NTPC COMMENTS ON CERC APPROACH PAPER ON TERMS AND CONDITIONS OF TARIFF REGULATIONS, 2024

1. Alternative Approach to Tariff Determination (7.1.1 of the Approach paper)

Approach Paper:

Suggestions are sought as to how the present system of hybrid mechanisms of tariff setting under the cost-plus approach can be made more efficient by moving closer to a normative or performance-based approach so that the same would positively impact the interests of consumers as well as utilities. Two possible options could be as follows.

1. Approach 1: Shift to a normative tariff, wherein, once capital costs are approved on an actual basis after prudence check, all other AFC components are determined on normative basis.

2. Approach 2: Further simplification of the existing Performance Based Hybrid Approach, wherein on the basis of admitted capital cost, AFC components can be approved based on actuals or norms as may be specified for the control period. Further, additional capitalisation may be allowed on certain counts on a normative basis.

NTPC Comments

1. **Background -** With the objective of simplification of tariff determination process, the Approach Paper is exploring the options for shifting to a normative tariff, wherein, once capital costs are approved on an actual basis after prudence check, all other AFC components shall be determined on normative basis. This pragmatic approach, which does not involve microanalysis of each cost component, is a welcome step that would result in reducing the considerable time and recurring efforts being put in by the generating companies and the Hon'ble Commission.

2. **Approach - 1**
   a. It is submitted that under the proposed methodology in Approach 1 for clustering the components of AFC (excluding O&M expenses) & determination of indexation factor may still require the same level of efforts, time, intervention, and exercise by both the generating company and the Hon'ble Commission.
   b. For the Tariff Period FY 2024-29, Approach 1 would still require determination of Annual Fixed Charges (AFC) and associated parameters for the base year (i.e., 2024-25) based on truing up of 2019-24 tariff period and tariff for 2024-29 based on the review of the Tariff Petitions by the Hon'ble Commission for each station. These parameters would include:
      i. Determination of Opening Capital Cost for the Control Period (which would only be available once true-up for the previous control period is completed), which may take around 2-4 years based on past experience.
      ii. Computation of various components of the Annual Fixed Cost (AFC) i.e., Interest on loan, depreciation, Interest on Working capital, Return on Equity and O&M expenses for first year of the

Tariff Period (Nth year) i.e., 2024-25 along with AFC for preceding year (N-1 year), i.e., 2023-24, which can be done only after step (i) above is completed.

iii. Determination of Indexation for AFC (other than O&M) component for which the Hon'ble Commission would be required to determine the AFC for each year of the control period for this purpose as well.

iv. Truing up of the Interest rate of loan, Interest rate of working capital & Working Capital after completion of each Tariff Period.

v. Revision of Indexation factor for each year post expiry of each Tariff Period after truing up.

vi. Approval of additional capitalization carried out on account of Change in Law & Force Majeure based on a separate petition filed by the generator. However, this is common step in both Approach-1 and Approach-2.

c. For determination of the above parameters, the existing methodology of filing of petitions by the generating company followed by detailed scrutiny and analysis of the Petition submitted by the generator shall still be required to be undertaken both at the beginning of the tariff period and after the completion of tariff period.

d. As indexation is a derived parameter from the AFC components, computed as the ratio of the AFC components of Nth year and (N-1) th year the AFC components would still require determination by the Commission at the beginning and true up after the tariff period.

e. The indexation mechanism may result in over recovery or under recovery of tariff in cases where there is sudden change in certain AFC components like depreciation after the 12th year, Special Allowance allowed to the generators after 25 years from COD, Supplementary tariff in case of commissioning of emission control system, etc. Therefore, mechanism for the indexation to factor the impact due to above changes is required.

Therefore, it is felt that the efforts of Commission will be similar to the existing approach and the objective of simplification of existing approach may not be achieved.

3. **Approach 2 –**

The Approach Paper has proposed a second alternative to further simplify the tariff determination process. The approach is to continue with the current practice of tariff determination with more AFC components being allowed on a normative basis. As more and more AFC components are approved on normative basis, it would ease the transition to a complete normative regime.

It is submitted that once capital cost is determined, the components of Annual Fixed Cost, namely depreciation, return on equity, O&M expenses, and Interest on working capital are determined largely based on various normative parameters. Few parameters like fuel cost and GCV for computation of energy charges and working capital, interest rate on loan, keep changing. Certain parameters like interest rate on working capital is indexed to MCLR. It is felt that Approach-2 would yield simplification to a large extent with introduction of normative approach for few parameters, which is further elaborated as under:

a. **Approach for Depreciation, Return on equity, and Special Allowance**

It is submitted that once capital cost is determined, the components of Annual Fixed Cost, namely depreciation, return on equity, and special allowance can be determined based on various normative parameters like rate of depreciation, rate of return on equity, effective tax rate and norm for special allowance.

b. **Approach for Additional Capitalization**

i. The Approach Paper has proposed to move towards a normative allowance for additional capitalization and minor items. The norm would be arrived based on actual expenses incurred in the past year and would vary based on aspects, such as unit-size and vintage, etc.

ii. It is submitted that the existing tariff determination mechanism to a large extent is based on various financial and operational normative parameters, except for the capital cost considered for tariff purposes. The capital cost of a generating station determined by the Commission after prudence check as per the regulations forms the basis for determination of tariff. For a new project, actual capital expenditure incurred up to date of commercial operation is considered. For existing projects, the capital cost as admitted by the commission on commencement of tariff period is considered. Further, capital cost is determined based on cash expenditure excluding liabilities.

iii. Further, substantive portion of the tariff determination is centered around approval of projected annual additional capitalization for various years of the tariff period. The tariff allowed is determined as per the admitted additional capitalization on projected basis, and subject to the true up after the end of the tariff period based on actual expenditure. Based on the past actual data of additional capitalization in various stations in the age brackets of 6-10, 11-15, 16-20 and 20-25 years, normative annual compensation in lieu of additional capitalization in Rs. Lakhs per MW is proposed to be allowed.

iv. The approach of normative additional capitalization is based on the principle of reimbursement of expenses and that there would be no revision in the capital cost. Therefore, it is presumed that capital cost would be frozen as on cut-off date for new projects and as on 01.04.2024 for existing projects.

v. Therefore, in order to arrive at a representative norm of additional capitalization, it is suggested that the norm may be fixed so that the generating company is in the same economic position vis-à-vis the existing dispensation of servicing through capital cost. Further, the norms need to be arrived after considering the impact of inflation on past actual data. Annual escalation factor may also be provided for 2024-29 period.

vi. The Approach Paper has proposed extension of cut-off date from 3 to 5 years, which would in most cases enable the generator to complete majority of capital works by cut-off date of 5 years and balance works under original scope beyond cut-off date is to be required to be met from normative additional capitalization.

vii. **It is therefore suggested that additional capitalization on normative basis beyond cut-off date under original scope with certain regulatory provisions to approach the Commission in certain exigencies and unforeseen circumstances, such as geological surprises, replacement due to technological changes / obsolescence, Force majeure, Change in Law, contractual issues which are outside the generators control, deferred works, etc., may reduce the regulatory burden of the Hon'ble Commission. Deferred works which are within the original scope of works but could not be completed due to unforeseen reasons may be paid separately on yearly basis.**

viii. **NTPC comments on the normative additional capitalization have been provided in detail under the relevant part of the Approach Paper on Additional Capitalization, may also be considered for Approach-2.**

c. **Approach for Working Capital**

i. The existing tariff regulations has prescribed specific norms for various components of the working capital, such as, cost of coal for 10 days for pithead stations and 20 days for non-pithead stations, advance payment of 30 days towards cost of coal, cost of secondary fuel for 2 months of generation, maintenance spares @ 20% of O&M expenses, receivables of 45 days of capacity charge and energy charge, O&M expenses for 1 month. Thus, the components of working capital are based on normative parameters and the interest on working capital is also indexed to SBI MCLR.

ii. The cost of fuel considered is based on the landed cost and GCV as per actual weighted average for the third quarter of the preceding FY in case of each FY for which the tariff is determined. The Approach Paper has pointed out that the actual fuel price keeps varying and affects the total receivables. However, this is necessary for factoring the variation in fuel prices with the working capital. The possibility of exploring a suitable indexation mechanism for cost of fuel is elaborated as under:

iii. Indexation of fuel prices is possible if the coal source is fixed and is not subject to sudden variations. It may be noted that the shortfall of domestic coal in the current tariff period was met through importing coal. However, as majority of the imported coal was received outside the third quarter, the impact of imported coal cost in working capital could not be factored completely.

iv. In view of the above following is suggested as under:

The cost of fuel for purpose of computation of working capital may be considered based on the actual weighted average Energy Charge Rate (ECR) for the preceding FY in case of first FY of the control period for which the tariff is determined. The fuel cost arrived for the first year as above may be used in computation of working capital for

subsequent years of the tariff period. The same shall be subject to annual adjustment / reconciliation of fuel cost variation at the end of respective year based on the actual weighted average ECR of that year.
Further, such annual adjustment / reconciliation of fuel cost variation can be done by the generating company based on actual ECR of that year.
Revision in rate of interest on working capital as on 1st April of FY can be made every year after the end of that year along with fuel cost adjustment.
This approach would capture actual fuel cost variation for entire year and shall be a fair approach from both generator and beneficiary perspective.

NTPC comments on the working capital have been provided in detail under the relevant part of the Approach Paper on Working Capital, may also be considered for Approach-2.

d. **Approach for Interest rate on Loan:**

Power sector companies in India maintains a diverse loan portfolio to minimize the risk, volatility & ensuring adequate funds for investment. Generally, loan portfolios comprise of Rupee Term Loans (RTL), External Commercial Borrowings (ECB) & Domestic Bonds.
Interest rates on RTL are dependent on various externalities such as inflation, recession, monetary policies of RBI, liquidity position etc. Rupee term loans are generally linked with the MCLR of Banks, RBI Repo Rates etc. Although the lending rate of ECBs is competitive as compared to RTL, it involves the risks associated with exchange rates.
Considering variations in the RTL & ECB loans, forex risk variations, absorption of hedging, risk premium costs etc. and in view of the long tenure of Thermal/Hydro power plants, there is a requirement of suitable margins available over the base rate to cover the borrowing risk. Therefore following is suggested:

i. **Therefore, in order to optimize the tariff, the generator may be given the discretion to decide whether to hedge the loan or not. Therefore, the existing provisions in the 2019 Regulations may be continued that allows Generators to recover the cost of hedging and FERV variation on year-to-year basis as income or expense in the period in which it arises.**
ii. **Suitable margin of at least 450 basis points may be provided over MCLR to take care the FERV risk on account of ECB, etc.**
iii. **Further, in case of shifting to normative interest rate on loan, the generating company may be provided option to continue with existing methodology based on actual project specific interest rate or shift to normative interest on loan with margin of 450 basis points above MCLR.**

e. **Approach for O&M Expenses:**

i. It is suggested that O&M expenses may be on normative basis with normative escalation factor. Normative O&M expenses may exclude ash transportation expenses since net ash transportation expenses are recoverable under change in law and these expenses vary from station to station. Therefore, it may not be possible to arrive at any standard normative figures as such. Therefore, these expenses may be excluding from the norms and reimbursed under change in law.

ii. Water charges can be made normative based on CEA norms for water consumption. Security expenses and capital spares may be made normative based on past actual data. Impact on change in law and force majeure may be excluded from the norm.

iii. Employee wage revision is mandatorily required to be done as per relevant directives of DPE and are statutory in nature. While revising the wages, some of the factors including the impact of inflation are paid to the employees in order to adequately compensate them and to cover their expenditures. Therefore, wage revision is a legitimate cost and is a change in law event. It is submitted that in a cost plus regulatory all expenses prudently incurred are to be allowed in tariff. Accordingly, entire impact on account of pay revision needs to be allowed in tariff. Therefore, 100% impact of pay revision needs to be considered on normative basis.

iv. Further, regulatory provision may be made for exigencies like events which may not be change in law but need to be complied with such as directions of local administration, guidelines of Govt, etc.

v. **NTPC comments on O&M expenses have been further elaborated in detail under the relevant section of the Approach Paper on O&M expenses, which may also be considered for normative tariff under Approach-2.**

f. **Approach for Change in Law, Force Majeure:**

Change in Law and Force Majeure have been defined in the 2019 Tariff Regulations as under:

Change in Law means the occurrence of any of the following events:

(a) ….

(b)……..

(c)..…..

(d)…….

Force Majeure for the purpose of these regulations means the events or circumstances or combination of events or circumstances including those stated below which partly or fully prevents the generating company or transmission licensee to complete the project within the time specified in the Investment Approval, and only if such events or circumstances are not within the control of the generating company or transmission licensee and could not have been avoided, had the generating company or transmission licensee taken reasonable care or complied with prudent utility practices.

(a)…..

(b)….

(c)…..

(d)…..

As normative tariff approach cannot foresee force majeure and change in law events in advance and incorporate the same in the dispensation, regulatory intervention would be required to provide relief to the utilities under cost-plus tariff mechanism. The Approach Paper has proposed to provide exclude change in law and force majeure events in the normative additional capitalization. It is felt that it would be necessary to do so. It is suggested that the same may not limited to additional capitalization, but a generic provision may be provided to deal such events in tariff as a whole. For instance, change in law or force majeure events may have to be compensated as part of O&M expenses, working capital, or annual fixed charges or energy charges, or in supplementary capacity charges and supplementary energy charges, etc. It is therefore suggested that a generic provision for consideration of impact due to Change in Law and Force Majeure events may be provided in the Tariff Regulations for the Hon'ble Commission to deal with such events during the course of the control or tariff period. Accordingly, the definition of change in law and force majeure may be broadened to include the above aspect.

To sum up it is felt that as compared to Approach-1, Approach 2 is more conducive for regulatory oversight, achieving simplification as well as having a flexible approach for interventions in cases of any unforeseen event requiring regulatory intervention during the tariff period. With few changes to the existing regulations by way of normative additional capitalization, normative working capital, and normative interest on loan, as elaborated above, the objective of simplification in tariff can be achieved to a large extent.

2. **Interim Tariff - (Issue 7.1.3 of the Approach Paper)**
Approach Paper

4.2.1 Background

The approval of capital costs is one of the most important aspects of the tariff determination process, as almost the entire fixed charge throughout the life cycle of the project depends upon it. In the process of tariff determination, the Commission has been approving the capital cost of the projects on a case- to- case basis, which is dependent on the actual expenses incurred, duly certified by the auditors, and after carrying out due prudence on the reasonability of the expenses incurred. The CERC Tariff Regulations, 2009, introduced an enabling provision that 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 The provisions for interim-tariff can, therefore, be continued in the next tariff period as well.

However, comments and suggestions are sought from stakeholders on the continuation of the said provision.

NTPC Comment

The existing regulations provide that the generating company may make an application for determination of tariff of new generating station or unit thereof in accordance with the Procedure Regulations within 60 days of anticipated date of commercial operation. It is submitted that the provision of interim tariff may be reintroduced in the next tariff period, which would facilitate revenue stream for generating stations.

3. Procurement of Equipment and Services - (7.1.4 of the Approach Paper)

Approach Paper:
Need to mandatorily award work and services contracts for developing projects under the regulated tariff mechanism through a transparent process of competitive bidding, duly complying with the policy/guidelines issued by the Government of India as applicable from time to time. (Refer 4.2.2).

NTPC Comment:
The procurement of equipment and services are carried out through transparent process of competitive bidding in compliance with the policy / guidelines issued by the GOI from time to time in this regard. However, exemption to this may be allowed in under construction projects acquired through NCLT where it may not be possible to follow the above process, as the vendor / manufacturer cannot be changed in midway of the procurement process. For instance, BTG and other main packages cannot be changed in the midway. Further some works which are awarded to government agencies/ departments such as Railways, PWDs, etc., on deposit works basis for exclusive nature of work who intern carry out works based on appropriate government guidelines shall be exempted. Therefore, in such cases exemption from competitive bidding may be provided.

4. Reference Cost – Benchmark Cost V/s Investment Approval Cost - (7.1.5 of Approach Paper)

Approach Paper:
Another aspect with regard to the approval of capital costs that has been debated while framing earlier Tariff Regulations is the reference cost that needs to be considered while approving capital costs. The existing methodology of relying on the investment approval cost was also debated; however, in the absence of a better reference/benchmark cost due to the paucity of reliable data and the complexities and difficulties involved, the reliance on investment approval has continued. However, the hard costs of recently commissioned projects of similar specifications are referred to for prudence checks.
For a thermal generating station, it is observed that there are several differences with regard to site conditions, water handling, coal handling systems, etc., and one benchmarked cost may not be a true representation of all such plants on the basis of which actual costs can be disallowed. These issues are even more profound in the case of hydro generating stations, as the costs significantly depend on several aspects such as choice of technology, design, reservoir based/Pondage/ROR, etc. With regards to transmission systems, the cost is affected by tower design, terrain, soil type, and wind zones, and therefore it is generally argued that benchmarking

will serve a limited purpose and may not be a better alternative to current project specific Investment Approvals.
Comments and suggestions of stakeholders are invited on other efficient reference costs other than Investment Approval costs that can be considered for prudence checks.

NTPC Comment:

a) Presently, prudence of capital costs is done by Hon'ble Commission based on the initial investment approval cost and the hard cost of recently commissioned projects of similar specifications.
b) It is submitted that the capital cost of a thermal generating station is influenced by various technical factors, such as, unit size and configuration, technology adopted, site conditions, water source and handling system, ash management requirements, quality of coal and handling system, emission control systems, etc. Other factors include market condition, availability of vendors, cost of land, gestation time, etc., all of which differ from one project to another. With so many variables which can impact the capital cost, arriving at a benchmark capital cost is difficult. The Hon'ble Commission did carry out an exercise for benchmarking hard cost in 2012 but the same was discontinued due to various limitations.
c) Therefore, the Approach Paper has rightly recognized the limitations of one benchmark capital cost as a reference may not be a true representation of all such plants on the basis of which actual costs can be disallowed. Therefore, relying solely on benchmarking capital costs using historical values may not adequately reflect the circumstances of upcoming projects.
d) Furthermore, there has been a reduction in the number of newly finalized thermal power plants over the past five years while the cost of basic metals, etc. has increased significantly resulting in impact on the market for main plant and Balance of Plant (BOP) vendors. These market-based shifts in competitive dynamics shall have repercussions on equipment and service pricing for future power plants.
e) **It is therefore suggested that considering the variable factors as elaborated above, limitations of arriving at a representative benchmark capital cost, and changes in the market scenario of thermal generating stations impacting the cost of plant and equipment, it would be prudent to continue with the current approach of prudence of capital costs based on the investment approval cost approved by the board of the generating company and reference to hard cost of recently commissioned projects of similar specifications. This would ensure a balanced, practical, and prudent approach for assessment of capital costs for future projects.**

5. Capital Cost - Projects Acquired post NCLT Proceedings - (7.1.7 of Approach Paper)

Approach Paper:
12. Historical Cost or Acquisition Value, whichever is lower, should be considered for the determination of tariff post approval of Resolution Plan.

13. Tariff provisions to be included to address the issue of the cost of debt servicing, including repayment, that were allowed as a part of the tariff during the CIRP process. (Refer 4.3)

NTPC Comments:

a) The tariff determination based on cost-plus principle considers the historical cost data of the assets as the capital cost for tariff purposes. The capital cost considered for tariff purposes in on cash basis. The existing Tariff Regulations define the capital cost of any generating station / transmission asset as the expenditure incurred up to the date of commercial operation of the project. This basically implies that the actual cost incurred towards development / construction of the asset shall be considered for tariff determination. This approach has been followed by the Commission for the assets for which tariff is being determined based on cost-plus principles under Section 62 of Electricity Act 2003.

b) It may be seen that almost all the plants which are under NCLT are set up based on either competitive bidding under Section 63 as well as combination of Section 63, Section 62 including power at ECR etc. Even fixed charge and ECR quoted by the developer does not reflect actual fixed charge, actual ECR or heat rate etc. Assumptions of the developers at the time of bidding and tariff quoted have gone wrong and became financially unviable.

c) While bidding for stressed assets, the acquirer considers several factors including cost to be incurred for completion of the facilities, standardization of the schemes as per the industry practice, discounting the losses due to shortfall in design vs norms, etc. After consideration of above the factors and any unforeseen factors the acquisition value is arrived. Therefore, considering the acquisition value for purpose of tariff determination will deny the servicing of legitimate costs to the generator.

d) Under NCLT process of sale/ purchase, the price at which exchange of shareholding takes place is discovered through transparent process of bidding based on revenue earning potential. As the tariff offered at the time of bidding cannot be changed under the contract or the special dispensation like tariff at ECR etc., as agreed by the developer cannot be discontinued, post take over through NCLT should neither impact the tariff process, nor tariff as already agreed. CERC should ensure that there is no increase in tariff beyond the agreed contract / assumptions, while taking over station through NCLT process.

e) It may be noted that the projects which undergo NCLT process are unviable loss-making projects and therefore the recovery of tariff is inadequate to compensate for the expenses and earn the reasonable level of return. In view of the operational losses, the procurer would acquire the asset at a discount to the existing price in order to ensure that reasonable levels of returns are obtained from the stranded asset. It is highly unlikely that such an asset is acquired at any premium. Generally, it is observed the creditors take a haircut and defaulting project developers have to forgo their equity.

f) Therefore, consideration of acquisition price for tariff determination process would further reduce the revenues and thereby result in continued financial stress against the acquired asset. This would therefore defeat the entire process of revival of the stranded project. It would therefore be unreasonable to consider the acquisition price for the assets acquired under the NCLT process.

g) If lower of acquisition price or historical price is to be considered for tariff determination post-acquisition, the same may be made upfront clear to prospective bidders of the project in the NCLT process. However, this is likely to reduce the takers for acquiring such assets.

h) Further, any additional investment required to make the plant operational, same also need to be considered in tariff.

i) The Approach Paper has highlighted that before finalization of Resolution Plan, wherein no debt servicing was done by utilities, and tariff allowed including such debt servicing need to be considered while determination of tariff for such entities during that period. It is submitted that since tariff is based on historical cost, these issues do not rise and may not be considered in tariff determination. Therefore, specific provision for non-consideration of any additional cost /expenses on account of servicing on loans or liabilities towards procurement of fuel, goods, etc. relating to the past periods in case of truing-up or future tariff determination may be considered.

j) **Therefore, the following is suggested:**

   i. **Historical price may be considered for tariff purpose as consideration of acquisition price would reduce the revenues and thereby result in continued financial stress. This would add further difficulties in process of revival of the stranded project.**

   ii. **It is submitted that since tariff is based on historical cost, these issues do not rise and may not be considered in tariff determination. Therefore, specific provision for non-consideration of any additional cost /expenses on account of servicing on loans or liabilities towards procurement of fuel, goods, etc. relating to the past periods in case of truing-up or future tariff determination may be considered.**

6. Computation of Interest During Construction (7.1.8 of the Approach Paper)

Approach Paper:

The Commission has sought comments with respect to the following:

1. Existing mechanism wherein the pro-rata deduction (based on delay not condoned) is done on IDC beyond SCOD.

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 up to SCOD and period of delay condoned over total implementation period.

3. IDC approved in the original Investment Approval to be considered while allowing actual IDC in case of delay.

NTPC Comments:

1. In cost-plus regulatory framework, the IDC is capitalized and forms a part of the capital cost considered for tariff purposes. In case of delay, IDC is allowed

/ disallowed by the Commission after prudence after considering the justifications and reasons given by the utilities for the project delay.

2. In this regard, the CERC Tariff Regulations, 2019 provides the following:
    a. If the delay in achieving the COD is not attributable to the generating company, IDC and IEDC beyond SCOD may be allowed after prudence check and liquidated damages recovered from the contractor shall be adjusted in the capital cost.
    b. If the delay in achieving the COD is attributable either in entirety or in part to the generating company, IDC and IEDC beyond SCOD may be disallowed after prudence check either in entirety or in part on pro-rata basis corresponding to the delay not condoned and liquidated damages recovered from the contractor shall be retained by the generating company.
    c. The CERC regulations consider controllable and uncontrollable factors for deciding time over-run and cost escalation. Delay in execution of project on account of contractor or supplier or agency of the generating company is considered as controllable.
3. The Approach Paper has sought comments specifically on the methodologies / options for computation of IDC in case of delay in the COD, including consideration of IDC approved in the original investment approval while allowing IDC.
4. Option-1 is the existing mechanism wherein the pro-rata deduction (based on delay not condoned) is done on IDC beyond SCOD. This methodology that is presently followed pro-rates the IDC pertaining to the period of delay beyond SCOD and actual COD (i.e., Y as per the illustration) based on the delay condoned and the total delay beyond SCOD and actual COD. The above methodology has certain shortcomings as elaborated further below.
5. As a certain activity gets delayed, the corresponding fund infusion including debt also gets delayed. The IDC accrued in the initial stages of project execution is less as compared to the IDC accrued in later period. In other words, IDC increases as the debt deployed in the project progressively increases with the progress of the project.
6. Moreover, this methodology assumes that entire delay occurs beyond SCOD, which is not correct. As the delays can be caused anywhere during entire period of project execution, disallowing the IDC beyond the SCOD is not appropriate when the IDC accrual during such period is much higher. This is true in later stages of project since almost full project cost is deployed during this period.
7. It would therefore be appropriate to pro-rate the total IDC based on the period up to SCOD including the delay condoned and actual implementation period up to actual COD, which is option 2 proposed by the Approach Paper.
8. Option 2 is more rational and justified as this assumes uniform spread of the impact of IDC throughout the project implementation period from zero date to actual COD. This is also the case as delays occur throughout the project cycle and is not limited to SCOD. As execution of projects are fraught with high degree of risks, delays may be condoned except in cases where the delay is on account of willful negligence and lack of prudence by the generating company. Without prejudice to the above, it is submitted that Hon'ble Commission may consider option 2 for computation of IDC in case of delay not condoned after prudence check.

9. Further, there is need to limit disallowance of IDC. As rightly recognized by the CERC, delay happens on account of both controllable and uncontrollable factors. While awarding contract, there is a maximum limit of liability to the contractor on account of the default/delay. No contract is viable if there is unlimited liability and there is no mechanism to mitigate such risk by any stakeholders. **Therefore, Hon'ble CERC may limit IDC disallowed to certain percentage of original / revised IDC**.
10. **Approved IDC as per Original Investment Approval -** The Approach Paper has rightly recognized that the approved investment approval cost of any project includes IDC expenses under the no delay scenario. At times, even though the project is delayed, due to prudent phasing of funds, the actual IDC considering the impact due to the delay is well within the approved IDC. The Approach Paper has suggested that to have a pragmatic and holistic approach towards approving IDC, the amount approved in the investment approval may also be considered. It is therefore submitted that in case the actual IDC is less than the IDC as per original / revised investment approval, as the case may be, the same may be allowed. This is because the impact of delay on IDC has been mitigated by prudent phasing of funds adopted by the utility. The deployment of higher equity ahead of debt is generally adopted by the utilities during the initial phases of the project. **Therefore, option 3 is a welcome step and is appropriate considering the prudent management of phasing of funds by the utility**.
11. **Therefore, it is submitted that methodology proposed by the Approach Paper in option 2 may be adopted for computation of IDC in case of delay. Further, in case of delay, option 3 may also be considered and if the actual IDC is lower than the approved IDC as per the approved original / revised investment approval, the actual IDC may be allowed in the capital cost. Further, disallowance of IDC shall be limited to some percentage of original / revised IDC.**

7. Treatment of Liquidated Damages (7.1.9)

It is observed that the current provisions specify that in the event that the delay is not attributable to the generating company or transmission licensee, the additional IDC and IEDC beyond SCOD shall be allowed and the total LD amount collected shall be deducted. Further, in case the delay is fully or partially attributable to the generating station or transmission licensees the additional IDC and IEDC shall be disallowed completely or allowed partially on a pro-rata basis, and the LD amount shall be retained by the generating company or transmission licensee as the case may be.

In this regard, it is observed that APTEL in its Judgment in Appeal no. 72 of 2010 has laid down very specific approach that can be adopted while treating Liquidated Damages.

APTEL has then specified the following method by which delay impacts need to be allowed.

a) If the delay is entirely due to the Implementing Agency's fault, the LD amount collected by it should be allowed to be retained by the Implementing Agency.

b) In case the entire delay is way beyond the control of the Implementing Agency then the entire LD if any shall be deducted before allowing the impact.

c) Under the third scenario, where partial delay is on account of the Implementing Agency and the rest of the delay is due to uncontrollable factors, LD if any, should be shared equally between the consumers and the Implementing Agency.

In view of the same, LD may be accounted for as specified by APTEL.
In addition to above, it is further observed that in the CERC Tariff Regulations, 2019, difficulties have been faced in ascertaining the amount of liquidated damages (LD) to be retained by the generating stations and transmission licensees from the additional capitalisation claim made subsequently as the amount of LD is being adjusted by these utilities from the balance payable and payment is made on net basis to such vendors. In the absence of such clarity in the tariff forms without being supported with auditor certificate there may be chances of double deduction, i.e., first in the form of deduction in IDC and then LD which was supposed to be retained by the utilities which gets adjusted in additional capitalisation. In such cases, utilities are required to declare such adjustments upfront to avoid any double accounting. In order to address this issue, it is proposed that the additional capitalisation forms need to be tweaked so that such information is submitted along with the tariff petition.
In view of the above, comments and suggestions are sought from stakeholders on necessary changes in tariff forms and regulations, if any, to provide further clarity on the adjustment of LD.

NTPC Comment

It is agreed LD may be accounted in accordance with the principles enunciated in the APTEL Judgment in Appeal no. 72 of 2010. However, in case of third scenario, only the part of LD for the delay which is due to uncontrollable factor will be shared equally and remaining LD will be retained by implementing agency.
The Regulation 21 of CERC Tariff Regulations provides for furnishing of details of liquidated damages recovered or recoverable corresponding to delay. If delay is condoned liquidated damages shall be adjusted in capital cost and if delay is not condoned LD shall be retained by generating company. Generating company is already providing the details of LD recovered or recoverable corresponding to delay. Therefore, the existing provisions may be continued.

8. **Price variation – (7.1.10)**

Approach Paper –
It is observed that time overrun due to delay in commissioning of projects not only increases IDC and IEDC; it may also result in increase in the hard cost in case the contract provides for cost escalation beyond SCOD. In such cases, if the impact corresponding to such delay is disallowed for the delay not condoned, it appears logical to extend the same treatment to price variation. Therefore, 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. Comments and suggestions are sought from stakeholders on the above proposal and suggest alternatives, if any.

NTPC Comments:

a) As per 2019 Tariff Regulations, contractual delays are presently classified as controllable and may be disallowed subject to prudence. The Approach Paper has stated that delay in commissioning of projects may also result in the hard cost in case the contract provides for cost escalation beyond SCOD.

b) Contracts can be broadly classified into supply contract and erection contract. Price variation is provided as compensation to the contractor due increase in cost of materials, such as, cement, steel, labour, etc. Supply contracts constitute major portion of the project value. Further, price variation due to delay on part of owner is generally not encountered in supply contracts due to limited pre-requisites to be met by the owner in such contracts.

c) It is submitted that in cases where delay is attributable to the contractor, as per the terms and conditions of the contract, cost escalation due to such delay in contract is not incorporated. Therefore, no price variation or increase in hard cost is allowed on this account. Since most of the controllable delay occur due to contractual issues, such delays do not inflate the hard cost.

d) It is therefore submitted that in most cases of contractual delay, since no additional impact is anticipated on account of price overrun, the present approach to allow the hard cost as incurred by the developer may be continued. Moreover, this would further complicate the prudence of capital cost. Therefore, existing methodology based on prudence of IDC and IEDC (soft cost) may be continued.

e) Even otherwise, it would be necessary to consider savings in IDC, if any, due to delayed draw down of loan vis-à-vis the original schedule.

9. R&M - 4.6

Approach Paper –

Regulation 27 of the CERC Tariff Regulations, 2019 allows generating stations or transmission licensees to opt for R&M for the old generating stations and transmission systems that have outlived their useful life with the consent of the beneficiaries. The provisions also specify the manner in which such costs shall be considered for tariff purposes once cost reasonability is ascertained based on the residual life assessment and cost benefit analysis submitted along with the petition. Further, CEA, with an objective to maximise generation with efficiency enhancement, has already issued guidelines for R&M of Hydro and Thermal generating stations that need to be followed.

As R&M allows the deferral of huge capital investments on the construction of new capacities and avoids seeking fresh approvals and clearances, it is a cost-effective alternative and hence has been allowed in the past. In addition to the above, Regulation 28 of the CERC Tariff Regulations, 2019 provides for Special Allowance in lieu of R&M. Presently, the utilities have the option to choose between Special Allowance or to undertake R&M. In this regard, it is felt that in the event that an utility intends to undertake R&M, the same cannot be an abrupt choice as it

requires proper planning, and therefore, appropriate provisions may be provided wherein any utility that has opted for
Special Allowance for the first year of the tariff period shall have to continue with the same for the rest of the tariff period. In view of the inherent benefits of undertaking R&M as against going for fresh capital investment, the current provisions may be continued. Further, utilities that opt for a special allowance for the first year of the tariff period shall have to continue with the same for the rest of the tariff period. ***Comments and suggestions are sought from stakeholders on continuation of the existing provisions and on the above suggestion of continuing with Special Allowance, if opted at the beginning of the tariff period for the rest of the tariff period.***

NTPC Comments

a) The proposal of the Approach Paper to continue with the current options available to units that have completed 25 years from COD, namely R&M and Special Allowance is a welcome step considering the inherent benefits of sustained generation from the existing thermal fleet as against going for fresh capital investment.

b) As R&M allows the deferral of huge capital investments on the construction of new capacities and avoids seeking fresh approvals and clearances, it is a cost-effective alternative and hence has been allowed in the past. Only when R&M is not a techno economically viable or in case of old and obsolete units, such units need to be phased out.

c) The option of Special Allowance was introduced first in the 2009-14 tariff period and has been continued in successive tariff periods as it a sustainable and cost-effective approach. Special Allowance has been effective mechanism for carrying out need based R&M in old units so that they are well maintained and continue to operate efficiently without the need of relaxed norms. These units are required to provide base load and balancing requirements for RE integration. Therefore, proposal of the Approach Paper for continuing with Special Allowance, if opted at the beginning of the tariff period for the rest of the tariff period is acceptable dispensation for the generators and discoms.

d) In case of NTPC coal-based stations which have completed 25 years from COD, Special Allowance has been opted in most of the cases. This is also cost effective and economical for the Discoms as there is no revision in capital cost. Further, Special Allowance is suitable and yields very well to normative approach to tariff, as there are no need file specific petitions for obtaining consents / approvals seeking approval of capital expenditure. Therefore, option of Special Allowance is required to be continued in the next tariff period.

e) **<u>It is submitted that there should not be any revision in capital cost for tariff purposes on account of special allowance. Presently, the capital cost gets eroded gradually due to old assets being replaced by new assets funded through special allowance due to decapitalization of old assets. It is therefore suggested that the deletions also may not be done for tariff purposes for such assets.</u>**

f) As per 2019 Tariff Regulations, the option of Special Allowance is not available for a generating station or unit thereof for which renovation and modernization has been undertaken and the expenditure has been admitted by the Commission before commencement of these regulations, or a generating station or unit which is in depleted condition or operating with relaxed norms. However, there is no restriction on shifting from special allowance to R&M.

g) The Approach Paper has opined that in the event that an utility intends to undertake R&M, the same cannot be an abrupt choice as it requires proper planning, and therefore, appropriate provisions may be provided wherein any utility that has opted for Special Allowance for the first year of the tariff period shall have to continue with the same for the rest of the tariff period. As Special Allowance dispensation is annually applicable, it is felt that flexibility may be given to shift from special allowance to R&M within the control tariff period. Therefore, it is suggested that the present provisions of the Regulation 28 may be continued in this regard.

h) It is submitted that planning and execution of need-based works under special allowance takes around 3-4 years from conceptualization to final completion of the required works. This lag in commissioning the schemes out of funds received through Special Allowance may be appreciated by Hon'ble Commission. Continuation of Special Allowance would provide regulatory certainty for the schemes already in implementation from 2019-24 tariff period that are expected to be completed in the next tariff period.

i) As the Indian power sector is undergoing a transition from thermal to renewable sources of energy, the thermal fleet is expected to contribute increasingly to peaking operations, balancing, and flexing to absorb the intermittent renewable energy generation. In the emerging operational regime with high RE penetration more wear and tear are anticipated in thermal units due to flexing. The need for incentivizing old stations has been dealt separately in the Approach Paper and our comments on the same have been elaborated in detail there.

j) In the context of special allowance norm, it is submitted that additional Special Allowance is required for incurring capital expenditure on necessary modifications for enhancing the flexibility of the thermal fleet. It is therefore submitted that Hon'ble Commission may consider the above factor while fixing the norms of special allowance the above factors. Further, suitable annual escalation may be provided in the norms of Special Allowance in line with the escalation factor prevailing during 2009-14 and 2014-19 tariff periods.

k) Therefore, the following is suggested:

i. To continue with the existing provisions of R&M / Special Allowance on completion of 25 years from COD considering the efficacy and benefits of the dispensation.

ii. As Special Allowance dispensation is annual mechanism, flexibility may be given to shift from special allowance to R&M within the control / tariff period.

iii. There should not be reduction in capital cost for tariff purposes due to decapitalization in case of replacement of assets funded through special allowance.

iv. To enhance Special Allowance norm considering the need for incurring capital expenditure on necessary modifications for enhancing the flexibility of the thermal fleet.

v. **To reintroduce suitable annual escalation in the norms of Special Allowance in line with the escalation factor prevailing during 2009-14 and 2014-19 tariff periods.**

10. Initial Spares - 4.7

Approach Paper

The Commission, in its Explanatory Memorandum to the draft Tariff Regulations for 2019-24 observed as follows.

> *"2.5.7 It is noticed that there is not much difference between the initial spares of green field and brown field substations. Further, the initial spares of all compensation devices including series and shunt compensation and HVDC are kept at the same. The Commission proposes to maintain same level of initial spares for green field and brown field substation."*

The Commission accordingly removed the distinction between green and brown field projects and specified the draft norms. However, on the basis of comments received from various stakeholders, the Commission while finalising the norms in its Statement of Reasons observed as follows.

"…..The stakeholder submitted detailed reasons for the need of higher ceiling norms for brown filed substations, both AIS and GIS. Further, for new technology equipment, which are fewer in numbers and are generally manufactured and supplied by foreign manufacturers, there is a need to provide higher initial spares norms. The Commission, after considering the suggestions made by the stakeholders, revised the provision by allowing separate initial spares norms for AIS Sub-station (Brown Field) at 6% and GIS Sub-station (Brown Field) at 7% and increasing the norm for Static Synchronous Compensator from 3.5% to 6%."

It is observed that there are eleven (11) separate categories and sub-categories pertaining to ceiling norms for initial spares. A need is felt to simplify the classifications, and further, a single norm for green and brown field projects can also be considered. It is further observed that the use of HV underground cables is now increasingly common in ISTS systems for which there are no separate norms to allow initial spares and may require appropriate provisions allowing the same. Alternatively, as not much actual data is available, it may also be considered on an actual basis, subject to prudence check. In view of the above, a single norm can be considered for each of the following classes of transmission assets:

1. *Transmission Lines, including HVDC lines*
2. *Substations (including HVDC S/s)*
3. *Dynamic Reactive Compensation devices*
4. *Communication Systems*
5. *Underground cable*

Comments and suggestions are sought from stakeholders on the above proposed approach and alternative options to standardise and simplify the norms for initial spares.

NTPC Comments:

a) The CERC Tariff Regulations 2019 provides for ceiling norms for Initial Spares @ 4% of the plant and machinery cost for coal and gas stations. The plant and machinery cost considered for the ceiling norms is the original project cost excluding IDC, IEDC, land cost and cost of civil works. Initial spares if procured and capitalized within cut-off date are admitted under regulation 24, i.e., additional capitalization within the original scope of work and up to cut-off date.

b) The generator executing a project is faced with a host of risks in the scenario, where land acquisition is becoming the biggest challenge. Due to the constraints being faced OEM / OES for meeting the requirement of generators for COD of the projects, supply of initial spares is often delayed, and generators are not able to capitalize the entire initial spares is not capitalized within the cut-off date even though procurement action is initiated well ahead in time. Considering that Initial Spares are essential for reliability of supply, such expenditure should not be barred by the restriction of cut-off date. Therefore, extension of cut-off date proposed by Approach Paper will facilitate procurement and capitalization of initial spares within the cut-off period. However, it is requested that Commission may provide relaxation in cases where action for procurement has been initiated but spares have not been received by cut-off date due to delay due to OEM / OES.

c) **Following options are suggested for admitting initial spares:**
   - **i. Cut-off date may be extended from existing 3 to 5 years, as proposed by the Approach Paper.**
   - **ii. Subject to ceiling norm of 4% of the plant and machinery, relaxation may be provided in cases where action for procurement has been initiated within cut-off date but spares have not been received by cut-off date due to delay by OEM /OES.**

11. Controllable and uncontrollable factors – (7.1.13)
Approach Paper

4.8.1 Delay towards obtaining Forest Clearance - The Commission, while framing the CERC Tariff Regulations, 2019, in its Explanatory Memorandum, observed as follows.

"2.5.5 The Commission has observed while dealing with tariff petitions, that matters pertaining to acquisition of land or getting right of way, have become one of the main causes of delay in commissioning of projects. In the existing 2014 Tariff Regulations, only force majeure and change in law have been specifically identified as uncontrollable factors. However, the Commission has noticed that land acquisition and Right of Way issues have been largely outside the control of the project developer and accordingly, the Commission has also been condoning the delay and allowing the associated cost to form part of the capital cost. In the light of these practical issues, the Commission has proposed to include time and cost over-runs on account of land acquisition, as an uncontrollable factor, except where the delay is attributable to the generating company or the transmission licensee…"

For the reasons mentioned above, the Commission included the delay on account of land

acquisition in the list of uncontrollable factors along with Change in Law and Force Majeure.

In this regard, it has been observed during the current period that, apart from land acquisition, delays on account of getting forest clearances may also be many times beyond the control of utilities and therefore have been condoned in the rightful cases. In view of the same, delays on account of forest clearances can also be considered for inclusion as uncontrollable factor provided that such delays are not attributable to the generating company or the transmission licensee.

Comments and suggestions are sought from stakeholders on continued inclusion of delay on account of land acquisition as an uncontrollable factor and on the further inclusion of delay on account of forest clearances as an uncontrollable factor.

NTPC Comments

a) **Land Acquisition -** Land acquisition poses significant challenges and obstacles in infrastructure projects, causing delays that surpass the expected timelines. Land acquisition is involved in power projects such as green field thermal generation projects, captive mines, right of way for laying transmission lines and pipelines, land corridor for railway line approach to railway siding and construction of dedicated merry go round coal conveying system, etc. Acquisition of land includes both government land and private land, and even after payment of prescribed compensation, taking possession of land is often delayed by agitations, claims of owners, involvement of vested groups, etc. Stakeholder consent requirement and compensation issues further compound the challenges associated with the acquisition process. Obtaining environmental and local clearances from relevant authorities consumes considerable time due to elaborate consideration of environmental factors, legal title verification, government land allocation, adherence to state regulations, and other complexities. Moreover, the absence of digitized land records in most states hinders the efficient retrieval and verification of essential information, contributing to further delays. These factors highlight the pressing need for streamlined processes and improved digitization efforts to expedite land acquisition and promote timely infrastructure development, where much is still lacking. **Therefore, it is required to continue inclusion of delay in land acquisition as uncontrollable factor.**

b) **Forest Clearances -** Forest clearances are also time taking process and subject to environmental regulations, impact assessments. In many cases these are often delayed by oppositions and objections by various environment groups. Forest clearances are more frequently encountered in mining, hydro projects, transmission lines, etc. **Therefore, in addition to land acquisition, forest clearance clearly falls under uncontrollable factors and has been rightly highlighted by the Approach Paper. Therefore, forest clearance may be included as uncontrollable factor.**

c) **Contractual Issues –**

   i. The existing CERC Tariff Regulations 2019 considers delay in execution of the project on account of the contractor or supplier or agency of the generating company as controllable factor.

   It is submitted that delays due contractual issues need to be seen in the proper context of overall project execution environment in the country. In the present scenario, the execution of thermal projects is fraught with a host of risks, which are beyond the control of the generating company. The entire process of project development broadly consists of the structuring of contracts, options / mechanism for allocation of risk, and mitigation of risks with the overall objective of completing the project on schedule.

   Structuring of contracts - Allocation of risks is done through the contract structuring. Contractual terms provide safeguards for compliance of timelines by Suppliers / contractors. As a safeguard to ensure that the Successful bidder(s) adheres to the contractual terms and project timelines, following safeguarding provisions are provided in the contracts such as **Earnest Money Deposit (EMD), Performance Bank Guarantee (PBG)**, **Liquidated Damages (LD) and Termination of Contract** .

ii. **Allocation of Risk -** To ensure timely completion of projects, there are measures like Liquidated Damages (LD) in the contract. These deterrence measures are adopted for allocating apportion of risk to the contractors. For instance, the percentage of LD is generally fixed at 5%-10% of the contract value. In case a higher consideration of LD is proposed in contract, the same will have ramifications on the prices quoted by the bidders who would load the cost of the products/services upfront by such amount. Therefore, higher loading of risks on the contractor / vendor / agency will result in higher prices which would not be overall interest of the Discoms. Disproportionate allocation of risk is not desirable. Therefore, significant risk has to be retained with the project developer. Often project delay is caused by a small contract in the entire project, whose contract value may be very small as compared to the project cost. As delays have a cascading effect, the overall impact may be significant. It is not possible for a contractor to assume unlimited liability of project delay.

iii. The uncontrollable aspects of contractual delay are elaborated as under:

a. **Poor performance by agencies due to deterioration in their financial condition during course of execution of project –** In some cases, it has been observed that the performance of reputed agencies with established track record at the time of award has deteriorated mainly due to financial problems. Some of such cases have also referred to NCLT.

b. **Shortage of contractors -** Shortage of contractors operating in certain areas of thermal power sector due to various reasons, such as NCLT, shifting of focus of some contractors from thermal to emerging and more attractive renewable energy sector, etc. Therefore, paucity of contractors often restricts the generating company to award the jobs to available contractors.

c. **Competitive Vendor Selection process adopted by NTPC -** NTPC, with a comprehensive vendor enlistment system, follows a stringent competitive bidding process to identify and engage with suppliers and service providers. Vendors must fulfil the Qualifying Requirements such as technical competence, price competitiveness, past performance, financial stability, compliance with specifications, delivery timelines, and quality assurance measures, specified in the Notice Inviting Tender (NIT) and Special Purchase Conditions (SPC). Evidently, the contract procedures adopted by NTPC ensure highest level of transparency, robustness to ensure only technically sound and financially viable bidders participate in the tender process and rates are discovered in the most competitive manner.

d. **Contractual Terms provides safeguards for Compliance of timelines by Suppliers -** To ensure that the successful bidders adhere to the contractual terms and project timelines, NTPC has safeguarding provisions like Earnest Money Deposit (EMD), Performance Bank Guarantee (PBG), Liquidated Damages and Termination in its contract. The contract documents provide unequivocal terms which are mutually agreed upon by the contracting parties before the start of the projects.

e. **Viability of Exercising Unilateral Termination -** Termination process is complex and involves settling of the rights and liabilities of the respective parties to the contract. If the termination is applied through mutual consensus, then dispute resolution mechanism method can be invoked. In case of absence of consensus (Unilateral Termination), Arbitration clause can be invoked. Unilateral termination of the Contract can have grave legal ramifications till the matter attains finality. Termination in itself a lengthy process and quite subjective as well. The termination essentially brings generating company again into the same position as was earlier before initiating termination process and timely completion of the works as envisaged cannot be undertaken resulting into such delay which is clearly not controllable.

f. **Time and Complexity involved in Reappointment of Vendors is significant and is Uncontrollable -** Even after termination of the contract, it is still not possible for selecting a vendor in the current power development landscape. Reappointment of vendor is a time-consuming process. Normally the re tendering process takes up to 10-12 months, right from site evaluation to selection of new contractor. Majority of BTG and BOP suppliers are facing financial stress, pending order books, and undergoing diversification. Especially in BOP space where many companies have gone bankrupt, increasing the complexities. It needs specific mention that the replacement of BTG contractor is prohibitive owing to the very fact that establishing oneself as a BTG market player is a long-drawn process. The Boiler Turbine units being the heart of a thermal power station are designed to perform on critical operational parameters which is based on the proprietary technology developed by such manufacturer. Needless to say, that such technology is unique to each BTG (boiler or Turbine) player. Furthermore, the civil works associated around any specific BTG unit is also unique based on the Boiler and Turbine construction and design.

g. **LD Provisions may not substitute recovery of Regulatory Disallowances -** Provisions such as levy of Liquidated Damages or encashment of Bank Guarantee act as a deterrent to ensure due performance of the Contractor in the stipulated time frame. Claims related to levy of damages on Contractor makes the determination of such matters even more complicated and subjective in absence of any specified process/formula for levy of damages. Further, the LD liability for contractors on account of delays is limited to ~5% as stated above which is also open to dispute before the arbitrator and higher courts. Therefore, the there is a limited liability on contractors on account of delays whereas, NTPC or any generating company has an unlimited liability on account of the same delay. The Regulator needs to appreciate this fact or else the generating company would not be able to operate its plants in a sustainable manner if such unlimited liability is laden on it. Courts construe the provisions of LD quite differently vis-à-vis the fixed approach adopted under Tariff Regulations which out rightly consider all contractual issues as Controllable. On the contrary, in spite of keeping appropriate contractual provisions delays on account of contractor remain essentially uncontrollable and needs to be decided on a case-to-case basis.

h. **Projects under Section 62 do not factor any plausible margin for time and cost overruns -** Public sector enterprises are subject to audit by the CAG and have to ensure prudency and transparency in all its processes, planning and implementation mechanisms. An upfront consideration of cost and time overruns would essentially mean that the organization is factoring in inefficiency in cost/project timelines without passing through the test of regulatory scrutiny.

iv. The observations of the Hon'ble Appellate Tribunal (APTEL) (Judgement dated 24th April, 2011 in Appeal 72 of 2010) provides the guiding principles for evaluating Contractor related time overruns. The relevant excerpt of the aforesaid Order is reproduced as under; *"i) due to factors entirely attributable to the generating company, e.g., imprudence in selecting the contractors/suppliers and in executing contractual agreements including terms and conditions of the contracts, delay in award of contracts, delay in providing inputs like making land available to the contractors, delay in payments to contractors/suppliers as per the terms of contract, mismanagement of finances, slackness in project management like improper co-ordination between the various contractors, etc. ii) due to factors beyond the control of the generating company e.g. delay caused due to force majeure like natural calamity or any other reasons which clearly establish, beyond any doubt, that there has been no* *imprudence on the part of the generating company in executing the project."*

v. **In spite of exercising all due diligence and prudence by the generator, delay due to non-performance of contractor needs to be considered as uncontrollable. In view of the above, it is suggested that only contractual delays that are attributable due to the generating company as per the guiding principles in APTEL judgement dated 24th April 2011 may be categorized as controllable factor.**

vi. **In view of the above, following amendment in the CERC Tariff Regulations may be considered with respect to the Contract related delays.**

a. **It is suggested to add another clause to the uncontrollable factors i.e., regulation 22 (2) (d). - *"22 (2) (d). Contractual related issues not attributable to generating company or transmission licensee including but not limited to non-performance of contractor due to NCLT, supply disruptions, change in legal status of vendors, insolvency of contractors, termination and retendering, etc. leading to delay in projects."***

12. Differential Norms - Servicing Impact of Delay (7.1.14)

Approach Paper

The Commission has sought comments with respect to the following:

1. 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.

2. Alternatively, RoE corresponding to cost and time overruns allowed over and above project cost as per investment approval may be allowed at the weighted average rate of interest on loans instead of a fixed RoE.

3. The current mechanism of treating time overrun may be continued, considering that utilities are automatically disincentivized if the project gets delayed.

NTPC Comments:

1. The Commission, while approving the capital cost undertakes a detailed assessment of the reasons for delay and accordingly condones the delay which was outside the control of the developer. While undertaking such prudence, every aspect of delay is scrutinized and verified based on supporting documents. Only after the Commission is satisfied, the delay is condoned. Based on the delay condoned, the Commission pro-rates the IDC/IEDC incurred during the delay period resulting in disallowance of such costs. While the generators are only being allowed a partial cost to be recovered (to the extent of delay condoned), the proposal for further deduction of an amount equivalent to 20% of the cost impact is irrational and unjustified.
2. The Approach Paper has observed that it is not possible to ascertain if adequate efforts were made at the senior level to get the clearances. It may be pertinent to

mention here that despite of challenges involved in implementation and completion of projects, the management of generating company is putting its best efforts for completing the project as per envisaged timelines as they have committed to undertake the project and deployed capital towards the project. Due to adoption of best project management practices, the delay in project completion is being reduced significantly as compared to the roadblock faced during the erection stage. Meetings and correspondence at various levels are done and issues are often escalated at appropriate higher forums for effective and quick resolution. Therefore, it may not be appropriate to conclude lack of assertive and rigorous approach because the same cannot be ascertained.

3. The Approach Paper has suggested that Forest clearance is uncontrollable and proposed to add the same. It is a welcome step and most required for generation projects, transmission projects and particularly in captive mines. In view of the above, considering delays due to statutory approvals and clearances as uncontrollable, it would not be consistent approach to condone such delays and at the same time disallow 20% of allowed cost. It is suggested that delays condoned must be recognized as legitimate project cost which is incurred prudently and serviced at par with the admitted capital cost.
4. In this regard, reference is drawn to APTEL judgment which elaborates the approach to be followed for prudence of capital cost in detail. The Appellate Tribunal for Electricity (the Tribunal) in its judgment dated 27.4.2011 in Appeal No. 72 of 2010 (MSPGCL V MERC & ors) has laid down the following principles for prudence check of time overrun and cost overrun of a project as under:

   "In the absence of specific regulations, we will now find answer to the question raised by us relating to prudence check of time overrun related costs. 7.4. The delay in execution of a generating project could occur due to following reasons:
   i) due to factors entirely attributable to the generating company, e.g., imprudence in selecting the contractors/suppliers and in executing contractual agreements including terms and conditions of the contracts, delay in award of contracts, delay in providing inputs like making land available to the contractors, delay in payments to contractors/suppliers as per the terms of contract, mismanagement of finances, slackness in project management like improper coordination between the various contractors, etc.
   ii) due to factors beyond the control of the generating company e.g. delay caused due to force majeure like natural calamity or any other reasons which clearly establish, beyond any doubt, that there has been no imprudence on the part of the generating company in executing the project.
   iii) situation not covered by (i) & (ii) above.
   In our opinion in the first case the entire cost due to time over run has to be borne by the generating company. However, the Liquidated Damages (LDs) and insurance proceeds on account of delay, if any, received by the generating company could be retained by the generating company.

   In the second case the generating company could be given the benefit of the additional cost incurred due to time over-run. However, the consumers should get full benefit of the LDs recovered from the contractors/suppliers of the generating company and the insurance proceeds, if any, to reduce the capital cost.
   In the third case the additional cost due to time overrun including the LDs and insurance proceeds could be shared between the generating company and the

consumer. It would also be prudent to consider the delay with respect to some benchmarks rather than depending on the provisions of the contract between the generating company and its contractors/suppliers. If the time schedule is taken as per the terms of the contract, this may result in imprudent time schedule not in accordance with good industry practices.

In our opinion, the above principles will be in consonance with the provisions of Section 61(d) of the Act, safeguarding the consumers' interest and at the same time, ensuring recovery of cost of electricity in a reasonable manner. "

5. As per the above judgment in case of delay not accountable to generators, the additional cost needs to be given to generators for balancing the interest of both generators and consumers as per Tariff Policy. It is reiterated that as per the Tariff Regulations, the generators are not eligible for ROE during the construction phase resulting in direct losses for any delay caused due to controllable or uncontrollable parameters. Further, delay in project also increases the interest burden on the generator which to the extent of delay not condoned is not allowed for tariff purposes.
6. The approach paper has rightly recognized the associated risks and adverse impact faced by generators due to project delay and has observed that " *In order to study the impact of an increase in gestation period on equity IRR, workings were carried out, and it was observed that if a project that was to be executed in 5 years is executed in 7 years with a 2 year delay, even if RoE is allowed at 15.50% and the entire delay is condoned, the Equity IRR reduces from around 12% to 11% and for every subsequent year of delay, the Equity IRR reduces further."*
7. Many upcoming projects have been delayed due to various reasons beyond the control of the generator. Although consistent efforts are put to commission the projects as per the schedule, delays due to law-and-order issues, pandemic, land acquisition, R&R issues, contractual issues beyond control of the generator are witnessed in almost all projects. The effective return on equity gets eroded significantly with every year of delay.
8. Therefore, there are significant losses accruing to the generator both in form of the loss of return as well as uncertainty / risk over condonation in delay by the Commission leading to disallowance in IDC/IEDC.
9. If implemented, such provisions will have a detrimental impact on the project developer's financials and returns and shall discourage development of thermal plants. Already the difficulties and risks related to setting up of thermal generating stations are very high due to climate concerns. Attractiveness to set-up thermal generating stations have reduced significantly due to long gestation period and other hurdles such as clearances, water requirement, ash disposal, coal availability, etc. Provisions such as these would further demotivate the developers to undertake any thermal projects.
10. Further, disallowance of any cost beyond SCOD if it was established that there has been no imprudence on the part of the generating company in executing the project, is not in line with the APTEL Judgment dated 27.04.2011 in Appeal No 72 of 2010.
11. Also, considering weighted average rate of interest on loans corresponding to cost and time overruns allowed over and above project cost would be imprudent and against the regulatory principles established by CERC and APTEL if the delay is found to be beyond the control of generator company. Such a provision may be considered in case project cost is disallowed after prudence due to controllable factors to facilitate debt servicing of assets as these will continue to serve the

Discoms throughout the life. Any way generators are penalized due to lower returns and deprivation of return on equity.

12. **Therefore, the existing approach with respect to treatment of time overrun should be continued wherein all costs allowed after prudence are serviced at par with no differential treatment or token penalty, as this has been the consistent regulatory practice followed by the Commission since its inception. This would ensure consistency and certainty in the regulatory approach.**

13. **Additional capitalization – (7.1.15)**

Approach Paper

As per CERC Tariff Regulations, 2019, additional capitalisation for generating stations and transmission licensees is allowed under the following main categories.
1. Additional Capitalisation within the original scope of work executed up to cut-off date
(Regulation 24).
2. Additional Capitalisation within the original scope of work executed after the cut-off
date, including replacement under certain conditions. (Regulation 25).
3. Additional Capitalisation beyond the original scope of work includes increased need for safety and security, Change in Law, Arbitration Award, Force Majeure, deferred works related to the ash handling system. (Regulation 26).
4. Additional Capitalisation on account of Renovation & Modernisation. (Regulation 27).
5. Additional Capitalisation on account of revised emission standards. (Regulation 29).

It is however observed that the above provisions under which additional capitalisation is allowed is for specific works that are part of the original scope of work, are to carry out R&M, pertain to ash handling, are required due to uncontrollable factors such as a change in law or force majeure. It is further observed that Regulation 19(3)(e) of the CERC Tariff Regulations, 2019 specify that the capital cost of any existing generating station shall include the cost of railway infrastructure and its augmentation for the transportation of coal up to the receiving end.

However, there are no enabling provisions under which a generating station can seek approval of costs pertaining to Railway Infrastructure and its augmentation for transportation of coal up to the receiving end of the generating station (excluding any transportation cost and any other appurtenant cost paid to railways) that are not covered under the above provisions that may result in better fuel management, can lead to a reduction in operation costs, or shall have other tangible benefits. ***Therefore, in order to have an enabling provision under which such additional capitalisation can be allowed with prior approval, a provision may be introduced to existing Regulation 26 to allow such expenses if they are found to be beneficial/essential for continued operations.***

Comments and suggestions are sought from stakeholders on the above and any other ways to address the issue flagged above.

NTPC Comment:

a) According to Regulation 19(3)(e) of the CERC Tariff Regulations, 2019, the capital cost of an existing generating station / new projects should cover the expenses related to railway infrastructure and its enhancement for transporting coal to the receiving end. However, there are no corresponding enabling provisions under the Regulation 26 - Additional Capitalization beyond the original scope of work, through which an existing generating station can seek approval of costs pertaining to railway infrastructure and its augmentation for transportation of coal up to the receiving end of the generating station.

b) Implementation of the railway infrastructure for thermal stations is required to ensure smooth transportation of coal up to the receiving end. Such systems would enable to build the last mile connectivity for seamless transportation of coal up to the receiving end, optimize operational costs through better fuel management.

c) Without this enabling infrastructure, the station may not to be able to achieve target availability and meet the demand of the Discoms. This will result in under recovery of annual fixed charges. The option of arranging coal through alternate modes in the last mile often leads to various issues and results in sub optimal fuel management. For instance, transportation through road may not be as efficient as the rail transport.

d) At some plant sites, Indian Railways is unable to strengthen the rail infrastructure up to the receiving end of the power plant due to other priorities and shortage of funds resulting in increased cost of transportation for the generating plants. In such cases, the generator has no other option but to finance the required infrastructure through customer funding model. Without the required infrastructure, the generating company shall not be able to give DC and thus face under recovery of AFC.

e) Therefore, servicing of capex towards rail infrastructure under Add Cap would enable the generators in improving the end mile connectivity and achieve optimal fuel management. This will facilitate improvement in domestic coal movement to generating stations and benefit the Discoms by way of reliable supply of power at optimal tariff. The benefit of reduction in costs would get be passed on to the beneficiaries.

f) Under this additional capitalization, augmentation / additional installation of coal unloading facilities, in case of change in type of coal supply rake, may also be included.

I. **Therefore, inclusion of "Cost towards Railway infrastructure augmentation" in existing provisions of additional capitalization beyond original scope of work (Regulation 26) would be a long-awaited step to operationalize the provision already provided in capital cost (Regulation 19(3)(e)) and shall reduce logistic challenges with respect to transportation of coal and facilitate smooth transportation of coal up to the receiving end of the station. This will result in better fuel management and overall reduction in costs due to the optimization shall benefit the Discoms by way of lower tariff.**

II. **A thermal generating station may have to incur capital expenditure for developing certain infrastructure which may include the following:**
    i. **Smooth fuel transportation up to the receiving end of the station.**
    ii. **Water supply to the generating station.**
    iii. **Ash disposal and utilization as per MOEF Notifications / Statutory Notifications.**

In certain cases, some of these assets may not be owned by the generating company. However, such expenditure is required to be done by the generating company. Suitable enabling provisions need to be provided in regulations to deal with such requirements.

III. In order to increase flexibility of thermal fleet, modification in existing plant is mandatory. Moreover, alternate solution like integration of Thermal energy storage may be deployed to support flexibilization of coal based thermal plant. In view of above, additional capitalisation under the head of biomass/ ammonia/ methanol co-firing, CCUS and integration of thermal energy storage need to be included.

Approach Paper:

It is observed that additional capitalisation under Sr. No.1 relates to additional capitalisation up to the cut-off date and pertains to works that are generally within the original scope of work and are relevant and incurred by both generating stations and transmission licensees. These expenses are incurred mainly for deferred works and the discharge of liabilities for works already executed. As these expenses are required to be analysed only once in the project life cycle, the current practice of allowing the same on an actual basis may be continued subject to a prudence check.

Further, with regard to additional capitalisation under Sr. Nos. 3, 4 & 5 above, which are nonrecurring and generally require substantial expenses to be incurred, the current practice of allowing the same on an actual basis may be continued as such non-recurring and heterogeneous expenses cannot be translated into norms.

However, additional capitalisation under Sr. No. 2 are generally not substantial but recurring in nature, and it has been observed that the same, for one reason or another have been recurring time and again, which is one of the prime reasons for which the entire exercise of tariff determination of hundreds of assets is done twice in the same tariff period. As the entire exercise does not have big impact on tariffs, possible options, if any, need to be explored to eliminate the need for such an elaborate exercise.

4.10.1. Normative Add-Cap - Generating Station

1. Existing Generating Stations – These generating stations can further be classified into the following two sub-categories.

a) Existing generating stations with a cut-off date on or before 31.03.2024.

b) Existing generating stations whose cut-off date shall fall in the upcoming tariff block 2024-29.

2. New Generating Stations – Generating stations that shall achieve COD in the next tariff block, i.e., 2024-29.

For generating stations that have already crossed the cut-off date as on 31.03.2024, the additional capitalization for such generating stations can be considered as per the following.

1. *Thermal Generating Stations – Based on the analysis of actual additional capitalisation incurred by such generating stations in the past (15-20 years) and co-relating such expenses to different unit sizes such as 200/210 MW series, 500/660 MW Series and different vintages (5-10, 10-15, 15-20, 20-25 years post COD), a special compensation in the form of yearly allowance may be allowed*

based on unit sizes and vintage, which shall not be subject to any true up and shall not be required to be capitalised.

2. *Hydro Generating Stations - As each hydro generating station is unique owing to various factors, additional capitalisation of such generating stations may not be benchmarked as can be done for thermal generating stations. However, in the case of a specific hydro generating station, the additional capitalisation is recurring in nature, and hence station wise normative additional capitalisation may be approved in the form of special compensation which shall not be subject to any true up and shall not be required to be capitalised.*
3. *While determining such special compensation for a thermal or hydro generating station, costs incurred towards works presently covered under Regulation 26 to Regulation 29, wherever applicable, may not be included as these expenses may be allowed separately.*
4. *Further, any items that cost below Rs. 20 lakhs that may be in the nature of minor items such as tools and tackles, and those pertaining to Capital Spares may be allowed only as part of O&M expenses and may not be considered as part of additional capitalisation in case of both thermal and hydro generating stations.*
5. *Further, discharge of liabilities of works already admitted by the Commission as on 31.03.2024 may be allowed as and when such liability is discharged.*

Further, for generating stations whose cut-off date falls in the next tariff block (2024-29), or are expected to achieve COD after 31.03.2024, the following approach can be adopted.

1. *By extending the cut-off date from the current 3 years to 5 years, which shall allow time to close contracts and discharge liabilities and eliminate the need to allow additional capitalisation post cut-off date unless in the case of Change in Law and Force Majeure.*
2. *However, based on past data of similar existing generating stations, if there is a need to allow additional capitalisation that may be legitimately required post cut-off date other than those presently allowed under Regulation 26 to 29, the same may be allowed as special compensation as proposed in the case of existing station that have crossed the cut-off date.*
3. *While determining special compensation for a thermal or hydro generating station, costs incurred towards works presently covered under Regulations 26 to 29, wherever applicable, may not be included as these expenses may be allowed separately.*
4. *Further, any item that costs below Rs. 20 lakhs that is in the nature of minor assets, including Capital Spares below Rs 20 lakh, can be allowed only as part of O&M expenses, and may not be considered as part of additional capitalisation in case of both thermal and hydro generating stations. Further, any major capital spares costing above Rs. 20 lakh may form part of the special compensation.*
5. *Further, discharge of liabilities of works already admitted by the Commission as on 31.03.2024 may be allowed as and when such liability is discharged.*

Comments and suggestions are sought from stakeholders on the above suggested approaches and other alternatives, if any.

NTPC Comment:

a) The existing approval process for Additional Capitalization in power generating stations is elaborate and time-consuming process. Petitions are filed by generating company seeking approval of additional capitalization on projected basis for the tariff period at the beginning of the tariff period. Admitted additional capitalization forms part of the capital cost and is serviced through tariff. However, considering that large number of stations are involved and first truing up of last tariff period has to be done, tariff determination has become time taking exercise and usually takes 2-4 years. The determination of tariff is time taking as this involves filing of petitions, scrutiny of the petitions, replies by discoms and hearing process and prudence of actual add cap by the Commission.

b) Therefore, simplification of the tariff approach through normative Additional Capitalization is a welcome step and would to be a beneficial proposition in view of the exclusion of the approval process required. This would result in simplification of the tariff determination process to a large extent and reduce the regulatory burden of Hon'ble Commission. The efforts and time spent by generating companies in filing of tariff petitions for approval of projected additional capitalization in the beginning of the tariff period and true up after the tariff period can be reduced by normative Additional Capitalization.

c) The Approach Paper has proposed an approach of providing a normative Add Cap for additional capitalization within original scope of work and beyond cut-off date. The norm for additional capitalization is proposed based on benchmarking of actual additional capitalization incurred by generating stations in the past years (15-20 years) and co-relating those with size and vintage.

d) The approach of normative additional capitalization is based on the principle of reimbursement of expenses and that there would be no revision in the capital cost. Therefore, it is presumed that capital cost would be frozen as on cut-off date for new projects and as on 01.04.2024 for existing projects.

e) Therefore, in order to arrive at a representative norm of additional capitalization, it is suggested that the norm may be fixed so that the generating company is in the same economic position vis-à-vis the existing dispensation of servicing through capital cost. Further, the norms need to be arrived after considering the impact of inflation on past actual data. Annual escalation factor may also be provided for 2024-29 period.

f) Although the normative additional capitalization may suffice the requirements in most of the cases, there could be certain exceptions due to exigencies and unforeseeable factors. As in a cost-plus framework, all costs prudently incurred needs to be serviced, it is suggested to incorporate a regulatory mechanism / provision to consider any large deviations with respect to the normative Add-cap in case of exigencies in certain stations due to unforeseen factors including but not limited to geological surprises, replacement of assets due change in technology / obsolescence, change in law, force majeure, can be suitably addressed.

g) The Approach paper has proposed that any item that costs below Rs. 20 lakhs that is in the nature of minor assets, including Capital Spares below Rs 20 lakh, can be allowed only as part of O&M expenses, and may not be considered as part of additional capitalisation in case of both thermal and hydro generating stations. Further, any major capital spares costing above Rs. 20 lakhs may form part of the special compensation. The above proposal is generally acceptable and may be considered.

14. GFA/NFA/Modified GFA Approach (7.1.18)
Approach Paper

Increasing the Investors' confidence by ensuring assured returns is important, and further considering the recent spikes in power tariffs in power exchanges indicating shortage of power availability, investment in Power sector needs a boost, and therefore the existing GFA approach, being a balanced approach, may be continued. However, comments/ suggestions are invited on alternate approaches, i.e. GFA/ NFA/ Modified GFA approach.

NTPC Comment:

a) From the beginning, the Hon'ble Commission has adopted the Gross Fixed Asset (GFA) approach in the previous Tariff Periods. During 2019-24 regulations, the issue of GFA was again discussed in detail and it was settled that the GFA approach is the most appropriate considering the internal returns that is generated under the approach for future capacity expansion/ new capacities.

b) In the existing practice of considering GFA also there are few limitations such as no return on equity during the construction phase. However, shifting to any different approach such as NFA/ Modified GFA would be detrimental for investment in new capacity addition / expansion. Also, in case of old stations, the equity component is already very small rendering the Return on equity (RoE) amount to be negligible as compared with new stations. On the contrary, these plants have significantly high O&M costs and also have to comply with the normative norms prescribed in the Regulations without any relaxations. This is already putting pressure on the profitability and therefore any change to NFA/ Modified approach is not warranted.

c) In the present context, CEA has already come up with a Report on Optimal Generation Capacity Mix For 2029-30 which primarily focusses on the optimal generation capacity mix that may be required to meet the projected peak electricity demand and electrical energy requirement of the year 2029-30 as per 19th Electric Power Survey. As per the study report, it has projected that an additional coal-based capacity of 43 GW would be required by 2029-30. Therefore, continuation of the GFA approach shall promote generation of adequate internal resources which would be required for ploughing back to facilitate new capacity addition. The importance of these new units is critical in view of the CEA highlight requirement of additional thermal generation capacity to meet base load. Therefore, it is important that existing GFA approach is continued as it shall promote future investment in the thermal generating plants.

d) The present tariff structure puts the break-even point at around 68 % of DC under GFA approach, meaning that ROE is zero at this level of operation and only on achieving 85 % of DC; prescribed ROE of 15.5 % can be earned. If the Net Fixed Asset approach is followed, the owner's equity in the old power plant will get reduced to 10 % of the historical cost and it may be noted that the ROE is completely wiped off at a DC of around 78 % (i.e. drop in DC by 7 % from the current NAPAF of 85 % will make the ROE zero), Thus, any decrease in availability (DC) due to factors beyond the control of the generators, such as, fuel availability, logistics of fuel transportation, etc., or increase in O&M expenses over the normative O&M allowed in tariff, will not only result in complete erosion of return on equity but also will result in losses and negative cash flow due to which the business growth and survival can be dramatically affected.

e) The risks of operating the fossil fuel-based power projects are much higher as compared to hydro, nuclear, renewable power projects and will continue to increase as the plants gets older and the NFA approach will totally dis-incentivize the promoters to continue, and more and more generating assets may get stranded. To further substantiate the above point, it is noted that under the Net Fixed Asset approach, the return on equity will be a much small percentage of annual fixed charges. The return on equity starts moving down as a percentage of the total cost of power from the 13th year through 25th year (end of the useful life) from 6.15% to 1.2%, whereas under GFA approach it slopes from 6.15 % to 3.47% in the same period.

f) Under NFA approach, developers will have no incentive for operating the plant at the optimum level. Stake of the project developer will reduce to just residual value of the plant and as a result developer may not be in a position to adopt best O&M practice or incurring Renovation and Maintenance expenditure for life extension of the project. Rather, the promoters will prefer to close down the project. This may result in wastage of scarce national resources and hamper the economic growth in the country.

g) Generation is not permitted any return on the equity invested during the long gestation period when the project is under construction. The existing GFA approach to some extent mitigates the generating company for the returns the lost revenue which it was deprived upfront.

The other advantage of GFA approach is that it ensures the predictability of returns and thus provides the consistency under uncertain market scenario on long-term basis. Any change in the approach at this stage on such fundamental principle would affect the cash flow / liquidity of power generators and would jeopardize their own existence and the power supply scenario in the country. Therefore, in short, in the interest of the entire sector and to facilitate future capacity addition, it is submitted that the Hon'ble Commission needs to consider continuation of GFA principles in the Regulations for the 2024-29 period.

15. O&M Expenses (7.1.19)

39. O&M norms may be specified under the following two categories.

1. Employee Expenses

2. Other O&M Expenses comprise of Repair and Maintenance and Administrative and General Expenses.

However, considering that systems that are more automated will require less manpower and systems that are less automated will require more manpower, approving separate norms may result in inequity even though the total O&M expenses of such systems may be comparable.

Therefore, the above suggestion may also be seen from the perspective that these expenses have historically been allowed as one expense and any change in the methodology as suggested above may result in unnecessary complications. Alternatively, to give effect to the impact of pay/wage revision, 50% of the actual wage revision can be allowed on a normative basis.

(Refer 4.12.1)

NTPC Comment:

a) O&M expenses has been historically seen as a single expense, although actual expenses are split into various heads. It is suggested that O&M expenses norms may be considered as a single consolidated norm and not split into two categories as the same may have unnecessary complications.

i. The Approach Paper has proposed considering 50% of the actual wage revision to give effect to the impact of pay / wage revision on normative basis. Pay / wage revision is one-time phenomenon in the tariff period and has been separately allowed in the past.

ii. Employee wage revision is mandatorily required to be done as per relevant directives of DPE and are statutory in nature. While revising the wages, some of the factors including the impact of inflation are paid to the employees in order to adequately compensate them and to cover their expenditures. Therefore, wage revision is a legitimate cost and is a change in law event. It is submitted that in a cost plus regulatory all expenses prudently incurred are to be allowed in tariff. Accordingly, entire impact on account of pay revision needs to be allowed in tariff. Therefore, 100% impact of pay revision needs to be considered on normative basis.

iii. Further, it is submitted that the actual increase in employee wages on account of pay revision will be known only at the time of wage revision. Therefore, on ad-hoc basis 50% (as proposed by Approach paper) of the employee expenses of current year, may be considered in the normative O&M expenses as increase in employee expenses on account of pay revision on normative basis, subject to true-up at the end of tariff period based on actual impact of wage revision.

iv. Since O&M expenses consists of a substantial amount of employee cost and labour charges in the form of service charges under Repairs and Maintenance, a suitable escalation on O&M expenses may be given by Hon'ble Commission with more weightage on CPI.

1. *In view of discussion held in Section 4.12.4, it is anticipated that if Capital Spares are analysed for a longer duration say 15-20 years, there can be some correlation and predictability to such expenses. Therefore, if the same can be projected with some degree of predictability, the same may be allowed on a normative basis along with O&M expenses. Alternatively, instead of including all such capital spares as part of normative O&M expenses, recurring and low value spares below Rs. 20 lakh may be made part of normative O&M expenses, while for capital spares with a value in excess of Rs. 20 lakh, utilities may submit the same on a case to case basis for reimbursement with appropriate justification for the Commission's consideration. (Refer 4.12.4).*

NTPC Comment

a) Both the approaches are acceptable principally as it is proposed to either (1) allow entire capital spares on a normative basis, or (2) allow recurring and low value spares below Rs. 20 lakhs on normative basis, while capital spares with value in excess of Rs, 20 lakhs may be reimbursed on case-to-case basis.

b) Further, based on actual data and predictability of such expenses, normative basis may be adopted for entire capital spares. Or else, norm based on low value spares below 20 lakhs may be provided.
c) It is further suggested that separate norms for normative capital spares (as proposed by the Approach Paper either on entire basis or less than 20 lakhs basis) and Normative O&M expenses may be provided instead of clubbing the two into a single norm.

43. Comments and suggestions are therefore sought from stakeholders on whether to include any provisions with regard to allowing impact of change in law in O&M expenses. (Refer 4.12.5)

NTPC Comment

In the past impact due to change in law under O&M expenses was allowed in case of reimbursement of ash transportation expenses. It is therefore suggested that such provision to deal with change in law events may be provided in the O&M expenses, so that any change in law impact can be dealt by Hon'ble Commission under O&M expenses.

16. Depreciation (7.1.20)

Approach Paper

Depreciation is one of the cost components that is allowed, along with other cost components, in the form of annual fixed charges. The regulatory meaning of depreciation was pronounced in the 2009-14 tariff period, where it was held that there should be enough cash flow available to meet the repayment obligations of the generating company or transmission licensee which was in accordance with Clause 5.8.2 of the National Electricity Policy 2005, which specifies that depreciation should be able to fully meet the debt service obligations. The Commission, while formulating the CERC Tariff Regulations, 2009, specified depreciation rates considering a repayment period of 12 years to repay a normative loan corresponding to 70% of capital cost, and since then, the rate of depreciation has been specified based on this approach.

The Tariff Policy, 2016 also stipulates that, the Central Commission may notify the rates of depreciation in respect of generation and transmission assets, and the rates so notified would be applicable for the purpose of tariffs as well as accounting.

Further, Part B of Section 123 of the Companies Act, 2013, with regard to the residual value of any asset specifies as follows.

"4. The useful life or residual value of any specific asset, as notified for accounting purposes by a Regulatory Authority constituted under an Act of Parliament or by the Central Government shall be applied in calculating the depreciation to be provided for such asset irrespective of the requirements of this Schedule."

Further, Depreciation depends on the following three factors:

1. Rate base (gross fixed assets on which the rate of depreciation applied), which includes subsequent additions.

2. Method of depreciation – Straight Line Method (SLM) has been followed in all preceding years.

3. Depreciable life – As the assets are required to be provided with 90% depreciation over the life. Hence, the rate of depreciation is directly linked to life of the assets.

It is observed that while specifying the depreciation rate, the tenure of the loan considered is 12 years, whereas the life of most of the assets is between 25 and 40 years. It is observed that shorter loan duration and higher depreciation in the initial years have resulted in front loading of tariffs. Considering that nowadays loans are available for 15-18 years, the possibility of increasing the loan tenure for the computation of depreciation rates needs to be explored. Excessive front loading of tariffs increases resistance to future investments. For example, external loans have much lower interest rates, therefore, spreading depreciation over longer periods in the case of external loans can be a viable option for reducing costs in the initial years, which shall, however, include FERV factor and other financing cost. Therefore, there is a need to create a balance and align the depreciation rate with the actual loan tenure and life of the assets. In view of the above, a depreciation rate may be specified considering a loan tenure of 15 years instead of the 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). Comments and suggestions are therefore sought from stakeholders on the above proposal and any modifications required, if any.

NTPC Comments

a) The existing regulations provides for higher depreciation rate during initial 12 years considering the repayment tenure of 12 years. Repayment of loan for each year is deemed to be equal to the depreciation allowed in tariff for the corresponding year. Presently, such depreciation rate is arrived based on the schedule of rates of different assets and involves detailed computation of weighted average rate through a separate tariff filing format. The Approach Paper has proposed increasing this period from 12 years to 15 years in view of available loan tenure of 15-18 years. The Approach Paper is proposing to simplify tariff determination process as well as minimization of tariff filing formats. It is further submitted that such derived depreciation rate is not recovering 70% of capital cost in 12 years. In view of this**, normative depreciation rate of 5.83% (i.e., 70 /12) may be provided in the first 12 years considering repayment of loan in 12 years.**

b) The spreading of depreciation from 12 to 15 years shall reduce front loading of tariff. However, the lowering of tariff due to spreading of depreciation over 15 years is expected to be marginally set-off by the increase in interest charges on the loan, since longer-term loans carry a higher risk of interest rate fluctuations and economic uncertainties. This may result in higher interest rates outgo during the entire loan period.

c) While benefit of lower interest rate is assigned to external loan, it is difficult to have longer duration external loans of 15-18 years. External Commercial Borrowings (ECBs) have the following additional issues:
    i. ECBs with duration more than 10 years are available through multilateral development banks only and not through commercial banks. In the past, NTPC has been able to raise loans for door-to-door maturity of up to 10 years at the most.
    ii. Due to ESG constraints, Foreign Banks/Institutions are not readily willing to lend for financing of fossil fuel-based projects.

d) With the changing scenario and energy mix, it is expected that the availability of loans to coal-based generating stations is expected to be constrained or at higher rate of interest due to the following aspects:
    iii. Higher risk perception of fossil fuel generation due to transition to RE, climate change issues, etc.
    iv. Tendency to shift from long-term coal-based capacities to RE sources for meeting the higher RPO commitments.
    v. In case of domestic loans, share of power sector loans is already high and nearing exposure ceiling norms of the banks which may limit their capacity to additional exposure towards thermal generation loans considering their large fund requirement. Further, domestic loans of longer tenure would be at higher rates of interest.

In view of the above, following is suggested:

i. **in case of existing stations, the loans continue to be governed under the existing loan tenures and any changes in depreciation would result in loan payment difficulties and may cause liquidity issues for the generators.**
ii. **It would be appropriate to provide Normative depreciation rate of 5.83% (i.e., 70 /12) may be provided in the first 12 years considering repayment of loan in 12 years.**

17. Interest on Loans (7.1.21)

Approach Paper

4.14.4) Weighted Average Rate of Interest and FERV

The cost of debt is the cost incurred by the utility in the form of interest payments and an upfront fee for raising finances through debt. As per the prevailing Tariff Regulations, the weighted average interest rate calculated on the basis of the *actual loan portfolio deployed towards the asset by the utility is considered the cost of debt. The cost of debt thus arrived at is applied to the normative outstanding loan to compute the annual interest expenses of the utility, which are allowed to be passed through in the tariff. In addition to the same, in the case of foreign debt, the utility is required to carry out hedging to take care of exchange rate variations, the cost of which is allowed to be recovered separately.*

It has been observed while dealing with tariff petitions, especially in the case of transmission licensees that in most cases the loans are not availed for specific project, and in such cases, it becomes a cumbersome task to ascertain one to one co-relation between assets and loans, which also requires considerable time and effort. To address the same, the possibility of computing interest on loans on the basis of the actual weighted average rate of interest for a company as a whole can be explored.

It is further observed that the current Regulations already have such a provision for those generating stations or transmission systems that do not have any actual loans. According to the provision, interest on loans is computed based on the WAROI of the generating company or transmission licensee. However, it is also observed that there are certain foreign loans that entail FERV/hedging costs in terms of repayment of the loan as well as interest. In this context, the Tariff Policy 2016 states that only for projects where the tariff has not been determined on the basis of competitive bids, the cost of hedging and swapping such loans to take care of FERV shall be allowed without allowing any actual FERV.

To simplify the approval of interest on loans, the weighted average actual rate of interest of the generating company or transmission licensee 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.

Comments and suggestions are sought from stakeholders on the above suggestions and alternatives, including in respect of treatment of FERV/cost of hedging.

NTPC Comment

<u>Weighted average actual rate of interest</u>

a) As per Regulation 32 of Tariff Regulations 2019, the current provision is to consider the weighted average rate of interest as quoted below:

"(5) The rate of interest shall be the weighted average rate of interest calculated on the basis of the actual loan portfolio after providing appropriate accounting adjustment for interest capitalized:

Provided that if there is no actual loan for a particular year but normative loan is still outstanding, the last available weighted average rate of interest shall be considered;

Provided further that if the generating station or the transmission system, as the case may be, does not have actual loan, then the weighted average rate of interest of the generating company or the transmission licensee as a whole shall be considered."

c) The weighted average rate of interest considers the overall financing structure of a company, while station-specific interest refers to the interest rate of loans deployed for a specific station.

d) The Weighted Average Rate of Interest (WAROI) for a company doesn't provide a correct reflection of the cost of financing of a station because of the following reasons:

   i. **Diversification of business:** A utility may have businesses across different parts of the value chain. The loan basket would include long term loans which are not deployed in the regulated business. Further, a certain portion of the loan may be deployed in OPEX (for R&M etc.), intercorporate loans/advances or may be part of disallowed capital expenditure. Recently many generating companies may have diversified their electricity generation mix. Renewable energy sources form a significant part of their overall electricity generation portfolio. Loans to such other businesses may be at a higher or lower rate of interest in view of their associated operational, commercial, technical, and other risks. Therefore, separate WAROI would be required computed after segregation of the above components.

   ii. **Sharing of saving in interest due to re-financing or restructuring of loans:** The generator is required to share the gains with beneficiaries on refinancing of costlier loans with cheaper ones. In case if a company wide average rate is considered for tariff purposes with the entire benefit of refinancing shall be passed on the beneficiaries of all stations irrespective of the project specific loans that have been refinanced.

   iii. **Project Specific Loans:** Although most of the loans are raised on Balance sheet basis, there exist certain funds raised for specified projects e.g., KfW Mauda, JBIC Barh, JBIC Kudgi, KfW ESP, FGD GREEN loan etc. Such loans are raised for specific projects and carry lower rate of interest and separate utilization report is required to be sent to the lenders. In case WAROI of the company is used for determining the Interest of loan for AFC purpose (revenue recognition), the interest expense of such loan shall continue to be charged based on actual deployment (expense recognition) and may lead to mismatch on project-to-project basis, though would be compensated on Company level. At certain times, project specific requirements dictate deployment of specific loans to a particular project (for e.g. Bongaigaon) which would not be possible in case company-wide average interest rate is considered.

   iv. Cross-subsidization of Interest Cost: Considering the variation rate of interest across different projects and across non-regulated business would lead to cross-subsidization of the interest cost, which is not desired in case of regulated business. For instance, loans for green energy projects are available at lower interest rates which would have been availed by the generators. Utilizing the cheaper rate of loans against such projects would not only reduce the recovery against actual cost of loans for TPPs but also make the other project unviable.

Weighted average rate of interest for project also affected by the period in which loans were deployed during construction. Projects completed during low interest regime tend to have lower WAROI as compared to projects completed during higher interest rate regime. Therefore, applying same interest rates on all the projects may result in cross subsidization.

v. **Project specific risk:** Overtime investment into a thermal has become risky. Finance for the construction of a new TPP is not easily available as banks are hesitant to finance them due to lower offtake and limited access to subsidized coal. Hence, WAROI would not capture the risks associated with a TPP and loans will be available at higher interest rates.

In view of the above, following are submitted:

i. **Using WAROI of a generating company to calculate interest rate of a specific project would be inappropriate.**

ii. **Instead of considering weighted average rate of return, the MCLR (Marginal cost of funds-based lending rate) with suitable margin can be considered for approving the interest on capital loan.**

MCLR is utilized by Banks as benchmarks for the purpose of fixation of interest rate on loans. This would eliminate the concern highlighted in the approach paper regarding unavailability of project specific loan and cumbersome task to ascertain one to one co-relation between assets and loans, which also requires considerable time and effort.

In view of the widespread acceptance of MCLR as the benchmark for determining interest rate across different sectors, it is suggested that MCLR with suitable margin should be used instead of WAROI for calculating project specific interest on loans.

HEDING OF FOREIGN LOAN

e) Currently, the provisions of tariff regulations provide flexibility of undertaking hedging to the generator as follows:

"68. Hedging of Foreign Exchange Rate Variation: (1) The generating company or the transmission licensee, as the case may be, may hedge foreign exchange exposure in respect of the interest and repayment of foreign currency loan taken for the generating station or the transmission system, in part or in full at their discretion.

(2) ………………………

(3) Every generating company and transmission licensee shall recover the cost of hedging of foreign exchange rate variation corresponding to the normative foreign debt, in the relevant year on year-to-year basis as expense in the period in which it arises and extra rupee liability corresponding to such foreign exchange rate variation shall not be allowed against the hedged foreign debt.

(4) To the extent the generating company or the transmission licensee is not able to hedge the foreign exchange exposure, the extra rupee liability towards interest payment and loan repayment corresponding to the normative foreign currency loan in the relevant year shall be permissible, provided it is not attributable to the generating company or the transmission licensee or its suppliers or contractors."

f) The Approach Paper has proposed that cost of hedging related to foreign loans be allowed on an actual basis, without allowing any actual FERV.

g) However, the Approach Paper has not elaborated on the following aspects:
   i. Whether above provision is applicable for new loans or existing loans also?
   ii. How the annual payment of hedge cost is to be recovered from beneficiaries?
   iii. What would be the treatment of hedge cost in case the loan tenure/hedge tenure is longer than the normative debt?
   iv. In case the provision is revised back from mandatory hedge to optional hedge in next tariff period say 2029-34 or so on, whether cost of unwinding the hedge agreement shall be permitted?

h) In absence of any explicit mention on the above aspects, it is presumed that all ECB loans existing as on 31.03.2024 shall be subject to hedging and thereafter all new loans will be on all hedge basis.

i) In terms of clause 69 of tariff regulation 2019, "Every generating company shall recover the cost of hedging and foreign exchange rate variation on year-to-year basis as income or expense in the period in which it arises. Since the recovery of FERV is linked with the period in which the repayment is made, the generating companies always have exchange rate variation on outstanding foreign currency loans, which will be materialized on repayment in future periods. In case, proposal of 100% Hedging is adopted, the Hon'ble Commission must take into consideration the mechanism of recoverability of exchange Rate variation on outstanding foreign currency loans accrued as on the date of implementation of the new regulation.

j) The market for hedges of more than 5 years is quite illiquid and therefore either the hedge would not be available for longer tenures and if at all available, would be at a very high cost. It is likely that hedge of loans for complete tenure isn't available and therefore hedging on rollover basis might have to be resorted to in which case the mechanism for rolled over hedges shall be required. It has been observed that long term currency depreciation is generally less than the cost of hedging.

k) **In view of the above, following is suggested:**
   i. Therefore, in order to optimize the tariff, the generator may be given the discretion to decide whether to hedge the loan or not. Therefore, the existing provisions in the 2019 Regulations may be continued that allows Generators to recover the cost of hedging and FERV variation on year-to-year basis as income or expense in the period in which it arises.

ii. **Suitable margin of at least 450 basis points may be provided over MCLR to take care the FERV risk on account of ECB, etc.**

iii. **Further, in case of shifting to normative interest rate on loan, the generating company may be provided option to continue with existing methodology based on actual project specific interest rate or shift to normative interest on loan with margin of 450 basis points above MCLR.**

18. RoE/RoCE Approach: (7.1.22)

As in the past much has been deliberated and discussed on the two approaches and in view of the long-standing position of this Commission, the present system, or RoE approach, may be continued. (Refer 4.15).

NTPC Comment

The issue of ROCE Vs ROE has been raised and debated by the Commission during the framing of earlier Regulations. However, due to practical difficulties in implementing the ROCE approach, the Commission has continued with ROE approach so far.

Existing ROE model is fair and equitable. The actual cost of financing is charged from the beneficiaries and any savings resulting on account of refinancing / loan substitution, etc. during the currency of any loan is shared with the beneficiaries. ROCE model involves working out of the rate base and estimating WACC. Tariff calculations may become very complex in case ROCE approach is adopted. As per the current Tariff Regulations, the rate base changes on a year-on-year basis on account of liability discharge, addition of permitted capital assets, de-capitalization of assets, etc. Further, the debt equity ratio will also change every year due to repayments and consequently the WACC.

In view of the above, RoE approach may be continued considering that the same has worked well and is simple, fair, and equitable.

19. Rate of Return on Equity (RoE) – (7.1.23)

Approach Paper

Methodology

47. Keeping in view the international approaches to regulated rates of return, the average of 10-year GOI securities rate over a one-year horizon may be considered a risk-free rate.

48. Keeping in view the international approaches, daily data on the SENSEX and BSE Power Index for the latest 5 years may be considered for equity beta estimation.

49. Keeping in view the international approaches, the Market Risk Premium (MRP) reflecting the historical returns for a period of 30-years or beyond instead of the existing practice of considering 20 years may be considered for MRP estimation.

50. Alternatively, MRP may be computed using any other method including the Survey Method.
(Refer 4.16.4)
Other Key Issues
51. Review of Rate of RoE to be allowed including that to be allowed on additional capitalisation that is carried out on account of Change in Law and Force Majeure.

52. Whether the revised rate of RoE to be made applicable to only new projects or to both existing and new projects?

53. Whether timely completion of hydro generating stations can be incentivised to attract investments?

54. Merit behind approving different Rate of RoE to thermal, hydro generation and transmission projects with further incentives for dam/reservoir-based projects including PSP.

55. Merit in allowing RoE by linking the rate of return with market interest rates such as G-SEC rates/MCLR/RBI Base Rate.

(Refer 4.16.4)

NTPC Comments

1. In a cost-plus tariff framework, the generating company is expected to make reasonable returns on the investment after meeting all the costs incurred prudently. However, the regulatory approach is such that while upsides are generally capped, downsides are not protected, thus creating inherent asymmetry in the tariff design resulting in lack of level playing field for the generator.

   For instance, Annual Fixed Charges (AFC) is recovered based on achievement of target availability with pro-rata reduction / penalty for any shortfall. AFC under recovery can be due to many reasons, such as, availability shortfall, under achievement of operational norms, under recovery in O&M expenses, etc. In addition to loss of RoE component, any under recovery of AFC erodes the returns further as all other expenses, such as, employee costs and overheads, debt servicing, etc., are to be now serviced out of the return on equity.

   However, there is no incentive for surpassing the target availability by the generator. Incentive is generation based and linked to plant load factor, which is dependent on the demand and dispatching by the Discoms. The generator thus has no control over incentive despite taking all efforts to maintain availability higher than the target availability.

   Therefore, the RoE prescribed in the Tariff Regulations is not only a critical factor for profitability of the generating company but also for the long-term sustainability of the generation business. The returns allowed on equity in a cost-plus timeline is also germane to the interest rate prevailing during that period. The RoE is also determined keeping in view the construction period of the projects as longer gestation period leads to lower equity IRR for a given RoE. The inherent risk in project implementation also poses serious concern for the generators as the delays not only lead to further dilution of the equity IRR but it also runs the risk of disallowance of interest during construction (IDC) thus lowering the project return.

2. **Risks in power generation business**

2a. Inherent Risks of the business

a) **Project Execution Risk –**
Thermal projects are inherently risky due to various factors such as:
   i. Power projects are capital intensive and have high gestation period.
   ii. Project management of thermal projects is more challenging, and its execution is fraught with various risks, such as, land acquisition, law & order issues, obtaining environment / forest clearances / contractor defaults / equipment delays, etc.
   iii. Law & order issues cause prolonged disruptions of work resulting in disproportionate delay.
   iv. Project delays result in increased IDC, which may be at risk for pass through in tariff.

Any disallowed project delay due to above risks lower the effective returns.

b) **Operational Risk –** Thermal stations in operation phase are exposed to a host of operational risks, such as, fuel constraints, transportation bottlenecks / railway limitations, water shortage, machine breakdowns / outages, non-achievement of operating parameters, etc. Fuel shortage is mostly caused by macro-economic factors beyond the control of the generator, such as, the shortfall in domestic coal in last 2 years which had to be met through imported coal as per MoP's directive. Any under recovery of AFC due to the above risks results in eroding the returns.

c) **Commercial Risk -** Financial health of discoms is a significant risk for generators as has been witnessed in past several decades, which in turn leads to liquidity issues for generators as well. Many a times waiver / concessions are mandated to recover the outstanding dues. The above risks affect the cash flow of the company and also impacts the profitability.

d) **Regulatory Risk**
   i. Stringent tightening of operating norms every successive tariff period.
   ii. Normative O&M Expenses not adequate to meet need-based expenditure on repair & maintenance.
   iii. Inadequate part-load compensation and frequent start/stops.
   iv. Tightening of operation norms in units commissioned long back and operating without comprehensive Renovation & Modernization takes away all gains.

The above risks impact the recovery of normative costs and thus lower the effective returns. The Approach paper has rightly recognized that the generation sector needs to be de-risked.
Investment decisions are taken after assessing the viability based on extant regulatory provisions. Post-investment, RoE / other parameters should not be tightened without adequate justification.

2b. Additional factors and risks due to changed business & economic environment

a) **Risk caused by global supply chain issues, COVID & Ukraine war-** The global economy is under significant risk due to ongoing factors like global supply chain disruptions, the Ukraine War, and the persistent COVID pandemic. These challenges show no signs of diminishing, posing an economic risk for countries worldwide, including India. In the past three years, major economies have experienced substantial increases in electricity prices, highlighting the rising costs of fuel and in-turn the cost of electricity generation. This unprecedented economic situation poses the highest-ever risk for investments in the electricity business in the regulatory history of CERC.

b) **Inflationary risks**- Inflation poses another significant risk factor in the current economic climate, affecting not only global economies but also India. This unprecedented situation in the past 20-30 years, has heightened investment risks in the regulated energy business. The imminent presence of inflationary forces necessitates attention as it is expected to drive an increase in interest rates in the near future. This rise in rates will render the Return on Equity (ROE) redundant due to a corresponding increase in the risk-free rate of returns. For instance, the SBI 1 Year MCLR, a benchmark for bank's cost of funds, has already increased from 7.0% on June 10, 2020, to 8.5% on June 8, 2023, representing a substantial 21% increase.

c) **Resource generation for capacity addition-** The Central Electricity Authority (CEA) has projected that by 2030, the existing capacity of FY 2021-22 will need to nearly double to approximately 777 GW, with thermal generating capacity accounting for 275 GW. This requires an addition of around 38 GW of thermal capacity from the current level of approximately 237 GW. To achieve this, a total capital investment of Rs 2,66,000 Crores (2.6 trillion Rupees) is required at a rate of Rs. 7 Crores per MW. The additional equity investment needed, following a debt-to-equity ratio of 70:30, amounts to Rs 79,800 Crores. Given the inherent risks associated with the thermal power generation business, the commission must provide an additional return on equity investment to attract such a substantial amount of equity from the market.

Further, RE based capacity addition of 297 GW is required by 2030. To achieve this, a total capital investment of Rs 14,85,000 Crores (14.85 trillion Rupees) is required at a rate of Rs. 5 Crores per MW. The additional equity investment needed, following a debt-to-equity ratio of 80:20, amounts to Rs 2,97,000 Crores.

On the onset of 2019-24 tariff regulation periods, the energy deficit and peak deficits were at their lowest point, indicating an excess supply in the industry. So, the regulator did not hike the Return on Equity (ROE) of 15.5%. Currently, due to resurgent demand and slower thermal capacity addition in recent years, the gap between demand and supply, particularly during peak hours, is increasing and expected to widen in the future. This scenario presents a compelling case for allowing an extra ROE to incentivize investment in thermal generation. Further, in the past few years, equity investment in the thermal power business has not garnered propitious returns due to stranded projects. (At one point in time almost 40GW of projects were stressed). Investors will be apprehensive about new rounds of investment in the sector. Considering these factors, it is crucial for the commission to recognize the significance of the investment required and the associated risks in the thermal power generation sector. Offering an additional ROE will not only attract the necessary equity investment but also support the industry's growth and bridge the gap between demand and supply.

Given the multi-year nature of the regulatory tariff framework, it is crucial to consider not only the current economic conditions but also future investment risks. Anticipating and accounting for the impact of such factors and its associated risks in the long-term sustainability of investments is essential in ensuring a robust regulatory framework. The commission must take cognizance of such added risks while allowing normative ROE for the period valid till 31.03.2029 so that rate of return remains relevant for the equity investors.

3. **Calculation of cost of equity as per CAPM methodology enunciated in approach paper 2024-29**

	CAPM components		**Particulars**	**Remarks**
i.	Rate of risk-free returns, R_f	%	7.31%	As given in the Approach paper
ii.	Beta of Power Sector	Number	1.17	Beta based on power index and Sensex, 5 years daily movement data
iii.	Market rate of return, R_m	%	15.97%	Based on 20 years Sensex returns. (Period March 2003-March 2023) *
iv.	Equity Risk Premium (R_m-R_f)	%	8.66%	
v.	Cost of equity, $R_e = R_f +$ beta (R_m-R_f)	%	**17.45%**	

* 20 years period for calculation of market rate of return is more pertinent as 30 years period involves the time frame between the 1993-2003 characterized by initial phase of economic reforms due to monetary and economic crisis, political instability, and scams in stock market causing vicissitudes in market returns.

The cost of equity @ 17.45% has been calculated following the methodology as mentioned in the approach paper and it is evident that equity investment is poorly remunerated as per the present normative rate. Considering the added business risks in the present situation, the commission must re-consider the normative rate of return equity for adequate returns for the corresponding overall risks.

Besides, the current CERC tariff framework with respect to allowance of ROE needs consideration of following factors too-

A. **No Returns during Construction Period –**

i. Power plant takes at least 6-7 years from land acquisition to COD. While equity deployment starts with land purchase, debt is deployed only after investment approval.
ii. Since equity invested during the construction phase does not earn any return, the effective RoE is only 11.3%. This decreases to 10.35% due to a delay of one year and would be further lower depending on disallowance due to project delay.
iii. One approach could be to treat equity during construction period as notional debt for capitalization and determination of the project cost.

Therefore, rate of RoE needs to be enhanced suitably considering the fact that no returns are available on equity during the construction period or commission may allow extra ROE during the period of operation to compensate the loss of returns on equity investment during gestation period.

B. **Parity of returns with respect to other regulated business-** As per Section 5.3(a) of the Tariff Policy (inter-alia)-

"Balance needs to be maintained between the interests of consumers and the need for investments while laying down rate of return. ***Return should attract investments at par with, if not in preference to****, other sectors so that the electricity sector is able to create adequate capacity. The rate of return should be such that it allows generation of reasonable surplus for growth of the sector.*

The Central Commission would notify, from time to time, the rate of return on equity for generation and transmission projects keeping in view the assessment of overall risk and the prevalent cost of capital which shall be followed by the SERCs also. The rate of return notified by CERC for transmission may be adopted by the State Electricity Regulatory Commissions (SERCs) for distribution ***with appropriate modification taking into view the higher risks involved.*** *For uniform approach in this matter, it would be desirable to arrive at a consensus through the Forum of Regulators."*

The Tariff Policy propagates the parity of return not only inter sector but intra sector also. The tariff policy recommends the higher returns for distribution business as it has higher risks as compared to generation and transmission business.

Similarly, the thermal (and hydro) generation business is fraught with higher risks as compared to transmission businesses or Renewable business. Still the effective rate of return in generation business is way lesser. The biggest element in risk profile of generation business is significantly higher gestation period.

Business	**Gestation period (Approx months)**	**Regulated ROE**	**Remarks**
Transmission	36	15.50%	CERC tariff regulation 2019
RE	24	14.00%	CERC RE regulation 2020
Thermal	60	15.50%	CERC tariff regulation 2019

Besides gestation period, in the thermal generation business there is requirement of arranging fuel, managing more complex and large plant & machineries and its O&M, managing machine efficiencies and outages, managing larger manpower and higher number of contracts. All such factors including comparable market returns advocate the case for higher ROE from present level of 15.5%.

4. **Conclusion:** To summarize, the following factors need to be taken into consideration while fixing the rate of return on equity of thermal generating stations for the tariff period 2024-29 as under:
    i. The existing cost of equity as per the CAPM – 17.45%
    ii. The expected increase in risk-free rate of return in the wake of unprecedented global as well as domestic inflation and greater peril of increase in interest rates in the foreseeable future.
    iii. The overall risks in the thermal generation business.
    iv. Additional economic and business risks caused by persistent COVID, resulting supply chain crisis and still continuing Ukraine war.
    v. The need of capacity addition in the thermal sector and the requirement of overall investment and equity in particular. Higher returns attract larger capital.
    vi. Compensation of loss of return to equity investor during the large gestation period
    vii. Parity of returns with transmission and RE business based on corresponding risks and effective equity IRR.
    viii. Provisions for not only current risks but future risks also as the regulation is based on a multi-year tariff framework

In view of the above, rate of return on equity for thermal generating stations should consider the above aspects which would not only help the existing stations to remain sustainable but also generate resources for further investment in the sector. For attracting extra equity investment, some extra ROE is required to be offered.

Therefore, a favorable climate needs to be provided through an enhanced rate of return on equity for the tariff period 2024-29, so that thermal generation becomes attractive for investment.

20. Rate of Return – Old Thermal Generating Station

Approach Paper:

It may be inferred from above, that by lowering the equity base or reducing the return for old generating stations, there is not much to gain in overall terms considering the risks involved in operating these stations. In such cases, if the returns are reduced, there may be too little incentive for the generating companies to manage the operations of such plants. Therefore, to encourage the continued operation of these plants, additional incentives for such generating stations may be considered. This will encourage these generating companies to continue operating such power plants.

As sustained operations of these units are in the best interest of beneficiaries, incentivising these low-cost generating stations would prove mutually beneficial.

Possible options to encourage higher availability and generation from old generating stations can be as follows.

1) Allowing additional incentive in the form of paise/kWh apart from those currently allowed may be allowed to such generating stations against generation beyond the target PLF.

Comments and suggestions are sought from stakeholders on various possible alternatives that incentivises generation from these efficient old generating stations.

NTPC Comments

Rate of Return – Old Thermal Generating Station

It is submitted that following aspects may be considered to incentivize old generating stations:

Capital Cost of Old generating Stations-

Existing framework of Generation Incentive for thermal generating stations-

<u>Capital Cost of Old Generating Stations:</u>

1. As on 31st March 2023, generating stations of NTPC having a total capacity of 16386 MW have completed 25 years from CoD. These stations consist of 11,900 MW of pithead coal-based power plants, 1,260 MW of non-pithead coal-based power plants and 3,226 MW of gas power plants. These stations form a balanced mix having pithead plants for base load operation, non-pit head plants for flexibility and gas plants for peaking and ramping requirement.
2. These stations are well maintained and efficient units and provide reliable power supply. Emission Control System (ECS) are under installation in coal-based units for ensuring compliance with the revised emission standards.
3. Moreover, these are depreciated assets with loans repaid and thus have nominal fixed charges. Although these were units set up based on original D/E ratio of 50:50, equity for tariff purposes as on 01.04.2019 or on completion of 25 years has been capped to maximum 30% of historical capital cost.
4. The capital cost of the older plants is very low resulting in insignificant amount of equity against which the returns are being provided. These returns translate into Per unit RoE of as low as 4 Paisa per unit at 85% in case of Singrauli which is negligible as compared to the RoE of 50-60 paisa per unit for the new power plants. The return is not commensurate with various risks involved in operating these plants. Any under recovery in AFC due to fuel risks, forced outage, O&M expenses, under achievement of operating norms, Heat Rate, APC, Specific oil, etc., could wipe off the entire returns.

5. The Approach Paper has rightly observed as under "It is further observed that these stations are vintage plants for which the approved capital base is around Rs. 1.5-2 Cr/MW and therefore the equity component of these generating stations is comparatively low. Due to low equity base the RoE in today's term may not be significant enough when compared to the risks associated with these plants."
6. The distribution utilities are scheduling these plants fully as the cost of electricity per unit is low with nominal capacity charges and very competitive energy charges as most of these plants are pit-head stations.
7. In view of high operating PLF of these plants, significant efforts and costs are required to be incurred for proper upkeep and maintenance of these stations to keep them in reasonable running conditions. However, there is enhanced risk of under-recovery of capacity charges due to non-achievement of target availability and other normative parameters due to various operational risks. In such cases, any under recovery of capacity charges / energy charges not only results in under recovery of costs but also has the potential to wipe the return on equity even due to marginal shortfall in availability due other norms. In other words, the meagre return on equity component is insufficient to meet any potential loss due to various risks associated with these plants.
8. In view of the above, it may not be financially prudent to continue with the plants from the investor perspective as the stations are not providing commensurate returns to the shareholders, rather eroding the stakeholders' funds. In such a scenario, the generator may be inclined to decommission these existing plants which has completed the useful life of 25 years, with technologically advance and efficient new plants or renewable power plants for which they would be compensated with better returns.
9. In the absence of incentives for these plants, the above factors may lead to eventual retirement of these units in due course of time and replacement by new capacity addition. Sustained operation of these units is in the interest of the Discoms and are required to conserve capital cost on any new capacity addition and for RE integration. **Therefore, higher incentives need to be provided in the regulatory framework to keep these units in operation thereby reducing the cost of power purchase for Discoms.**

10. Suitable methodology for higher incentive may be arrived by comparing the return of plants achieving 25 years with the new generating stations commissioning during the same year (when the older plants are completing the useful life of 25 years) may be considered for the purpose of providing incentive. For example:

Particulars	**Unit**	**Old Plant**	**New Plant**
Capital Cost	Rs. Cr. Per MW	1.0	8.0
Equity Component (@30%)	Rs. Cr. per MW	0.30	2.4
RoE @15.5%	Rs. Cr. per MW	0.0465	0.372
RoE (@85% PLF)	**Paisa per Unit**	**7**	**53**
Differential (RoE)	**Paisa per Unit**	**47**	

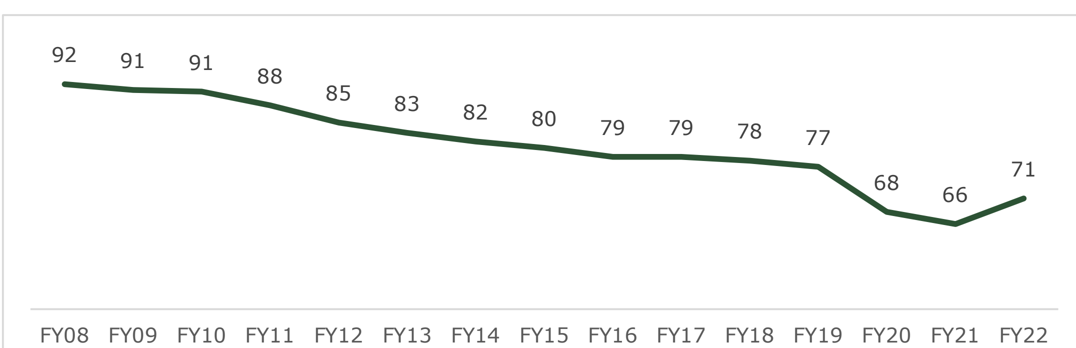
Therefore, additional incentive of at least 50 paisa per kwh rate may be provided for old generating stations over and above the incentive rate applicable for other stations.
Old stations may be provided inflation adjusted return instead of return on equity based on historical capital cost.
Fixed margin over scheduled generation may be provided.

<u>Existing framework of Generation Incentive for thermal generating stations-</u>

In view of larger integration of RE resources and declining PLF of thermal generation, there is need to review the existing incentive framework for thermal generators:

1. The operational norms for availing incentive by thermal generating stations for better performance are as under:
   "Normative Annual Plant Load Factor (NAPLF) for Incentive:
   a) For all thermal generating stations, except those covered under clauses (b), (c) - 85% ;"
   "In addition to the capacity charge, an incentive shall be payable to a generating station or unit thereof @ 65 paise/ kWh for ex-bus scheduled energy during Peak Hours and @ 50 paise/ kWh for ex-bus scheduled energy during Off-Peak Hours corresponding to scheduled generation in excess of ex-bus energy corresponding to Normative Annual Plant Load Factor (NAPLF) achieved on a cumulative basis within each Season (High Demand Season or Low Demand Season, as the case may be), as specified in Clause (B) of Regulation 49 of these regulations"
2. The increasing emphasis on renewable energy sources in recent years has brought about a significant transformation in the power sector. Also, the increasing share of RE power in the overall generation capacity is putting significant pressure on the PLF of thermal generating stations. RE energy needs to be consumed as it is generated and the grid integration of intermittent RE is being done by thermal units. With increase in RE penetration, the PLF of the thermal generating stations is expected to decrease further in future. It is observed from the graph below that the average PLF of the thermal plants of NTPC have been continuously on the down trend from the high of 91-92% during FY08-FY09 to low of 66-68% during FY20-FY21 with minor revival in FY22 due to increasing demand.

Average Plant Load Factor (%) for thermal generating stations of NTPC



3. The above trend of reducing PLF has not been captured while approving the normative PLF required by thermal generating stations to be eligible for incentive. Also, as per the National Electricity Plan - Generation 2022-32 issued by CEA, it is envisaged that the average PLF of coal-based stations are expected to decline to 58-59%. *"The average PLF of the total Installed coal capacity of 235.1 GW is likely to be about 58.4% in 2026-27 and that of 259.6 GW of coal-based capacity is likely to be about 58.7 % in 2031-32."* Therefore, a relaxation in normative PLF is required to be provided for thermal generating stations in view of the planned increase in RE capacity by 2030.
4. The average thermal PLF is expected to follow a decreasing trend in coming years from the present band of 60-70 % and is nowhere in the range of normative PLF of 85% prescribed in the existing Tariff Regulations of 2019-24. As compared to earlier of select non pithead generating stations not being scheduled due to higher cost in the merit order, in the existing scenario, majority of the thermal stations are not being scheduled due to higher penetration of RE power. Such scenario is unnecessarily leading to denial of incentive to the thermal generating stations even when they are available, and ready to dispatch.
5. It is highlighted further that the providing for Declaring Capacity (DC) lies in the hands of the generator but the option to utilize the capacity rests with the Discoms / beneficiaries and therefore PLF should not be considered as a measure for providing incentive to the generator.
6. The lower PLFs for the thermal generating stations are expected to continue and limit any possibility to earn incentive by the thermal generating stations. Therefore, NAPLF norms for generating stations need to be lowered so as to provide them with an opportunity to earn some incentive.

In view of the above, it is suggested that the incentive may be made available for generation over 70% PLF instead of the existing norms of 85%.

<u>Further, incentive based on availability may be considered for old thermal generating stations as elaborated below:</u>

7. It is prayed to allow vintage pit-head stations to recover incentive based on capacity charges in line with 2009-14 regulation i.e., based on availability, which provides appropriate compensation. Increased availability of these cost-effective stations benefits discoms by allowing them to generate more power at a lower cost compared to other expensive options. Vintage stations require special consideration due to the extra risks they undertake. By adopting this approach, the regulatory framework can provide appropriate incentives and recognition for vintage pit-head stations, promoting their efficient operation, and ensuring a stable and cost-effective power supply for discoms. Since the distribution utilities are scheduling these plants fully the impact on Discom tariffs would be marginal, only increasing by 2-3 paisa.

8. **Following is suggested to incentivize old generating stations through following options:**
   a) **Therefore, additional incentive rate may be fixed for old generating stations at say 50 paisa per kwh over and above the incentive rate applicable for other stations.**

b) **Further, it is suggested that the incentive may be made available for generation over 70% PLF instead of the existing norms of 85%.**
c) **Old stations may be provided inflation adjusted return instead of return on equity based on historical capital cost.**
d) **Fixed margin over scheduled generation may be provided.**
e) **Incentive based on availability.**

The above measures would provide returns that are commensurate with the risks and would encourage these old generating stations to undertake better upkeep and regular maintenance which would enable them to generate power beyond the useful life on a sustained basis. Also, this would be a win-win situation for the beneficiaries as the fixed cost of the plants have been fully depreciated and therefore, they would be able to avail less costly power for a longer duration of time and limit their average cost of supply.

21. Tax Rate (7.1.24)
Approach Paper
In view of the above discussion and recent amendments to the Income tax regime, a domestic company shall fall under one of the following brackets, and the maximum tax amount that shall be payable is limited by the tax rates notified for the relevant category. Therefore, Base Rate of RoE may be grossed up as follows:
1. At MAT rate (If not opted for Section 115 BAA)
2. At effective tax rate (if not opted for Section 115BAA) subject to ceiling of Corporate Tax Rate; or
3. At reduced tax rate under Section 115BAA of the Income Tax Act or any other relevant categories notified from time to time subject to ceiling of rate specified in the relevant Finance Act.
Further, tax shall be allowed only in cases where the company has actually paid taxes as under no circumstances tax can be allowed to be recovered if the company has not paid any tax for the year under consideration.
In view of the above discussion, comments and suggestions are sought on the above and any other alternative(s).

Comments:
1. Regarding Tax on Return on Equity, relevant portion of Tariff Regulations, 2019 is extracted as under:
   31. Tax on Return on Equity.
   (1) The base rate of return on equity as allowed by the Commission under Regulation 30 of these regulations shall be grossed up with the effective tax rate of the respective financial year. For this purpose, the effective tax rate shall be considered on the basis of actual tax paid in respect of the financial year in line with the provisions of the relevant Finance Acts by the concerned generating company or the transmission licensee, as the case may be. The actual tax paid on income from other businesses including deferred tax liability (i.e. income from business other than business of generation or transmission, as the case may be) shall be excluded for the calculation of effective tax rate.
   (2) Rate of return on equity shall be rounded off to three decimal places and shall be computed as per the formula given below:

Rate of pre-tax return on equity = Base rate / (1-t)
Where "t" is the effective tax rate in accordance with clause (1) of this Regulation and shall be calculated at the beginning of every financial year based on the estimated profit and tax to be paid estimated in line with the provisions of the relevant Finance Act applicable for that financial year to the company on pro-rata basis by excluding the income of non-generation or non-transmission business, as the case may be, and the corresponding tax thereon. In case of generating company or transmission licensee paying Minimum Alternate Tax (MAT), "t" shall be considered as MAT rate including surcharge and cess.
Illustration-
(i) In case of a generating company or a transmission licensee paying Minimum Alternate Tax (MAT) @ 21.55% including surcharge and cess:
Rate of return on equity = 15.50/(1-0.2155) = 19.758%
(ii) In case of a generating company or a transmission licensee paying normal corporate tax including surcharge and cess:
(a) Estimated Gross Income from generation or transmission business for FY 2019-20 is Rs 1,000 crore;
(b) Estimated Advance Tax for the year on above is Rs 240 crore; When truing-up ROE with the effective tax rate, adjustments are made to the financial statements to reflect the tax expense calculated using the effective tax rate. This adjustment takes into account various factors such as tax credits, allowances, and the applicable tax rate.
c) Effective Tax Rate for the year 2019-20 = Rs 240 Crore/Rs 1000 Crore = 24%;
(d) Rate of return on equity = 15.50/ (1-0.24) = 20.395%.
(3) The generating company or the transmission licensee, as the case may be, shall true up the grossed up rate of return on equity at the end of every financial year based on actual tax paid together with any additional tax demand including interest thereon, duly adjusted for any refund of tax including interest received from the income tax authorities pertaining to the tariff period 2019-24 on actual gross income of any financial year. However, penalty, if any, arising on account of delay in deposit or short deposit of tax amount shall not be claimed by the generating company or the transmission licensee, as the case may be. Any under-recovery or over-recovery of grossed up rate on return on equity after truing up, shall be recovered or refunded to beneficiaries or the long-term customers, as the case may be, on year to year basis."

2. In the approach paper, it is proposed that effective tax rate can be a rate in between MAT and the Corporate Tax Rate, however, such effective tax rate considered for the grossing up of RoE under no circumstances can be higher than the ceiling rate specified under relevant Finance Act.
3. In case of a typical generating company –
    a) In initial years effective tax rate may be zero due to various tax concessions and incentives provided under the Income-tax Law. Such companies then fall under the MAT regime and are required to pay MAT.
    b) As per the concept of MAT, the tax liability of a company will be higher of the following:
        i. Tax liability of the company computed as per the normal provisions of the Income-tax Law, i.e., tax computed on the taxable income of the company by applying the tax rate applicable to the company. Tax computed in above manner can be termed as normal tax liability.

ii. Tax computed @ 15% (plus surcharge and cess as applicable) on book profit is called MAT.

c) However, in later years after absorbing depreciation losses, effective tax rates are higher than corporate tax rate.

4. In case of NTPC, taxation is at the company level and is not at station level. Presently, NTPC is paying MAT.
5. Capping the Effective Tax Rate in cases other than MAT is not justified as it can be higher than rate specified in the Finance Act. The main reason being that high depreciation under the IT Act in initial years may result in effective tax rate lower than specified rate, which will reverse in later years. Hence, even though the effective tax rate of previous years might have been lower than the corporate tax rates / ceiling rate as per the Finance Act, leading to a reduced tax rate for the utility/generator, it is important to recognize the reversal or recovery of past reductions in later years. This reversal / recovery can inflate the effective tax rate in the later years, potentially surpassing the corporate tax rates / ceiling rate as per the Finance Act.
6. Consequently, it follows that beneficiaries who have availed themselves of the advantage of lower taxes in previous years also need to bear the reversal of lower taxes in later years. Capping the effective tax rate will therefore deny the recovery of legitimate costs or revenues, as the generators/utility will not be permitted to offset the resulting higher tax liability. Therefore, if we limit the effective tax rate to corporate tax rates, then RoE truing up would be constrained in this case leading to lower RoE than has been legitimately allowed in the regulations.

Therefore, in order to remove such aberrations, following is suggested:

a) The Effective Tax Rate should be considered without capping at ceiling rate except in cases when generating company is paying Minimum Alternate Tax (MAT).

b) In case generating company is paying Minimum Alternate Tax (MAT), Effective Tax Rate shall be MAT rate including surcharge and cess.

c) Therefore, the existing provisions in CERC Tariff Regulations 2019 need to be retained as such.

22. Interest on Working Capital (7.1.25 of the Approach Paper)

Interest on working capital depends on the following two cost factors.
1. Working Capital requirement.
2. Rate of interest to be considered.

The Commission, while formulating CERC Tariff Regulations, 2019, has carried out several changes in the norms pertaining to working capital as well as the rate of interest to be considered for computing interest on working capital for generating stations and transmission licensees. Each of the above two key parameters has been discussed separately as below.

4.18.1 Working Capital Requirement

The Commission has been specifying different norms for approving working capital requirements for coal/lignite, gas, hydro generating stations and transmission business. The Commission, while formulating the CERC Tariff Regulations, 2019, has adjusted the norms considering the following key determinants.

1. Actual fuel stock position maintained by plants – Pit Head (changed to 10 days from 15 days) and Non-Pit Head (changed to 20 Days from the earlier 30 days)
2. Average Credit Cycle – Changed to 45 days Receivables.

The CERC Tariff Regulations, 2019 also allowed the fuel cost for the purpose of computation of working capital to be linked with the latest available prices, as against the previous mechanism of calculating the fuel cost at the commencement of the tariff period without any price escalation. The Commission has now allowed the reset of the fuel price during every financial year of the tariff period.

In addition to the above, the Commission also specified the working capital norms for Emission Control System through the first amendment to CERC Tariff Regulations, 2019.

It is observed that the working capital norms are efficient, so the existing norms may be retained. However, comments and suggestions are invited on any modification that may be required in the norms.

NTPC Comments:

a) The 2019 Tariff Regulations provides for linking of fuel cost with the prices of the third quarter of preceding FY for the purpose of computation of working capital. Relevant clause, i.e., Regulation 34 (2) is extracted as under:

The cost of fuel in cases covered under sub-clauses (a) and (b) of clause (1) of this Regulation shall be based on the landed fuel cost (taking into account normative transit and handling losses in terms of Regulation 39 of these Regulations) by the generating station and gross calorific value of the fuel as per actual weighted average of the third quarter of the preceding financial year in case of each financial year for which tariff is to be determined:
Provided that in case of new generating stations, the cost of fuel for the first financial year shall be considered based on the landed fuel cost (taking into account normative transit and handling losses in terms of Regulation 39 of these Regulations) and gross calorific value of the fuel as per actual weighted average for three months, as used for infirm power, preceding the date of commercial operation for which tariff is to be determined.

b) Further, Landed Fuel Cost is defined as under:

Landed Fuel Cost means the total cost of coal (including biomass in case of co-firing), lignite or the gas delivered at the unloading point of the generating station and shall include the base price or input price, washery charges whenever applicable, transportation cost (overseas or inland or both) and handling cost, charges for third party sampling and applicable statutory charges.

c) In case of pit head stations, the methodology of considering third quarter fuel prices is quite representative. However, in non-pithead stations particularly ones with multiple sources, the third quarter prices may not be representative, more so in cases of blending with imported coal. It may be pointed out that there has been shortfall in domestic coal in the current tariff period which was met through imported coal as per the directions of the Government of India (GOI). The impact of imported coal in working capital gets covered only if there it is delivered during the third quarter. In actual conditions the imported coal is as per GOI directions and cannot be practically imported in a quarter but shall be spread out across the year. Therefore, it is suggested to consider the fuel cost and gross calorific value of fuel on actual weighted average for the preceding FY used in the computation of the Energy Charge Rate (ECR) for the purposes of computation of working capital.

It is further observed that CEA has revised coal stocking norms for coal based thermal generating stations with effect from 06.12.2021 and CEA has suggested disincentives for thermal power plants in the event the availability of any coal based power plant is lower than the normative availability (as per prevailing CERC Regulations/Norms, as applicable) due to a lower stock of coal maintained by the power plant as compared to the norm specified by the CEA. A Staff Paper titled "Methodology for Computing Deterrent Charges for maintaining lower coal stock by coal based thermal generating stations" was issued in May 2022 wherein the methodology for determining deterrent charges was proposed. In this regard, comments and suggestions were invited from generating stations and stakeholders. Various generating stations and stakeholders have submitted their responses, however, any further suggestions on the issues flagged therein may be submitted for consideration.

NTPC Comments:

In this regard, NTPC has submitted comments on the Staff Paper titled "Methodology for Computing Deterrent Charges for maintaining lower coal stock by coal based thermal generating stations" vide letter dated 27th May 2022, which is reproduced as under. It is submitted that the above NTPC comments on the Staff Paper may be considered.

NTPC Comments on CERC Staff Paper Methodology for Computing 'Deterrent Charges' for maintaining lower coal stock by coal based thermal generating stations.

1. **Availability on Quarterly Basis –**
   The CERC Staff Paper has proposed as under:
   "42(8) (i) In case, the Plant Availability in any month is short by more than 5 % but up to 25 % of NAPAF and average coal stock availability for the last three months (month for which reduction in capacity charges are computed and two months preceding that month) is lower than the average coal stock norms specified by CEA for the respective three months:"
   Revision of Coal Stocking Norms in Coal Based Thermal Plants was issued by CEA vide letter dated 27.11.2022 with approval of MOP which stipulates maintaining Normative Availability on a quarterly basis.
   Relevant portion of the CEA Revised Coal Stocking norms is extracted as under:
   a) Power plant designed on domestic coal: In the event, the availability is less by 5% or more from the Normative Availability (as applicable) on quarterly

basis, the fixed charge shall be reduced to the extent of shortfall in Normative Availability and in addition, the reduction below the Normative Availability shall be multiplied by a factor of 0.2 (i.e. levy of additional 20% due to reduced availability) to determine the charges payable for non-maintenance of coal stock on quarterly basis.

b) Power plant designed on imported coal: In the event the availability is less by 5% or more from the Normative Availability (as applicable) on quarterly basis, the fixed charge shall be reduced to the extent of shortfall in Normative Availability and in addition, the reduction below the Normative Availability shall be multiplied by a factor of 0.5 (i.e. levy of additional 50% due to reduced availability) to determine the charges payable for non-maintenance of coal stock on quarterly basis.

c) Further, in case the availability is less by 25% or more from the Normative Availability (as applicable) on quarterly basis, the fixed charge shall be reduced to the extent of shortfall in Normative Availability and in addition, the reduction is beyond 25% below the Normative Availability shall be multiplied by a factor of 1 (one) (i.e. levy of additional 100% due to reduced availability) to determine the charges payable for non-maintenance of coal stock on quarterly basis.

This above is also aligned to the existing FSA provisions which also provides quantities on quarterly basis. The Fuel Supply Agreement (FSA) provides that the Annual Contracted Quantity (ACQ) shall be divided into Quarterly Quantity which is specified as a certain percentage of the ACQ. The Monthly Quantity is specified as one third of the Quarterly Quantity.

Considering monthly availability would have significant implications. The same has not been envisaged by the CEA Revised Coal Stock Norms and the MOP directions in this regard. Achieving target availability in a shorter period enhances the risk considerably and multiplies the penal implications. It may be mentioned that presently target availability is to be achieved separately in high demand season and low demand season which is for periods of 3 months and 9 months respectively.

It is therefore submitted that availability may be considered on quarterly basis as stipulated by CEA in its revised coal stock norms instead on monthly basis as proposed by CERC Staff Paper. The staff paper has proposed average coal stock for preceding three months including the current month for which computation is being made. On similar lines, it is suggested that average availability of the preceding three months including the current month for which computation is being made may be used.

2. Penalty should be levied only if target availability is not achieved due to coal shortage - The direction issued by MOP to CERC under Sec-107 of EA-2003 vide letter dt. 22.02.2022 at S. No. 3(c) provides as under:

In the event availability of any power plant is less than Normative availability due to less coal stock maintained by the power plant, the power plant has to face disincentive in terms of reduction in fixed charges to the extent of shortfall in Normative availability and levy of additional factor due to reduced availability as penalty.

Therefore, in line with the above MOP direction, the plant should not be penalized if the shortfall in availability is due to reasons other than shortfall in coal stock. Penalty should not be levied in the following reasons.

i. Penalty should not be levied during the period when a unit / station is under planned capital shutdown or annual overhauling, or a unit is under shut down due to reasons not attributable to coal shortage.
ii. There could be instances where the unit may be under shutdown for long periods due to breakdown of major equipment like Generator Transformer, high turbine vibration, etc.
In such cases, where outage or reduction in DC is due to reasons other than coal shortage, there is already provision for reduction in fixed charges in the existing CERC regulations. Therefore, the stations should not be double penalized on this account and must be exempted from levy of penalty because of non-maintenance of normative coal stock.

3. **Obligation for Ensuring Coal Stock only on generators is not fair -** Penalty should not be levied in case shortfall in coal stock is due to lower supply by the coal company or due to logistics and transportation issues attributable to the Indian railways and is not directly attributable to any negligence on part of the generating company. It is submitted that NTPC coal stations have Coal Supply Agreement with the Coal India Limited and its subsidiaries. Transportation of coal from the linked mine to the station in pithead stations is through dedicated MGR system, which is operated by the station. It may be noted that pithead stations are better placed as compared to non-pithead stations with respect to coal stock position as station has direct control over the transportation logistics.
In case of non-pithead stations, the transportation of coal is through Indian Railways (IR). Both CIL & its subsidiaries and IR are government instrumentalities and natural monopolies. While the Coal Companies are CPSUs operating under the administrative control of the Ministry of Coal, Indian Railways comes under the Ministry of Railways, Government of India. Thus, in addition to NTPC, the responsibility of making requisite quantity of coal available at the station rests equally on the Coal Companies and Indian Railways. The generating company is accountable for arranging coal for achieving target availability to ensure full recovery of fixed charges. However, penalizing the generating company for not maintaining coal stock as per the revised coal stock norms in spite of taking all efforts to procure coal diligently is not justified.
The CEA revised coal stocking norms dated 6th Dec 2021 provides for recommendation by CEA / MoP for enhancing coal supply to generating station according to system of monthly grading of Gencos/IPPs based on the performance of generating company in maintaining coal stock and status of payment to coal companies. It further provides that if Central State Genco or IPP submits programme as per the Monthly Scheduled Quantity (MSQ as per the FSA) of the individual plant, but still is not able to maintain coal stock due to reasons, such as less coal supply by CIL, less rake availability, running at very high PLF, etc. (>= 85% PLF), then such plant will be kept in green zone.
NTPC regularly participates in the sub-group meetings held for coal coordination, where all stakeholders including MOC, MOP, CEA, Indian Railways and generating companies participate. NTPC places the requirement of coal for each station, which is then endorsed by the Coal Supply subject to the coal availability. Indian Railways then sanctions railway rakes as per availability and operational considerations. NTPC makes advance payment to the coal companies for supply of coal. Similarly, there is LC mechanism for payment to railways. Therefore, Coal

companies and Indian Railways play a pivotal role in materialization of supply to the stations, over which the generating companies do not have much control.
It is therefore submitted that if generating company is able to demonstrate its actions for procuring coal diligently, i.e. it submits programme as per the Monthly Scheduled Quantity (MSQ as per the FSA) of the individual plant, requisition for rakes, makes advance payment, etc., but is still not able to maintain coal stock due to reasons, such as less coal supply by CIL, less rake availability, attributable to Coal Company or the Indian Railways; it should not be penalized for any deficiency or lapse on part of the coal companies or the Indian Railways.

4. **Revision in Coal Stock Norms used for Computation of Working Capital -** CERC Tariff Regulations, 2019 provides following cost of coal stock for computation of working capital as under:
i. Pit-head stations - 10 days
ii. Non pithead stations - 20 days.
Revised coal stock norms proposed by the Staff Paper is as under -
i. Pit-head stations - 12 to 17 days depending on month of year.
ii. Non pithead stations - 20 to 26 days depending on month of year.
Existing Norms for coal stock in working capital is lower than the proposed coal stock norms for both pithead and non-pithead stations. The implication of revised coal stock norms on the working capital requirement of NTPC coal-based stations would be approximately Rs. 910 crores, which would translate to increase in interest on working capital by approximately 100 crores.
In order to ensure continuous power supply to the beneficiaries and considering the current materialization of domestic coal, the Govt. of India vide letter dated 28.04.2022 has issued revised targets for NTPC regarding importing 20 million MT coal by October 2022, which would need additional working capital requirement of Rs. 36,000 crores (considering landed price of imported coal @ Rs. 18,000 per MT) and would translate to interest on working capital of Rs. 3780 crores.
In-principle, all expenses incurred in a cost-plus tariff framework subject to regulatory prudence is allowed in tariff. It is therefore submitted that coal stock norm for computation of working capital need to revised accordingly and aligned to the proposed revised coal stock norms.

5. **Force Majeure Events -** Coal supply to generating company would be affected on account of force majeure events impacting the Coal Company or the Indian Railways or the generating company, like unprecedented natural calamities, floods, accidents in mines, disruption in rail traffic, law & order situation etc. It is submitted imposition of penalty in such cases must not be insisted upon.

6. **Phased Implementation -** It may be noted that presently the country is facing severe shortfall in domestic coal. Generators have been directed to import coal for blending at least 10% and to up to 30% imported coal with domestic coal. There is also direction for operationalization of non-operating imported plants. In such a scenario of high coal requirement, it would not be possible to build required stock levels especially in non-pithead stations. Therefore, it is submitted that the penalty mechanism may be implemented in a phased manner. This is required as stations would not be able to build up required stocks in view of high PLF and present levels of supply.

With regard to gas based generating stations, from the operational data in recent years, it is observed that the PLF of such generating stations is around 20%-25%. As power from these plants is costlier it is generally scheduled by beneficiaries only to meet peak requirements. It is anticipated that these generating stations will continue to operate at such low PLFs in the next tariff period, and therefore, the current practice of allowing working capital requirements considering generation at normative PLF may need review.

Comments and suggestions are invited on any modification that may be required in the norms of old gas generating stations to factor in the actual generation while allowing for the working capital requirement for gas based generating stations.

NTPC Comments:

It is submitted that the Ministry of Power vide letter dated 20th April 2023 has issued "Scheme for Pooling of Tariff of Stations whose PPAs have expired", with the objective to ensure continued operation of the gas-based plants of generating companies to provide peaking / balancing power for smoother and affordable energy transition towards RE and for resource adequacy. The scheme envisages pooling fixed charges and energy charges at the generating company level. In case of NTPC, all gas stations will be part of this pool in the next tariff period. It is expected that the PLF of gas stations shall increase substantially from the existing levels due to pooling of energy charges. Moreover, as RE penetration increases, the gas plants will be required for more flexing / balancing operations in future. In the above scenario, it is felt that the need for reviewing the computation of working capital requirements considering normative PLF would not be necessary. As gas has to be arranged for declaration of DC and running these plants as per the dispatch, which is expected to increase, working capital requirements may be linked with normative PAF as per existing methodology. It is therefore suggested to continue with the existing practice of computation of working capital requirements considering normative PAF may be continued. Alternatively, normative availability factor may be reduced suitably considering the expected operational levels in future.

4.18.2 Rate of Interest on Working Capital

The Commission, while formulating the CERC Tariff Regulations, 2019, shifted from base rate to a more efficient MCLR based funding which is more responsive to policy rate changes. **As per the existing Regulations, the Bank Rate for the purpose of computing the Interest on Working Capital (IoWC) is defined as one-year MCLR plus 350 bps. Stakeholders may comment as to whether the same may be continued or may suggest any better alternative to the same.**

NTPC Comments:

MCLR is utilized by Banks as benchmarks for the purpose of fixation of interest rate on loans. Bank Rate has been considered as one-year MCLR of SBI issued from time to time plus 350 basis points. It is submitted that the dispensation of Bank Rate as on 1st April of each FY during the tariff period for computation of Interest on Working Capital (IoWC) is more efficient MCLR based funding mechanism and may be retained in the next tariff period.

4.18.3 Normative Working Capital and interest thereon

As discussed in Section 3 of this Approach Paper, in order to simplify the process of tariff filing and its determination and reduce the regulatory burden on generating and transmission companies, the possibility of determining Annual Fixed Charges (AFC) on a normative basis is being evaluated. Most of the cost components, such as Depreciation, RoE, O&M Expenses, are already determined on a normative basis.

It is further observed that the working capital norms are allowed and then trued up after factoring in the actual receivables, fuel prices (Thermal Generation), MCLR and normative O&M expenses.

With regard to thermal and gas based generating stations, fuel costs form sizeable part of the working capital requirement, and as working capital requires truing up on the basis of actuals primarily because of changing fuel expenses, it is to be explored how working capital can be approved such that yearly truing up is not required.

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.

NTPC Comments:

The existing tariff regulations has prescribed specific norms for various components of the working capital, such as, cost of coal for 10 days for pithead stations and 20 days for non-pithead stations, advance payment of 30 days towards cost of coal, cost of secondary fuel for 2 months of generation, maintenance spares @ 20% of O&M expenses, receivables of 45 days of capacity charge and energy charge, O&M expenses for 1 month. Thus, the components of working capital are based on normative parameters and the interest on working capital is also indexed to SBI MCLR.

Receivables of 45 days may be enhanced considering Issuance of REA

a. Issuance of Regional Energy Account (REA) by respective RPCs is pre-requisite for issuance of monthly energy bills. Presently, based on scheduling data made available by the RLDC, REA is prepared by respective RPC and REA is uploaded on websites of RPC generally on 4th - 5th of each month for the energy supplied in the previous month. Accordingly, the energy bills by NTPC are generated and presented to the Discoms on 5th or 6th of every month.
b. Issuance of energy bills by power utilities to Discoms on 5th or 6th of the billing month has a financial implication of carrying cost of 5-6 days for the billing amount is borne by the generating company. Considering an annual

billing of Rs. 1,50,000 crores, the financial implication for 6 additional days at 10% p.a works out to around Rs. 250 crores.

c. **It is suggested that receivables of 45 + 6 days may be considered for computation of working capital or provision of raising of provisional bill on 1st of each month by the generating company may be provided in regulations before issuance of REA.**

It is felt that the truing up of working capital at the end of tariff period would be required as revision of working capital due to changing fuel price would be only possible after completion of the FY. Indexation of fuel cost would be difficult and has practical limitations.

The cost of fuel considered is based on the landed cost and GCV as per actual weighted average for the third quarter of the preceding FY in case of each FY for which the tariff is determined. The Approach Paper has pointed out that the actual fuel price keeps varying and affects the total receivables. However, this is necessary for factoring the variation in fuel prices with the working capital. The possibility of exploring a suitable indexation mechanism for cost of fuel is elaborated as under:
Indexation of fuel prices is possible if the coal source is fixed and is not subject to sudden variations. It may be noted that the shortfall of domestic coal in the current tariff period was met through importing coal. However, as majority of the imported coal was received outside the third quarter, the impact of imported coal cost in working capital could not be factored completely.
Further, there are other variables which have significant bearing of the overall landed cost of coal. A few of the variables which have no specific benchmark include transportation cost, levy of any additional duty or cess, etc. Transportation charges are dependent on the source and mode of coal being transported and may vary significantly based on demand-supply positions. Therefore, suitable indexation of coal cost in the present scenario may be difficult considering blending of imported coal, supply from multiple sources, transportation modes, price hike, etc.

Therefore, existing mechanism of considering actual fuel cost may be continued with slight modification. The cost of fuel for purpose of computation of working capital may be considered based on the actual weighted average Energy Charge Rate (ECR) for the preceding FY in case of first FY of the control period for which the tariff is determined. The fuel cost arrived for the first year as above may be used in computation of working capital for subsequent years of the tariff period. The same shall be subject to annual adjustment / reconciliation of fuel cost variation at the end of respective year based on the actual weighted average ECR of that year.
Further, such annual adjustment / reconciliation of fuel cost variation can be done by the generating company based on actual ECR of that year. Revision in rate of interest on working capital as on 1st April of FY can be made every year after the end of that year along with fuel cost adjustment. This approach would capture actual fuel cost variation for entire year and shall be a fair approach from both generator and beneficiary perspective.

23. Life of Generating Stations and Transmission System (7.1.26 of the Approach Paper)

The Commission, in its Explanatory Memorandum to the draft CERC Tariff Regulations, 2019, has carried out a detailed analysis of increasing the life of assets and its impact on tariff, as well as a sensitivity analysis of the various components of tariff vis-à-vis asset life and has re-assessed the life. Based on the study carried out, the Commission increased the life of hydro generating stations from 35 years to 40 years, keeping the life of other asset classes same as specified in the CERC Tariff Regulations, 2014.

Further, the Commission, through the second amendment to the CERC Tariff Regulations, 2019, has recently specified the life of mines and related assets on the basis of a detailed study carried out by the Working Group.

It is observed that as more and more coal based thermal generating stations are operating efficiently even beyond 25 years, there may be a case to align the normative life of these stations, considering that with proper upkeep, these generating stations can operate even beyond 30 years. Similarly, in the case of transmission sub-stations it is observed that these assets can operate way beyond 25 years similar to transmission lines, and therefore, **the useful life of coal based thermal generating stations and transmission sub-stations may be increased to 35 years from the current specified useful life of 25 years.**

It is, however, observed that one of the factors that has enabled these assets to operate beyond 25 years is the regular operations and maintenance carried out by the utilities. In the past, the Commission has allowed a special allowance for these assets in order to take care of the increasing need for repairs that are required to keep the equipment operating efficiently. **As the need for higher repairs will still be required, the current dispensation of allowing a special allowance or provision of R&M may be continued after 25 years.**

Comments and suggestions are sought from stakeholders on the above proposal and the necessity of further changes, if required.

NTPC Comments:

a) Presently, the PPA tenure is 25 years. Hence, plant life more than PPA period will generate risk in return when secured demand is for lesser period.

b) Further, with increase in RE penetration, thermal power stations need to run in flexible mode. And as a result, there will be accelerated aging of thermal power plant.

c) Further, to meet the Net zero target, thermal plant may be decommissioned well before target years. Hence, new plant which are under construction / under planning may need to shut down even before its consumption of normal life. Considering above, 25 years life may be considered as being followed presently.

d) In line with the industry practice of useful life of coal-based stations of 25 years, the tenure of PPA of thermal stations entered with the Discoms is 25 years. Useful life in tariff specifies the period over which the depreciation of a station is recovered. In case the useful life is increased from 25 years to 35 years, the depreciation will not be entirely recovered in 25 years. However, since the PPA tenure is over, the Discoms may refuse to continue offtake power from these stations after 25 years on expiry of PPA, in which case the depreciation remains unrecovered. It may be noted that long-term PPA were signed for 25 years considering the useful life of 25 years in tariff at the time of investment approval. Therefore, it is required that regulations may provide for recovery of residual depreciation and other costs remaining unserviced in case a Discom does not continue to off take power till 35 years.

e) On the same principle, Regulations may also provide servicing of stranded assets due to Change in Law, Force Majeure, or any other statutory measures.

f) Therefore, following is suggested:

1. **Therefore, it is required that regulations may provide for recovery of residual depreciation and other costs remaining unserviced in case a Discom does not continue to off take power till 35 years. On the same principle, Regulations may also provide servicing of stranded assets due to Change in Law, Force Majeure, or any other statutory measures.**
2. **Further, considering the accelerated aging anticipated due to flexible operations, risk of pre-mature retirement due to decarbonization, etc., risk due to mismatch of PPA and useful life, the existing useful life of 25 years may be retained.**
3. The Approach Paper has proposed continuation of the current dispensation of allowing a special allowance or provision of R&M after 25 years, recognizing the need for higher repairs will still be required. **It is submitted that higher expenses in the form of R&M or special allowance shall be necessary after 25 years as these plants need the same for sustained operation without any relaxation in the operating parameters.**

24. Input Price of coal – Integrated Mine (7.1.27 of the Approach Paper)

The Government of India, on 21.10.2014 notified "The Coal Mines (Special Provisions) Ordinance, 2014, [now "The Coal Mines (Special Provisions) Act, 2015 (11 of 2015) or "The Coal Mine Act"] which provides for the coal allocation through public auction or through an allotment order. As per Section 5 of the Coal Mine Act, the allocation of mine through allotment order is allowed to a Government Company and Case-2 generation projects.

Unlike allocation by auction, allocation by Allotment Order on the basis of Government dispensation, is made without specifying the cost of coal mining or the price of coal. The allotment documents and standard Coal Mine Development and Production Agreement (CMDPA) issued by the Ministry of Coal, GoI does not provide any coal price for using coal in specified end use plants, except for specifying the end use as power generation.

The Commission vide the second amendment to CERC Tariff Regulations, 2019 has incorporated provisions with regard to the determination of the input price of coal and lignite, wherein such mines have been allocated to the generating stations. The Commission, before specifying the norms, had constituted a Working Group to suggest a regulatory framework for the determination of input price of the coal and lignite. The Commission, on the basis of the report submitted and after considering the suggestions received from various stakeholders, notified the second amendment to CERC Tariff Regulations, 2019 on 19.02.2021 which specified the terms of the determination of the input price of coal to be considered for the determination of energy charges for power stations with integrated mine.

It is observed that so far the Commission has received a couple of petitions for the determination of the input price of coal and therefore not much actual data is available to review the current operational norms and other provisions. In view of no compelling reasons to revisit the current terms and conditions for the determination of the input price of coal, it is proposed that the current provisions be continued.

Comments and suggestions are sought from the stakeholders on any modifications that may be required to current tariff provisions with regard to the determination of the input price of coal and lignite from integrated mines.

NTPC Comment:

CUF for Integrated Mines may be fixed at 80%.

a) The transfer price of coal of an integrated / captive coal mines shall be determined by CERC in case such coal is supplied to stations of a generating company whose tariff is determined under section 62 of the Electricity Act 2003 by CERC. Such transfer price of coal shall be determined by CERC as per the 2nd Amendment to the CERC Tariff Regulations, 2019 which was notified in Feb'21.

b) The above regulations specify the Annual Target Quantity (ATQ) for recovery of full fixed cost which is equal to production schedule as per the Mine Plan. Therefore, Capacity Utilization Factor (CUF) for full fixed cost recovery is equal to 100%.

c) The mine plan is prepared as per prescribed guidelines in this regard. It is applicable for entire life of the mine and approved before the mining activity begins. However, there are a large number of uncertain events and risks involved in mining which cannot be predicted upfront especially with respect to its time of occurrence so that the year wise production schedule can be accurately worked out at the time of approval of mine plan.

d) Further, revision in Mine Plan as per the guidelines is permissible under limited circumstances i.e. change of method of mining and low balance reserves otherwise downward revision in production schedule is not allowed.

e) Some of the uncertainties / risks encountered in mining are elaborated as under:

i. Land acquisition in mining is a continuous process. Land is acquired as and when mining progresses and mining operations carry risk of land acquisition during the entire mine life.

ii. Fencing of mine boundary is not feasible as mines are spread over larger area. Therefore, mines are exposed to greater geo-political risks. For example, Pakri Barwadih mine is spread over 47 Sq Km area, it covers around 27 villages and PAPs are more than 8000.

iii. Mines are directly exposed to harsh weather conditions like torrential rains, flooding, etc.

f) In a cost-plus regulatory framework, norms should be set based on past performance. In this regard, the Tariff Policy provides that the norms should be efficient, relatable to past performance and capable of achievement. Further, it also provides that performance norms of operation together with incentives and disincentives would need to be evolved.

g) The past performance of NTPC mines as well as those of NLC and CIL, is tabulated as under:

	2019-20	**2020-21**	**2021-22**
CIL	73.04	80.57%	77.10%
CCL	72.73%	73.50%	71.60%
NLC	88.48%	68.55%	89.37%
NTPC-Pakri	Met as per plan	74.42%	83.20%

Past performance of NTPC mines as well as NLC and CIL mines, indicates that prescribing 100% CUF for fixed cost recovery is too harsh.

h) It is pertinent to mention that before notification of these regulations, CERC had been fixing the transfer price of lignite based on the guidelines issued by Ministry of Coal from time to time, latest being guidelines dated 02.01.2015, wherein CUF for full fixed cost recovery was considered at 85%.

i) The Working Group constituted by CERC under the chairmanship of Sh. Sutirth Bhattacharya, Ex CMD CIL, also recommended the normative CUF of 85%. Further, CIL considers 85% CUF and 12% FIRR of new project for deciding feasibility of new project. With normative CUF of 100%, generating company can only incur disincentive and there is no possibility of any incentive.

j) **Keeping in view of the provisions of the Tariff Policy, the timing of uncertain events & risks involved which cannot be exactly predicted at the time of preparation of Mine Plan, and past performance of the mines, recovery of fixed cost may be allowed @ 80% CUF and proportionate recovery of fixed cost if production is more than 80%.**

RETURN ON EQUITY - Presently, return on equity of integrated mine as per extant regulations is @14%. Considering the several of the risks associated in mining operations and returns available, it is submitted that Hon'ble Commission may review the RoE from the existing 14% to at least at par with the thermal generating station. Following aspects may be considered:

a) It is submitted that coal mining operations may encounter several of the risks which may include geological surprises, seasonal impact, socio-political factors etc. Further, Mining sector faces significant developmental & operational risks like huge area of land acquisition, environment clearances, Rehabilitation and Resettlement of huge number of Project affected Persons, geological surprises, direct exposure to extreme weather conditions like rain etc. It is submitted that the return on equity has to be commensurate with the risks.
b) In cases of MDO operated mines, though there is lessor investment in the plant & machinery, however mine developer has to absorb several of risks as elaborated above.
c) It is pertinent to mention that Coal India is also considering IRR of 12% for its projects.
d) It is therefore submitted that similar rate of return, as being considered by Coal India for its projects, may be allowed for integrated mines also. It may be noted that RoE @ 15.5% will be equivalent to approximately 11.55% of IRR which will still be lesser then that considered by Coal India.
e) It is therefore submitted that the Hon'ble Commission may enhance the RoE from the existing 14% to more than 15.5% at par with the thermal generating station.

Additional Capital Expenditure: New sub-clause may be added for allowing additional capital expenditure after COD as under:

"The additional capital expenditure incurred for enhancing the evacuation capacity may be allowed by considering, but not limited to, the Mining Plan including mine closure plan and such other details as deemed fit by the Commission."

Adjustment on account of shortfall in GCV (GCV Adjustment):

As per existing regulations, in case the weighted average GCV of coal extracted from the integrated mine(s) in a year is lower than the declared GCV of coal of such mine(s), GCV adjustment is applicable. On the other hand, no GCV adjustment is allowed in case the weighted average GCV of coal extracted is higher than the declared GCV. It may be appreciated that there would be variations in the GCV of coal extracted due to quality variations in the coal seams. Therefore, it would be fair to consider both positive and negative variations. In view of the above, it is suggested that incentive for higher GCV may also be allowed.

Overburden:

a) As per existing regulations, adjustment of overburden is allowed in subsequent three years. Further, the shortfall in overburden removal is not made good during the subsequent 3 years, the regulations specifies overburden adjustment based on the actual quantity of coal, annual stripping ratio, etc. In this regard, following is submitted:
b) The overburden is estimated based on the geological studies and removal of such overburden is envisaged during the lifetime of the mine. Therefore, the

total overburden to be removed during lifetime of the mine is fixed. If lower quantity of overburden is removed in one-year, higher overburden shall be required to be removed in subsequent years.

c) In view of the above, it is submitted there may not be any requirement to keep provision/ formula for adjustment on account of stripping ratio variations.

Procurement from Commercial Mines:

It may be noted that going forward mines are being bid as commercial mines. Considering shortage scenario for domestic coal, generating companies may have to depend on commercial mines also. Therefore, suitable regulatory provisions to procure such coal for use at power stations without competitive bidding may be provided.

25. Sharing of Gains (7.1.28 of the Approach Paper)

Regulation 60 of the CERC Tariff Regulations 2019, allows sharing of gains on account of the following:

1. Due to efficiency gains related to operational parameters namely Station Heat Rate, Auxiliary Energy Consumption, SFOC which are to be shared in the ratio of 50:50.

2. Due to the refinancing or restructuring of loans, net gains are to be shared in the ratio 50:50.

3. Non-Tariff Income – The net income to be shared in the ratio of 50:50.

4. Clean Development Mechanism (CDM) Benefits – 100% of gross proceeds towards CDM benefits in the first year are to be retained by the developer, and from the second year onwards, 10% is to be shared with beneficiaries, and thereafter, every year 10% incremental benefits are to be shared, subject to a maximum of 50%.

5. Sharing of income from other businesses of transmission licensees – To be shared with the beneficiaries as per the Central Electricity Regulatory Commission (Sharing of revenue derived from utilization of transmission assets for other business) Regulations, 2007.

It is observed that both generating companies as well as transmission utilities have considerable resources in the form of assets such as land banks and other enabling infrastructure and human resources that can be utilised to increase non-core revenues through lease, data centres, eco-tourism, etc., which should be explored, and in order to generate such lateral revenue opportunities, the utilities need to be incentivised.

Comments and suggestions are sought from the stakeholders on the following:

1. Ways to increase non-core revenues through optimal utilisation of available resources.

2. Any modification in the sharing mechanism that may be required.

NTPC Comments:

a) **Sharing of Gains due to variation in norms:** The Regulation 60(2) provides for sharing of Energy Charge Rate gains on annual basis. Regulation 60(2) of CERC Tariff Regulations 2019 provides as under:

The financial gains by the generating company or the transmission licensee, as the case may be, on account of controllable parameters shall be shared between generating company or transmission licensee and the beneficiaries or long-term customers, as the case may be on annual basis. The financial gains computed as per the following formulae in case of generating station other than hydro generating stations on account of operational parameters as shown in Clause (1) of this Regulation shall be shared in the ratio of 50:50 between the generating stations and beneficiaries.

……………………………………

ECR_A = Actual Energy Charge Rate computed on the basis of actual Station Heat Rate, Auxiliary Energy Consumption and Secondary Fuel Oil Consumption for the month…….

The need for sharing gains on annual basis was explained by Commission in SOR of 2014 Regulations as below:

"10.14 The Commission agrees with the views of some of the stakeholders that the monthly figures would vary widely depending upon the seasonal changes, maintenance schedule of the Units and the load that is maintained depending on the prevailing conditions. Therefore, the Commission has decided to include the provision of annual reconciliation with respect to sharing of gains. As regards considering the variation in heat rate due to backing down and part loading, frequent start/stop, etc.,"

The above view of consideration of annual reconciliation to even out the effect of seasonal variation was re-iterated by Commission in order dated 06.12.2021 in Review Petition No.19/RP/2020 in Petition No.284/RC/2019.

However, in implementation of this regulation lot of disputes have been faced by generators. Therefore, sharing of gain in the same tariff period may be discontinued.

Further, Commission has rightly proposed Normative approach for tariff determination to reduce time and cumbersome process of going through each cost elements. In line with that, Regulations should avoid sharing of gains over whether operational or financial parameters based on actual. It will amount to again prudency check and adopting same process which CERC wants to avoid. Otherwise also any improvement of performance is shared with Discoms in subsequent Regulations when norms are fixed. Moreover, the Hon'ble Commission sets the operational and financial norms for the tariff period after due consideration of various aspects including past actual data. Therefore, such improvement in the performance by utility is passed on the beneficiaries through tariff in the next tariff period.

In view of the above, sharing of gains may be discontinued during the same tariff period.

Income from Sale of Scrap –

Regulations 62 of CERC Tariff Regulations 2019 provide for Sharing of Non-Tariff Income as under:

The non-tariff net income in case of generating station and transmission system from rent of land or buildings, sale of scrap and advertisements shall be shared between the beneficiaries or the long term customers and the generating company or the transmission licensee, as the case may be, in the ratio 50:50.

Scrap is generated out of spares and plant and machinery. In both the cases 90% of capital cost (so far) is recovered from tariff and 10% is un-serviced for life of plant. The income from sale of scrap even does not cover even the salvage value cost (10%) of these assets. Further, company also incurs certain administrative cost on disposal of asset. Besides that, all the sale of scrap is not from the admitted part of the capital cost and even if it is part of admitted cost, the same is deducted from the admitted capital cost in the event of decapitalization.

Further, Hon'ble Commission does not consider the loss on disposal of asset as allowable/claimable expenses. Therefore, it is grossly unfair to transfer the benefit of something which has not been serviced by the beneficiary and any such sharing now proposed is not fair.

The provision for sharing of non-tariff income is not justified in case tariff determination is done based on cost-plus approach. Under the framework, the returns available to the generators are restricted and monitored through a truing-up exercise towards the end of the tariff period. Any other income other than that of generation of electricity by the generator need not be shared with the beneficiary as these are solely attributable to the efforts of the generator.

Based on the existing regulations, the salvage value of the assets is considered as 10% and is not allowed to be recovered as part of tariff from the beneficiaries. Further, during prudence of capital cost or additional capital expenditure, the Commission disallows certain part or costs against the assets of the plant. Recovery through sale of scrap cannot be earmarked to such approved or disallowed part of the capex of the plant. Further, there are expenses in form of tender processing, transportation, etc. charges associated with respect to sale of scrap which have to be borne by the generator and not accounted for while recording recovery from such sale of scarp. It is worth noting that the any loss incurred from asset disposal is also not allowed to be claimed by the generator. **Therefore, any considerations received by the generator against sale of scrap should also not be made part of the non-tariff income.**

Also, with the change in regime, the risks associated with thermal power generation business has increased considerably. With the regulated tariff only considering past expenses as the base to approve future expenses. However, it is submitted that there are certain expenses / costs that not recovered through tariff. Such unrecovered cost may lead to losses. In a situation when the such costs cannot be passed on to the consumers, the concept of sharing of any other sources of revenue is incorrect and should not be considered. Therefore, no such income which is accruing to the generator due to its own efforts should be considered for sharing with the beneficiaries under the head of non-tariff income.

b) Due to Refinancing or Restructuring of loans

The existing mechanism for sharing of any benefits arising for refinancing / restructuring of loans does not provide adequate incentive to the generator as against all the efforts required to be undertaken by the generator. On the contrary, the beneficiary receives 50% of the benefits arising from such refinancing of loans while no effort is undertaken at its end. Therefore, keeping in view that the efforts for such refinancing / restructuring of loans, a higher share of incentive (two-third) should accrue to the generator which would adequately encourage them to pursue such proposals with the banks/ financing agencies.

Further, the existing regulations principally allows for refinancing of loans and sharing of gains between generators and beneficiaries based on the 50:50 ration. **However, the methodology with respect to adjustment for the sharing has not been clearly defined leading to confusion in billing and realization of the same. Therefore, the existing provisions may provide clear methodology for sharing of refinancing gain and refinancing cost either through Form-13 or separately.**

In case of normative interest on loan approach, sharing of gains with beneficiaries may be avoided as it would become cumbersome to implement in the normative approach and defeat the purpose of simplification of tariff.

26. Treatment of arbitration award – Servicing of Principal and Interest Payment (7.1.29 of the Approach Paper)

The CERC Tariff Regulations, 2019 provide for allowing Additional capitalisation including liabilities, to meet an award of arbitration or for compliance with the directions or an order of any statutory authority, or order or decree of any court of law.

It is observed that in certain cases, these awards are issued after prolonged litigation. In general, these awards have two components the principal amount and the interest amount. At times, the financial impact associated with these matters is considerable, and capitalising the entire award amount may result in increased AFC, leading to an additional recurring burden on the beneficiaries over the remaining useful life of the asset. ***To avoid such situations, the principal amount may be capitalised and the interest amount may be allowed to be recovered in instalments from the beneficiaries. However, such a recovery of interest may also involve carrying cost.***

Comments and suggestions are sought from stakeholders on the above approach and alternative ways, if any.

NTPC Comments:

The existing regulations allow capitalization of liabilities to meet award of arbitration or for compliance with the directions or an order of any statutory authority, or order or decree of any court of law under additional capitalization consist of principal and interest amount as the awards are often issued after prolonged litigation. The Approach Paper has proposed that to avoid recurring burden on the beneficiaries, the Principal amount may be capitalized, and the interest amount may be allowed to be recovered in instalments from the beneficiaries. However, such a recovery of interest may also involve carrying cost.

It is submitted that in cases where the contractor / agency is non-performing, the generating company may be constrained to levy LD, or terminate such contract. Further, any action of the generating company to penalize the contractor for non-performance or delay has to be dealt in accordance with the terms and conditions of the contract and other guidelines / rules for procurement in this regard. **In cases where dispute cannot be resolved, the option of arbitration becomes necessary, for which the generating company has no control. Therefore, the generating company may not be denied capitalization of the principal and interest amount in a cost-plus regulatory framework as there is no imprudence on the part of the generating company.**

Moreover, these costs are related to capital assets that are providing service and the beneficiaries are deriving benefit from the same. However, due to arbitration, these assets are not included in the capital cost for tariff purposes till award of arbitration. It may be noted that arbitration process results in delayed servicing of costs for such assets. Therefore, these assets being of capital nature, it follows that their servicing has to be through capital cost in line with other capital assets.

in view of the above, treatment as per existing practice may be continued.

27. Treatment of Interest on Differential Tariff after Truing up (7.1.30 of the Approach Paper)

69. Interest may be allowed to be charged on the differential amount by the utility only till the issuance of the order and no interest may be allowed during the recovery in six equal monthly instalments. (Refer 4.23)

NTPC Comment

a) The time value of money is a settled financial principle and the same has also been recognized by various *foras* including the Hon’ble Tribunal. The utility gets compensated by way of carrying cost on this very principle i.e., when amount is due and recovery is deferred, the utility gets compensated by way of carrying cost. Thus, when a beneficiary adopts for a payment mechanism, where the payment is made in the instalments, the utility should be compensated for the delay in recovery of its revenue as the amount has already become due and being deferred on the account of the payment mechanism chosen by the beneficiary.

b) When a beneficiary chooses to pay the arrears in monthly installments (six installments in the present case) the same will be subject to interest because interest on arrears is nothing more than a restriction on account of the affected party's loss of funds up until the point at which the restitution is implemented. It is further submitted that the EMI payment principle is always subject to interest assessments. Hence, the imposition of interest on the instalments is in accordance with the well-established notion of restitution, which is to restore the affected party being deprived of its legitimate reimbursements.

c) In this regard, reliance is placed on the Judgment passed by the Hon'ble Appellate Tribunal in Appeal No. 308 of 2017 titled as *Lanco Amarkantak Power Limited v. Haryana Electricity Regulatory Commission & Ors.,* wherein it was held as under:

"93. Our findings and analysis

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iv) Therefore, ***for equity and restitution payments made at a later stage, of the amount, due in the past, must be compensated by way of appropriate rate of interest so as to compensate for the loss of money value. This is a proven concept of time value of money to safeguard the interest of the receiving party****.*

v) The Appellant has placed reliance on several judgments passed by this Tribunal in several similar matters wherein it has been clearly brought out that the developers are entitled to interest on the differential amount due to them as a consequences of redetermination of tariff. ***It has been clarified in various judgments that the interest is not a penal charge if it is fixed according to commercial principles. It is only compensation for the money denied at the appropriate time****. The Appellant has also relied on the judgment by this Tribunal in the following:*

i. SLS Power Limited V. Andhra Pradesh Electricity Regulatory Commission and Ors. in Appeal Nos. 160, 166, 168, 172, 173 of 2011 and 9,18,26,29 and 38 of 2012.

ii. The judgment of this Tribunal in SLS Power case has been reaffirmed recently in Adani Power Limited v. Central Electricity Regulatory and Ors. in Appeal No. 210 of 2017.

iii. The judgment in Adani case has been reaffirmed by this Tribunal in its decision dated 21.12.2018 in Appeal No. 193 of 2017- GMR Kamalanga Energy Ltd. v. CERC.

iv. The judgment in Adani case has been reaffirmed by this Tribunal in its decision dated 21.12.2018 in Appeal No. 193 of 2017- GMR Kamalanga Energy Ltd. v. CERC.

v. Alok Shanker Pandey v. Union of India (2007) 3 SCC 545, wherein the Hon'ble Supreme Court of India.

vi) In view of the above it emerges that the State Commission committed an error by not taking these aspects into consideration while deciding on the matter and not granting interest to the Appellant.

vii) The Respondent No.3 have submitted that interest cannot be paid until the amount is crystallized. ***It is pertinent to note here that though the amount was crystallized by the State Commission vide their Impugned Order but the most important fact to be kept in mind is that the State Commission redetermined the tariff from the date of commencement of supply which clearly shows that the due date is the date of commencement of supply. In such matters the crucial point for consideration is that interest is not a penalty or punishment at all. But, it is the normal accretion on capital. Equity demands that the paying party should not only pay back the principal amount but also the interest thereon to the recipient and therefore the argument of the Respondent does not hold any ground and needs to be rejected****."*

[Emphasis Supplied]

d) The issue of carrying cost levied on legitimate expenses, whether or not specified in any specific Regulation has been further elucidated by the Hon'ble Tribunal in the following judgments:

(a) Judgment dated 04. 10.2019 passed in Appeal No. 246 of 2017 titled as *Torrent Power Limited vs. GERC & Ors.* wherein it was held as under:

*"****9.4*** *The Learned Counsel for the Appellant has also relied on the judgment of this Tribunal in Appeal No. 308 of 2013 dated 09.10.2015 in the matter of Chhattisgarh State Power Distribution Co. Ltd. Vs. Chhattisgarh State Electricity Regulatory Commission; wherein this Tribunal has held as under….*

*…****Thus, the value of money is settled financial principle and the same has also been recognized by this Tribunal. The utility gets compensated by way of carrying cost on this very principle i.e. when amount is due and recovery is deferred, the utility gets compensated by way of carrying cost.*** *Thus, when the Commission has arrived at the revenue gap after following due process of truing up exercise, the utility should be compensated for the delay in recovery of its revenue.*

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9.13 Upon perusal of the judgment of this Tribunal in Appeal Nos.190 of 2011 and 162 & 163 of 2012, it is observed that after deliberating the applicable judgments of this Tribunal and principles laid down in those judgments, this Tribunal has come to the conclusion that carrying cost is to be allowed to the Appellant on the revenue gap as a result of legitimate expenditure in true up. It is to be noted that the Commission has verified all the expenses during true up exercise and approved the same. The resultant gap is arrived at after this truing up exercise. Thus, it is admitted fact that the recovery of the Appellant is delayed till the Commission *allows recovery of this revenue gap.* ***As per well settled financial principle in catena of judgments, carrying cost is to be allowed to compensate the utility for such delayed recovery****. From perusal of referred judgment, we agree that rather this Tribunal has categorized the carrying cost on the revenue gap arrived after true up exercise under 83(d)(iv) and allowed the recovery of same. Therefore, we are unable to agree with the Commission that this Tribunal has required the Commission to further verify the carrying cost in the referred judgment of this Tribunal."*

[Emphasis Supplied]

(b) Judgement dated 05.10.2020 passed in Appeal No. 97 of 2020 titled as *Karnataka Power Transmission Corporation Limited vs. KERC* wherein it was held:

"11. The principles governing "Carrying Cost" are well settled. Some of the decisions of this tribunal on this subject are enlightening. The same may be noted at this very stage.

12. In Tata Power Co. v MERC, Appeal 173/09 decided by this tribunal, by judgment dated 15.02.2011, it was explained (in Para 43) thus:

"*Carrying cost is a legitimate expense. Therefore, recovery of such carrying cost is legitimate expenditure of the distribution companies.* ***The carrying cost is allowed based on the financial principle that whenever the recovery of cost is deferred, the financing of the gap in cash flow arranged by the Distribution Company from lenders/promoters/ accruals is to be paid by way of carrying cost.*** *In this case, the Appellant, in fact, had prayed for allowing the legitimate expenditure including carrying cost. Therefore, the Appellant is entitled to carrying cost****"***

(emphasis supplied)

*13. In SLS Power Limited v. APERC****,*** *2012 SCC OnLine APTEL 209, by judgment dated 20.12.2012, this tribunal held (at page 63 of the report):*

"The principle of carrying cost has been well established in the various judgments of the Tribunal. The ***carrying cost is the compensation for time value of money or the monies denied at the appropriate time and paid after a lapse of time****. Therefore, the developers are entitled to interest on the differential amount due to them as a consequence of re-determination of tariff by the State Commission on the principles laid down in this judgment.* ***We do not accept contention of the licensees that they should not be penalized with interest. The carrying cost is not a penal charge if the interest rate is fixed according to commercial principles. It is only a compensation for the money denied at the appropriate time.****"*

(emphasis supplied)

14. In the matter of Torrent Power Limited vs GERC, Appeal Nos. 190/2011 and 162-63/2012, decided by this tribunal on 28.11.2013, it was ruled that:

"83. The relevant principles which have been laid down in these decisions are extracted below:

(a) We do appreciate that the State Commission intents (sic) to keep the burden on the consumer as low as possible. At the same time, ***one has to remember that the burden of the consumer is not ultimately reduced by underestimating the cost today and truing it up in future as such method also burdens the consumer with carrying cost. The carrying cost is allowed based on the financial principle that whenever the recovery of cost is deferred, the financing of the gap in cash flow arranged by the distribution company from lenders and/or promoters and/or accruals, has to be paid for by way of carrying cost.***

(b) The ***carrying cost is a legitimate expense and therefore recovery of such carrying cost is legitimate expenditure of the distribution company****.*

(c) … ***The utility is entitled to carrying cost on its claim of legitimate expenditure if the expenditure is:***

i) accepted but recovery is deferred e.g. interest on regulatory assets,

ii) claim not approved within a reasonable time, and

iii) Disallowed by the State Commission but subsequently allowed by the Superior authority.

iv) Revenue gap as a result of allowance of legitimate expenditure in the true up….."

[Emphasis Supplied]

e) **Therefore, in view of the above judgements, it is a settled principle that the carrying cost is to be allowed on the basis of financial principle that whenever the recovery of cost is deferred, the financing of the gap in cash flow has to be paid for by way of carrying cost.**

28. Normative Annual Plant Availability Factor (NAPAF)

5.1.1 Review of Existing Norms

Historically, the target availability has been determined based on the data available for the few past years. The recovery of fixed charges was linked to the Plant Availability Factor (PAF). The Normative Annual Plant Availability Factor (NAPAF) has been specified considering the past years' data and best industry practices. However, due to changing dynamics such as technological improvement, better O&M practices, and shorter shutdowns and outages, the PAF has improved.

However, a shortage of domestic fuel affects PAF, and it has been an area of concern in recent years. In the event of bridging the gap through e-auction or imported coal *(other than fuel arrangements agreed in PPA), the need for prior consent of beneficiaries, the maximum permissible limit of blending, etc. has also been deliberated under Section 5.9 of this Approach Paper.*

Similarly, for Hydro generating stations, PAF is impacted due to changing hydrology, and restrictions imposed on the flow of water, and changes in the pattern of water usage in the case of multipurpose dam projects.

In view of the above, the existing norms of NAPAF may need review by considering past years' PAF, the procurement of coal from alternate sources, other than designated fuel supply agreements, changes in hydrology, etc.

Further, it is observed that current Regulations, although specifies the mechanism for computing PAF of storage-based hydro generating stations, do not specify a methodology for computing PAF of Run-of River (ROR) Plants. There is a need to specify a mechanism for the same, and based on such a specified mechanism, the current NAPAF value may need reconsideration.

One option can be to re-introduce the methodology that was being adopted in the CERC Tariff Regulations, 2004. Based on Regulation XI (b) under Chapter 3 of the Tariff Regulations, 2004, the methodology can be specified as follows:

In case of purely run-of-river power stations, declared capacity means the ex-bus capacity in MW expected to be available from the generating station during the day (all blocks), as declared by the generating station, taking into account the availability of water, optimum use of water and availability of machines;"

Comments and suggestions are sought from stakeholders on the above suggested option and any other methodology that can be considered for the computation of plant availability for ROR based hydro generating plants.

NTPC Comment:

The CERC Tariff Regulations 2019 defines Plant Availability factor as under:

'Plant Availability Factor' or '(PAF)' in relation to a generating station for any period is the average of the daily declared capacities (DCs) for all the days during the period expressed as a percentage of the installed capacity in MW less the normative auxiliary energy consumption.

As per the 2019 regulations, the normative plant availability factor (NAPAF) for thermal projects is 85%. However, there is a case for lowering the NAPAF for thermal stations to 80% based on the following considerations:

i. **Increased Forced Outages due to Flexible Operation -** Therefore, a large number of thermal power plants are expected to experience partial loading along with frequent ramp-up and ramp-down in operation, which is expected to lead to higher forced outages. In view of the above challenge, NAPAF may be relaxed from the current level of 85% to 80%.

ii. **Fuel shortage -** In case of coal stations, blending of imported coal had to be carried out to meet the shortfall in domestic coal while electricity demand has been on an increasing trend. Blending of imported coal results in increased ECR, which is resisted by the Discoms. However, the generating company has made all efforts to import coal as per directions of GOI and maintain reliable supply of power to the beneficiaries. In case of gas stations, due to diversion of domestic gas to other sectors, reliance is on RLNG / spot gas.

In the past, Hon'ble Commission in 2014 Regulations had lowered the NAPAF to 83% considering shortage of coal and uncertainty of assured coal supply on sustained basis by generating companies.

In view of the above challenges, following are proposed:

1) **In view of the increased forced outages due to flexible operations, NAPAF norm may be reviewed and lowered to 80%.**
2) **In addition, following liberty may be allowed to generators as domestic coal shortage and price volatility of gas are governed by macro-economic factors and are not in the control of the generating company.**
    a) **If station is not available due to fuel shortage, then in that case disincentive shall be limited to the value of ROE in such period of disincentive (other AFC components being based on principle of reimbursement) as failure of arranging fuel cannot be exclusively attributed to generating company alone. There are other macro-economic factors beyond the control of gencos.**
    b) **Regulatory framework to address fuel shortage situations may be incorporated. It is suggested that specific provisions to allow lower NAPAF norms in case of acute shortage of coal / gas may be provided in the regulations since it may not be possible to assume the extent of coal shortage upfront given the energy demand scenarios and growth in mining of domestic coal. Hon'ble Commission may lower the NAPAF norm in such years on its own (or on request of generating company) like it did in the initial three years of 2014-19 tariff regulations. Such specific clause will ease the difficulties and set transparent regulatory approach to deal with fuel shortages.**

29. Peak and Off-Peak Tariff (7.1.32 of the Approach Paper)

In the tariff period FY 2019-24, the concept of peak and off-peak tariff was introduced for thermal generating stations to incentivise peak period availability and availability during peak demand season. Further, the Tariff Policy also specifies that differential rates for fixed charges should be introduced.

By introducing the mandatory requirement of achieving target availability during peak hours and during high demand season, the generating stations were incentivised to be available during the time beneficiaries needed them the most. The Regulations stipulate the requirement for the generating stations to maintain specified target availability against the regional peak hours/demand season as declared by RLDCs.

It is observed that though the segregation of recovery through peak and off-peak periods has brought in more accountability, there have been some operational difficulties while declaring high demand and low demand season which need to be taken care of. The current provisions require the Regional Load Despatch Centres (RLDCs) to notify in advance the months of high-demand season and low demand season so that overhauling can be planned by the generators accordingly. The following issues have been brought before the Commission in this context:

1) The actual period of high demand did not coincide with the forecast, and the generators had to postpone overhauling considering the sudden increase in demand. In some cases, such deferment has led to forced outages, thereby impacting the recovery of the AFC.

2) The period of high demand and low demand is not the same for all the States in the Region, so declaring the common high and low demand period for all the States has its own challenges. For example, in Northern Region, the high demand season for hilly States such as Uttarakhand and Himachal Pradesh is the winter months, whereas for adjacent Punjab the same lies in the months of August-September and for Delhi it is the summer months.

3) Some of the generating stations have beneficiaries in different regions, which again increases the diversity of demand. Therefore, declaring common high and low demand period is practically not possible. For example, Kahalgaon STPS and Farakka STPS have allocations to beneficiaries that belong to all five regions; therefore, in such cases, the objective of devising the above mechanism is rendered ineffective and may require tweaking of existing practice by RLDCs.

4) While States have been demanding availability from the generators coinciding with State Peak, the generators have difficulty meeting this requirement due to the wide diversity of peak in different States.

5) On the other hand, suggestions have also been received for a 'National' level Peak Period in view of the fact that the grid is integrated and India has a National market in operations.

As recovery of reasonable costs is of prime importance for any infrastructure sectoral growth, comments/suggestions are sought on the possible interventions/modifications required to address the issues highlighted above. Specific suggestions are also sought on the following.

1. Whether it would be advisable to limit the recovery based on daily peak and off-peak periods.

2. Suggestions on National versus Regional Peak as a reference point for recovery of fixed charges.

NTPC Comments:

a) CERC Tariff Regulations, 2019 had first time introduced the concept of recovering fixed charges in two parts: High demand season (3 months) and Low demand season (9 months). As per the provisions of these Regulations, the target availability of 85% needs to be achieved separately during both the seasons for full recovery of fixed charges of stations.

b) It is observed that there is low correlation (50%) between actual high demand (HD) months and HD months declared upfront by RLDCs. Also based on actual high demand, generating stations are advised to postpone all overhauling during certain months to maintain maximum availability of power. This rescheduling of overhauling often results in increased forced outages of generators and causes clustering of unit overhauling in balance period. Therefore, some of the units failed to achieve target availability separately in high demand / low demand season as per CERC Tariff Regulations, 2019. Consequently, there is Annual Fixed Charges under recovery in some of the stations for 2021-22 (Rihand-I, Gadarwara) & 2022-23 (Farakka-I&II) because of this methodology.

c) Further, there are variations in the period of high demand between various states of a region. Some stations like Farakka, Kahalgaon have beneficiaries across more than one region. Therefore, the basic intent behind the dispensation is not accomplished. **Therefore, it is suggested that the dispensation of achieving target availability separately in high demand and low demand conditions may be discontinued.**

d) **Recovery of capacity charges based on daily peak and off-peak periods -** Presently, the recovery of AFC is based on PAF achieved vis-à-vis NAPAF between cumulative peak and cumulative off-peak hours within a season. The concept of achieving NAPAF for recovery of entire AFC is based on annual approach considering the allowed planned and forced outages on annual basis. Limiting the recovery based on daily peak and off-peak periods is against this basic philosophy of NAPAF on annual basis and will be losing proposition for the generating company. **It is therefore suggested that the peak and off-peak hours should be considered on cumulative basis for the year. In other words, target availability or NAPAF needs to be achieved separately in peak hours and off-peak hours on annual basis. Further, any shortfall in recovery of capacity charges for cumulative off-peak hours derived based on NAPAF shall be allowed to be off set over achievement of PAF in peak hours, if any. In short, the existing dispensation without the differentiation of high demand season and low demand season may be retained.**

e) **Suggestions on National Peak versus Regional Peak as reference point for recovery of fixed charges:** It is presumed that comments are sought regarding peak (high demand season) and off-peak (low demand season) on National basis instead of Regional basis. The demand diversity of various States with the National Peak would even higher than the demand diversity of States with the Regional Peak. Therefore, adoption of National Peak will not serve the purpose and shall not be beneficial for the States. **Therefore, it is suggested that the current dispensation of achieving target availability separately during high demand**

season and low demand season may be discontinued and availability may be based on annual basis.

30. **Operational Norms (7.1.33 of the Approach Paper)**

The Commission, while framing the Regulations for terms and conditions of tariff for different tariff periods, has been considering the operational data of the generating stations for the past 5 years. The methodology of considering 5 years' data ensures that the generator is able to recover the cost of electricity generation in a reasonable manner.

It is observed that the Central Generating Stations that used to operate at around 80%-85% PLF prior to FY 2013-14 have now been operating at part load and much below the target PLF due to the need for higher RE integration, as evident from the following figure:

As these generating stations are operating at a much lower PLF, the actual performance data will also have a degradation impact. ***Further, as the generating stations are separately allowed degradation impact due to low load operations, it is felt that the norms may be fixed considering the ideal loading of generating units.***

Comments and suggestions are sought from stakeholders on the above proposal and other key determinants to be considered while approving the norms.

NTPC Comments

a) The existing practice of fixing operational norms, namely, Gross Station Heat Rate (SHR), Auxiliary Energy Consumption (APC) and Specific Fuel Oil Consumption (SFOC) is at normative level of 85%. The norms are fixed based on actual data of last 5 years. Degradation in SHR and APC due to low load operations or partial loading is allowed separately based on the loading factor varying from 85% to 55% of MCR. Start-up fuel oil cost over and above 7 start / stop in a year is additionally compensated based on hot, warm, and cold start-up. The Approach Paper has proposed that norms may be fixed considering ideal loading of generating units. However, the existing methodology of fixation of operating norms is well established. It is therefore felt that fixation of norm 85% may be continued and degradation may be provided for operation at loading factor lower than 85% till technical minimum load.

b) The following factors may be considered while approving the operational norms:

   i. **For units achieving COD after 01.04.2009, suitable margin over design heat rate may be provided irrespective of minimum boiler efficiency limit -** Boiler efficiency norms as per extant tariff regulations form basis of design and award of contract for new Units. Higher efficiency norms in the subsequent tariff period cannot be anticipated. Operation of boiler above design efficiency is neither envisaged nor practically possible. Presently Regulations prescribe a minimum boiler efficiency of 86% and such efficiency norms have been applied even to units (whose efficiency is 84% or 85%) which were awarded in the previous tariff period. Fixing of efficiency norm higher than its design not justified and fair. Many NTPC stations (Barh-II, Farakka-III, Kahalgaon-II, Mouda-I, etc.,) are similarly placed. It may be noted that CEA recommended margin over unit design rate instead of minimum boiler efficiency and maximum turbine heat rate. In view of the above, for units achieving COD after 01.04.2009, suitable margin of at least 6% over unit design heat rate may be provided irrespective of min boiler efficiency limit.

ii. **Adequate SFOC norm may be provided for supercritical units-** The time taken for cold start up from Pre-boiler light-up activity to grid synchronization takes around 36 hours in super critical units which is much more as compared to 13 hours taken by subcritical units. Due to the high start-up time, boiler light up with oil support and hot boiler clean-up process prescribed for supercritical units, oil consumption is higher in supercritical units in comparison to subcritical units. The typical oil consumption for cold start up in Super Critical units is about 350 KL/start as against the oil consumption of 110 KL/start allowed in the CERC IEGC Regulations (4th amendment). The norms of oil consumption for start-up were fixed by Hon'ble Commission in April 2016, when only few super critical units were operational and therefore not much data was available. It is submitted that the norms provided in the CERC IEGC Regulations (4th amendment) for Oil consumption during cold start up is not adequate for Super critical units. It is also pertinent to mention that CERC Tariff Regulations 2019 provides normative Specific Oil consumption of 0.5 ml/kWh for both Sub critical & Super critical units. However, owing to high start-up time, the Specific Oil consumption of super critical units is higher than the norms of 0.5 ml/kWh provided in the Tariff Regulations. The average actual Specific Oil consumption in some of the NTPC Super Critical units in last 5 years ranges from 1.03 to 1.89 ml per kwh. **It is therefore requested that additional Specific Oil Consumption norms of 1.50 ml/kWh allowed for Super Critical units.**

iii. **Additional SFOC Norms of 0.5 ml per kwh may be allowed for front-fired boilers as per the inherent design -** Front fired super critical boilers (namely NTPC LARA, Kudgi, Barh-I, Solapur, Meja) are incurring higher specific oil consumption in view of OEM guidelines and inherent design, as all 5 oil guns are required to be taken in service before starting and stopping of any mill. This is also envisaged in BMS logic for Mill and Feeder start permissive which holds true for all loads. All five LDO burners provide the required flame support at initial firing of pulverized fuel and also during Pulveriser shutdown. With likely increase in variation in scheduled generation & reduction in minimum power level in days to come, the increase in specific oil consumption due to Mill changeover is estimated to be around 0.50 ml/kWh. **It is therefore requested that additional specific oil consumption of 0.50 ml/kWh for front and rear fired supercritical units in addition to submission at (ii) above may be allowed.**

iv. **Specific Norms for special features – Additional norms for specific features like tube mills, pipe conveyor, air cooled condenser, RO system for coastal plants, etc., may be incorporated in the Regulations.**

v. As per MoP notification all thermal plant is mandatorily co-fired biomass pellet of minimum 5% annually. Co-firing of biomass increases Heat rate, Auxiliary power consumption and O&M requirement. Hence, same may be taken care during formulation of tariff norm**.** Increase in energy charge rate due to biomass co-firing, if any should not be considered for merit order scheduling.

31. Operational Norms – Inefficient Generating Stations (7.1.34 of the Approach Paper)

For those generating stations that have not been operating efficiently in the past and for which the Commission has been considering actual achievements to fix relaxed norms, in the interest of limited resources, such relaxation of norms may need re-consideration. This is necessary as the coal/lignite is limited resource that needs to be consumed efficiently and can be re-allocated to more efficient plants. ***Comments and suggestions are sought from stakeholders on the option to do away with relaxed norms currently allowed on the basis of actual performance for various efficiency norms of generating stations.***

NTPC Comments

a) Some of the small size units of capacity 110 MW have been dealt with separately and it may be noted that such units do not fall under the category of relaxed norms. **It is submitted that norms for units less than 200 MW may be continued on case-to-case basis.**

b) Few old units operating on relaxed norms in the 2019-24 tariff period need to be provided relaxed norms in the next tariff period. R&M of these units is not economically viable and therefore improvement of operational efficiency is not envisaged. In case relaxed norms are withdrawn, these plants would have to be shut down due to operational losses. Most of these units are in the fag end of their useful life. In the eventuality of shut down of these units before completion of useful life or PPA tenure, there would be under recovery of balance depreciation. **Regulatory framework may provide provision for recovery of depreciation in the event of shut down due to uneconomical operations as a result of stringent norms. Their norms may be fixed based on past performance.**

32. Operational Norms - Emission Control System (7.1.36 of the Approach Paper)

The Commission included the need to determine the tariff and the norms for ECS in view of the Ministry of Environment, Forest, and Climate Change's (MoEF&CC) notification mandating implementation of Flue Gas De-sulphurisation System (FGD) and other ECS in its Staff Paper while framing the CERC Tariff Regulations for 2019-24. As adequate actual operational data were not available, the Commission in the Principal Regulations only provided for in-principle approval of *additional capital expenditure, admissibility, and tariff structure (Supplementary Energy Charges and Fixed Charges) and stipulated the operational and financial norms subsequently through the first amendment to CERC Tariff Regulations, 2019, which were based on inputs from CEA and various other stakeholders.*

As only very few of such emission control systems have been commissioned, and in the absence of sufficient data on actual operational performance and its impact on auxiliary consumption, the current tariff norms may be continued for the next control period. However, comments and suggestions are sought from stakeholders on the continuation of the existing norms, or is there a need to modify the same?

Further, as considerable expenses have been incurred to reduce the adverse impact on the environment, suggestions are also sought on ways to incentivizing proper operation of such emission control systems so that the very purpose of incurring such huge expenses can be achieved and accounted for.

Implementation of an emission control system also requires the determination of supplementary energy charges, which impacts the power plant's standing on merit order. The Commission, considering that most of the generating stations are yet to install these systems, ruled that these supplementary energy charges shall not be considered while preparing merit order. In view of the earlier approach and considering that most of these generating stations are still in the process of implementing such systems, the current practice of excluding such expenses while preparing merit order may be continued.

Comments and suggestions are sought from stakeholders on whether the current mechanism to exclude these expenses may continue until these generating stations equip themselves with emission control systems as per the MoEF&CC notification dated 31.03.2021?

NTPC Comments

a) The existing norms for emission control system may be retained as these systems in majority of the units shall be commissioned in the next tariff period. It is suggested that the existing norms may be retained till sufficient operational data is built up for review of these norms based on actual data.

b) Units with emission control systems should not be at a disadvantage when compared to units without these systems on account of merit order dispatch. Therefore, Supplementary Energy Charges for emission control system should not be considered for merit order dispatch till all units have equipped themselves with emission control systems as per the MoEF&CC notification dated 31.03.2021.

c) It is suggested that in cases where ECS capital cost is a part of the main plant capital cost, i.e. supplementary fixed charges of ECS are part of Annual Fixed Charges, a separate provision may be provided in the regulations for billing of supplementary energy charges.

d) **Rate of Return on equity for ECS -** Presently, tariff regulations provide for differential rate of return on equity on certain investments like FGD, which is lower than the main plant. While meeting the emission standards, such capital expenditure is facilitating the cleaner environment which is need of the hour. Therefore, such returns on such expenditure in fact should be more than the normal regulated investments. In view of the above, it is submitted that the rate of return on capital investments on Emission Control Systems needs to be serviced at rate of return on equity at par with the main plant.

e) In current tariff norms, normative O&M expenditure for FGD is defined as percentage of Capex. However, O&M cost is not directly dependent on Capex. Requirement of O&M will be almost same for all plant of Wet limestone based FGD irrespective of its capex. Moreover, Capex of FGD has been progressively increasing over the time. Therefore, for the same system which was installed at the early phase to meet MOEF guideline will suffer from losses though those utilities should be incentivized due to their proactive action.
Considering above, Normative O&M cost for Wet limestone based FGD may be linked with plant size but not as a percentage of Capex.

Further, in the current tariff norm, same normative is applicable for both DSI and Wet Limestone based FGD which is actually not same. Hence separate normative for DSI may be defined.

f) Auxiliary power for DSI need to be included in the tariff regulation.
g) Approximately two years' time period is required to stabilize FGD operation from commissioning.
h) As per present tariff norm, gypsum selling price is fully shared with consumer which should be at least equally shared with both utility and consumer to incentivize the generator for its efforts to utilize the valuable product.
i) It is suggested to incentivize the utilities with suitable methodology which are implementing emission control systems and installing systems to meet environment norms.
j)

33. Compensation for Part-Load Operations (7.1.37 of the Approach Paper)

The compensation mechanism for the thermal generating stations operating on loads below normative level up to the technical minimum, was included as part of the amendment to the Indian Electricity Grid Code, 2010, in the year 2017. The compensation was introduced mainly because the norms for Section 62 projects under the Tariff Regulations have been specified considering specific past data, and if loading is below the data based on which the norms were specified, the variable charge based on the norms may not correspond to the actual parameters of Station Heat rate, Auxiliary Energy Consumption etc. Further, the Commission, in its Explanatory Memorandum to the draft IEGC, 2022 has mentioned that since norms for generating stations under Section 62 are determined under the Tariff Regulations, the appropriate placement of compensation for such projects should be through the Tariff Regulations. Therefore, the norms are now to be dealt with as a part of the Tariff Regulations and therefore, appropriate provisions need to be inserted.

It is observed that the current dispensation allows degradation in the following operational norms, for part load operations of the generating stations.

1. Station Heat Rate
2. Auxiliary Energy Consumption
3. Secondary Fuel Oil Consumption
It is observed that currently the impact is being allowed considering the norms or actuals, whichever is lower. This mechanism results in operational gains being passed on to the beneficiaries, while any losses are borne by the generator. The mechanism may need a review wherein either normative norms are followed, or compensation is limited to actuals.
It is further observed that there have been instances where the actual PLF of plants has been even below 55%. The current provisions for compensation do not cover operating PLF below 55%, and therefore, devising a compensation mechanism to govern such cases may also be required.
With regard to the compensation norms, an Expert Committee has already been constituted; however, in view of the above discussion, ***comments and suggestions are sought from stakeholders on the earlier norms and any changes that may be required to compensate the generators to operate the plants in a flexible manner to support the Grid.***

NTPC Comments

a) Presently, part-load compensation for degradation in operational norms (heat rate & APC) between 85% to 55% loading factor, which is fixed at out to 0 to 4.04% of ECR for subcritical and 0 to 7.07% of ECR for supercritical coal-based units.
b) Start-up fuel cost is allowed above 7 start / stop in a year. It is submitted that 350 KL is required for cold start up in case of supercritical units, against which presently 110 KL per start up is provided. In view of the above, start-up oil for more than 2 start / stop may be allowed.
c) These norms are now proposed to be made part of Tariff Regulations.
d) The current dispensation of part-load compensation allowed is based on norms or actuals, whichever is lower. As a result, operational gains of stations performing better than norms is passed on to the Discoms through the mechanism of sharing of gains while losses in stations performing inferior to the norms is borne by the generating company. So, the generating company considered as one incurs loses on account of operating parameters.
e) The Tariff Policy provides that the operating parameters should be on “normative basis” only and not on “lower of normative and actuals”. It is required to align Part-load compensation as per the principles of the Tariff Policy.
f) In this regard, the Expert Committee constituted for review of IEGC has also recommended compensation on normative basis only.
g) It is therefore suggested that compensation may be provided on normative basis.
h) Part-load compensation for Supercritical units: it is submitted that part-load compensation for super critical units is inadequate. As a result, many supercritical units are incurring losses at part-operations. CEA has vide its recommendation dated 10.12.2018 has provided part-load compensation for supercritical units. It is suggested that part load

compensation of supercritical units may be provided in line with the CEA recommendations.

i) **For further comments regarding compensation, NTPC comments on the Addendum may also be considered.**

34. Gross Calorific Value (GCV) of Fuel (7.1.38 of the Approach Paper)

Gross Calorific Value (GCV) of fuel is one of the most important factors on which energy charges depend. Based on the measurement points, the GCV of any specific fuel can be different, such as GCV "as Billed" (As billed by Coal Company), GCV "as Received" (GCV measured when the fuel is received) and GCV "as fired" (GCV of coal just before it is sent for firing). The GCV of fuel keeps on varying at different reference points due to various factors such as moisture content, and grade slippages at the mine end, or during transportation or during storage at the plant end. The current Regulations specify that the GCV of fuel for the purpose of allowing energy charges shall be considered on an as received basis as other factors due to which there is a loss in GCV are not under the control of the generating stations. The Commission, considering the same allowed computation of energy charges on the basis of GCV "as received" basis plus an additional margin of 85 kCal/kg towards storage losses without differentiating between pit head and non-pit head stations.

The approach has found wider acceptance; however, it is observed that the variation in GCV "as billed" and "as received" is significant due to loss of GCV at mine end and during transportation, often leading to grade slippages. Though, the magnitude of such losses has reduced in the past, they are still significant and may need to be accounted for in terms of risk sharing between the coal company, the railways, and the generating station. At present, the generator pays for the coal based on GCV "as billed" and quantum of coal at the loading point. It is observed that the loss in GCV from "as billed" to "as received" has been allowed on an actual basis. As mentioned earlier, even though the loss in GCV "as received" vis-à-vis "as billed" has reduced, one can argue that as the actual loss has been allowed in the past, there have not been considerable efforts made by generators in minimising the loss.

Comments and suggestions are sought from stakeholders on ways to reduce the gap between GCV "as billed" and "as received".

NTPC Comments

a) Presently, the supply and transportation of coal is through entities which are essentially monopolistic. Since fuel cost consists of 60-70% of input cost of generating power, generator is not in a position to absorb risks associated with losses in quality & quantity of coal. Loss of quantity and quality between mine end and station end is beyond the control of the generator.
b) The Approach Paper has proposed to allocate the above losses amongst the Coal Company, Railways and generating station.
c) The generating company has been taking all efforts to reduce the grade slippages, such as, carrying out third party sampling as per GOI guidelines at mine end and station end, taking up quality issues with the coal companies,

coal controller, and at various ministerial forums, etc. Further, sensitization of the issue has also been made during various interactions with discoms. Some of the States have also raised concerns and requested MoC for suitably addressing the issue with provision of billing of coal supply at station end.

d) **However, in the present scenario, it is felt that risk allocation between coal companies, Railways and generating station because of grade slippage during transit may not be workable. It may generate lot of new disputes and reconciliation process may be tedious and time consuming. Further, the generating company is not in the position to take over all the risk considering that it the grade slippage during transit is beyond its control and payment to the coal companies is made by the generator based on the GCV on declared basis as per the terms and conditions of the FSA.**

e) One of the suggestions is that the Coal Company may transfer title of coal to the generator at the plant end. This change in methodology will require modifications of existing FSAs and also intervention at the level of the Ministry of Coal (GOI), and the Ministry of Power (GoI). Facilitation and support of Hon'ble Commission in this regard is sought so that interest of consumer and generator is protected.

35. Blending of Coal (7.1.39 of the Approach Paper)

In order to address the issue of depleting coal stocks and building stocks before the monsoon, the Ministry of Power issued an advisory dated 07.12.2021 to all domestic coal based power plants to import coal to meet their requirements by blending with imported coal to an extent of 4% by State generating companies & Independent Power Producers (IPPs). MoP again vide its letter dated 28.04.2022 directed the concerned stake holders to import at least 10% of their coal requirements for blending. Due to the easing out of the shortage situation, MoP again, issued revised directions vide letter dated 09.01.2023 wherein the domestic coal based generating stations are required to plan for 6% blending until September 2023.

The generating companies are reported to be facing problems complying with the above directions of the Ministry of Power on account of the absence of permission by the concerned beneficiaries, which is required under Regulation 43(3) of the CERC Tariff Regulations, 2019. Regulation 43(2)(b)(3) of the CERC Tariff Regulations, 2019 stipulates as follows:

"43 Computation and Payment of Energy Charge for Thermal Generating Stations
(1) ..

(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 pre-condition, 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 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."

Staff of the Commission, in June 2022, published a paper analysing the impact of blending of coal on the energy charges and noted that even when blending of coal is less than 10%, the 30% ECR threshold limit gets breached. In view of the same and considering that the shortage situation may recur, following can be analysed.

Linking the consent of beneficiaries with the percentage blending of imported coal instead of an increase in ECR may enable a swift response to an increase in demand by the generating company. Procurement of such coal (other than linkage coal) has to be done through a transparent competitive bidding process.

Comments and suggestions are sought from stakeholders on the above proposal and any other alternative, if any.

NTPC Comment:

a) The Approach Paper has stated that linking the consent of beneficiaries with the percentage blending of imported coal instead of an increase in ECR may enable a swift response to an increase in demand by the generating company. Procurement of such coal (other than linkage coal) has to be done through a transparent competitive bidding process.
b) In the past there have been shortages in domestic coal in the country along with increasing trend of demand, which necessitated intervention by the GOI at national level to import coal to ensure uninterrupted supply of power. Although efforts are being taken up to maximize the production of coal by CIL and its subsidiaries, increasing production by captive / integrated mines by generating companies and also by the recent initiative of GOI of awarding commercial mines, shortfall in domestic coal supply may still be faced by power plants in the next tariff period. Therefore, it is necessary that the regulatory framework needs suitable enabling provisions to allow blending of imported coal based on guidelines / directions / advisory issued by the GOI from time to time. The provision of prior consultation with the beneficiaries in case of breach of ceiling ECR needs review for enabling swift response as rightly pointed out by the Approach Paper.
c) It is felt that the process of obtaining consent of beneficiaries needs to be avoided as this results in practical difficulties in implementing the directions of the GOI regarding blending of imported coal. Since multiple beneficiaries are involved, denial of consent by some beneficiaries would create practical difficulties in implementation. It is therefore suggested that regulatory framework needs to have suitable provisions for allowing the quantum / proportion of blending as per

direction / guidelines / advisory of GOI issued from time to time, so that swift response by generators in shortage scenario can be achieved.

36. Incentives (7.1.40 of the Approach Paper)

It is observed that the incentives linked to NAPLF, NAPAF and NATAF have been specified in existing Tariff Regulations. In this regard, it is observed that the incentive linked to availability is already allowed as per the prescribed formulation on a pro-rata basis and may be continued.

However, incentives linked to generation in excess of target PLF/NAPAF especially during peak periods, in the case of hydro stations and old pithead generating stations, may need a review in order to encourage higher generation from such plants. This will result in increased generation from such plants and will also benefit beneficiaries.
Comments and suggestions are sought from beneficiaries on the above proposal and any other alternative options, if any.

NTPC Comments

a) In case of old pithead stations, the Energy Charge Rate is very competitive and the Discoms schedule such stations to the full level. Therefore, the difference between the PAF and PLF is not significant. The capacity charges of these plants is nominal, and these plants are well maintained and operating efficiently. The returns from these plants is not commensurate with the risks taken by the generating company.
b) Vintage pit-head stations benefit from their proximity to coal mines, resulting in competitive Energy Charge Rates (ECR) and the capacity charges are also very less as there is no/small element of interest on loan and depreciation. However, the current Return on Equity (RoE) for such stations is relatively low, and it fails to adequately compensate for the overall risks associated with the thermal power business. The cost of energy from these stations is significantly more economical for distribution companies (discoms) compared to alternative arrangements like new stations or renewable energy sources.
c) These vintage stations typically operate at higher Plant Load Factors (PLF) than the normative levels and often become eligible for incentive schemes such as 50p/65p. However, the current incentive scheme does not provide sufficient remuneration for these stations. The Approach Paper has stated the same in the approach paper.
d) **Therefore, in old pit-head stations incentive may be linked to availability in order to higher generation from such plants. It is also suggested that the rate of incentive may be 1.5 times the incentive rate of other thermal stations.**

Further, it is submitted that there is need to review the existing incentive framework for thermal generators in view of the following:

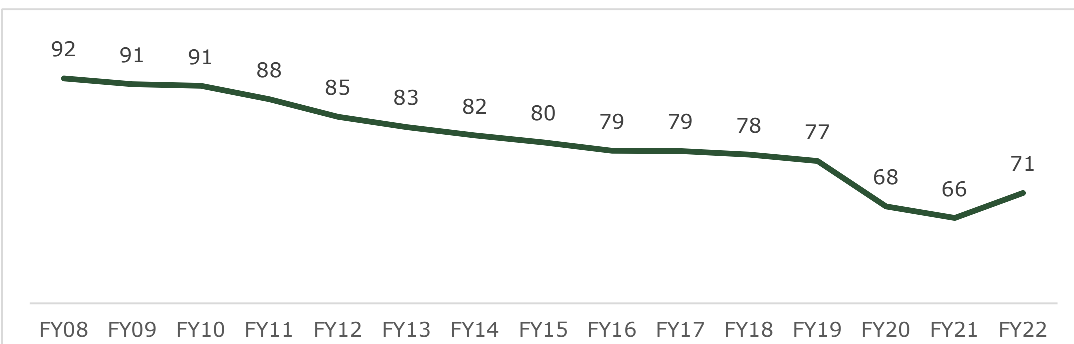
1. The operational norms for availing incentive by thermal generating stations for better performance are as under:

   "Normative Annual Plant Load Factor (NAPLF) for Incentive:

   b) For all thermal generating stations, except those covered under clauses (b), (c) - 85% ;"

   "In addition to the capacity charge, an incentive shall be payable to a generating station or unit thereof @ 65 paise/ kWh for ex-bus scheduled energy during Peak Hours and @ 50 paise/ kWh for ex-bus scheduled energy during Off-Peak Hours corresponding to scheduled generation in excess of ex-bus energy corresponding to Normative Annual Plant Load Factor (NAPLF) achieved on a cumulative basis within each Season (High Demand Season or Low Demand Season, as the case may be), as specified in Clause (B) of Regulation 49 of these regulations"
2. The increasing emphasis on renewable energy sources in recent years has brought about a significant transformation in the power sector. Also, the increasing share of RE power in the overall generation capacity is putting significant pressure on the PLF of thermal generating stations. RE energy needs to be consumed as it is generated and the grid integration of intermittent RE is being done by thermal units. With increase in RE penetration, the PLF of the thermal generating stations is expected to decrease further in future. It is observed from the graph below that the average PLF of the thermal plants of NTPC have been continuously on the down trend from the high of 91-92% during FY08-FY09 to low of 66-68% during FY20-FY21 with minor revival in FY22 due to increasing demand.

Average Plant Load Factor (%) for thermal generating stations of NTPC



3. The above trend of reducing PLF has not been captured while approving the normative PLF required by thermal generating stations to be eligible for incentive. Also, as per the National Electricity Plan - Generation 2022-32 issued by CEA, it is envisaged that the average PLF of coal-based stations are expected to decline to 58-59%. *"The average PLF of the total Installed coal capacity of 235.1 GW is likely to be about 58.4% in 2026-27 and that of 259.6 GW of coal-based capacity is likely to be about 58.7 % in 2031-32."* Therefore, a relaxation in normative PLF is required to be provided for thermal generating stations in view of the planned increase in RE capacity by 2030.
4. The average thermal PLF is expected to follow a decreasing trend in coming years from the present band of 60-70 % and is nowhere in the range of normative PLF of 85% prescribed in the existing Tariff Regulations of 2019-24. As compared to

earlier of select non pithead generating stations not being scheduled due to higher cost in the merit order, in the existing scenario, majority of the thermal stations are not being scheduled due to higher penetration of RE power. Such scenario is unnecessarily leading to denial of incentive to the thermal generating stations even when they are available, and ready to dispatch.

5. It is highlighted further that the providing for Declaring Capacity (DC) lies in the hands of the generator but the option to utilize the capacity rests with the Discoms / beneficiaries and therefore PLF should not be considered as a measure for providing incentive to the generator.
6. The lower PLFs for the thermal generating stations are expected to continue and limit any possibility to earn incentive by the thermal generating stations. Therefore, NAPLF norms for generating stations need to be lowered so as to provide them with an opportunity to earn some incentive.

In view of the above, it is suggested that the incentive may be made available for generation over 70% PLF instead of the existing norms of 85%.

Further, incentive based on availability may be considered for old thermal generating stations as elaborated below:

7. It is prayed to allow vintage pit-head stations to recover incentive based on capacity charges in line with 2009-14 regulation i.e., based on availability, which provides appropriate compensation. Increased availability of these cost-effective stations benefits discoms by allowing them to generate more power at a lower cost compared to other expensive options. Vintage stations require special consideration due to the extra risks they undertake. By adopting this approach, the regulatory framework can provide appropriate incentives and recognition for vintage pit-head stations, promoting their efficient operation, and ensuring a stable and cost-effective power supply for discoms. Since the distribution utilities are scheduling these plants fully the impact on Discom tariffs would be marginal, only increasing by 2-3 paisa.

8. **Following is suggested to incentivize old generating stations through following options:**
    a) **Therefore, additional incentive rate may be fixed for old generating stations at say 50 paisa per kwh over and above the incentive rate applicable for other stations.**
    b) **Further, it is suggested that the incentive may be made available for generation over 70% PLF instead of the existing norms of 85%.**
    c) **Old stations may be provided inflation adjusted return instead of return on equity based on historical capital cost.**
    d) **Fixed margin over scheduled generation may be provided.**
    e) **Incentive based on availability.**

The above measures would provide returns that are commensurate with the risks and would encourage these old generating stations to undertake better upkeep and regular maintenance which would enable them to generate power beyond the useful life on a sustained basis. Also, this would be a win-win situation for the beneficiaries as the fixed cost of the plants have been fully

depreciated and therefore, they would be able to avail less costly power for a longer duration of time and limit their average cost of supply.

37. Separate Norms for ROR/Storage Based Hydro Projects (7.1.41 of the Approach Paper)

Hydro generating stations can primarily be classified into the following three main categories.

*1. **Run-of-River (ROR) Hydro Stations:** These stations utilise water that runs off the river by channelling some of the flow through a canal or penstock. As these types of stations do not have any storage facilities, generation is purely dependent upon the flow of water and has little scope to adjust to demand needs.*
*2. **Pondage/Storage based Hydro Stations:** These stations use a dam or reservoir that acts as a storage facility to store water, and therefore, depending upon the grid requirements, the generation can be controlled and principally should be used as peaking plants for peak shaving.*
*3. **Pumped Storage Plant - Hydro Stations (PSP):** These stations are primarily pumping facilities that pump water from a reservoir at a lower level to a reservoir at a higher level during off-peak times and generate power during peak times by releasing water from the reservoir at a higher level to the lower level utilising the differential head between the two reservoirs.*

Currently, the terms and conditions for tariff components, stipulated in the CERC Tariff Regulations, 2019, for all these types of hydro stations are the same except for the higher RoE allowed for storage based hydro stations and PSP. In addition to the cost components, in general, the NAPAF of storage based generating stations is higher than that of ROR based projects considering the ability of storage based generating stations to generate on demand.
*However, it is observed that there is a need for a more enabling framework or incentive mechanism for dam/reservoir based generating stations to operate as peaking plants. **Considering the anticipated increase in peaking loads, these stations may be incentivised to operate as peaking plants. One way to do so is by providing additional incentives for energy supplied during peak periods.***

Comments and suggestions are sought from stakeholders on the above proposal and any alternative solutions, if any.

NTPC Comments:
In order to encourage generation during peak periods, these stations may be provided incentives as under:

a) Additional incentive @ 50% during peak hours over the incentive rate during off-peak hours.

b) Additional incentive linked to Market Clearing Price over the incentive rate during off-peak hours.

38. Tariff Structure for Cost Recovery for Emission Control System (7.1.42 of the Approach Paper)

The Commission, in Tariff Regulations, 2019, specified recovery of the impact of the installation of emission control systems through Supplementary Fixed Charges and Supplementary Energy Charges. While specifying the said recovery mechanism, the Commission in its explanatory memorandum specified as follows:

"The Commission is aware of the fact that the additional capital expenditure on account of setting up the pollution control facilities to meet the revised emission standards in the generating stations will result in increase in the capacity charge of the generating station. Further, the pollution control facilities shall also require additional recurring expenses in the form of reagent, consumables, additional O&M expenses and also result in additional impact on the operating norms, specifically the auxiliary energy consumption of the generating station. Thus, the impact will result in increase in capacity charges as well as energy charges of the generating stations. The generating stations which set up the pollution control facilities for meeting the revised emission standards earlier will be at competitive disadvantage in terms of landed cost of power to the beneficiaries, as compared to the generating stations which may set up such pollution control facilities for meeting the revised emission standards at a later stage.

Therefore, with a view to provide level playing field to all generating stations in the transition phase, till the time the revised emission standards are met by all the generating stations, the Commission has proposed that the tariff on account of additional capital expenditure incurred for setting up the pollution control facilities shall be determined separately as supplementary tariff."

The Commission, subsequently, through first amendment to CERC Tariff Regulations, 2019 introduced a following proviso under Clause 1 of Regulation 9.

"Provided also that the generating company shall file an application for determination of supplementary tariff for the emission control system installed in coal or lignite based thermal generating station in accordance with these regulations not later than 60 days from the date of operation of such emission control system."

The Commission also provided appropriate provisions for the computation of supplementary capacity charges and supplementary energy charges in the first amendment.

As not all generating stations have installed the emission control system, and most of these works are in the execution stage, therefore the existing tariff recovery mechanism may be continued. However, comments and suggestions are sought from stakeholders on alternatives to the existing tariff mechanism for recovering the impact of the installation of emission control systems.

NTPC Comments

a) The existing tariff structure of emission control system consisting of supplementary capacity charges and supplementary energy charges may be retained as these systems in majority of the units shall be commissioned in the next tariff period.
b) Further, some units have FGDs envisaged in the original scope of work of the main plant. Thus, the capacity charges of FGD is not separate. However, supplementary energy charges need to be kept separate so that the units is not disadvantage position w.r.t merit order due to FGD. Therefore, such cases need to be considered in the regulations.
c) The Existing regulations provides following depreciation recovery of emission control system
    i. twenty-five years, in case the generating station or unit thereof is in operation for fifteen years or less as on the date of operation of the emission control system; or
    ii. balance useful life of the generating station or unit thereof plus fifteen years, in case the generating station or unit thereof is in operation for more than fifteen years as on the date of operation of the emission control system; or
    iii. ten years or a period mutually agreed by the generating company and the beneficiaries, whichever is higher, in case the generating station or unit thereof has completed its useful life.

   It is submitted that the category of plants under (iii) the depreciation recovery has been mentioned 10 years irrespective of the life of plant. However, many of our old plants which has been / are being retrofitted with FGD, many of them crossed their life 25 years. Therefore, it is suggested to allow recovery of the depreciation for the period maximum up to 10 years from the useful life of old plant or 5 years from date of operation of FGD , whichever is later.
d) Units which have installed emission control systems should not be at a disadvantage when compared to units without these systems on account of merit order dispatch by Discoms. Therefore, it may be mandated through Regulations that Supplementary Energy Charges for emission control system should not be considered for merit order dispatch till all units have equipped themselves with emission control systems as per the MoEF&CC notification dated 31.03.2021.

39. Decommissioning of Generating Station and Transmission Assets (7.1.43 of the Approach Paper)

With the growing concerns over inefficient generating stations and their impact on climate change, it is imperative to have appropriate provisions in the Tariff Regulations to deal with all eventualities. Also, there would be the scenario wherein any generating station or transmission system is decommissioned prior to the completion of its useful life in order to comply with any statutory orders or due to technological obsolescence duly approved by RPC or any other uncontrollable factors. It is observed that, on one hand, the disposal of such decommissioned generating station/system entails a cost (unrecovered depreciation) towards such pre-closure, on the other hand, these generating stations have some salvage value *that can be realised. It is to be analysed how these costs and revenues can be accounted for so that they can be cost neutral to the generating or transmission company and also do not impact the beneficiaries. This would also reduce risk perception among investors and may provide necessary clarity on such matters thus reducing litigations.*

One approach could be that the net profit/loss post decommissioning and disposal of assets may be adjusted in one go from the beneficiaries, duly factoring in the un-recovered depreciation admissible under the Tariff Regulations.

In view of the above, comments and suggestions are sought from stakeholders on the possible approaches to recover or refund the impact of decommissioning costs in case the generating stations/transmission systems are decommissioned before the completion of their useful lives, if such decommissioning is done in compliance of a statutory order or due to technological obsolescence duly approved by RPC.

***NTPC Comments**:*

a) The existing 2019 Tariff Regulations provide a definition of decommissioning but lack comprehensive coverage of the associated aspects. Therefore, it is necessary to establish a comprehensive regulatory framework that encompasses all aspects of power plant decommissioning. It is prayed to formulate specific regulations that address decommissioning, covering both "before useful life" and "after useful life" scenarios. Decommissioning thermal power plants (TPPs) prior to their expected useful life can have adverse financial implications for the generators. The regulatory framework should incorporate clear provisions to handle various challenges that may arise from forced decommissioning due to statutory orders and allow for appropriate compensation or cost recovery.

b) Post-plant closure, we need to recover two types of costs:
   i. Residual capital base of 10%.
   ii. Additional decommissioning costs in the form of employee expenses and station overheads.

c) The following should be considered for decommissioning and asset disposal:
   i. The only source of income available for recovering these expenditures is through the sale of scrap. Enhancing the depreciable base from 90% to 95% (which is in line with the Companies Act 2013) would partially alleviate this challenge, considering the significant number of capacities that will require decommissioning in the near future.
   ii. Unrecovered depreciation: Decommissioning before the plant's expected life will result in the under-recovery of depreciation that was scheduled to be recovered from the tariff over the remaining useful life.

iii**. Capital Spares:** Capital spares stock that are not serviced should be treated separately and allowed as "deemed consumption" during decommissioning since they were originally procured for the plant's operation. It is important to address and resolve any difficulties arising from forced decommissioning which prevents future utilization of spares which have not been serviced till date. The generator will make all possible efforts to utilize the spares by transferring them to other plants. However, the residual capital spares if any, have to be serviced considering as deemed consumption. The cost of these spares becomes unrecovered during decommissioning.

iv. **Compensation for Loss of ROE for balance life -** Considering pre-mature decommissioning, there would be loss in return on equity, which also needs to be compensated suitably

By addressing these aspects and incorporating them into the regulatory framework, we can ensure a fair and comprehensive approach to power plant decommissioning. This will safeguard the financial interests of the generators and provide clarity on compensation and cost recovery, ultimately facilitating the decommissioning process in an efficient and sustainable manner.

40. Simplification of Tariff Formats (7.1.44 of the Approach Paper)

Some stakeholders have expressed the view that the tariff formats, required to be submitted along with the tariff petitions, instead of being simpler, are getting more intricate. The information filling and preparation of tariff forms takes considerable time and effort on the part of the petitioner and also results in delays in processing as these formats are required to be thoroughly checked by the Commission. ***Comments and suggestions are invited from stakeholders for simplifying the existing tariff formats.***

NTPC Comments:

As per the existing Tariff Regulations, a generating company needs to file a Tariff Petition along with the detailed calculation sheet in the tariff formats for determination of tariff for each of its generating stations. The existing provision of filing the petition along with the tariff formats, which is about 40 in number, is a lengthy & a comprehensive exercise which takes considerable time and efforts.

For determination of the tariff, the detailed scrutiny and analysis of each component of the tariff formats is required to be undertaken by the Hon'ble Commission which would defeat the objective of simplification in the exercise of determination of tariff.

it is proposed that the approach as suggested by the Central Regulator for computation of additional capitalization & capital spares on normative basis may help in simplifying the tariff formats as submission of details of additional capitalization, decapitalization & capital spares would no longer be essential.

In addition to the above, consideration of interest rate of capital loan on normative basis may further simplify the loan related formats as prudence check of several parameters of loan by the Commission for finalization of interest rate would be redundant. This would reduce the time & effort put in by the generator, regulator & beneficiaries in processing of the tariff petitions.

To summarize, the number of tariff forms & intricacy involves in computation of tariff can be reduced appreciably by considering additional capitalization, capital spares, depreciation rates for first 12 years @5.28%, & interest rate of capital loan on normative basis.

41. Assumed Deletions (7.1.47 of the Approach Paper)

When an asset, that forms part of Gross Fixed Assets (GFA) gets decapitalised, then ideally the historical cost of such an asset should be reduced from the GFA. However, in certain cases, where the asset under consideration is part of a larger scheme, the individual value of the asset may not be available, and while removing/replacing the said asset from service, a corresponding reference cost is needed to be deleted from the GFA.

As per the extant methodology, the Commission verifies the expenditure on replacement of assets; and if found justified, the same is allowed for the purpose of tariff, provided that the capitalization of the asset is considered against the de-capitalization of the original value of the corresponding old asset. However, in certain cases where de-capitalization is affected in books during the years following the year of capitalization of a new asset, the de-capitalization of the old asset for the purpose of tariff, is affected from the very same year in which the capitalization of the new asset is allowed. Such decapitalization, which is not a book entry in the year of capitalization, is termed "Assumed deletion". Further, in the absence of the gross value of the asset being de-capitalized, the same is calculated by de-escalating the gross value of the new asset @ 5% per annum until the year of capitalization of the old asset.

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.

NTPC Comment

a) As per 2019 Tariff regulations, relevant provision for decapitalizing an asset is as below:
"26 (2) In case of de-capitalisation of assets of a generating company or the transmission licensee, as the case may be, the original cost of such asset as on the date of decapitalisation shall be deducted from the value of gross fixed asset and corresponding loan as well as equity shall be deducted from outstanding loan and the equity respectively in the year such de-capitalisation takes place with corresponding adjustments in cumulative depreciation and cumulative repayment of loan, duly taking into consideration the year in which it was capitalised."

b) As rightly highlighted in the Approach Paper, there may be situations where it may be difficult to obtain the historical cost of the asset/ part of the asset which is being decommissioned and for the purpose of tariff determination it is proposed that in such situations, the cost of replacement shall be de-escalated @5% p.a. until the year of capitalization of old asset.

c) The proposed formulation is generally acceptable.

42. Necessity to Review the need of Regulation 17(2) – (7.1.48 of the Approach Paper)

The Commission, in its Tariff Regulations, 2019 introduced the following Regulation.
"17. Special Provisions for Tariff for Thermal Generating Station which have Completed 25 Years of Operation from Date of Commercial Operation: (1) In respect of a thermal generating station that has completed 25 years of operation from the date of commercial operation, the generating company and the beneficiary may agree on an arrangement, including provisions for target availability and incentive, where in addition to the energy charge, capacity charges determined under these regulations shall also be recovered based on scheduled generation.
(2) The beneficiary shall have the first right of refusal and upon its refusal to enter into an arrangement as above, the generating company shall be free to sell the electricity generated from such station in a manner as it deems fit."
As per Regulation 17 above, the generating stations and beneficiaries have the option after 25 years of operation to enter into a mutual agreement to recover capacity charges based on scheduled generation. However, the beneficiaries are allowed under 17(2) with the first right of refusal to such arrangement and can exit from the ongoing PPA. It is observed that generation, being a delicensed activity, is purely guided by terms and conditions of PPA and unilateral right to any party, bound by a contract, should not be allowed through Regulations.
Further, commercial mechanisms and terms & conditions for transactions between a generator and beneficiaries are governed by the long term PPAs executed between them, which are generally valid through the life of the PPA. It is noted that a number of generating stations, at times, operate beyond the tenure of the PPA, and that such extended operations should also be governed by the PPA as in the case of the original PPA period, and any interventions in the PPA through tariff Regulations, that too, every five-year, including such a unilateral exit clause, may not be desirable as it may violate contract sanctity and could be inequitable.

NTPC Comment

a) As per current tariff regulations, provision for thermal generating stations completing the useful life is as below:
   "17. Special Provisions for Tariff for Thermal Generating Station which have Completed 25 Years of Operation from Date of Commercial Operation: (1) In respect of a thermal generating station that has completed 25 years of operation from the date of commercial operation, the generating company and the beneficiary may agree on an arrangement, including provisions for target availability and incentive, where in addition to the energy charge, capacity charges determined under these regulations shall also be recovered based on scheduled generation.
   (2) The beneficiary shall have the first right of refusal and upon its refusal to enter into an arrangement as above, the generating company shall be free to sell the electricity generated from such station in a manner as it deems fit."

b) As rightly opined in the Approach Paper, a number of generating stations, at times, operate beyond the tenure of the PPA, and that such extended operations should also be governed by the PPA as in the case of the original PPA period, and any interventions in the PPA through tariff Regulations, that too, every five-year, including such a unilateral exit clause, may not be desirable as it may violate contract sanctity and could be inequitable.

c) Such a formulation is not based on level playing field. Regulation 17 confers first right of refusal to the beneficiaries only and thus provides unilateral right to any party, bound by a contract, should not be allowed through Regulations. Thus, there is conflict between Regulation 17 and the PPA beyond completion of 25 years. These provisions in the Regulations have resulted in litigations between the generator and beneficiaries at various legal forums.

d) Further, MOP vide letter dated 20.04.2023 has asked CERC to take necessary action for making appropriate regulatory provisions in CERC regulations for operationalizing the Scheme of pooling of tariff of those plants whose tariff has expired.

e) In view of the above, after completion of the PPA term, the parties need be allowed to mutually decide on extension of the term of PPA. Therefore, in order to prevent any conflict of the Regulations with respect to the provisions of the PPA beyond the tenure of PPA / its extension beyond the useful life of the plant, the Regulation-17 may be removed.