. Therefore, to protect the interests of the state generators, it is essential that such SHR benchmarking may be avoided, as the operating conditions and fuel sourcing may be different in case of the latter. Hence, such SHR reduction based on any benchmarking is requested to be avoided.

(FF) Operational Norms - Inefficient Generating Stations (Clause 5.4)

Certain vintage generating stations may have become inefficient owing to their vintage and/or technological obsolescence. However, their existence and need must be viewed with respect to the systemic support they are able to provide, for supporting peak period operation of the grid as well as demand management. It would be imprudent if such blanket disallowance of relaxed norms for such stations are considered, as some of these stations play a critical role in serving the load requirement of the associated beneficiary licensee. Therefore, it is requested that the proposed modification must be viewed in light of the necessity of such stations and requirement of relaxed normative parameters, so as to allow them to serve their purpose accordingly.

(GG) Operational Norms for Washery Rejects based Plants (Clause 5.5)

Existing operational norms as provided for washery rejects based plants in the existing Tariff Regulations may continue for the next tariff period as well.

(HH) Operational Norms - Emission Control System (Clause 5.6)

It is submitted that the Hon'ble Commission may revise the operating norms for Emission Control System, once sufficient operational data are available. Till such time existing operating norms may continue.

Further, the practice of excluding Supplementary Energy Charge associated with Emission Control System while preparing merit order of generating station may be continued as most of these generating stations are still in the process of implementing such systems.

(II) Gross Calorific Value of Fuel (Clause 5.8)

The Hon'ble Commission is kindly aware that heat losses occur at multiple points before the actual firing point of the boiler. It is an unfortunate but settled position that there is a serious mismatch between the "as billed" and "as received" heat values of coal.

It is pertinent to mention that in the report of Forum of Regulators (FOR) on "Analysis of Factors Impacting Retail Tariff and Measures to Address Them" it is stated that,

"The GCV loss due to grade slippage between "as billed" and "as received" has been in the range of approximately 600 kCal/ kg."

“As per the fuel supply agreement (FSA) between the coal supplier and the generators, the coal supplier does not provide any compensation for surface moisture of coal upto 7% in dry season and 9% in wet season. Full compensation should be provided for the surface moisture as it has no heat value

Thus, Ministry of Power and Ministry of Coal need to find out a solution to the issue of grade slippage and losses due to moisture content…..”

Hence, it is a well-accepted fact that there might be wide divergence between “as billed” and “as received” heat values.

‘GCV as received’ at the unloading end of a power station should be the basis of computation of fuel cost and energy charge of generating stations. IS 436 (Part-I/Section 1) - 1964 dealing with collection, preparation and testing procedure of samples, needs to be considered as basis for derivation of the “as received” GCV and may be stipulated in the Tariff Regulations.

It is a well-acknowledged fact that significant deterioration of heat value of coal occurs due to ingress of moisture. Therefore, moisture correction is required to be made in accordance with relevant Indian Standards (Clause 6.2 of Indian Standard (IS) 1350, (Part-II) - 1970) in order to arrive at the “as received” GCV. Regulations of the Hon’ble Commission may kindly be specified mentioning these Standards. It may be noted that the Ministry of Power has also acknowledged the principle of unloading end heat value less stacking losses in arriving at coal consumption reconciliation in relation to linkage coal vide notification dated 20 July 2021.

It is also an acknowledged fact that loss of heat value happens during storage. A study conducted by the Central Electricity Authority with due consultations with notable experts in the fields, e.g. CIMFR and CPRI, has recommended a margin of 105-120 kCal/kg for non-pit head stations towards stacking losses of heat value of coal received in power station and stored till firing of boilers. Thus it may be stated that while it is possible to an extent to control the heat value loss within the station by the generator during storage, it is beyond the control of the generating station to minimize the loss between the as billed and as received heat values.

The observation made in the Approach paper that there may be a need to share the risk of grade slippage / loss of GCV between the coal company, the railways and the generating station as the generators have not made considerable efforts in minimising the loss is, unfortunately, a very misplaced one. It needs to be appreciated that the generating company has no control on the activities of coal mining, loading onto wagons of the railways at the mining end and transportation of the loaded wagons at the doorsteps of the power stations. Only after the coal reaches the power station, the ownership and control of the coal is actually transferred to the generating company. Before this point the generating company has no control whatsoever on the quality / quantity of the coal being despatched to it. As a result the generating companies are always at the receiving end of the unilateral actions of the CIL and Railways. Grade slippage at the mine end is a real issue faced by all generators in the country. Therefore, passing on a part of the burden of this risk of grade slippage / loss of GCV on the generating company is against the principle of natural justice. The risk sharing mechanism should be limited to the Coal supplier and the Railways only, for the aforestated reasons.

It is further submitted that due representations and negotiations with the coal supplier, including furnishing of GCV certificates based on sampling at unloading end takes prolonged time. Any claims pertaining to such differential amounts on account of coal quality (including arrear amounts with respect to previous years) must be duly allowed through tariff, irrespective of the timeline as prescribed through clause 56(2) of the Electricity Act, 2003.

In this respect, it may kindly be noted that even the former Chairman of the Hon'ble CERC, Mr. Poojari, in a recent event organised by Centre for Social and Economic Progress on 14.06.2023, observed these dominating role played by the CIL and the Railways that ultimately affects the end consumers as well as the financial viability of the generating companies.

There are concerns on appropriateness of coal grade declaration of mines by CIL and necessary independent review by the authorities is not adequate. Thus, appropriate degradation of coal mines is needed to be ensured through more frequent testing and periodic declaration of quality by the concerned authorities in order to somewhat address this issue. Given the monopolistic nature of the business of Coal India Limited, generating companies often have to bear the entire risk on account of price variation and grade slippage of coal. It is therefore submitted that discussions in various forums have often led to the conclusion that establishment of a coal regulator is an essential step towards establishing control over the price and quality of coal. The key issue with respect to grade slippage, may be effectively mitigated if a transparent process is ascertained to re-validate the coal grading across mines and ensuring adequate quality controls at unloading end.

In this respect, the erstwhile CERC methodology of relying on GCV ‘as fired’ basis may be relied upon. It is submitted that loss of heat value occurs at multiple storage points before the actual firing point of the boiler. Moreover, such loss of heat value is more prominent for Indian coal. As per the past experience, we believe that the loss of GCV due to storage may be greater than 85 kCal/kg. The loss depends on the Volatile Matter of the coal and the number of days of storage. Storage of coal is inevitable since procurement of coal is not under the control of the generator and may not be synchronous with the generation plan. The final loss in GCV from coal stockyard to the point of feeding into the boiler, i.e. coal as fired, can go much higher than 85 kCal/kg if coal has been stored for a longer period of time. The current methodology of heat value determination, while addressing certain shortfalls of quality determination, still does not reflect quality of coal being fed to the boilers in its ambient conditions and is proposed to be modified accordingly.

(JJ) Blending of Coal (Clause 5.9)

The current provisions of the Tariff Regulations stipulate requirement of consent from beneficiary with respect to percentage increase in Energy Charge Rate in case of blending of coal. However, as rightly identified in the Approach Paper, determination of such percentage increase is often difficult to gauge considering the dynamic pricing of import of coal. Further, blending of import coal is primarily done through mandate / policy guidelines of the Ministry of Power, to alleviate power shortage scenarios and limiting such decision making based on cost economics alone would be both detrimental for the system as well as meeting of electricity demand. Therefore, such a shift wherein prior consent is to be linked with percentage blending of imported coal would be a much better alternative that should be adopted.

Further, we request the Hon’ble Commission not to specify any normative blending ratio as it is operationally impractical. It is better that the generating companies decide the blending requirement depending on factors such as quality of domestic, imported coal, boiler design, vintage of the plant etc. Taking consent of beneficiaries before blending with imported coal is a welcome move since the same may ultimately result in the benefit of end consumers in the form of higher availability of energy / reduced shortage of power. However, it may not be feasible for the beneficiary to specify the percentage of blending of imported coal to be adopted by the generating company. Therefore, the specific ratio of blending may best be left to be decided by the generating company itself.

(KK) Tariff Structure for cost recovery of Emission Control System (Clause 6.2)

Existing tariff structure for cost recovery of Emission Control System may be continued. However, return on equity for such an Emission Control System should be in line with the return on equity for the generating station. Determination of cost of debt for such a system should be based on weighted average rate of the actual loan to recognise the actual interest payment/ finance cost obligation by the generating companies towards such emission control systems.

The necessity of an emission control system has been mandated through MoEFCC notification in December 2021 and therefore, must be treated as a change in law event. Therefore, it is pertinent that the entire capital cost of such an emission control system must be allowed in entirety after due prudence by the Hon’ble Commission. In this regard, it is also submitted that as per the Hon’ble Commission’s Order in suo-motu petition No. 06/SM/2021 dated 13.08.2021, the Hon’ble Commission had determined that the applicable rate of return for Emission Control System would be at the weighted average cost of capital. It is humbly submitted that arranging for equity investment for any capital items including emission control system would bear the same risk for the company and therefore must be treated at equitable levels corresponding to the other generation assets. Therefore, the ROE rate applicable for generation thermal power stations is to be allowed for such capital servicing costs.

Further, the existing methodology of non-consideration of supplemental energy charges on account of emission control systems in determination of merit order may be continued, considering that there are multiple stations who are yet to install the same.

(LL) Simplification of Tariff Formats (Clause 6.4)

This approach paper provides an option of simplification of the existing tariff filing formats which is a welcome step for the petitioners. Determination of final tariff involves submission of detailed formats which is followed by Technical validation sessions, public hearings etc. which takes a lot of time. Tariff formats should be designed in such a way that furnishing of data / information is not very intricate which takes a considerable amount of time for the petitioners. Simple tariff filing structure enhances clarity and ease of retrieving / understanding of the petition. Repetitive formats in various ways should be avoided. This simplified tariff filing structure would also enable the Hon'ble Commission in understanding and processing the forms / petition as these require thorough checking and when the such process undergoes public consultation reduces unnecessary comments / suggestions from the stakeholders.

(MM) Necessity to Review the need of Regulation 17 (2) (Clause 6.8)

The Hon'ble Commission has rightly observed that current provision 17(2) provides the beneficiary the first right of refusal for an arrangement for procurement of power from the generating stations who have completed their useful life. While clause 2 does provide first right of refusal, clause 1 provides that the beneficiary and generating company may agree on an arrangement. Therefore, it automatically provides the stakeholders to renegotiate any terms and conditions (can even be exactly the same as per erstwhile PPA that gets exhausted). This effectively insulates the stakeholders from any adverse conditions.

Addendum

The addendum to the CERC Tariff Approach Paper 2024-29 was published on 03.07.2023 towards Compensation methodology for operating a Thermal (Coal) Generating unit below 55% Minimum Power Level, as identified through clause 5.7 of the approach paper.

(A) Procedure for participation for generating station units under flexible operation

Generating Station units are required to operate in a flexible manner to support the intermittency of renewable energy in the grid. Low PLF of thermal generating stations are envisaged on account of flexible operations to accommodate the intermittent renewable energy sources in the grid. In this regard, reference has been provided towards Central Electricity Authority (Flexible Operation of Coal based Thermal Power Generating Units) Regulations, 2023.

Considering that CERC has also published the Central Electricity Regulatory Commission (Ancillary Services) Regulations, 2022, that allows for flexible loading of generating stations in the Secondary Reserve Ancillary Services, it would be beneficial if harmonization of both the Regulations and clear procedure and guidelines for determination of the PLF for the generating units are stipulated in the Tariff Regulations (or separately as may be found appropriate).

Further, it may be the case that overall PLF of a generating station on a monthly / annual basis may not go down below 55%, while for specific time blocks, on account of grid stability, NLDC may direct operations at extremely low levels. The detailed procedure is therefore requested to clarify the accounting methodology of the PLF of operations accordingly, considering the time block wise schedule as well as the annual / monthly final PLF of the unit. Compensations may be considered based on actual low load operation at the specific time blocks.

(B) Fixed Cost - Capital Expenditure (Clause 3A a.)

The proposed normative capital expenditure requirements for generating stations towards retrofitting various measures for low load operation stipulates unit sizes of 200 MW, 500 MW, 660 MW and 800 MW. However, there are a number of generating stations with unit sizes of 250 MW and 300 MW. In this respect, existing CERC Tariff Regulations, 2019 also stipulates norms for generating stations based on their capacity ranges (has a separate category for 300/330/350 MW series). Hence, harmonization of the unit sizes and corresponding norms is requested considering the different existing generating station units across the country.

The current addendum specifies a single capital expenditure norm for generating stations based on their vintage only (INR 30 crores for stations with COD prior to 01.01.2004, INR 10 crores for stations with COD on or after 01.01.2004 and, Rs. 6 crores for units whose investment approval have been received on or after 01.01.2011). The said retrofitting of the generating stations as per CEA (Flexible Operation of Coal based Thermal Power Generating Units) Regulations, 2023 can be directly attributed as a change in law event and therefore may be allowed to be automatically passed through. Instead, the actual capital requirement should be allowed after due prudence check by the Hon'ble Commission.

Firstly, it is unclear as to how such a figure has been arrived at, based on the vintage of the stations or how the said dates have been identified for determination of applicable capital expenditures.

Secondly, considering a single normative capital expenditure for all the unit sizes appears to be too simplistic as the expense towards retrofitment, may vary based on unit sizes as well as vintage considering rapid evolvement of control systems / technologies over the years. Therefore, normative capital expenditures may be developed which vary based on the unit sizes and technologies and not the vintage alone as currently stipulated.

Thirdly, the proposed capital expenditure norms specified allows for INR 30 crores for units whose COD lies prior to 01.01.2004 and INR 10 crores for units whose COD lies on or after 01.01.2004. Similarly, INR 6 crores has been specified for subcritical units whose investment approval has been accorded on or before 01.01.2011, considering the OEM specifications for regular low load operation at 40%. In this regard, it is submitted that such differential approaches based on COD and investment approval should not be considered. Moreover, attention may be drawn to the fact that there would be a few generating station units whose in-principle clearance (and subsequent Investment Approvals) may have been accorded in 2010 (period immediately preceding the CEA standards), without considering the control and instrumentations requirement of OEMs (for regular 40% load operations) as per findings of the said PG tests. Moreover, the period starting 01.01.2011 falls in the middle of the CERC MYT Tariff period of 2009-2014 and may be avoided to minimise complications arising due to defining a period in the middle of an MYT period. Therefore, it is requested that the said norms may kindly be specified for units whose COD falls on or after 01.04.2004 (beginning of MYT period 2004-09) and on or after 01.04.2014 (beginning of MYT period 2014-19) respectively. This would also allow to provide lower capital expenditures for units who are relatively newer in vintage and have also submitted their investment approvals duly considering the said CEA standards.

Finally, all the normative capital expenditures have been stipulated based on current estimated costs as on date. Considering stations who undertake these modifications at a later date, it is requested that the normative capital expenditures may be allowed with an escalation factor duly considering the prevailing inflation rates.

(C) O&M Cost due to increased Life Consumption (damage costs) (Clause 3A b.)

The addendum provides for additional O&M expenditures for stations who operate at a PLF lower than 55% (upto 40%). There may be cases wherein overall PLF of the generating station units on an annual/monthly basis remains higher than 55%, but for specific time blocks the stations have to operate at a PLF much lower than 55%.

Furthermore, kind attention is also drawn to the fact that current scheduling of the generating stations are provided for the entire generating station or for blocks of units based on the phases of development and not for particular units of the generating station, whereas the relaxed norms and additional compensations are to be provided for lower loading of generating station units. Therefore, the scheduling pattern may also need to be revised to incorporate such unitwise PLF assessment, as the same would have significant financial impact for the utility.

Moreover, it has been mentioned that increased O&M costs would be allowed for units who have participated in flexible operation for at least 85% of days in a year. However, the methodology of assessment of such participation has not been stipulated, which may lead to complexities and litigations in the future.

It is requested that clarity may be provided for the following cases discussed above -

a. In case of generating stations with multiple units, how would be the scheduling be done, so as to assess the unit wise PLF for determination of compensation (in case units would have different levels of PLF)
b. Time blockwise scheduling requirement for participating units and corresponding allowance of relaxed norms and additional compensation for time blocks wherein the PLF would be lower than 55% level, instead of assessment based on PLF over the entire period
c. Methodology of assessment of participation of a generating station unit for a minimum of 310 days (85%) in a year

It may be further pointed out that increased O&M expenses have been factored in for higher wear and tear of the units, but the addendum is silent on the probable reduction in life of capital assets which may need an early replacement before completion of its useful life. Therefore, the Hon'ble Commission is requested to consider the requirement of increased capital expenditure / early retirement of assets as a consequence of participation in flexible operations.

(D) Variable Cost - Cost due to increase in Net Heat Rate (Clause 3B a)

An important aspect that has not been considered while providing for relaxed norms and additional costs is related to units, who would be required to significantly ramp up or ramp down based on the flexible operation instructions. Stations who undertake a higher number of ramping up/down operations would experience significant deterioration of net heat rate than stations who consistently operate at a lower PLF. Therefore, it is requested that a separate cost allowance may be provided linked with the number of ramp up/ ramp down operations by the particular generating unit as well as number of blocks for which Units are operated below 55%

The proposed variable cost compensations for generating station units for lower PLFs have been done considering a number of assumptions as detailed at the end of the addendum, including station heat rate, coal cost, coal heat value etc. However, these parameters vary significantly based on the demography, vintage, type etc. of the generating stations and therefore should be done on a case specific basis, instead of providing a single normative compensation based on such assumptions as proposed through the addendum document.

It may be noted that with the said notification, thermal generating stations are required to ramp down from their target operating load level (at least of 85%, being level of utilisation) to even up to 40% load. The compensation, accordingly, is also required to be proposed for load levels from 85% to 55%. It may be pertinent to refer to the IEGC 2010 (since repealed with introduction of IEGC 2023) which provided for compensation for levels of 85% to 55%. The present IEGC appropriately provides continuation of earlier part load compensation till determination of compensation through appropriate Commission. The principle as well as the level of loading for compensation, being more relevant today with increased renewable integration, may be suitably accommodated considering size, vintage of the generating units.