TATA

To,

Date: 31.07.2023

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

Sub: Submission of Comments/ Suggestions on Approach Paper - Terms and Conditions of Tariff for the period 01.04.2024 to 31.03.2029 by The Tata Power Company Limited (Tata Power).

Dear Sir,

This is in reference to the Public Notice issued by the Hon'ble Commission dated 26.05.2023 and its addendum dated 03.07.2023 in File No. L-1/268/2022/CERC wherein the Hon'ble Commission has sought for the Comments/ Suggestions on the Approach Paper - Terms and Conditions of Tariff for the period 01.04.2024 to 31.03.2029, latest by 31.07.2023.

2. In compliance with the aforementioned, please find attached Comments/ Suggestions alongwith Annexures on behalf of Tata Power for its regulated entities, for kind perusal and consideration of the Hon'ble Commission.

Yours Sincerely,

Pankaj Prakash,
Head - Regulatory (ER)

Encl: As above.

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Comments on

Approach Paper on Terms and Conditions of Tariff Regulations for Tariff Period 1.4.2024 To 31.3.2029

By

The Tata Power Company Limited

Contents

Summary of the Issues raised in the Approach Paper and Comments / Suggestion thereon

7.1.1 and 7.1.2: Tariff Determination – General Approach

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 a 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.
3. Whether clustering the components of AFC based on their nature to increase/ decrease will allow better projections? Any other possible method to cluster the AFC components?
4. What other methodology can be adopted to determine the increasing/ decreasing factors?
5. Whether the impact of additional capitalisation can also be allowed through the same indexation mechanism or through a separate revenue stream?

Comments: It is understood that in Approach 1 the Approach Paper is proposing to shift from existing tariff determination methodology to a normative approach, wherein once the capital cost is approved on actual basis, the rest of the AFC parameters will be allowed on basis of norms fixed on account of indexation formula as determined by Hon'ble Commission. While Tata Power welcomes this progressive approach, it needs to be evaluated whether it can be adopted now or in stages. The Approach Paper has not explained the complete methodology proposed to be adopted in this regard. Though, the graphs represented in the Approach Paper clearly depicts convergence of the trendlines of both components, i.e. O&M Expenses and AFC component (excluding O&M Expenses), however, this is due to the fact that the two components i.e. O&M expense and Rest of AFC components are being considered as percentage of total of the AFC components.

However, the same does not depict the actual impact/scenario when AFC is considered in absolute terms/numbers. Further, it is not clear on which AFC base, these % shall be applied and how the impact of y-o-y additional capital expenditure shall be incorporated in the AFC components. There is lack of clarity regarding the data, time frame, uniformity of approach, normalization of distinguishing plant specific factors etc. to be considered. Therefore, in order to understand the exact methodology to be adopted and its impact on value of norms particularly for Additional Capitalization, we request CERC to provide end to end illustrative examples of determining the indexation factor and AFC Parameters with base line figures of Capital Cost as well as the additional capital expenditure till cut-off date and beyond. Further, it is also requested to provide all the data available and to be used to arrive at the desired indexation formula, so that stakeholders have complete understanding of the approach to analyze the proposal and provide meaningful suggestions in favor of the power sector.

In case of the Normative approach, we are of the view that the indexation may not work as different assets and different projects have different issues. The indexation factor as given in sample calculations is being calculated on the basis of the determined tariff only and then are being trued up based on the additional capitalization, which is being done presently as well, however, the additional calculation of indexation factor will further increase the complexity of tariff determination. It is also assumed that tax component is already considered for grossing up of ROE that shall be considered for formulation of norms for AFC and, hence, tax is also proposed to be allowed on normative basis. The same also needs to be clarified by the Hon'ble Commission.

Further, the Second Approach is similar to the current approach followed by the Hon'ble Commission i.e. all components are calculated on normative basis except determination of Capital Cost and Interest on Loan which has to be computed as per actual weighted average rate of interest. Thus, Tata Power is of the view that the Hon'ble Commission may explore this option to link the interest on loans with reference rate providing sufficient cushion to protect interest of diverse developers in the sector. The rate of interest on loan may be linked with the benchmark rates by allowing normative rate of interest of 250 basis points above the average SBI MCLR (one year tenor) prevalent during the period October to March of previous financial year, consistent with the normative approach being followed for RE Tariff Regulations, 2020.

In addition, the thermal generating stations are posed with a new challenge of continued operations at technical minimum (or even below), high ramping rates, to accommodate the ever- increasing penetration of intermittent RE sources. While the generating stations are being compensated for operating below a specified level through relaxed norms under provisions of the Grid Code, the long-term impact w.r.t higher O&M requirement, higher additional capital expenditure due to higher wear and tear, decrease in useful life from 25 years, are yet to be witnessed. These impacts cannot be fully incorporated in any normative approach, as there is no data for gauging the impact of these eventualities.

Hence, we are of the view that Hon'ble Commission should continue with the existing approach itself with modification in interest rate considered for the computation of interest on loan. However, for analysis of First Approach and its impact on the stakeholders Hon'ble Commission may illustrate with examples of determining the indexation factor and AFC Parameters/norms with all the data used to arrive at the desired indexation formula.

7.1.3 Provision of Interim tariff

6. 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.

Comments: We agree with the suggestion to continue with the existing provision of interim tariff.

7.1.4 Procurement of Equipment and Services

7. 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.

Comments: We agree with the general proposition of competitive bidding for developing projects. However, complying with government guidelines is neither possible in all cases nor required under law for private entities. It is also time-consuming and, hence, leads to delays. Therefore, it is suggested that procurement of goods/services for projects may be done as per corporate policy of the company, which on rational criteria based on size and scope of contract provide for open/limited tendering as nomination basis. Further, in some of the cases, especially for the under-construction projects acquired post NCLT proceedings where work was already awarded but was yet to be completed. It is pertinent to note that every generation project is unique from construction point of view. Accordingly, the work already executed by existing EPC contractor is usually unique and in such a scenario, either the pending works can only be completed by the existing contractor, or it has to be awarded freshly to a different contractor through competitive bidding which may lead to scrapping up of progress made by previous entity due to technological exclusivity. Therefore, the Hon'ble Commission is requested to allow the procurement of works/good and services on single sourcing basis, through limited tender and open competitive bidding as per Corporate policy to get the work executed and project commissioned at the earliest.

7.1.5 Reference Cost – Benchmark Cost V/s Investment Approval

8. Comments and suggestions of stakeholders are invited on other efficient reference costs other than Investment Approval costs that can be considered for prudence check.

Comments: The capital cost of a project depends on various factors such as project size, Technology and design, Civil works and infrastructure, Electro-mechanical equipment, land acquisition and environmental factors etc. The methods used to estimate the capital costs of thermal generation projects includes Engineering Cost Estimates, Cost Indexing, Benchmarking, Parametric Estimating, Comparative Cost Analysis etc and each may give different cost estimate. Apart from this, it is very important to note that capital costs for generation projects can vary significantly depending on local factors, such as geographical conditions, regulatory requirements, labour costs, environmental laws, and the availability of construction materials. Therefore, local expertise and detailed analysis are crucial for accurate cost estimation. Along with these factors there are other parameters which vary from one generating stations to the other such as the choice of technology, design, fuel delivery system, distance from fuel source, etc. as mentioned above.

Similarly, the capital cost of transmission projects may depend upon Project specific conditions such as terrain, project location, Right of Way (RoW) Constraints (including urbanization, river/highway/ railway line crossings, crossing of other transmission lines, forest area) and weather conditions may lead to different capital costs of similar transmission assets. Further, the results of any econometric model may be way beyond actual costs and may result in severe losses for the transmission licensees, if benchmarks are set low or to the transmission users, if the benchmarks are set too high.

In most of the countries determining tariff under RTM, either actual capex or inflation adjusted capex is used without following benchmarking. Therefore, it is difficult to compare the cost of two projects based on historical data/similarity/magnitude/ benchmarking. Hence, we are of the view that Investment Approval costs as approved by Appropriate Authority/or Board of the Company, which includes technical & financial in-depth evaluation of all project specific parameters, and broad comparison with recently commissioned projects, duly accounting for the specific conditions of a given project, may be considered for prudence check for the project cost only if there is huge divergence between the two.

7.1.6 Capital Cost – Hydro Generating Stations

9. As these expenses towards the advancement of the Local Area are required for the development of the project and for alleviating public resistance and delays, such expenses may be allowed as part of the capital cost with certain limits. Alternatively, these expenses may be met through Budgetary support for funding the enabling infrastructure, i.e., roads and bridges on a case-to-case basis, which could be

(i) as per actuals, limited to Rs. 1.5 crore per MW for up to 200 MW projects and (ii) Rs. 1.0 crore per MW for above 200 MW projects, as per the Ministry of Power guidelines dated 28.09.2021 for Budgetary support for Flood Moderation and for Budgetary Support for Enabling Infrastructure.

10. Comments and suggestions are further sought from stakeholders on ways to expedite development of hydro generating stations especially the construction phase, and increase their commercial acceptability.

11. Comments and suggestions are sought from stakeholders to incentivize the developer if it executes the project faster/or ahead of schedule and vice-versa if it delays.

Comments: The option proposed for funding of the enabling infrastructure, i.e., roads and bridges, on a case-to-case basis is welcome step. As people are affected from the construction of hydro generating stations does impact local areas, especially those falling under the catchment area, there is generally a growing dissatisfaction against the developer. While the developer voluntarily carries out local area development initiatives such as building roads, schools, and clinics for the benefit of the people and to mitigate resistance to the project, however, many times these are perceived insufficient by the local population.

Since the above fund is granted by the Ministry of Power on prudence basis, therefore, we are of the view that other enabling infrastructure expenses apart from the roads and bridges that are expensed to manage the local issues usually being faced by the developer should also be included and allowed through as part of the enabling infrastructure. The expenses may be reduced to the extent budgetary support is availed but should not be limited to such support amount. However, if the same is not being considered by the concerned authority as part of enabling infrastructure, then the Hon'ble Commission is requested to allow the same as part of the capital cost as it will enable the developer to complete the projects in shorter span of time, which will lead savings of additional cost on account of time overrun.

To expedite the development of hydro generation stations, especially during the construction phase, in India, several strategies can be employed to streamline processes, optimize resources, and overcome potential obstacles. The Commission can play its part in promoting the development of hydro generating stations by incentivizing timely completion – through higher rate of returns, escalable tariff adjusted for inflation, allowing return on all funds including equity infusion during the construction phase to be part of the capital cost, with some reasonable conditions linked to timely completion of the project.

7.1.7 Capital Cost – Projects Acquired post NCLT Proceedings

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.

Comments: The Hon'ble ATE vide its judgment dated 27.09.2019 in Appeal No. 183 of 2019, has already settled for section 63 project that the adopted tariff in terms of PPA is the basis to bid for purchase of equity in the project and any further reduction in the already adopted tariff would further reduce the bid price. The reduction/change in the PPA tariff, which being the fundamental basis for arriving at the bid amount by the bidders, post conclusion of the bid process by lenders of the project, would amount to change in the fundamental basis of the bid. Therefore, if the tariff of the generating station/Transmission System has already been determined, there should be neither re-setting of tariff nor of the operating parameters with the objective of reducing the tariff. Accordingly, on the same lines, in case of Section 62 projects, as the historical cost as on COD with subsequent Additional Capitalization/Incidental Expenditure forms the basis for tariff determined by the Hon'ble Commission, the same premise should continue for the purpose of tariff determination even post approval of Resolution Plan, as the acquisition value has taken into consideration the revenue stream based on historical cost and future investment requirement including any incidental expenditure for acquisitions for under construction projects, which are assumed to form the basis of future tariff determination by the Commission. Since approved tariff that included debt servicing and other expenses would have already been considered in acquisition price, the same need not be considered again. Hon'ble Supreme Court has held in multiple cases that no claim prior to approval of Resolution Plan can be made by anyone as this would nullify the resolution plan and basis of bidding. Further, if the tariff is not determined and the acquisition cost is arrived through the balance sheet, then acquisition cost is most suited for the such projects acquired post NCLT proceedings, however, any additional capital expenditure along with any incidental cost that is required to be incurred for completion of remaining works in case of under construction projects or operationalizing of the completed assets which may have remained stranded and shut-down for long duration of time during the NCLT proceedings, should also be considered as part of the Capital Cost.

Further, this approach should also be considered for stranded assets resolved out of NCLT proceedings, as the fundamental issues remain common, irrespective of the acquisition of stranded /distressed assets through NCLT proceedings or outside it.

Also, since benefit of lower acquisition price is proposed to be considered for assets under construction, the delay in commissioning due to stressed asset resolution proceedings should also be condoned and additional time should be provided for completing under construction stranded assets.

Moreover, it may also be clarified that these regulations should strictly be applicable only for Section 62 projects and not Section 63 projects.

7.1.8 Computation of IDC

14. Existing mechanism wherein the pro-rata deduction (based on delay not condoned) is done on IDC beyond SCOD.
15. Pro-rata IDC may be allowed considering the total implementation period wherein the actual IDC till the implementation of the project is pro-rated considering the period upto SCOD and period of delay condoned over total implementation period.
16. IDC approved in the original Investment Approval to be considered while allowing actual IDC in case of delay.

Comments: According to the CERC Tariff Regulations, 2019, Interest during construction (IDC) shall be computed corresponding to the loan from the date of infusion of debt fund, and after taking into account the prudent phasing of funds upto SCOD. In case of additional costs on account of IDC and IEDC due to delay in achieving the COD, the project developer is required to furnish detailed justifications with supporting documents for such delay including prudent phasing of funds in case of IDC and details of IEDC during the period of delay and liquidated damages recovered or recoverable corresponding to the delay. If the delay in achieving the COD is not attributable to the developer, IDC and IEDC beyond SCOD may be allowed after prudence check and the liquidated damages, if any, recovered from the contractor or supplier or agency shall be adjusted in the capital cost of the asset. If the delay in achieving the COD is attributable either in entirety or in part to the developer or its contractor or supplier or agency, in such cases, IDC and IEDC beyond SCOD may be disallowed after prudence check either in entirety or on pro-rata basis corresponding to the period of delay not condoned and the liquidated damages, if any, recovered from the contractor or supplier or agency shall be retained by the developer.

1. In the first option the Approach Paper has proposed to continue with the existing mechanism with a little tweak that the IDC beyond SCOD is pro-rated based on the condonation/non-condonation of the delay. The allowable IDC in this case would be calculated as

$$\boxed{₹\ X + [Y*(A/B)]}$$

, i.e., only IDC pertaining to delay is pro-rated.

X= IDC upto SCOD

Y=IDC beyond SCOD till actual COD

A= no. of months of delay condoned

B=total no. of months of delay

2. The other option proposed in the Approach Paper is that the total IDC is pro-rated based on the SCOD, and delay condoned with respect to the actual no. of months taken for the project to be commissioned. The allowable IDC in this case would be calculated as

$$\boxed{₹\ (X+Y)*[(A+B)/C]}$$

where

X= IDC upto SCOD

Y=IDC beyond SCOD till actual COD

A= no. of months approved for the project to be commissioned

B=total no. of months of delay condoned

C=total no. of months taken for the project to be commissioned

It is submitted that the developer follows a prudent phasing practice, wherein most of the payments are done at the later stages of the construction period in order to reduce IDC and IEDC incurred towards the project. Therefore, the right approach should be to undertake the prudence check of the proposed IDC at the time of provisional approval of capital cost, i.e. determination of interim AFC itself, and if there is no delay then IDC allowed in the Investment Approval (IA) should be allowed. However, in case of delay, the IDC up to amount as per IA should be allowed as such and any excess IDC incurred should be prorated as per methodology proposed in option 2 i.e.

$$\boxed{₹(X)+(Y-X)*[(A+B)/C]}$$

X= IDC approved in IA

Y= Actual IDC incurred upto COD

A= No. of months approved for the project to be commissioned

B= Total no. of months of delay condoned

C= Total no. of months taken for the project to be commissioned

Therefore, we request Hon'ble CERC to consider third approach while allowing IDC.

7.1.9 Treatment of LD

17. In view of discussion held in Section 4.4.2, 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.

Comments: We agree with the views in the Approach Paper for the treatment of Liquidated Damages in line with the Judgment by APTEL in Appeal No. 72 of 2010. Therefore, the Hon'ble Commission is requested to notify a separate disclosure form for the Liquidated Damages along with the tariff formats to avoid the double deduction of LD amount, and also include a specific provision in the Tariff Regulations to provide further clarity on the approach regarding LD adjustment**.**

7.1.10 Price Variation

18. 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 the 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 variations.

Comments: The Hon'ble Commission while approving the hard cost of a project, undertakes prudence check in terms of reasonableness of the project cost, taking into consideration the specific conditions of the project and deducts IEDC and IDC accordingly. Therefore, there is no reason to curtail the hard cost further on account of price variation, proportionate to the delay not condoned, which is as per the contract terms. Further, such contracts are very strict/prudent and any variation, thereof is provided only for delays beyond terms of contractor's control, which may be due to another contractor in predecessor activity. Even recovery of LD from another contractor does not prevent delays and price escalation. But, if price variation in the contracts will be subjected to deduction as suggested in the Approach Paper, developer will bid only for fixed price contract and the EPC / contractors will adopt a practice to inflate their respective quotes, taking into account any anticipated variation in the future which may result in increased project cost and the purpose of the proposed amendment would be defeated. Further, in case there is no price variation clause in the contract and due to some uncontrollable reasons for instance say Covid-19, there is a price variation it should be considered on case-to-case basis. The decision regarding fixed price contract or contract with price variation may be left to developer. In case of delay in the project commissioning, the developer has already been penalized on account of delay in return on equity infused and also disallowance in IDC and IEDC on the delay not condoned by the Hon'ble Commission on account of time overrun. Therefore, no disallowance due to price variation should be carried out.

7.1.11 Renovation and Modernisation (R&M)

19. In view of the inherent benefits of undertaking R&M as against going for fresh capital investment, the current provisions may be continued.

20. Further, utilities that opt 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.

Comments: The present tariff regulations do not specify any methodology for the tenure of recovery of capital cost incurred on account of R&M e.g., there is ambiguity w.r.t methodology, rate and tenure of depreciation and hence the normative loan repayment, on whether it will be 12 years or extended life. Therefore, the upcoming tariff regulations should provide clarity on these issues.

Further, the Special Allowance, though in lieu of R&M, being a part of AFC is considered as a revenue item and is subject to tax. Thus, the funds available to the developer for undertaking R&M are net of tax only. Therefore, the Hon'ble Commission may take into consideration the tax impact while determining Special Allowance. Also, the current provisions of Special Allowance in the 2019 Tariff Regulations have discontinued the provision of escalation factor, thereby eroding the value of Special Allowance with elapse of time. Therefore, the escalation factor to meet the inflation may be reintroduced. While the concept of continuing with the Special Allowance for the entire tariff period is agreed, it may be clarified that in case it becomes effective for part of the tariff period, say, from 2nd, 3rd, 4th or 5th year of the control period, the same shall continue to apply for the remaining life of the renovated Asset. Further, the Hon'ble Commission is also requested to disclose the methodology and computation adopted to arrive at the figure of the Special Allowance to be proposed as the base figure for the new Control Period, as the existing figure of INR 9.5 lakh / MW is outdated, not applicable in the present context and are grossly insufficient to meet the requirement.

7.1.12 Initial Spares

21. In view of discussion held in Section 4.7, single norm can be considered for each of the following classes of transmissions 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: The existing Tariff Regulations, 2019 allows a ceiling of 4.00% of Plant and Machinery cost for initial spares of generating stations. Generally, certain mandatory spares are supplied along with the mother plant equipment, by the supplier, as part of the major contract packages. As such, the cost of the same is included in the cost of mother plant equipment, and the segregation of cost of spares from the cost of mother plant is not possible. In such scenarios, the Hon'ble Commission has assumed the initial spares to be procured up to the ceiling limit along with the mother plant equipment and doesn't allow to procure required initial spares within the cut-off date. Therefore, it is proposed that some percentage of initial spares may be allowed separately for the cases where proper segregation of initial spares is not available and were procured along with the mother plant. Further, while initial spares getting consumed are allowed under Capital Spares, after about 8-10 years additional spares are also required. In such cases, either cost of new spares be allowed or if old equipment is repaired for reuse, it should not be decapitalized being at much lower cost than new spare.

Also, sometimes the order for initial spares is placed well within the cut-off date, however, some of these are delivered within the cut-off date and some beyond the cut-off date which is usually beyond the control of the Petitioner. Therefore, the initial spares for which the order is placed well within the timeline but are delivered beyond the cut-off date and are within the ceiling limit should be allowed.

7.1.13 Controllable and Uncontrollable Factors

22. In view of the discussion held in Section 4.8.1, delays on account of forest clearances can also be considered for inclusion as uncontrollable factor.

Comments: The delay on account of land acquisition and forest clearance may be considered in the list of Uncontrollable factors along with Force Majeure and Change in Law, since the delays faced by power projects in obtaining forest clearance can vary depending on the specific project, location and regulatory processes involved and are totally beyond the control of developer. The initiative taken by the Hon'ble Commission of continued inclusion of delay on account of land acquisition as an uncontrollable factor and on the further inclusion of delay on account of actual time taken for forest clearances as an uncontrollable factor will support the feasibility of the thermal generation/trasmission projects. Further, generation projects are facing severe delays for clearance of trees on forest land even after obtaining forest clearance, which again has to be approved from the concerned statutory/local authority. It is, therefore, requested to also consider delay in getting the forest land cleared as part of the uncontrollable factors. Besides delay in obtaining forest clearance, developer has to seek many other clearances from statutory authorities and/or Government Departments, including Railways, National Highway Authority, etc. It is suggested to include all such types of clearances, wherein the delay is attributable to the Government Agencies, as an uncontrollable factor.

Further, we have recently witnessed the impact of Covid-19 resulting in overall loss to society at large, including delays in infrastructure/development projects, to the extent that same was termed as pandemic. Further events like Cyber-attack, change in the course of river stream, any shortage arising due to limit on supply of goods/services by Civic bodies, shortage of water due to restriction by Government Authority or due to embargo/limitation on drawl of water from rivers, etc. are some examples of the events, which are beyond the control of the developer, price and quality of fuel, Force Majeure (FM) and Change in Law (CIL) and thus, may be included under Uncontrollable Factors. Further, the scope of application of Uncontrollable factors, including FM and CIL, may not be limited to capital cost but needs to expanded to include any component of tariff including energy charges.

7.1.14 Differential Norms – Servicing Impact of Delay

23. To encourage rigorous pursuit of approvals from statutory authorities, even if delay beyond SCOD is condoned, on account of any reasons are condoned, some part of the cost impact (Say 20%) corresponding to the delay condoned may be disallowed.

24. Alternatively, RoE on Equity corresponding to cost and time overrun allowed over and above project cost as per investment approval may be allowed at the weighted average rate of interest on loan instead of fixed RoE.

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

Comments: The Project Developers actively engage with the statutory authorities for getting clearances and approvals at the earliest, as they have their deepest stake in the project. However, they don't have much control over the approval processes of the statutory authorities and time taken for providing the same. Similarly, developers also continuously engage with the local authorities in case of local disturbances and other right of ways issues in order to resolve it in a timely manner. In such a scenario, disallowing some part of the cost impact corresponding to the delay condoned will lead to an additional penalty apart from already reduced returns (IRR) due to delays.

Further, allowing RoE at the rate of weighted average rate of interest on loans for the capital base corresponding to cost and time overruns allowed over and above project cost as per investment approval will lead to reduced returns over the already reduced IRR. The reduced RoE will lead to an additional penalty apart from already reduced IRR due to extended timelines. Further, the proposed methods shall also increase the complexity while calculating the tariff of the Assets.

It has been held by Hon'ble Commission in its Order dated 21.12.2000 that different assets of a project cannot be provided a different rate of RoE either based on vintage or otherwise. For funding any additional capital expenditure, equity is one of the sources of fund, without which Debt cannot be mobilised, and it has been well established that the cost of these two funds cannot be the same, considering the risk component associated with these two are totally different. Further, it is the basic principle of law that no one can be punished for something where he has been found not guilty i.e., when delay is condoned. For, delay not condoned disallowances are already being done. Further, such clauses will increase risk and future investments would also be dissuaded. Therefore, it is suggested to continue with the existing approach.

7.1.15 Additional Capitalisation

26. In view of discussion held under Section 4.10, in order to have an enabling provision under which 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: In case the capital expenditure is required for emergency work, which has not been approved in the Capital Investment Plan, the Generation Company/licensee may be allowed to submit an application containing all relevant information along with reasons justifying emergency nature of the proposed work seeking post-facto approval by the Commission. As such expenditure are also not covered under Force Majeure events, the Generating Company/Licensee may be permitted to take up the work prior to the approval of the Commission provided that the Management of the Generating Company/licensee has certified the emergency nature of the scheme, subject to prudence check at the time of truing-up.

7.1.16 Normative Add-Cap - Generating Station

For generating stations that have already crossed the cut-off date as on 31.03.2024, the additional capitalisation for such generating stations may be allowed as per the following.

27. **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.

28. **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.

29. 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.

30. Further, any items that costs 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.

31. 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 station 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 may be adopted.

32. 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.

33. 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 Regulations 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.

34. While determining such special compensation for a thermal or hydro generating station, costs incurred towards works presently covered under Regulations 26 to Regulation 29, wherever applicable, may not be included as these expenses but may be allowed separately.

35. 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.

36. 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: Regarding the option of providing special compensation based on unit sizes and vintage (Sr. Nos. 27 and 33), it is requested to provide the clarity regarding the following aspects, in order to provide comments for adopting the normative approach:

a) How the aspect of technological obsolescence, new/tightened environmental norms related compliances, anticipated higher wear and tear due to backing down, increased frequency of start-stop of the thermal generating stations, etc. shall be accounted for while providing special compensation?

b) The Tariff Regulations in the past had provisions w.r.t compensation allowance, special allowance with escalation, etc. to meet the add-cap requirement, which will not get reflected in the data-base for add-cap allowed to the generating stations for considering that they have not claimed any add-cap being ineligible. How will these aspects be accounted for while allowing normative add-cap for thermal generating stations?

c) How Add-Caps of specific nature, which may not be covered under existing Regulations 26 to 29, and which cannot be met through special compensation will be considered for allowance?

The alternatives of providing special compensation to meet the add-cap expenses of recurring nature for a specific hydro generating station (Sr. No. 28); considering the works presently covered under Regulation 26 to Regulation 29 separately and not allowing through special compensation (Sr. Nos. 29 and 34) and allowing discharge of liabilities of works already admitted by the Commission as on 31.03.2024, as and when such liability is discharged (Sr. Nos. 31 and 36) are supported.

Regarding the issue of considering Capital Spares upto Rs. 20 lakhs only as part of O&M expenses (Sr. Nos. 30 and 35), it is humbly submitted that the Hon'ble Commission has commenced allowing capital spares on consumption basis w.e.f. 2014-19 tariff period for items amounting to Rs. 1 lakh and above. While issuing truing-up orders for 2014-19 tariff period, the Hon'ble Commission itself has stated difficulty regarding any definition of Capital Spares. Therefore, there is no sufficient data to consider (not considering) items below Rs. 1 lakh or Rs. 20 lakh. Further, it is also worth noting that the Hon'ble Commission has not outlined any approach by which they will accommodate these Capital Spares up to a monetary value of Rs. 20 lakh under O&M expense norms, as these Capital Spares do not form part of the O&M expenses of the generating station/Transmission system. It is therefore humbly requested to explain what all constitutes Capital Spares with specific inclusions, exclusions for different assets, their differentiation from Initial Spares as part of Capital Cost, minor items, approach on how the Capital Spares shall be considered as part of O&M expenses norms, etc. While Rs. 20 Lakh may be all right for a generating company, it is too high for a transmission licensee for which it is proposed to be Rs. 1 Lakh.

Regarding extending cutoff date from 3 to 5 years for allowing add cap (Sr. No. 32), we are of the view that it is a good measure because most of the capitalization is incurred in the first 5 years of the project CoD, but some of the remaining works of the project under original scope might not get completed within 5 years from the COD of the project due to various reasons. Hence, we are of the view that only expenditure incurred towards replacement of asset which are recurring in nature should be put under the Special compensation and all expenses incurred by the generating station should also be allowed in the Add Cap itself after prudence check and verified through a true up process. Further, it is proposed that as the Audit is being conducted on quarterly basis, the cut-off date may also be linked to the last date of the quarter in which cut-off date is occurring i.e. 36/60 months from the date of commercial operation of the project.

Further regarding the minor assets including furniture, ACs, IT Equipments, which have a very short life span of 4-7 years, cannot be used for an extended period. The depreciation rate of IT Equipment's in the depreciation schedule is 15% which is equivalent to useful life of about six years (90% depreciable value at at the rate of15%). Hence, such minor assets including IT equipment technically need to be replaced with new assets as and when need arises for the sustained operation of the Project. Essentially, useful life as per Cost Accounting Standard is the period over which an asset is expected to be available for use by an entity. Notably, Hon'ble Commission, in view of such requirements had earlier in 2014 Tariff Regulations made provision for compensatory allowance to fund such minor assets on normative basis that was done away with in 2019 Tariff Regulations. It is, therefore, requested that regulatory treatment for funding Minor Capital Expenses having useful life of less than 25 years ought to be clearly spelt out in Tariff Regulations for recovery of legitimate cost in reasonable manner for both generating and transmission projects as per Section 61(b) and 61(d) of the Act i.e., either through Add-Cap or Compensation Allowance.

In addition, as per notification dated 31.12.2021, MoEF&CC has made it a statutory obligation for every Thermal Power Plants (TPP) to ensure 100% utilisation of fly ash within three to five years. The same has also been recognized by the Commission in its order dated 5.11.2018 in Petition No. 172/MP/2016 and order dated 28.10.2022 in Petition No. 205/MP/2021 as change in law event. As per Notification there are two types of ash i.e., legacy ash and operational ash. Since utilisation of legacy ash is now mandatory and obligatory in nature, it is proposed to allow such expenditure as per actuals. Further, the operational ash which is to be disposed of should be allowed as part of O&M expenses, however, the allocation of such ash evacuation expenses to beneficiaries should in terms of their actual schedule. The same should also form part of AFC while determination of tariff subject to truing-up on actuals.

7.1.17 Normative Add-Cap – Transmission System

37. For reasons discussed in Section 4.10.2, for Transmission Systems, additional capitalisation post cut-off date may be allowed on technological obsolescence, change in law, force majeure, or due to replacement as presently allowed under Regulation 26 and 27 of the CERC Tariff Regulations, 2019.

Comments: We agree with the views in the Approach Paper for allowing add-caps post cut-off date on account of technological obsolescence, change in law, force majeure, or due to replacement as presently allowed under Regulation 26 and 27 of the CERC Tariff Regulations, 2019. However, the rate of RoE on the same should be at the normal rate and not on WAROI, reasons of which have been discussed separately. Further, it is proposed to include add caps for technological advancements like use of drones for safety and security, security cameras equipment etc. In particularly Regulation 26(1)(d) should also include safety and security measures as required under law even though they are not mandated by Government agency.

7.1.18 GFA/NFA/Modified GFA approach

38. Increasing the Investors' confidence by ensuring assured returns is important, and further considering the recent spikes in power tariffs in power exchanges indicating a 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.

Comments: The GFA approach provides for internal resources for capacity replacement through return on equity even when the cumulative depreciation goes beyond the debt component. Whereas, in the NFA approach, the returns are allowed on the remaining equity component after adjusting for the depreciation received beyond the debt component. As per CEA's Report on Optimal Generation Capacity Mix for 2029-30 published in April 2023, 43104.5 MW (16204.5 MW of new Capacity apart from 26900 MW of coal based generation capacities at various stages of development) will be required. This capacity addition will require a significant investment in the generation sector for meeting the base load and complement the variable renewable generation capacities from the point of view of grid stability and reliability.

Further, there is no way the invested equity can be withdrawn from the entity by the shareholders till actual sale of the asset. Therefore, the equity component always remains invested in the business, even if hypothetically the cash is available through depreciation (post repayment of debt). The only way by which the equity shareholder gets returns, is through dividends, which can only be paid out of profits. Depreciation, in accounting terms, is a non-cash expenditure, cannot be a source to repay the equity or dividends to the equity shareholders. The required investment has to be funded through the internal accruals, direct investment from the investors and the financing institutions. Therefore, increasing the Investors' confidence is a necessity in such case and providing regulatory certainty will be a key factor and we agree with the Hon'ble Commission's views of continuing with GFA approach in this regard.

7.1.19 O&M Expenses

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.

Comments: The norms for O&M expenses are determined considering historical average O&M expenses of a large number of similar projects across regions. Private developers having single or few projects are expected to adap their overall O&M expenses budgets considering these norms. Splitting of O&M expenses norms any further between employee expenses and others will pose difficulties for the private entities to manage their O&M expenses efficiently. Therefore, it is suggested to continue with the existing approach of allowing the O&M expenses as per norms. Further, it is observed that the O&M norms are primarily based on the O&M expenses of stakeholders of the likes of NTPC Ltd and PGCIL, having substantial number of assets across regions with greater economies of scale. Therefore, the norms which are sufficient for these stakeholders on an overall average basis, will not suffice for meeting the O&M expenses of private entities having single/few assets in a particular area/location. Hence, we request the Hon'ble Commission that while fixing norms, the O&M norms for Private players needs to be revised upwards (by 25-30%) particularly in transmission having limited number of projects so that they are also able to recover the reasonable cost as envisaged under clause b & d of Section 61 of The Electricity Act, 2003.

The alternative approach of keeping the O&M expenses as combined and allowing 50% of the actual wage revision on a normative basis, essentially means remaining 50% has to be met through the existing norms or from the gains accrued on account of efficient operations. This approach will result in under recovery of cost of generation for the generator which is in clear contradiction to Section 61(d) of Electricity Act, 2003 which provides for safeguarding of consumers' interest and at the same time, recovery of cost of electricity in a reasonable manner. Further, the Commission should allow the wage revision impact to all the generating stations i.e., even private players as such revisions for Government entities effectively means revision of their O&M Norm, which should be applied to private companies as well. The Commission may also deliberate upon the methodology to capture the wage revision impact thoroughly in the Regulations.

As also discussed in

- Section 7.1.16, the operational ash which is to be disposed of shall be allowed as part of O&M expenses.
- Section 7.1.37, additional R&M expenses should be allowed for frequent wear and tears during backing down of the stations.

Further, in the case of Transmission Assets, way leave charges are mandatorily required to be paid to Indian railways and other statutory bodies like National Highway Authority of India (NHAI), PWD, MMRDA etc. for way leave facilities/easement rights/right of way etc. Such charges, incurred during construction, are charged to capital cost, however, such permissions/consents/agreements are valid for certain period whereafter they are required to be renewed to continue the operation of transmission lines/thermal projects etc. Renewal cost is essential and needs to be allowed either as one time reimbursement or under Additional Capitalization to be recovered under the renewed agreement period or remaining useful life of the line/project whichever is earlier. Hon'ble Commission in the case of Powerlink's Transmission Limited had recognized such renewal cost and allowed the same as one time reimbursement as and when incurred based on auditor certificate. Necessary provisions may kindly be introduced in the draft for better clarity and to minimize disputes.

Further, the Hon'ble Commission Commission while fixing the norms does not consider any abnormal O&M expenditure for normalization of O&M expenses. Such abnormal expenses, if actually incurred, should be allowed on case to case basis over and above O&M expenses on prudence check.

Norms of HVDC stations:

40. It is observed that there is a need to simplify the same and therefore one norm for all HVDC schemes in terms of per MW considering the actual expenses incurred in the past may be specified.

Comments: We agree with the views in the Approach Paper from the point of view of providing simplified norms, however, the rationale of the same need to be justified through historical data of actual expenses and not just to meet the objective of achieving simplicity.

Additional O&M Expenses for Transmission Assets in NE and Hilly Regions

41. Comments and suggestions are sought from stakeholders on whether additional O&M expenses can be given for transmission assets being operated in the North Eastern and Hilly Regions and the manner in which such additional costs can be considered.

Comments: We agree with the views in the Approach Paper regarding providing additional O&M expenses for transmission assets being operated in the North Eastern and Hilly Regions. The same can be based on the historical average of actual O&M expenses of PGCIL and private sector licensees operating in such difficult terrain. Further, some additional allowance may be considered for transmission licensees operating single / few assets as compared to the average O&M expenses derived based on average basis for the region/country as a whole.

Inclusion of Capital Spares

42. 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.

Comments: We are of the opinion that, the option proposed to include all the capital spares below Rs. 20 lakhs under normative O&M expense is a welcome step because currently as per the CERC Regulations, 2019 all the capital spares expenses are being claimed separately from the beneficiaries' post approval from Hon'ble Commission. This will ensure the timely recovery of expenses expensed incurred towards the capital spares. It is understood that the capital spares above Rs. 20 lakh will be approved on case to case basis whereas the capital spares amounting to less than Rs. 20 lakh will be included under O&M expenses, which may result in escalation of O&M norms. Therefore, CERC is requested to deliberate upon the methodology to be adopted for inclusion of such amount of capital spares as discussed above in the O&M expenses for fixing/determining the O&M norms. Hon'ble Commission is also requested to provide details of capital spares as claimed by generating stations for further analysis of stakeholders and provide comments, if any. Further, the ceiling limit of Rs. 20 lakh may not be appropriate for Transmission Licensees as the capital spares consumed in case of transmission are relatively cheaper compared to generation, therefore the ceiling limit for transmission may be retained to Rs. 1 lakh.

Impact on account of Change in Law and Taxes

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.

Comments: There are certain expenses that are prone to change in law such as GST rate for different services, increase in employee expenses due to pay/wage revisions, any additional levies/duties etc. imposed by the local authorities/government. As on date, the utilities don't have any clarity around the changes that may occur in this regard. Hence, it would be difficult to incorporate the same in base norms to be notified for the control period. Further, there is an ambiguity in terms of prospective timeline in which these changes may occur. Therefore, the above expenses may be allowed on actuals under change in law as and when they get notified and implemented. However, as stated above, such changes only for Government Company as and when allowed, need to be incorporated in norms for everyone as these revisions take place automatically in private company due to market forces.

7.1.20 Depreciation

44. In view of discussion held in Section 4.13, depreciation rate may be specified considering a loan tenure of 15 years instead of the current practice of 12 years. Further, additional provision may also be specified that allows lower rate of depreciation to be charged by the generator in the initial years if mutually agreed upon with the beneficiary(ies).

Comments: The existing treatment of weighted average useful life in case of combination of units, due to gradual commissioning of units, should be allowed to continue provided all the units are commissioned within a reasonable span of time. The reassessment of the life of assets at the beginning of every tariff period may act as a disincentive for proper maintenance of assets. The provision for reassessment, which would also include assessing an asset with potential reduction in life, may be sub optimally utilized to propose a reduction in the life of an asset for ensuring higher depreciation.

An important aspect to be considered is the fact that the investment decision by investors/lenders for existing assets were based on the loan tenure of 12 years as considered by the Hon'ble Commission in all its Tariff Regulations since inception. As a prudent business practice, generator has been raising debt every year in staggered manner with total repayment schedule of 12 years. A change in the regulatory approach in the suggested manner will result in regulatory uncertainty and may therefore not to be considered. This may also result in diminishing of investments in the sector. Further, over 90% of the bond issued in domestic market were of tenure less than 15 years. Further, the domestic banks are not willing to lend for duration longer than 10-12 years due to huge exposure of banks in the infrastructure sector. Consequently, the options to raise loans of longer duration are very limited in the domestic market. Moreover, the interest rates of long duration loans are higher by at least 120-150 basis points, which will lead to increase in interest on loan component, thereby negatively impacting all beneficiaries.

Currently, most of the PPAs are signed for 25 years, which matches with the original useful life of the thermal generating asset. Extension in useful life beyond 25 years, and hence reducing the depreciation rates, without corresponding assurance of the PPA extension, would result in under-recovery of the capital cost by the developer.

Increase in useful life would negatively impact the utilities. Further, it may be noted that the actual impact would be more negative, as the rate of interest would increase with increase in repayment tenure. Further, considering depreciation rate specific to a loan tenure of 15 years instead of the current practice of 12 years (after COD) shall lead to serious difficulty in debt servicing of the loans. Here it is also worth mentioning that the existing depreciation rates at around 5.28% are already resulting in an under-recovery of debt component in the first 12 years at approx. 63% of the capital cost as against 70%, i.e. normative debt component of the capital cost. Extending this tenure to 15 years will further deteriorate the cash position of the developers. Therefore, assuming without admitting that, even if the life is extended the depreciation should be allowed to be recovered within the originally determined useful life of 25 years.

Further, with the current scenario of flexibilization of thermal assets to accommodate the intermittent RE sources of generation, the thermal assets are bound to face a situation of accelerated wear and tear, thus, impacting the operational efficiency during the original life time. The impact on the extension of useful life from 25 years to 35 years on the operating parameters under such stressed conditions is still unknown. Therefore, it is not advisable to extend the useful life of the existing assets, without providing for appropriate mechanism for the likely additional capital expenditure and O&M expenses required for the proposed extended useful life. Hence, we are of the view that the Hon'ble Commission may retain the current methodology of depreciation.

7.1.21 Interest on Loan

45. To simplify the approval of interest on loan, the weighted average actual rate of interest of the generating company or transmission licensee may be considered instead of project specific interest on loan. Further, the cost of hedging related to foreign loans be allowed on actual basis, without allowing any actual FERV.

Comments: With the increasingly stringent environment norms, thermal generation project's per MW capital cost has increased significantly. Further, low cost financing are also not easily available to such projects due to perceived environmental impact. Therefore, loans are raised from the market that are specific to the need of the project considering the tenure of the loan matched with COD of the project. The approach proposed in the paper to calculate interest on loan based on weighted average rate of interest (WAROI) of the company shall result in passing on the benefit of project specific reliefs provided by the Government to beneficiaries of other projects and may turn those projects unviable. Therefore, consideration of weighted average interest rate of a particular project if project specific loans are available may be continued.

In addition, a large corporate organisation may avail many corporate loans which may not be associated to any specific project. Considering corporate loans for computing weighted average rate of interest, it may result in neglecting the project specific risk. Therefore, the existing practice of considering the loan (corporate/project specific) may be left with Petitioner. However, for the purpose of computation of carrying cost on the differential tariff after truing up, the WAROI of the company may be considered. Alternatively, if the Hon'ble Commission deemed it necessary to allow interest on loan to make the process simpler, the Hon'ble Commission may link the rate of interest with certain benchmarks such as SBI MCLR + 250 basis points for projects where cheaper loans have not been provided by the Government of India. FERV or the hedging cost may be allowed additionally as explained below.

For hedging related to foreign loans: As per present RBI norms also, hedging is not mandatory. As per current RBI norms, hedging is mandatory only in case of Infrastructure companies if the average maturity of the External Commercial Borrowings (ECB) is less than 5 years. Under such cases also, companies are required to hedge 70% of the ECB exposure (P+I) only. Thus, we are of the view that the existing provisions of passing of FERV or hedging cost may kindly be retained un-changed and decision in this regard may kindly be left to the generator. Further, the Approach Paper has not clarified regarding the band of exchange rate variation for which hedging would be allowed and how such band would be determined. If no FERV is allowed, the band and, hence, hedging cost would go up substantially, which will not be in consumer interest. Considering the cost of hedging and regulatory provisions of pass through for FERV, many of the developers of the existing projects may not have opted for hedging of the foreign exchange debts. Therefore, such projects should be protected by providing a grandfathering clause, in case the proposed alternative of allowing hedging cost on actual basis and not allowing the actual FERV, is considered.

7.1.22 RoE/RoCE Approach

46. 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.

Comments: To promote continuity of private sector investment and certainty to the Investor, we are of the view that the Hon'ble Commission may continue with the existing RoE approach.

7.1.23 Rate of Return on Equity

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.
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.

Comments: The Commission through its series of amendments in the 2019 Tariff Regulations has decided to provide asset wise ROE as follows:

(i) Original Capital Cost eligible for RoE at 15.5%;

(ii) additional capitalizations, including 'Change in Law' events excluding ECS, eligible for RoE equal to WAROI on loan subject to ceiling of 14%; and

(iii) ECS installation due to 'Change in Law' eligible for RoE at SBI MCLR + 3.50% subject to ceiling of 14%.

It is observed that the Hon'ble Commission itself in its order dated 21.12.2000 has recognized that the returns are to be estimated at company level and therefore, there shall be no differentiation between old and new assets in determining the rate of return. The Hon'ble Commission in the said order also noted that as long as assets of different vintage provide the same level and quality of service, there is no justification for a differentiated return between the two categories. Since no distinction is made in declaring dividend on equity based on the date of provision of the equity to the company, there shall be no distinction in RoE also. Further, Tariff Policy guidelines mandates that balance approach needs to be adopted while laying down rate of return for the interests of consumers and the need for investments. The Tariff Policy mandates that the rate of return on equity for generation and transmission projects should be based on overall risk and the prevalent cost of capital. Further, the equity Beta or levered Beta considered for the computation of un-levered beta is of company/organisation as a whole and not asset-wise and the same cannot be used to allow asset wise RoE. Hence, RoE should be allowed on overall capital cost and not asset wise.

Further, limiting the RoE rate to a ceiling rate is not apt as the same completely ignore the impact of market forces on interest rates. Putting a ceiling on the return on equity further widens the gap between the allowed return and real cost of equity, especially in the prevailing interest rate hardening scenario. It will also be not legitimate to link the RoE to cost of borrowing as it is against legislative intent as well as CERC's statement in Explanatory Memorandum that it has to be compensated at its cost, i.e. cost of equity, which must be higher than cost of debt. The Hon'ble Commission in its own SOR dated 24.4.2014 to Tariff Regulations, 2014 has stated that unless the debt market stabilizes, it may not be appropriate to link the rate of return to any benchmark rate with mark up. Therefore, it is requested to not consider the option of asset wise ROE or benchmark linked ROE for all additional capitalization's including Change in Law and

Force Majeure in the forthcoming Regulations.

Further, regarding the computation of RoE, the Hon'ble Commission in the approach paper has suggested the following methodology for determining the expected rate of return using the CAPM:

> "*The average 10-year GOI securities rate over a one-year horizon may be considered a risk free rate.*
>
> *Daily data on the SENSEX and BSE Power Index for the latest 5 years may be considered for equity beta estimation.*
>
> *Market Risk Premium 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. Alternatively, MRP may be computed using any other method, including the Survey Method."*

Considering a horizon of 5 years for computing beta doesn't allow the period of uncertainty to be averaged out such as impact of COVID 19 pandemic where the markets were volatile. Further, the beta computation should be in line with the computation of Market risk premium. The Airports Economic Regulatory Authority of India, AERA while computing the Asset Beta and Market Risk Premium also considers a long time frame of 20 years based on international practices by regulators and same should also be considered by the Hon'ble Commission. Further, the use of extended periods of market data in CAPM is described in various literature as well, highlighting the decrease in standard error of risk premium with the increase in estimation period. [*Aswath Damodaran, 2014, Applied Corporate Finance (4th Edition)]*. Further, most of the entities in the power sector were listed in last 2 decades. Therefore, **it would be prudent to consider market risk premium based on 20 years of data instead of 30 years**. Further, the Risk free rate may be computed considering average 10-year GOI securities rate over a time frame same as considered for Asset Beta and ERP.

Accordingly, considering a common time period of 20 years for computing market returns (Rm) based on historical data of returns of BSE Sensex; risk-free rate (Rf) based on yield of 10-year government bond; considering beta for listed power sector entities in India, corporate tax rate and considering normative debt-equity ratio of 70:30, the expected rate of return has been worked out at 19.40%, which is much higher than the existing number of 15.50% or 16.50%. It is worth noting that the expected return arrived through CAPM considers returns or IRR on investment from Day 1. However, the Tariff Regulations of the Hon'ble Commission allow return on equity from COD as result of which the existing RoE of 15.50%, yields a much lower IRR in the range of 12% - 13%, depending upon the construction period for the asset as no return is allowed during this period. Whereases, AERA allows capitalization of the notional return, on equity alongwith normative IDC during the construction period also in the form of financing allowance which is added to the Regulatory Asset Base (RAB) on which RoE is computed. Further, the Commission in its Explanatory Memorandum for 2019 Tariff Regulation has itself recognized the need for additional compensation for construction period as following:

> *"On the basis of this approach, the Commission observed that, barring few exceptions, the cost of equity for regulated entities in the power sector works out to be in **the range of 12%-15%.** Thus, the Commission is of the view that the cost of equity arrived at using CAPM is in line with the existing return on equity during the Tariff Period considering the **gestation period of 4 to 7** years and the Commission proposes to continue with the existing **rate of 15.50%** in the Draft Tariff Regulations"*

From above, it is observed that Commission while allowing rate of RoE has considered the margin of 1.5% to 3.5%, whereas this margin ranges actually from 2.5% to 4.5% to fully compensate the developer for loss of return during construction period. Considering the same, the Hon'ble Commission should allow a margin of ~ 2.50% - 4.50% or say 3.5% over and above expected Return arrived through CAPM to allow the effective rate of RoE (or Equity IRR) effective from the date of initial equity infusion till COD of the Project.

Additional Incentive for generation beyond target PLF

56. Possible options to encourage higher availability and generation from Old Generating Stations can be as follows.

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

Comments: The existing norms of 85% for NAPAF for recovery of capacity charges and NAPLF for incentive need to be reviewed in the wake of challenges posed to the thermal generating stations due to continued challenge of deficiency of coal availability at notified prices, increasing backing down of base load stations to accommodate RE integration, etc. generation at 85% PLF and beyond are being impossible or rare scenarios to say the least, especially for non pit-head stations. Therefore, there is a need to review and bring down the NAPAF and NAPLF norms to 80% for thermal generating stations.

7.1.24 Tax Rate

57. In view of the discussion held in Section 4.17 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.

58. 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.

Comments: Base Rate of RoE may be continued to be allowed to be grossed up at Effective Tax Rate (ETR) only (both under MAT/Normal Tax) for Future Tariff Periods irrespective of whether the same is lower/higher than the MAT/Corporate Tax Rate. ETR needs to be computed as (Actual Tax Paid)/PBT without any capping on it. Further, Considering the existing regulations and the history and development of Regulatory Jurisprudence on treatment of Tax on Income in tariff, it is requested to modify the formula for Effective Tax Rate suitably to take care of the non-adjustment of credit for carry forward losses, unabsorbed depreciation and credit for MAT on other businesses. The detailed note explaining the above proposition is enclosed hereto and marked as **ANNEXURE – A** for kind perusal of the Hon'ble Commission.

It is also noteworthy that the above proposition would broadly address the issues of a company engaged in single regulated business, it does not fully capture the tax implications for a company with multiple businesses particularly if other businesses have huge Income or Losses. This issue becomes more pronounced when the company as a whole pays NIL tax solely due to huge losses in other businesses and if Tariff Regulations are read to mean that no grossing up shall be allowed, it would effectively mean that regulated business is being subsidized by Other Businesses. In this regard, Hon'ble APTEL in its Judgement dated 28.11.2013 in APPEAL NO.104, 105 and 106 of 2012 has held that regulated and other businesses have to be kept in separate watertight compartments so that the regulated business neither subsidises not gets subsidized by other businesses. It is important to note that this Judgement has attained finality and, therefore, holds the field in this matter of law. Relevant extract of this Judgement is as follows:

> *"52. The Judgment in Appeal No. 251 of 2006 is based on the principle that* ***regulated business in question that is within the jurisdiction of the Regulatory State Commission, should neither subsidise nor get subsidy from other businesses whether unregulated or regulated by the same or different regulator. In other words, the Judgment mandates that the taxable income of the regulated business within the jurisdiction of the Regulatory State Commission should be computed on stand alone basis, irrespective of what is the impact of this business or other businesses on the overall tax liability. There is a possibility of distortion when the impact of regulated business or other businesses on total tax liability is considered or the overall tax liability is allocated for determining the tax liability for regulated business****."*

Thus, in light of the above settled position, it is also submitted that grossing up with applicable tax rate instead of Effective Tax Rate should be allowed even if actual tax paid is NIL which may be arising because of the losses by other businesses

7.1.25 Interest on Working Capital

59. 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.

60. 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.

61. 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.

62. 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.

Comments: We support for the continuation of existing regime of interest on working capital. However, the coal stocking norms for coal based thermal power generation stations were revised by CEA w.e.f. 6.12.2021. As per the revised coal stocking norms, coal based pit-head thermal power plants are required to maintain coal stock in the range of 12 days to 17 days, depending on the month of the year, as against prevailing coal stock norm of 15 days. The non-pit head plants are required to maintain coal stock in the range of 20 days to 26 days compared to the prevailing coal stock norms of 20 days to 30 days. It is requested to increase the coal stocking norms in line with CEA recommendations with a margin of 3 to 5 days. The said recommendations also included imposition of penalty for non-maintenance of coal stock. Subsequently, CERC vide its public notice dated 13.5.2022 invited comments from the stakeholders on the

Methodology for Computing "Deterrent Charges" for maintaining lower coal stock by coal based thermal generating stations. It shall be pertinent to mention that CEA in the above-mentioned notification itself recognizes that coal-based generation/consumption as well as coal dispatch varies during the course of the year. Further, power plants are not able to maintain high stock during rainy season due to less coal dispatch by coal companies. Penalizing the generator for merely not maintaining stocks as per norms is just not apt when there is already a regulation in place to penalize the generator on account of lower PAF. In case a TPP is able to achieve Plant Availability norms, it is entitled to recover full Fixed Charges else recovery of Fixed Charges are allowed in proportion to actual availability being achieved by the Plant vis-à-vis the Normative Availability Norms. So, inefficiencies of TPP on any count including maintenance of low coal stock has already been inbuilt in the existing Tariff Principles. Therefore, penalizing the generator twice for the same fault shall not be legally correct. Increase in number of stock days would mean requirement of additional working capital and consequently, additional interest on working capital loan. Further, in case penalty for coal shortages is to be levied additionally, a mechanism to compute impact of shortages on availability needs to be placed first. But, in order to avoid additional financial burden on the generators, it is imperative that the regulations are aligned with the revised coal stocking norms and the compensation for maintaining the increased number of stock days is provided to the generating companies instead of penalizing the generator twice. Therefore, we propose that while considering the Cost of Fuel, the Hon'ble Commission shall also consider the norms of stock mandated by the Central Electricity Authority, which is much higher than the existing norms of CERC without considering imposing any penalty on account non-maintenance of coal stock norms. Further, since energy accounts are released by RPC generally on 6th or 7th of the month, the working capital may be allowed for additional six days i.e., for 51 days.

Currently, the CERC MYT Regulation 2019-24 defines the Bank Rate as the one-year marginal cost of lending rate (MCLR) of the State Bank of India issued from time to time plus 350 basis points; this leads to the problem that Internal Benchmarks by the Banks are not accurately reflective of the Monetary Policy Changes. To address the same RBI in its circular issued on 4th September, 2019 in relation to "External Benchmarking of Retail and SME Advances" and on 26th February 2020 on "External Benchmark Based Lending"(EBLR), all Banks are required to link Retail Advances, and Advances given to Micro, Small Enterprises from 1st October 2019 onwards and Advances given to Medium Enterprises from 1st April 2020 onwards, with certain External Benchmark. It is likely that RBI may make EBLR mandatory for large enterprises like power sector utilities also. Further, CERC has linked the rate of interest on working capital to bank rate as on 1.4.2019 or as on 1st April of the year during the tariff period. The Commission in their 2014 Tariff Regulations defined the Bank Rate as:

> *"Bank Rate" means the base rate of interest as specified by the State Bank of India from time to time or any replacement thereof for the time being in effect plus 350 basis points"*

The Commission in their 2019 Tariff Regulations defined the Bank Rate as:

> *"Bank Rate' means the one year marginal cost of lending rate (MCLR) of the State Bank of India issued from time to time plus 350 basis points"*

Therefore, there is an ambiguity regarding consideration of reference rate in case MCLR is replaced by EBLR or any other rate. The Commission may provide clarity on the consideration of reference rate in case on rate is replaced by other during the control period as follows:

> *"Bank Rate' means the one year marginal cost of lending rate (MCLR) of the State Bank of India*

issued from time to time or any replacement thereof for the time being in effect plus 350 basis points"

7.1.26 Life of Generating Stations and Transmission System

63. 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.

64. 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: As already discussed in detail under comments to Sr. No. 44 (Depreciation), the useful life of the existing projects should not be increased unilaterally, till the related issues of PPA tie-up, recovery of depreciation within existing useful life and additional cost of wear and tear, etc. are addressed. Even for new projects it would send a negative signal and should not be carried out. For special allowance also earlier comments may kindly be referred to.

7.1.27 Input Price of coal – Integrated Mine

65. 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.

Comments: This aspect pertains to select Central Sector Generators, therefore, we have no specific suggestions to offer. However, the underlying principles for tariff determination should be applied consistently.

7.1.28 Sharing of Gains

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

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

Comments: Since, Operational norms have been fixed based on actual performance and are efficient norms, there is no logic in sharing gains for better performance with beneficiaries particularly if losses are not shared by beneficaries. Normative Approach would require that entire gains and loss should be with the generating company. In case sharing is still considered, following comments may be taken into account.

In order to promote efficiency and to generate additional gains, we propose that the benefits may be shared in the ratio of 3:1. Where 75% may be retained by the licensee and 25% be passed onto the Transmission Users.

Further, there is ambiguity regarding sharing of gains due to refinancing of loan as there is no clear methodology defined in the Regulations, therefore it is requested to define the methodology of sharing of gains through refinancing in the forthcoming regulations with Illustrative example clearly showing the impact through computation based on present value approach. Since the Tariff regulation mandates sharing the net saving on interest, after meeting the cost of refinancing or restructuring, only when refinancing results in net savings. This implies that **(i)** the project developer must be able to show that over the balance life of the loan to be used for tariff computation the NPV of the costs of refinancing and the yearly savings in interest cost over this period would be positive. Since the value of this NPV keeps changing at the end of each projection year. There might be a situation in future that the refinanced rate becomes higher than the original interest rate, which may result in loss rather than savings in that year. In this situation when the NPV upto that year is still positive i.e. there is still net saving, the loss in that year will have to shared in the given ratio as savings have already been shared earlier. **(ii)** the interest rate considered in the original loan should be fixed as benchmark rate and should not be changed. Any saving accrued by the developer on account of refinancing shall be shared by generator with the beneficiary as long as the net impact of savings is positive in the ratio of 3:1. However, in case the net impact if negative the developer shall be allowed to recover the impact from beneficiaries.

It is proposed that as operational norms are determined annually, the sharing of gains may be allowed on monthly basis with cumulative monthly as well as annual settlement mechanism based on actual figures. Therefore, the clarity may be provided regarding the period of sharing the gains and losses on annual basis.

7.1.29 Treatment of arbitration award – Servicing of Principal and Interest Payment

68. 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 amount may also involve carrying cost.

Comments: It is submitted that the existing approach for capitalizing the entire component of the Arbitration Award need to be continued. The 'interest component' in the arbitral awards should not be considered differently from the 'principal component'. However, if interest is paid in instalments, carrying cost needs to be allowed as no fund is free of cost.

7.1.30 Treatment of interest on differential tariff after truing up

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.

Comments: It is submitted that the interest should be allowed to be recover on the reducing balance method till recovery of all the installments, else one-time recovery should be allowed for recovery of the differential amount as against in six installments. This is in line with the judgement of the Hon'ble Tribunal in Appeal No 231 of 2017 dated 3.10.2019, which stipulates that no fund is free of cost.

7.1.31 Normative Annual Plant Availability Factor (NAPAF)

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.

70. As discussed in Section 5.1, One option to measure PAF of ROR plants 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;"

71. Comments and suggestions are sought from stakeholders on ways to simplify the tariff recovery process for hydro generating station.

Comments: It is submitted that the shortage of domestic fuel has significantly affected the availability of the plants, resulting in under recovery of Fixed Cost by generators. The availability of Fuel (domestic coal) are mostly beyond the control of the generating stations, and it is expected that shortage of coal will persist for next 4-5 years. The Ministry of Power recognizing the current situation issued direction u/s 11 of the Act to domestic/imported coal based plants last year as well as this year, which has been extended till December 23. Further, in case of procurement of coal through e-auction, or procurement of imported coal (other than fuel arrangements agreed in PPA), the need for prior consent of beneficiaries, the maximum permissible limit of blending, etc. requiring prior consent from beneficiary and if only a few beneficiaries are interested, in that case there can be delay in getting a common agreement from all beneficiaries. Such, delay can also lead to shortage of coal, and adversely impact PAF of station. CERC needs to address the way to overcome the issue.

Regarding the issue of change in approach for computing declared capacity for run-of-the river plants, we are of the view that Run of River (RoR), Hydro Power Stations having limited or no storage system and operation of such stations depends on the real time inflow. Change in the approach should be seen from the perspective whether it will result in under-recovery of the capacity charges which will impact their financial feasibility.

7.1.32 Peak and Off-Peak Tariff

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.

Comments: There is no evidence that this structure has laid to achievement of any objective for the same or there has been any improvement in grid operation. However, it has unnecessarily complicated not only the tariff structure but also operational planning by the generators. Therefore, it is proposed that the concept of peak off-peak whether seasonal or daily may be done away with. In case, this concept is still continued the following comment may kindly be considered.

While the Approach Paper has aptly captured the difficulties being faced in the existing provisions of Peak, Off-Peak and Normal Seasons, however, it has not provided any clarity on to how the issues of availability, scheduled maintenance, thermal flexibilization, etc. will be addressed while introducing the daily peak and off-peak periods. Further, while the thermal generating stations are being expected to quickly transform to meet demand variation as against meeting base load requirement, by putting the capacity charges recovery at stake, however, there is no corresponding reward for facing this newly introduced risk for these stations. It is suggested to introduce an incentive mechanism to allow the generating stations retaining some portion of the additional recovered capacity charges for ensuring availability in peak periods to support the grid. The peak season may be increased to 6 months -single or tow separate periods. Since National level merit order dispatch is yet to be implemented, as of now Regional Peak may be considered since SCED is already in place at regional level.

7.1.33 Operational Norms

72. Further, as the generating stations are being 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: The norms may be fixed considering the ideal loading of the generating units however due consideration for not meeting the targeted norms may be considered at the time of true-up activity.

Further, the change in law or force majeure event may also impact the operational norms of a generating station, therefore, it is requested to the Commission to capture such impact while determining the operational norms for generating stations.

Gross Station Heat Rate:

Comments: The Commission, while allowing GSHR for a generating station takes into consideration three factors, namely – Design Heat Rate, Operating Margin and Boiler Efficiency. One of the key factors affecting the GSHR, the consistent availability of poor-quality coal, which considering the monopoly situation in the coal sector is unlikely to improve in the near future. While relaxation in GSHR is allowed to certain.

Hon'ble Commission, while allowing GSHR for a generating station takes into consideration three factors, namely – Design turbine cycle Heat Rate, Design boiler efficiency and Operating Margin.

One of the key factors affecting the design boiler efficiency or GSHR is the consistent availability of poor-quality coal as compared to quality specified in FSA, which considering the monopoly situation in the coal sector is unlikely to improve in the near future. Some of the generators have taken care of such expected grade slippages in their design by considering GCV of coal much lower than FSA grade for design efficiency of the boiler. Accordingly, they have their design boiler efficiencies much lower than even minimum of 86% specified by Hon'ble Commission. Thus, they have already built a comfortable margin for deterioration in GSHR due to coal quality and able to sustain operations even though Hon'ble Commission limits the efficiency to 86% for boiler. On the other hand, some other generators like MPL have honestly taken design GCV as per the FSA quality assuming that promised quality shall be delivered to them and designed their plant with high boiler efficiencies around 87.8%. Unfortunately, they have been penalised by considering higher design efficiencies for allowing normative GSHR, which was much lower than those generators who had a comfortable margin of 1.8% (i.e. 87.8 – 86) in boiler efficiency. This had lead not only to disparity amongst similarly placed generators but also has put honest generators under severe financial stress. Due to such artificial distinction, not financial hardship is faced by said generators but also they are deprived of legitimate gains even after performing better than GSHR for others.

MPL represents unique example considering the above case and struggling to perform to achieve stringent target of GSHR with poor quality of coal. Geographically, MPL is landlocked and relies on domestic coal supplies. Imported coal is also not a viable or cost-effective scenario to meet the design boiler efficiency or design heat rate.

On Comparing current approved SHR for all thermal generating stations considering similar machines with 500 MW sets, MPL seems to be an outlier. To validate this statement, a comparative data of design and actual operational parameters with coal received against executed FSA and SHR allowed is tabulated below:

S. No.	Generating St. 500 MW Series	COD	Design TC HR	Des. Boiler η	Design SHR	SHR allowed 2009-14	SHR allowed 2014-19	Proj. SHR for 2019-24	Des GCV	Actual GCV of coal received
1	Mauda STPS stage I	Unit 1: 13.3.2013; Unit 2: 30.3.2014	1932	84%	2297.27	2424.44	2400.6	2358.8	NA	(2012-2017): 2304/ 2977/ 3833/ 3400/ 3525

S. No.	Generating St. 500 MW Series	COD	Design TC HR	Des. Boiler η	Design SHR	SHR allowed 2009-14	SHR allowed 2014-19	Proj. SHR for 2019-24	Des GCV	Actual GCV of coal received
2	Rihand-III	Unit 1: 19.11.2012; Unit 2: 27.3.2014	1932	84%	2298.6	(2446.59: Provisional) 2423.94	2402.1	2358.8	3500	(2012-2017): 3474.91/ 3400.12/ 3407/ 3677/ 3609
3	Simhadri-II	Unit 1: 16.9.2011; Unit 2: 30.9.2012	1932.50	84.84%	2277.82	2424	2380.32	2359.45	3300	(2011-2017): 3204/ 3285/ 3489/ 3607/ 3449/ 3585
4	Dadri Stage-II	Unit 1: 31.01.2010; Unit 2: 31.07.2010	1936	85.00%	2277.65	2424.00	2378.42	2363.7	3500	(2009-2017): 3983.38/ 3932.16/ 3916.80/ 3672.11/ 3806.69/ 3638.35/ 3678.42/ 3855.35; Non cvoking coal: 5200/5400
Average of Sets of machines having Turbine Cycle HR 1935								**2360.2**		
5	Vindhyachal -IV	Unit 1: 01.03.2013; Unit 2: 27.03.2014	1944.4	84.00%	2314.8	2424.4	2375.22	2373.98	3600.00	(2012-2017): 3188/ 3412.95/3378/ 3417/ 3560
6	Farraka Stage-III	Unit 1: 04.04.2012; Unit 2: 31.3.2014	1944.4	83.39%	2331.69	2443.11	2436.62	2373.98	3000.00	(2012-2017): 2980/ 3279/ 3274/ 3450/ 3850
7	Korba Stage-III	Unit 1: 21.03.2011	1944.44	84.91%	2290.00	2438.8	2390.5	2374.00	3300.00	(2010-2017): 3217.47/ 3307.90/ 3189.17/ 3268.86/ 3284.35/ 3417.87/ 3694.22
8	Kahalgaon-II	Unit 1: 01.08.2008; Unit 2: 31.12.2008; Unit 3: 20.03.2010	1944.00	83.29%	2334.00	2425.00	2425.00	2384.50	2850.00	(2009-2017): 2883.68/2982.87/2797/ 2609/ 2667/ 2782/ 2907/ 2962.62
9	Sipat -II	Unit 1: 20.6.2008; Unit 2: 01.1.2009	1948.00	85.85%	2269.00	2425.00	2375.00	2390.00	3300.00	(2009-2017): 3411.09/ 3426.22/ 3541.80/ 3729.55/ 3618.65/ 3775.69/ 3659.58/ 3784.28
Average of Sets of machines having Turbine Cycle HR 1945								**2379.30**		
10	Vindhyachal-III	Unit 1: 01.12.2006; Unit 2: 15.07.2007		85.14%		2425.00	2375.00	2390.00	3700.00	(2009-2017): 3536/ 3512/ 3444/ 3273/ 3412/ 3383/ 3417/ 3554
11	Rihand-II	Unit 3: 15.08.2005; Unit 4: 01.04.2006		87.12%		2425.00	2375.00	2390.00	4000.00	(2009-2017): 3531.71/ 3590.00/ 3454.04/ 3382.88/ 3325.76/ 3380.35/ 3454.19/ 3549.75
12	Ramagundam-III	Unit 1: 25.3.2005;		86.88%		2425.00	2375.00	2390.00	3400.00	(2009-2017): 3685/ 3599/ 3597/ 3495/ 3273/ 3236/ 3409/ 3621
13	Simhadri-I	Unit 1: 01.09.2002 ; Unit 2: 01.03.2003.		87.27%		2425.00	2375.00	2390.00	3300.00	(2009-2017): 3348/ 3291/ 3217/ 3262/ 3454/ 3578/ 3379/ 3574
14	Vindhyachal-II	Unit 1: 01.7.2000; Unit 2: 01.10.2000		87.77%		2425.00	2375.00	2390.00	3700.00	(2009-2017): 3538.00/ 3500.00/ 3439.73/ 3271.48/ 3418.47/

S. No.	Generating St. 500 MW Series	COD	Design TC HR	Des. Boiler η	Design SHR	SHR allowed 2009-14	SHR allowed 2014-19	Proj. SHR for 2019-24	Des GCV	Actual GCV of coal received
										3375.00/ 3420.78/ 3597.03
15	Rihand-I	Unit 1: 01.01.1990 ; Unit 2: 01.01.1991		86.99%		2385.00	2335.00	2390.00	4000.00	(2009-2017): 3674.56/ 3785.87/ 3537.95/ 3486.24/ 3342.02/ 3467.07/ 3612.99/ 3603.92
Averages of plants having life more than 10 years								**2390**		
Averages of all plants grouped above								**2378.5**		
16	**Maithon Power Limited**	**Unit 1: 1.9.2011; Unit 2:24.7.2012.**	**1945.00**	**87.80%**	**2215.26**		**2375.00**	**2326.03**	**4671.00**	**(2014-17) :3990.27,4102.51,4067.16**

From data extracted above, it is quite evident that all machines of similar capacity (500 MW) and same turbine cycle heat rate (1945 Kcal/kWh) have boiler efficiency ≤ 85 % (approx.). MPL has also shown a similar trend of boiler efficiency in PG test i.e. 85.5%.

But while framing the tariff norms for 2019-24 and due to limit of Boiler efficiency at 86 % specified by Hon'ble Commission, MPL tends to incur loss of 1.8% as design boiler efficiency for MPL was 87.8% . Whereas other stations do not have this impact even if they have similar machines. On further delving into the data, if we connect individual station's FSA and coal received, it is quite noticeable that for all stations, design GCV and GCV received are in same range except MPL. Only MPL is such a generating station for which design coal GCV is 4671 which was never met.

In FY2019-24, approved station heat rate for MPL was reduced to 2326.03 Kcal/kWh against 2375 Kcal/kWh. Whereas for all other stations approved SHR is 2390 (approx.). Approved SHR for MPL is less than average of all kinds of sets of 500 MW. However, in present regulation, there is no provision of adjustment in loss of boiler efficiency on account of poor coal supplied.

Therefore, our suggestion with respect to the above is to frame similar norms for similar machines to avoid differences and disparity. Encouraging for better operating performance is good but these norms should be relatable to the past performances. There should not be differences in norms for similar machines. Thus, either existing Regulation 49(C)(a)(i) should be applied in cases specified in 49(C)(b)(i) i.e. GSHR of 2430/2390 for 200/500 MW sets respectively or a provision for providing relaxation in such cases may be provided.

7.1.34 Operational Norms – Inefficient Generating Stations

73. 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.

Comments: The existing practice to fix the related norms may be continued as running of these plants in expected high demand scenario would still be cheaper than new plants as their fixed cost would be very low.

7.1.35 Operational Norms for Washery Rejects based Plants

74. In view of no compelling reasons to amend the same, the existing norms for such plants may be continued in the next tariff period.

Comments: The existing practice to fix the related norms may be continued.

7.1.36 Operational Norms - Emission Control System

75. 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 the 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?

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

77. 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 timelines specified in the MoEF&CC notification dated 31.03.2021?

Comments: The existing practice may be continued until the sufficient actual data is available for revision of norms. Further, incentivizing proper operation of such emission control systems may be considered for increasing the operation efficiency. The existing practice of excluding Supplementary Tariff for ECS in preparation of merit order stack till all stations comply with ECS norms may be continued.

7.1.37 Compensation for Part-Load Operations

78. 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.

Comments: Flexibility in Generation and Scheduling of Thermal Power Stations, whether under CEA Regulations 2023 (compulsory under RLDC directions) or RE Bundling Scheme(Voluntary Scheduling of RE as replacement power) or any Bilateral RE Bundling with Thermal/Exchange Power for Green Hydrogen production, may require generating stations running at PLF of 82%-85% to backdown or run at technical minimum which may result in the increase in the variable cost of an efficient generating station and decrease its useful life. The frequent start-up/back-down would increase stress in the machine and result in higher wear and tear etc. To overcome this issue the generating stations will be required to incur additional O&M expenses to keep the plant operational. The increased number of tripping may further lead the generating station which undergoes one Major Overhaul in a period of 3-4 years to frequent Minor Overhauls in every 1 or 2 years affecting the availability of plant. Hence, in order to safeguard the interest of the generating utilities and concerned beneficiaries, the Target Availability should be suitably aligned, and suitable regulatory framework needs to be in place so as to ensure that capacity is not stranded due to RE penetration coupled with fuel deficit. Therefore, the target availability to avail incentive may also be reduced from 85% to 80%.

Further, the RE Bundling scheme has also resulted in an ambiguity between the generator and the beneficiaries as in who will bear the impact of transmission losses, how the scheduling will be done i.e. whether Thermal Power Plant is supposed to procure power from RE, how degradation in Heat Rate, AUX and SFC norms would be allowed, how the DSM will be implemented, how the savings will be computed and shared with the beneficiaries etc.

Thus, it is proposed that CERC, firstly should include appropriate compensation mechanism to address the above discussed issues. Subsequently, it is proposed that for the next tariff Period norms should be revised by considering not only the past data i.e., the domestic fuel availability for past years, PAF, procurement of coal from alternate sources, other than designated fuel supply agreement, change in hydrology etc. of Generating Station but also expected future scenario due to RE penetration and fuel shortages. CERC may determine the PAF targets right now on assumptions basis, however the same may be modified after 2 years based on the actual data and revised expectation. Further, CERC may also detail out the methodology for computation of savings, implementation of DSM framework and costs to be borne by TPP and RE respectively.

In this regard, we support all the suggestion of CEA as provided in amendment notification to Approach Paper but only with reference to the degradation in operational norms and additional Capex/O&M norms. Their impact on tariff may be worked out based on the plant specific parameters. Further, as of now its impact on auxiliary consumption may be allowed with relaxation upto 2% additional allowance in graded manner till add-cap for its improvement is allowed.

7.1.38 Gross Calorific Value (GCV) of Fuel

79. In view of discussions held under Section 5.8, comments and suggestions are sought from stakeholders on ways to reduce the gap between GCV “as billed” and “as received”.

Comments: We propose that the existing norms may be continued, however, the normative and transit losses for imported coal which is to the tune of 0.2% is not sufficient as the mode of transport for most of Section 62 Projects for the imported coal is through road only, hence the normative and transit losses for imported coal should be fixed taking into consideration of loss through road/rail transport i.e., 0.8%.

7.1.39 Blending of Coal

80. 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: The entire country is facing a coal shortage scenario presently and the same would most likely continue in future as well until adequate resources are developed. Therefore, to address this issue, MoP at various intervals directed Generating Companies for blending of imported coal upto 30% and presently it has directed to blend 6% imported coal. It is, therefore, requested to make provisions enabling generators for coal blending upto 30%. Out of 30%, 6-10% imported coal can be used whereas remaining 24%-20% can be met through domestic coal preferably procured through e-auction route and in case of non-availability of e-auction coal, coal procured on nomination basis as domestic private mine may have reject/low grade coal, which would be slightly costlier than linkage and would also ease pressure on national coal shortage. Domestic coal in any case would be much cheaper compared to imported coal and would help to contain burden of imported coal. As observed by Hon’ble Commission, blending of even 10% imported coal leads to an increase of more than 30% to 40% in ECR and would always breach the existing threshold limits. Thus, to have enabling conditions such that neither Generators are given free had nor beneficiaries are given excessive control, the existing threshold limit of 30% of base energy charge rate as prescribed in 3rd proviso to Regulation 43(3) can be increased to 50% (considering blend of imported and domestic coal) and 20% of energy charge rate to 40% and for which no consent shall be required from the concerned beneficiaries. Further, deemed availability shall be considered, if consent for blending is denied by the beneficiary beyond these thresholds.

7.1.40 Incentives

81. Incentives linked to generation in excess of target PLF/NAPAF especially during peak periods, in the case of hydro stations and old pit head generating stations, may need a review in order to encourage higher generation from such plants. based 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: In the existing tariff regulations, the generating stations have their incentives linked to excess of target NAPAF, however, no incentive has been linked for energy generation during peak period. It is proposed to provided incentive at the rate of 10% of MCP during peak hours for energy generated during peak hours.

7.1.41 Separate Norms for ROR/Storage Based Hydro Projects

82. 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 period.

Comments: Additional incentives should be provided to all generating stations which supply energy during peak periods.

7.1.42 Tariff Structure for Cost Recovery for Emission Control System

83. As not all generating stations have installed the emission control systems, 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.

Comments: The tariff structure may be adopted in the same way as is done for other Add Caps particularly to ensure the cost is recovered within the remaining useful life of the asset. Further, ROE may be allowed at normal rates. Full AFC should be allowed to be recovered during shutdown period as it will be taken after consent with beneficiaries and synchronizing with other outage schedules.

7.1.43 Decommissioning of Generating Station and Transmission Assets

84. In view of discussion held in Section 6.3, 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.

Comments: Keeping in view the intended approach to make the cost of Decommissioning/Replacement of assets neutral to generating and transmission companies while at the same time not impacting other beneficiaries the following two approaches are proposed:

a) Continuation of existing tariff till the completion of useful life [Depreciation + RoE +IoL (for loan outstanding cases) + Interest on Working capital (excluding O&M Expenses)

b) One time allowance of unrecovered depreciation, that may be allowed to be recovered in three monthly instalments.

7.1.44 Simplification of Tariff Formats

85. Comments and suggestions are invited from stakeholders for simplifying the existing tariff formats.

Comments: While the existing tariff formats are okay, we seek permission to submit our comments on the tariff formats at the time of submission of comments on the draft Tariff Regulations.

7.1.45 Approval process for carrying out non-ISTS lines carrying inter-state power and associated Capital Cost

86. Comments and suggestions are invited from stakeholders, particularly, from STUs and State transmission licensees, for the approval process to be followed before undertaking the construction of new Intra State transmissions lines carrying inter-state power.

87. In view of changes that may be required to be carried out in CERC Tariff Regulations, 2024 comments and suggestions are sought from stakeholders on the capital cost to be considered for the computation of transmission charges in respect of intra-State lines (carrying inter-state power) of the State transmission utilities.

Comments: This aspect pertains specifically to STUs and State Transmission Licensees, thus, we have no specific suggestion to offer. However, for such STU lines which fall under ISTS category, the same should be billed under CERC tariff mechanism. The capital cost/Tariff of such lines should completely be removed from the asset base of the STU for the purpose of estimation of State ARR.

7.1.46 Up-gradation of Asset/Replacement

88. In view of the discussion held in Section 6.6 suggestions are invited from stakeholders regarding the treatment of unrecovered depreciation.

Comments: The Generating Companies/Transmission licensees are mandatorily or per force required to undertake replacement of assets on account of upgradation/or obsolescence/or due to failure for reasons beyond the developer's control/or in compliance of any directions etc. In such scenarios, the accounting principles allow the write off of such damaged/out-lived assets from the books of accounts and charging the same to P&L a/c as loss from sale of assets after sale of scrap. On the other hand, Tariff Regulations do not provide for any treatment of such damaged assets/outlived assets and simply allow decapitalisation of such assets. Doing this, causes the Generating Companies/Transmission Licensees absorbing the entire loss due to such failure which is not only limited to under recovery of principal value/cost of the asset and, hence, impacts non-recovery of the cost of financing of such assets as the loans/equity still remains outstanding. Hence, we humbly request the Hon'ble Commission that appropriate provisions may be introduced to allow the generating companies/licensees to recover at least the unrecovered depreciation adjusted for any income from scrap sale (after adjustment of residual value and any costs associated with it). This would at least support the generator/licensee to meet the loss corresponding to replacement of such asset for which reasons are beyond the control of developers. However, the final recoverable value may be decided by Hon'ble Commission on case-to-case basis upon scrutiny of the matter.

7.1.47 Assumed Deletions

89. Comments and suggestions are sought from stakeholders 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.

Comments: In view of the scenarios of assumed deletion namely

a) The asset under consideration is part of a larger scheme and the individual value of the asset may not be available.

b) The value of the old asset is available in the books of account; however, the asset has not been decapitalized during the year of capitalization of new asset.

Assumed deletion in case where value of old asset is available; and in case of the assets where value of old asset is not available, it is proposed that the value of old asset may be decapitalized by de-escalating the gross value of the new asset at the indexation rate worked out with 60:40 ratio of WPI and CPI for respective year.

Assumed deletion may be replaced at the time of true-up with the old asset value as provided by the generating station as per books of accounts in case where old asset is available in the books of account; however, the asset has not been decapitalized during the year of capitalization of new asset.

7.1.48 Necessity to Review the need of Regulation 17(2)

90. The provision under Regulation 17(2) of Tariff Regulations, 2019 may result in further complication and being seen as inequitable for the generator, is required to be modified.

Comments: We support the views expressed in the Approach Paper that Tariff Regulations should not intervene with the terms of the PPA. Further, introduction of unilateral first right of refusal for the beneficiary should not be allowed in the first place itself.

Additional Suggestions

91. Truing-up Directly with Beneficiaries

Comments: With an objective to further simplify the process of truing-up, it is proposed that in case there is no claim of new item in the additional capital expenditure and also the variation in the actual cost of allowed additional capital expenditure items at the time of determination of tariff by the Commission is below 20%, it should allow truing-up of AFC components directly with beneficiaries on submission of detailed formats and computations to the beneficiaries/transmission users, with CA Certificate of the actual expenditure incurred, with a copy to the Commission. Only in case of a dispute, the concerned parties may approach the Commission for detailed review of the proposed trued-up figures provided by the Generating Company/Transmission Licensee, however, beneficiaries should be obligated to make payments as per claimed amounts. Differences, if any, after adjudication may be adjusted with carrying cost. For new or additional claims only the generating company or transmission licensee to approach the commission for true-up.

92. Transmission Majoration Factor (TMF)

Comments: Existing Tariff Regulations provides for applicability of TMF for a period 25 years from the date of issue of licence for transmission projects executed through JV route in terms of Regulation 4.10A of the CERC (Terms and Conditions of Tariff) Regulations, 2001. However, while considering the useful life for determining the period for which TMF can be availed, the Commission inadvertently considered useful life as 25 years instead of 35 years as provided under the Appendix II of the Tariff Regulations, 2001. Secondly, it was incorrectly inferred that license was granted for 25 years on the basis of life being 25 years since license of 25 years was granted in accordance with Section 15(8) of the Act and not on account of the useful life of 25 years. The above understanding has also been recorded by this Hon'ble Commission in Explanatory Memorandum to CERC (Procedure, Terms and Conditions for grant of Transmission License and other related matters) (Amendment) Regulations, 2010. The detailed note explaining the above issue is enclosed hereto and marked as **ANNEXURE-B** for kind perusal of Hon'ble Commission. Restricting TMF to 25 years despite the fact that it was granted for the entire life of the project for 35 years shall cause grave prejudice to the developer and have direct bearing on viability of the project. It is, therefore, requested to clarify that the TMF shall be continued till the end of the useful life of 35 years of the asset in the upcoming Tariff Regulations.

93. Definitions

Comments: The definition of integrated Railway/Coal receipt system should be included in the forthcoming Regulations.

94. Sharing of Non-Tariff Income in Generation.

Comments: The Electricity Act, 2003 provides following under Section 41 and 51 of the Act:

> *"Section 41. (Other business of transmission licensee):*
>
> *A transmission licensee may, with prior intimation to the Appropriate Commission, engage in any business for optimum utilisation of its assets:*
>
> *Provided that a proportion of the revenues derived from such business shall, as may be specified by the Appropriate Commission, be utilised for reducing its charges for transmission and wheeling…"*
>
> *"Section 51. (Other businesses of distribution licensees):*
>
> *A distribution licensee may, with prior intimation to the Appropriate Commission, engage in any other business for optimum utilisation of its assets:*
>
> *Provided that a proportion of the revenues derived from such business shall, as may be specified by the concerned State Commission, be utilised for reducing its charges for wheeling…."*

Thus, The Electricity Act, 2003 only envisages adjustment of income/revenue of other business using assets of transmission and distribution licensees, however, nowhere it envisages adjustment of any revenue/income for determination for Generation Tariff. The above distinction was explicitly carved out since the Act envisages de-licensing of the generation, which was the prime object of the Act and, therefore, sharing the non-Tariff income in the manner it is done for licensed business would defeat the very purpose thereof. In other words, it would be like bringing the licensing provisions for generation business through the side door of Regulations. In this regard it would be pertinent to note the findings of the Hon'ble Supreme Court in its Judgement dated 06.05.2009 in Civil Appeal Nos. 3510-3511 off 2008 which are relevant and applicable in this regard "*If by reason of a provision of a statute the* ***generating companies are***

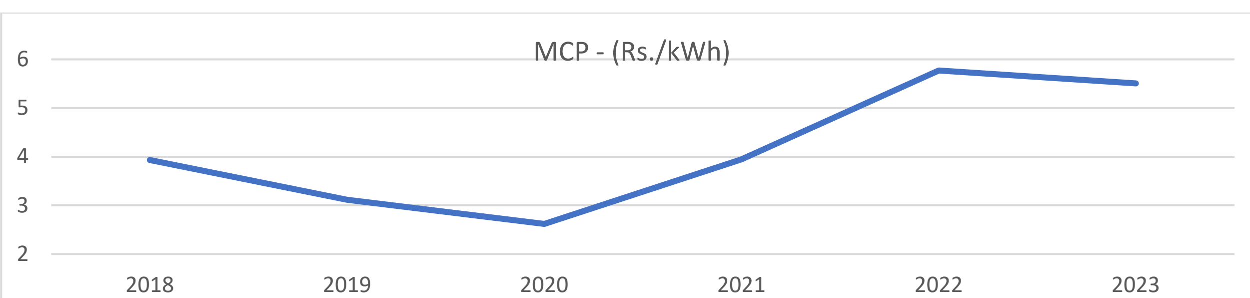
***excluded from the licensing provisions**, one of the principal tool of interpretation is **that the mischief which was sought to be remedied may not be brought back by a side door**. It has to be borne in mind that if the licence raj is brought back through the side door or regulations seeking to achieve the same purpose which the Parliament intended to avoid, there would be a possibility of misinterpretation and mis-application of statute*".

Further, the Act does not recognize ownership of consumers over the generation assets, more so, all the risks are not pass through to the beneficiaries. Therefore, for the income generated from use of generation assets which are owned by and maintained by developer at its own risk, there cannot be any sharing with beneficiaries. Only adjustment in Tariff could be for the identified and apportioned cost being borne by beneficiaries to neutralize the effect of associated cost linked to beneficiaries. Effectively, the above approach of sharing of applicable cost would also be in accordance with the Hon'ble APTEL Judgement dated 28.11.2013 in APPEAL NO.104, 105 and 106 of 2012 wherein it was held that regulated and other businesses have to be kept in separate watertight compartments so that the regulated business neither subsidises not gets subsidized by other businesses. In fact, in the circumstances when the cost is identifiable, the said cost can be adjusted in Tariff and wherever the cost is not directly identifiable, the notional cost as per prevailing market conditions can be adjusted. However, in the scenario where apportioned cost cannot be identified, portion of the net revenue received from other business as rentals/lease amount can be shared in the ratio of 75:25, i.e., 75% rests with generator and 25% is shared with beneficiaries. For example, revenue from Hoarding placed on towers, where apportioned cost pertaining to other business cannot be ascertained, net-revenue from rentals can be shared in the ratio of 75%:25%.

In view of above, it is requested to appropriately formulate the mechanism such that only identifiable allocated cost, if any, which has been already borne by the beneficiaries can be shared and only in scenario where allocable cost cannot be identified, net-revenue from rentals can be shared in the ratio of 75%:25%, 25% being the part of beneficiaries.

95. Retirement of Old Generating station.

Comments: From the DAM trend of power exchange, it can be observed that the power purchase rate in India has been significantly escalating over the period. With further, demand growth price of power is likely to increase significantly over the time. Over the period of time, the DISCOMs have been encouraged to purchase electricity in a cost effective manner, thus there is sudden need of capacity to keep the power purchase cost under affordable limit.



Further, Ministry of Power (MoP), Government of India on 15th November, 2022 notified the draft on Pooling of Tariff for Coal/Gas Generating stations which have completed 25 years. Objective of this concept note is to create a Genco-wise common pool (CP) of the plants (excluding Hydro) which have commenced or are going to commence 25 years of service. Such common pool can be utilized to maintaining grid stability until development of the appropriate storage capacity, to cater the need of increased RE integration. Moreover, MoP vide its letter dated 20.1.2023 has observed that the country is witnessing huge energy demand post pandemic which is projected to surge at all-time high in coming summer of 2023 and beyond. Therefore, the role of thermal fleets including old thermal units becomes crucial in order to support renewable integration and advised all power utilities not to retire any thermal units till 2030 and ensure the availability of units after carrying out R&M activities, if required.

It is to be noted that, in case the existing thermal generation plants crossing their lifetime are being shut down, it would be necessary to add new thermal capacity to meet the balancing and peaking requirements, which need additional investments in power sector. Moreover, setting up a new generating station, takes much longer and is more capital intensive. In contrast, power stations that are 25 years or older have already fully depreciated their assets and had recovered most of their capital cost, become debt-free, having established FSAs and having good operational characteristic. The old generating station might have a higher variable cost and may not get scheduled under Merit order Dispatch but overall AFC of such plant will be lesser than the that of a new generating station. Thus, the old generating station shall be more economic option, instead of capital investment on new stations. Hence, to ensure of adequate resources in the grid for peaking, balancing and flexible operation, it is crucial for the power sector to tap its old and under-utilized energy resources instead of building new ones.

Thus, de-commissioning the old generating station, shall be contradictory to the vision of Ministry of Power (MoP), Government of India to utilize the old generating station to its full extend. Accordingly, it is recommended that to continue with operation of such plants after useful life with special allowance/R&M cost to undertake renovation activities on need basis. Further, the old gas stations can be promoted for maintaining grid stability until development of the appropriate storage capacity, to cater the need of increased RE integration. Their working capital or fixed charge recovery, therefore, need not be linked with PLF or utilization.

96. Norms in Regulation to prevail over PPA

Comments: It may be clarified that any margin in the improved norm/term of tariff in the PPA given initially above the norms prevailing at that time, i.e., difference between improved norm and prevailing norm, should be continued over and above the norms laid down in Regulation.

The PPAs are executed based on terms and conditions of prevailing Tariff Regulations. While PPAs are executed for a period of 25 years, the Regulations are amended/modified after every control period. The margin/rebate as agreed in PPAs signed in one control period remains valid for the next 5 control period, whereas terms and condition of such margin are changed in every control period creating an ambiguity between the generator and beneficiary on the provision of such margin. While such margin decreases/increases on account of other terms and condition in the existing regulations in a control period, the beneficiaries claim to avail the margin agreed upon in the PPAs formulated based on Regulations which were prevalent at the time of signing of PPA or the new regulations whichever is beneficial to them. Therefore, it is requested to include such provisions in the Regulations that the Norms in the existing Regulations shall prevail over the figures agreed in the PPA provided that any margin fixed initially at the time of signing of PPA and should be allowed to be continued to be recovered over and above norms laid down in the Regulations. Since this proposal in line with the proposition of law that the regulations override the contract it may also be clarified that this position was true for previous control periods as well.

Note on Tax on Income

1. The history and development of Regulatory Jurisprudence on treatment of Tax on Income in tariff has been discussed by Hon'ble Commission in its Order dated 03.03.2015 in Petition No. 534/TT/2014 generally with reference to Tax on Income and specifically Deferred Tax Liability (DTL). Finally, Hon'ble Commission has directed the Petitioner to submit the computation of effective tax claimed conforming to Tariff Regulation 2014. Relevant extracts of this Order are given in Annexure 1. Hon'ble Commission has clarified the following:

(i) For the period 2001-09, actual tax on income stream from core business was allowed to be recovered directly from beneficiaries and, therefore, credit for carry forward losses and unabsorbed depreciation, refund or additional tax was also to be passed on to consumers.

(ii) During the tariff period 2009-14, the incidence of income tax on income of the generating companies or the transmission licensees was not allowed as a pass through, and it was left to the generating companies or the transmission licensees to manage their tax liability. The Commission allowed a grossed-up RoE (rate of RoE grossed up at the applicable tax rate) in tariff. Beneficiaries were not made liable to pay the income tax on the income streams of the generating companies or the transmission licensees unlike the provisions under 2004 Tariff Regulations and the liability of the beneficiaries was only limited to paying a rate of return grossed up at the applicable tax rate. Consequently, the beneficiaries were not required to bear the incidence of deferred tax liabilities created during the period 2009-14. However, if any deferred tax liability which was created during the period up to 31.3.2009 materialized during the 2009-14 period, the same was recoverable by the generating companies or the transmission licensees from the beneficiaries directly.

(iii) During the tariff period 2014-19, the income tax was only payable by the beneficiaries to the generating companies or the transmission licensees on the return on equity. **The principle of allowing grossed up RoE during 2014-19 period is the same as was prevalent during the 2009-14 period. The only difference is that the RoE is to be grossed up at effective rate in place of applicable tax rate. The allowable tax has to be worked out by grossing up the base rate of return on equity with the effective tax rate of the respective financial year during the tariff period on the same principles as dealt in tariff period 2009-14.** Further, the effective tax rate is required to be worked out on the basis of the actual tax paid by the generating companies or the transmission licensees for the respective financial year of the tariff period in line with the provisions of the relevant Finance Act. Further, actual income tax paid on other income streams of the company are excluded from the calculation of effective tax rate. The regulation also provides that **the grossed-up rate of return on equity at the end of every financial year shall be trued up based on actual tax paid** together with additional tax demand including interest thereon on duly adjusted for any difference of tax including income received from the income tax authorities during the tariff period **on the actual grossed income of the financial year**.

2. From the above, it is clear that Tariff Regulations 2014 provided for grossing up of RoE with Effective Tax Rate, which effectively does two things (i) Tax on Income is allowed on actual tax paid basis and (ii) Even actual tax paid is restricted to tax on RoE component alone, which automatically excludes tax paid on Other/Non-tariff income from Core/Regulated Business and Other Businesses (either Non-regulated/Regulated by same or different regulator). This essence is captured by Main Regulation 25(1) of Tariff Regulations 2014. Regulation 25(2) and 25(3) give the process of implementation of Regulation 25(1) and 25(2) at the time of initial determination of tariff under Regulation …. and truing up of tariff after the control period. This is not only clear from the language of these two provisions but also by the above explanation of Regulations given by Hon'ble Commission. Regulation 25(2) clearly says that "t" in the formula for Effective Tax Rate is to be

calculated at the beginning of the year as per estimated profits and income as per provisions of relevant Finance Act. This would mean including provisions relating to Corporate Tax Rate as well as MAT. Then it carves out an exception for MAT paying companies to say that it shall be equal to MAT rate. On the other hand, Regulation 25(3) very clearly deals only with truing up of tariff (obviously in terms of Regulation 25(1) as 25(2) is not applicable at this stage) and it does not mandate considering MAT rate. Thus, the reading of Tariff Regulations 2014 and the above interpretation by Hon'ble Commission both lead to the conclusion that intent of Hon'ble Commission is that at the time of truing-up of tariff, the grossing up is to be done with Effective Tax Rate computed as ratio of Tax Paid to Profit Before Tax for regulated business. This ensures that the company is able to recover the entire actual tax paid on regulated business i.e. excluding actual tax paid on other income streams.

3. It may also be noted that Effective Tax Rate though not defined in Regulation 25(1) has been clarified in the SOR to the Tariff Regulations 2014 as follows and has been used in same sense for initial determination of tariff in Regulation 25(2) for Companies paying tax at rate other than MAT:

   "25.5 In order to pass on the benefits and concessions available in income tax, the income tax rate to be considered for grossing up purpose shall be Minimum Alternate Tax (MAT) rate, if the generating company, generating station or the transmission licensee is paying MAT, or the effective Tax Rate, if the generating company or the transmission licensee is paying income tax at corporate tax rate. Accordingly, the Commission has decided to allow pre-tax rate of return on equity which shall be grossed up with the effective tax rate of the financial year or MAT rate and the tax on other income stream will not be considered for the calculation of the effective tax rate.

   ...

   24.8 ***The term "Effective Tax Rate" has been introduced to compute the tax rate at which the base ROE is to be grossed up and is expected to be lower than the corporate tax rate. The Regulation provides for the computation of effective tax rate.*** *The effective tax rate will be computed by the generating company or transmission licensee* ***on the basis of estimated tax payable and estimated gross income*** *from generation and transmission business, which refers the estimated gross profit before tax. The effective tax rate will be applied on the extent of return on equity admitted by the Commission for tariff purposes."*

4. Therefore, Effective Tax Rate should only be used for grossing up at the time of true-up irrespective of the provisions of Finance Act under which the company is paying tax i.e. MAT rate or Corporate Tax Rate or Reduced Rate under Section 115BAA. The interpretation in the Approach Paper that Effective Tax Rate for companies under MAT regime should be taken as MAT rate is, therefore, incorrect. Further, the Approach Paper incorrectly presumes that Effective Tax Rate under no circumstances can be higher than rate specified under the relevant Finance Act and, therefore, incorrectly proposes to restrict the Effective Tax Rate to applicable Tax Rate. It is also validated from the fact that a company which is under MAT regime will inherently have Effective Tax Rate more than MAT rate or even more than Corporate Tax rate due to very trigger condition specified in section 115JB for applicability of MAT as shown in the following paragraphs.

5. Assuming that MAT rate is "r" and Normal Corporate Tax rate is "R" and historically R has always been more than r. Section 115JB requires that if MAT on Book Profit at MAT rate is more than Tax payable at Normal Rate on Taxable Income (TI), then MAT is payable i.e.

   MAT = r x BP is payable

   if MAT > R x TI

   Or r x BP/PBT > R x TI/PBT

Or Effective Tax Rate > R x (PBT -+DTI)/PBT (for companies not under 80IA)

Or ETR > R x (1 -+DTI/PBT)

Or ETR > R x 0/PBT Or ETR > 0 (for companies under 80IA as TI=0)

6. Book Profit is computed by Adding certain Provisions of Expenses/Losses or Notional Expenses and Deducting certain Provisional Incomes/Profits or Notional gains. In a special case of a company having only regulated business, the income stream or PBT is only RoE and Non-tariff income such as incentives/savings in norms and, therefore, the Additions or Deductions are either not there or are very small/negligible compared to PBT. We can, therefore, assume that BP is very close to or say equal to PBT. In general, however,

   Effective Tax Rate or ETR = Actual Tax / PBT

   For a company under MAT regime,

   ETR = r x BP/PBT

   Only in a specific case, if difference between Book Profit and PBT is negligible or zero

   ETR = r x PBT/PBT = r i.e. MAT rate or very close to MAT rate

7. In all other cases, where difference between Book Profit and PBT is large, e.g. due to an event of Change in Law requiring notional income to be added or in normal computation of Book Profit or where Assessing Officer adds income in Book Profit, Book Profit may be much more than PBT and, hence, ETR for MAT paying company also shall be higher than MAT rate. Restricting the grossing up only to MAT rate would result in non-allowance of tax on core business (excluding incentives/savings etc.), which will not be in consonance of the intent of allowing actual tax on regulated business particularly when Effective Tax Rate is computed only on regulated business. Further, such restriction will lead to under-recovery of tax on regulated business and, hence, shall go out of allowed RoE resulting in post-tax RoE being lower than assured 15.5%. It may kindly be noted that in the above situations it does not matter whether the company is availing 80IA benefit or not as applicability of MAT provisions due to meeting the above stated trigger condition could be a result of timing difference or 80IA benefit resulting in TI being low or zero but the above facts do not change as ETR is dependent on Book Profit and PBT and not on TI.

8. The MAT rate may work for the purposes of initial determination of tariff to avoid rigour and guesswork for estimating book profit as a provisional measure. However, at the time of true-up actual ETR should be considered.

9. Even for companies paying tax at rates other than MAT, i.e. either Corporate Tax Rate or Special Rate, same argument as in MAT rate companies above holds good. Similar to Book Profit, TI also has certain additions and deductions, primarily Depreciation in Books and IT Depreciation respectively, which is nothing but timing difference in TI i.e. Deferred Taxable Income (DTI) captured by DTL. Thus, the ETR for such companies can be written as:

   ETR = R x TI/PBT
   = R x (PBT -+ DTI)/PBT
   = R x (1 -+DTI/PBT)

10. Thus, from the first equation, it can be seen that ETR can be less than applicable rate (R) or more than it depending upon whether TI is more than PBT or not. As we know, due to higher rates of depreciation in Income Tax Act, TI is generally lower than PBT (i.e. DTI is subtracted from PBT to arrive at TI in second equation) in initial 7-8 years, whereafter it becomes more than PBT (i.e. DTI is added to PBT) due to said timing difference. Thus, ETR is lower than applicable rate in the initial period and higher than applicable rate in later phase of project life. Since most of the electricity

companies having CoD before 01.04.2017 (when 80IA was withdrawn for future CoDs but for existing companies, benefit was allowed to continue for remaining period) were availing 80IA benefit, MAT was applicable for initial 15 years, whereafter they would come under Corporate Tax regime when TI will always be higher than PBT and, hence, ETR shall necessarily be higher than applicable tax rate. Again, considering the fact that ETR is being computed only for regulated business, to allow full recovery of tax on regulated business there should not be any capping of ETR to applicable rate.

11. Another reason why there should not be any cap on ETR is that TI may be higher than PBT not only because of timing differences but also due to various other reasons such as Change in Law for addition of any notional or actual income, addition of income by assessing officer. Further, a company that has started its operations after 01.04.2017 and has not availed 80IA benefit at all, shall have ETR more than applicable tax rate right after 7-8 years when timing difference becomes negative, and it would be unfair to them to ask payment of tax burden beyond Corporate Tax Rate particularly when they do not have any DTL for period prior to 2009. In view of the above reasons, ETR should not be capped to ceiling of applicable rate. In fact, if such companies are paid at ETR during initial period when DTL gets accumulated it would be unfair if the tax rate is capped to ETR when DTL materializes in future years. Therefore, if ETR is limited to applicable Tax rate, DTL should be allowed for the period FY 14-15 onwards also.

12. Another issue that is important is the necessity to remove distortion in the calculation of the Effective Tax Rate due to income from core business other than RoE i.e. incentives/savings etc. both in the numerator and denominator. Regulation 31(1) of Tariff Regulations 2019 as it reads today excludes only "income from other businesses (i.e. income from business other than business of generation or transmission, as the case may be)" for computation of Effective Tax Rate. Since Hon'ble Commission is grossing up only RoE with Effective Tax Rate for excluding Tax on incentive/savings/other income from core business, it follows that such income should also be excluded from numerator i.e. tax paid on such income as well as denominator i.e. gross income or PBT. Inclusion of this income from core business results in unintended distortion in Effective Tax Rate to be used for grossing up RoE. Thus, the language may be changed to "excluding income other than RoE from regulated business (i.e. business of generation or transmission, as the case may be) and income from businesses other than regulated business".

13. Yet another issue is with regard to considering tax credit for (i) carry forward losses and unabsorbed depreciation and (ii) MAT on income other than RoE, in the numerator for computing ETR, i.e. Actual Tax Paid. In the years after MAT regime, as brought out above TI would be more than PBT and actual tax payment would depend on the credit availed every year after MAT regime, which would effectively reduce the tax outgo to the level of MAT even though the company is in Corporate Tax regime till the year entire MAT credit is utilized and ETR for such period based on actual tax outgo would work out to MAT rate. However, the credit utilized may be for carry forward of losses/unabsorbed depreciation and tax on Other Income of Core Business, for which no tax would have been allowed in tariff and tax credit available now is for tax borne by the company earlier. In some cases of carry forward of losses/unabsorbed depreciation, the Hon'ble Commission has not allowed any grossing up as no tax has actually been paid due to such loss shown in ITRs. It is not fair to utilize the credit of such losses in ETR when these losses have been borne totally by the company. Therefore, it would be fair and equitable that credit for carry forward losses, unabsorbed depreciation and MAT on Other Income is added back to Actual Tax Paid on regulated business for computation of ETR.

14. Considering credit of MAT for 80IA companies is another concern. There is no denial that 80IA benefit was made available to those investors/assesses who invest in electricity generation/transmission/distribution business. Amongst the available investment options, the investors had chosen this sector with one of the factors being that 80IA benefit that shall be

available to it. It would only be fair to the investor that such benefit is made available to him only as passing on such benefit to consumers in tariff would amount to not implementing the will of Parliament in a special Act viz. Income Tax Act. Since MAT is passed on to the beneficiaries during MAT regime, the credit available for MAT under 80 IA should be added back to Actual Tax Paid so that investor's interest is protected. In fact, this finding has already been given by Hon'ble Commission in SOR for Tariff Regulations 2009 and National Institute of Public Finance and Policy, which is an autonomous research institute under Ministry of Finance, had also proposed to make Tariff Regulations 2014 on the same lines, which is recorded in SOR for Tariff Regulations 2014. Further, it is a settled principle of law that if two special statutes, in this case the income tax act and the electricity act, do not have anything conflicting or an act not having an overriding provision then the subordinate legislation under one special act like regulation cannot make any provision in contradiction to the other special act. It is, therefore, proposed that Hon'ble Commission may allow adding credit for MAT utilized under section 80IA to numerator, Actual Tax Paid, for computation of Effective Tax Rate.

15. Regulations provide for refund/recovery of excess/shortfall in tariff alongwith carrying cost at the time of true-up, which gets added to/reduced from the Taxable Income attracting more/less tax in the year of refund/recovery. Since this refund/recovery of tariff is purely from regulated business, hence, any tax implication should also be allowed as pass through. However, since this additional tax liability gets added to tax liability on RoE in Actual Tax Paid alongwith corresponding addition of Income in PBT in existing regulations, the ETR remains almost unchanged and, therefore, this additional tax is not recovered. To address this anomaly, it is suggested that for computation of ETR, additional tax may be considered in the numerator (Actual Tax Paid), but this excess/shortfall in tariff may be excluded from denominator i.e. PBT.

16. While the above proposition would broadly address the issues of a company engaged in single regulated business, it does not fully capture the tax implications for a company with multiple businesses particularly if other businesses have huge Income or Losses. This issue becomes more pronounced when the company as a whole pays NIL tax solely due to huge losses in other businesses and if Tariff Regulations are read to mean that no grossing up shall be allowed, it would effectively mean that regulated business is being subsidized by Other Businesses. In this regard, Hon'ble APTEL in its Judgement dated 28.11.2013 in APPEAL NO.104, 105 and 106 of 2012 has held that regulated and other businesses have to be kept in separate watertight compartments so that the regulated business neither subsidises not gets subsidized by other businesses. It is important to note that this Judgement has attained finality and, therefore, holds the field in this matter of law. Relevant extract of this Judgement is as follows:

> *"52. The Judgment in Appeal No. 251 of 2006 is based on the principle that* ***regulated business in question that is within the jurisdiction of the Regulatory State Commission, should neither subsidise nor get subsidy from other businesses whether unregulated or regulated by the same or different regulator. In other words, the Judgment mandates that the taxable income of the regulated business within the jurisdiction of the Regulatory State Commission should be computed on stand alone basis, irrespective of what is the impact of this business or other businesses on the overall tax liability. There is a possibility of distortion when the impact of regulated business or other businesses on total tax liability is considered or the overall tax liability is allocated for determining the tax liability for regulated business****.*
>
> …
>
> *55. However, a careful analysis of the above example with the ratio of the Judgment in Appeal No. 174 of 2009 would reveal that this Judgment is specifying tax allow ability for regulated business only and does not in any manner deal with implications on tax for regulated business due to other businesses. Further, the ratio is with regard to tax liability on the regulatory income, computed with permissible profits and applicable tax depreciation to be considered*

as taxable income, and not on the actual taxable income. Hence, any notional or actual income even within regulated business that is not permissible to be considered as regulatory taxable income cannot be allowed as it would amount to allowance of more than warranted regulatory tax liability/profits. ***As such, the above example when seen only with reference to the regulated business allows just the real tax payable for regulated business without taking or giving any support from other businesses and, hence, does not amount to making profit from tax. The tax benefit of exemptions/losses in other businesses should only be available to those businesses. In case, the situation would have been reverse in the above example, i.e. the regulated business had exemptions/losses then the tax benefit of such exemptions should have been attributable only to regulated business.*** *As such, there is no conflict in the above two Judgments and both can be implemented simultaneously with regulated business being treated separately on a standalone basis and tax liability computed as per applicable tax laws for that business only considering notional regulatory taxable income. This concept is followed by regulators for all items of ARR/Revenue which are considered on normative basis, where irrespective of actual expense/revenue normative expense/revenue is considered for tariff purposes. Accordingly, there is no requirement of allocating the overall tax liability on regulated and unregulated businesses.*

56. It is also to be noted that for difference in book depreciation and tax depreciation, the tax laws provide for creating Deferred Tax Liability (DTL) which gets amortised with time when tax depreciation becomes lower than book depreciation. However, in regulated business DTL is not considered as it is not the current tax liability. ***Thus, in case the benefit of accelerated tax depreciation for one year in regulated business may result in lower overall tax on overall book profit (due to MAT) and may seem to subsidise other businesses. However, in subsequent years the overall tax liability may be more than tax on overall book profit, which would seem to given subsidy from other businesses to regulated business. In both these situations, the methodology of standalone tax computation and allowance would give correct picture.”***

17. It is, therefore, submitted that grossing up with applicable tax rate instead of Effective Tax Rate should be allowed even if actual tax paid is NIL. The arguments advanced above for non-adjustment of credit for carry forward losses, unabsorbed depreciation and credit for MAT on other businesses would squarely apply in this case as well. After taking into account such adjustments, it is possible that the tax liability on regulated business is more than actual tax paid, which may be zero also. Hon’ble Commission is requested to modify the formula for Effective Tax Rate suitably to take care of the above situations.

Relevant Extracts of Hon'ble CERC Order in Petition No. 532/TT/2014 dated 03.03.2015

5. The Commission is of the view that the treatment of deferred tax liability for the purpose of determination of tariff during the 2014-19 period needs to be clarified for the purpose of compliance by the generating companies and transmission licensees whose tariff is regulated by this Commission. Para 9 and 10 of the Accounting Standards (AS) 22 recognize deferred tax liability as under:-

> *"9. Tax expense for the period, comprising current tax and deferred tax, should be included in the determination of the net profit or loss for the period. 10. Taxes on income are considered to be an expense incurred by the enterprise in earning income and are accrued in the same period as the revenue and expenses to which they relate. Such matching may result into timing differences. The tax effects of timing differences are included in the tax expense in the statement of profit and loss and as deferred tax assets (subject to the consideration of prudence as set out in paragraphs 15-18) or as deferred tax liabilities, in the balance sheet."*

6. The above provision relates to treatment of deferred tax expense in the statement of profit and loss account and treatment of deferred tax assets or deferred tax liabilities in the balance sheet of the company. However, for the purpose of tariff, the Commission has treated deferred tax liabilities differently in different tariff periods which are discussed in brief as under:-

> (a) Clause (1) of Regulation 7 of the Tariff Regulations applicable for the period 2004-09 (hereinafter "2004 Tariff Regulations") provides that tax on the income streams of the generating companies or the transmission licensees, as the case may be, from its core business shall be computed as an expense and shall be recovered from the beneficiaries. Further, fourth proviso to Clause (2) of Regulation 7 of 2004 Tariff Regulations provides that in the absence of any other equitable basis, the credit for carry forward losses and unobserved depreciation shall be given. According to Regulation 10 of the said Regulations, recovery of income tax shall be done directly by the generating companies or the transmission licensees from the beneficiaries without making any application before the Commission.
>
> (b) During the tariff period 2009-14, the incidence of income tax on income of the generating companies or the transmission licensees was not allowed as a pass through and it was left to the generating companies or the transmission licensees to manage their tax liability. The Commission allowed a grossed up RoE (rate of RoE grossed up at the applicable tax rate) in tariff. In this connection, Regulation 15 of the 2009 Tariff Regulations is extracted as under:-
>
>> *"15. (1) Return on equity shall be computed in rupee terms, on the equity base determined in accordance with regulation 12.*
>>
>> *(2) Return on equity shall be computed on pre-tax basis at the base rate of 15.5% for thermal generating stations, transmission system and run of the river generating station, and 16.5% for the storage type generating stations including pumped storage hydro generating stations and run of river generating station with pondage and shall be grossed up as per clause (3) of this regulation:*
>>
>> *x x x x*
>
> Further, Regulation 39 of 2009 Tariff Regulations provides as under:-
>
>> *"39. Tax on Income. Tax on the income streams of the generating company or the transmission licensee, as the case may be, shall not be recovered from the beneficiaries, or the long-term transmission customers, as the case may be: Provided that the deferred tax liability, excluding Fringe Benefit Tax, for the period up to 31st March, 2009 whenever it materializes, shall be recoverable directly from the beneficiaries and the long-term customers:"*

It is apparent from the provisions of the 2009 Tariff Regulations that the beneficiaries were not made liable to pay the income tax on the income streams of the generating companies or the transmission licensees unlike the provisions under 2004 Tariff Regulations and the liability of the beneficiaries was only limited to paying a rate of return grossed up at the applicable tax rate. Consequently, the beneficiaries were not required to bear the incidence of deferred tax liabilities created during the period 2009-14. However, if any deferred tax liability which was created during the period up to 31.3.2009 materialized during the 2009-14 period, the same was recoverable by the generating companies or the transmission licensees from the beneficiaries directly.

(c) According to Regulation 25 of the Tariff Regulations applicable for the period 2014-19 (hereinafter "2014 Tariff Regulations"), the income tax was only payable by the beneficiaries to the generating companies or the transmission licensees on the return on equity specified under Regulation 24 of the 2014 Tariff Regulations. **The principle of allowing grossed up RoE during 2014-19 period is the same as was prevalent during the 2009-14 period. The only difference is that the RoE is to be grossed up at effective rate in place of applicable tax rate.** Regulation 25 of the 2014 Tariff Regulations provides as under:-

> *"25. Tax on Return on Equity: (1) The base rate of return on equity as allowed by the Commission under Regulation 24 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 the 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 income on other income stream (i.e., income of non generation or non transmission business, as the case may be) shall not be considered for the calculation of "effective tax rate".*
>
> *Order in Petition No. 532/TT/2014 Page 7 of 13*
>
> *(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.*
>
> *x x x x*
>
> *(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 2014-15 to 2018-19 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 transmission customers/DICs as the case may be on year to year basis."*

As per the above provision, tax is payable on the "return on equity" admissible to the generating companies or the transmission licensees under Regulation 24 of 2014 Tariff Regulations. **The allowable tax has to be worked out by grossing up the base rate of return on equity with the effective tax rate of the respective financial year during the tariff period on the same principles as dealt in tariff period 2009-14. Further, the effective tax rate is required to be worked out on the basis of the actual tax paid by the generating companies or the transmission licensees for the respective financial year of the tariff period in line with the provisions of the relevant Finance Act. Further, actual income tax paid on other income streams of the company are excluded from the calculation of effective tax rate. The regulation also provides that the grossed-up rate of return on equity at the end of every financial year shall be trued up based on actual tax paid together with additional tax demand including interest thereon on duly adjusted for any difference of tax including income received from the income tax authorities during the tariff period on the actual grossed income of the financial year.** Regulation 49 of the 2014 Tariff Regulations deals with the treatment of deferred tax liability. The said regulation is extracted as under:-

> *"49. Deferred Tax liability with respect to previous tariff period: The deferred tax liability before 1.4.2009 shall be recovered from the beneficiaries or the long term transmission customers/DICs as the case may be, as and when the same gets materialised. No claim on account of deferred tax liability arising from 1.4.2009 upto 31.03.2014 shall be made from the beneficiaries or the long term transmission customers/DICs as the case may be."*

7. From the above provision it is seen that the deferred tax liability accruing before 1.4.2009, but materializing during the period 2014-19 are directly recoverable from the beneficiaries of the generating companies or the transmission licensees. It has been made abundantly clear in the said provision that there shall be no claim on account of deferred tax liability arising during the period 1.4.2009 to 31.3.2014. The reason for such a provision is that the management of the income tax on the income stream of the generating companies or the transmission licensees was the responsibility of the respective generating companies or the transmission licensees during 2009-14 period. It is relevant to note that Regulation 49 of 2014 Tariff Regulations does not provide for treatment of deferred tax liability arising during the period 2014-19, which means that the 2014 Tariff Regulations do not recognize the deferred tax liability for the purpose of tariff and as in case of the 2009 Tariff Regulations, the generating companies or the transmission licensees are required to manage their deferred tax liability.

8. An analysis of the provisions of the Regulations relating to tax on income of the generating companies or the transmission licensees during the three tariff periods namely, 2004-09, 2009-14 and 2014-19 reveals the following:-

(a) The beneficiaries were responsible for reimbursement of the tax on the income from the core business of the generating companies or the transmission licensees during the tariff period 2004-09. Accordingly, any deferred tax liability arising during the said period but materializing during the tariff periods 2009-14 and 2014-19 are directly recoverable by the generating companies or the transmission licensees from the beneficiaries in terms of Regulation 39 of the 2009 Tariff Regulations and Regulation 49 of the 2014 Tariff Regulations.

(b) During the tariff period 2009-14, the generating companies or the transmission licensees were entitled to a rate of return to be grossed up at the applicable tax rate. There is a clear stipulation that tax on income stream of the generating companies or the transmission licensees shall not be recovered from the beneficiaries. Consequently, the beneficiaries did not have any liability for payment of deferred tax arising during each of the years of the tariff period.

(c) **During the 2014-19 period, the generating companies or the transmission licensees are entitled for a return on equity grossed up at the effective tax rate to be worked out on the basis of the actual tax paid by the generating companies or the transmission licensees. There is no provision in the said regulation that the generating companies or the transmission licensees shall be reimbursed the deferred tax liability arising during each of the years of the tariff period 2014-19.**

9. In view of the above discussion, it is clarified that the generating companies or the transmission licensees whose tariff is regulated by this Commission are not permitted to claim in tariff the deferred tax liability arising in each of the years during tariff period 2014-19. Though the generating companies or transmission licensees may account for the deferred tax expense in the profit and loss account and the deferred tax assets or deferred tax liabilities in their balance sheet for the respective financial years during the 2014-19 period as per the provisions of AS 22, they are not permitted to qualify such deferred tax expense or deferred tax assets and deferred tax liabilities with the statement that the same shall be recoverable in through tariff in future years.

10. In view of the above, there is a requirement to examine that the effective tax rate adopted by the generating companies and the transmission licensees for computation of grossed-up ROE conform to the provisions of 2014 Tariff Regulations. We, therefore, direct the petitioner to submit the computation of the effective tax rate claimed…"

CLARIFICATION ON PERIOD OF APPLICATION OF TMF UNDER REGULATION 75 OF TARIFF REGULATIONS 2019

1. It is submitted that instant submission, Tata Power is humbly seeking for clarification on the applicability of the TMF for the entire life of the Project i.e. 35 years as against 25 years from the date of issue of licence as provided under Regulation 75 of the Tariff Regulations, 2019.

1.1 It is to be noted that TMF for the entire life of the project was assured to the investors/Petitioner by this Hon'ble Commission *vide* its Order dated 29.05.2001 in Petition No. 23/2001. Further, the said understanding was crystalised by this Hon'ble Commission in its Regulation 4.10A of the CERC (Terms and Conditions of Tariff) Regulations, 2001 ("**Tariff Regulations, 2001**") and the said entitlement has been upheld by this Hon'ble Commission in subsequent orders as elaborated below. Therefore, in view of the assurance provided to the Petitioner, this Hon'ble Commission may relax Regulation 75 and clarify the period of applicability of TMF on the Petitioner's Project for its entire life i.e. 35 years.

1.2 Further, this Hon'ble Commission may also appreciate that in a recent development, Ministry of Power ("**MoP**") has issued amendment to the Electricity Rules, 2005 on 30.06.2023 and inserted Rules (4A), (4B) and (4C) along with three provisos therein, which read as under:

> *"3. In the said rules, after rule 4, the following rules shall be inserted, namely:-*
>
> *(4A) Where any entity has been granted licence under section 14 of the Act, the period of the licence shall be in accordance with the terms and conditions of the licence granted by the Appropriate Commission;*
>
> *(4B) Where an entity is a deemed licensee under the first, second and fifth proviso to section 14 of the Act, the period of the licence shall be twenty five years from the date of the coming into force of the Act;*
>
> ***(4C) The licence granted by the Appropriate Commission under section 14 of the Act and the deemed licence under first, second and fifth proviso to said section 14 shall be deemed to be renewed unless the same is revoked:***
>
> ***Provided that such renewal, shall be for a period of twenty five years at a time or for a lesser period, if requested by the licensee****:*
>
> *Provided further that where the Appropriate Commission has renewed the licence for a particular period before the notification of these rules, the licence shall be deemed to be renewed for that particular period under these rules.*
>
> *Provided also that this rule shall not apply to the licence granted to transmission developers, selected through tariff based bidding, under section 63 of the Act."*
>
> [***Emphasis Supplied***]

1.3 Rule (4C) read with its first proviso makes the life of license virtually perpetual with renewal after every 25 years unless revoked or requested for shorter period by the licensee. Therefore, now the Regulation 75 of the Tariff Regulations 2019, which stipulates TMF to be applicable for 25 years from date of license, i.e. validity of license, needs to be read in terms of the said Rule to the effect that TMF shall be applicable for the period of validity of license or the transmission service agreement that may be valid upto the life of the assets.

Re. Historical background regarding application of TMF

1.4 On 26.03.2001, this Hon'ble Commission notified the CERC (Terms and Conditions of Tariff) Regulations, 2001 ("**Tariff Regulations, 2001**") for determination of tariff for the period 01.04.2001 to 31.03.2004. It is pertinent to note that Appendix II to the said Tariff Regulations

2001 provides for the 'Useful Life' of Assets including 'Lines on fabricated steel operating at nominal voltage higher than 66 KV' (i.e. the transmission line of the Petitioner) as 35 years. It may kindly be noted that the Petitioner's assets include only 400 KV and 220 KV AC transmission lines and associated civil structures and there are no other transmission components like Sub-Station Transformers or HVDC links. Relevant extract of Said Appendix II is reproduced below.

"Depreciation Schedule

Description of Assets	***Useful Life(yrs)***	*Rate Life(yrs) (Calculated w.r.t. 90%)*	
	1	*2*	*3=1*2*
(I) Overhead lines including supports:			
(i) *Lines on fabricated steel operating at nominal voltages higher than 66 KV*	*35*	*2.57*	*90*

………………………………"

1.5 Further, the concept of TMF was recognized in the Order dated 29.05.2001 issued by this Hon'ble Commission in Petition No. 23/2001 wherein this Hon'ble Commission devised an incentive scheme to attract private investors in the field of transmission. Such scheme was conceptualised by this Hon'ble Commission in order to address the need to expedite the investment of private players in the transmission business. Relevant excerpts from the above Order in this respect is re-produced below:

> *"Transmission Majoration Factor (TMF)*
>
> *22. In discussing the elements of "Insurance" and "Target Availability/incentive" for transmission lines, the Commission has mentioned a concept designated as "Transmission Majoration Factor". Introduction of this factor is in due consideration of the fact that the Commission* ***recognizes the need for expediting new investments in the transmission sector. It has also recognized the fact that the private investors, in transmission, have to incur additional liabilities in their pioneering efforts compared to long standing central transmission utility like PGCIL. Accordingly, in respect of such lines executed by private investors, the Commission proposes to allow 10% mark up (pretax) on transmission charges as Transmission Majoration Factor. This would be available only to the new private investors who would like to enter the field.*** *Accordingly, there would be no need to provide for TMF in respect of projects executed by PGCIL. This will not also apply to the HVDC projects to be executed by private investors involving heavy capital investments and do not, hence, justify a special treatment by way of Transmission Majoration Factor. In respect of PGCIL, the development surcharge of 10% provided to it takes care of requirements of TMF allowed for private investors in respect of new investments."*
>
> **[*Emphasis supplied*]**

1.6 The Hon'ble Commission had, while proposing the above Scheme, examined all the aspects of the transmission business including the adequacy of return on the investment and the interest of the consumers over the entire life of the Project. The Hon'ble Commission had envisaged additional Internal Rate of Return ("**IRR**") in the directions for this scheme, which was considered adequate to attract necessary private investments in the Sector. This is evident from the relevant excerpts as follows:

> *"23. The directions contained in the Commission's order shall yield an additional IRR of about 4.5% in US Dollar terms over and above 8.84% indicated by the petitioner. This additional IRR includes the effect of monthly payment of return on equity vis-a-*

> *vis the annual return on equity of 16%. By taking into account the effect of payment of depreciation and interest payment on monthly basis as compared to the quarterly or half yearly repayment of loan, the IRR would improve further.* ***The returns that may be earned by the petitioner and other private investors in the light of above directions is considered to be reasonable and adequate to attract necessary investment in the private sector, on the one hand and protect the consumers' interest on the other hand."***
>
> **[*Emphasis supplied*]**

1.7 Therefore, it is clear from the above excerpts that this Hon'ble Commission had proposed the scheme of TMF after due scrutiny of the investment requirement in the transmission sector and the interest of the consumers as well considering its impact over entire life of the Project. Further, this Hon'ble Commission had explicitly mentioned in the above Order, Regulation 4.10A of Tariff Regulations 2001 and other subsequent Orders that such scheme would be available to new entrepreneurs who enter the sector up to a pre-determined period ending 31.03.2004 and as such would be eligible to avail such TMF till the entire life of the Project. This was an unconditional assurance specifically provided not only to attract immediate investments in the Sector but also to assure the availability of such incentive scheme throughout the entire life of the Project which would ensure additional IRR, as mentioned above, to the investors. The relevant excerpts from the above Order are re-produced below:

> *"24. Commission would like to make it clear that the* ***TMF is a one-time measure to encourage private entrepreneurs to promote investments in transmission sector****. We expect that the serious entrepreneurs would seize this opportunity and we also expect that the PGCIL would also expedite urgent action to cover all the critical lines within a limited period in meaningful and constructive cooperation with private investors. Accordingly, the TMF would be available to new entrepreneurs only for the period up to 31st March 2004. This would, thus, be coterminous with the Commission's order dated 21-12-2000 on terms and conditions of tariff.* ***However, the benefit of TMF would continue to be available during the entire life of the project in respect of the investors who enter the transmission sector up to the period ending 31-3-2004.****"*
>
> **[Emphasis supplied]**

1.8 Based on the above, on 21.09.2001, the Hon'ble Commission carried out an amendment to the Tariff Regulations, 2001 by way of CERC (Terms and Conditions of Tariff) (First Amendment) Regulations, 2001 and crystalised the above by introducing Regulation 4.10A to ensure the investors regarding the applicability of TMF for the entire life of the Project. The relevant extract of the said Regulation 4.10A is reproduced below for kind convenience of this Hon'ble Commission:

> *"4.10A Transmission Majoration Factor*
>
> *In respect of the transmission projects executed through IPTC/JV routes,* ***10% (Ten percent) markup (pre-tax) on transmission charges shall be allowed as Transmission Majoration Factor.***
>
> *Provided that Transmission Majoration Factor shall not be allowed on HVDC projects executed through IPTC/JV routes.*
>
> *Provided further that the* ***Transmission Majoration Factor shall be allowed during the entire life of the transmission project*** *to the new investor entering the transmission sector through IPTC/JV routes and who has been granted a transmission license under Section 27C of the Indian Electricity Act, 1910, upto 31-3-2004."*
>
> **[Emphasis supplied]**

1.9 As evident from above, by way of Regulation 4.10A, this Hon'ble Commission assured that new investments will be encouraged by way of TMF and that the same will be applicable during the entire life of the transmission project. The criteria for qualifying for TMF were also specified by this Hon'ble Commission, namely-

(a) It should be a new transmission project;

(b) The new transmission project should be executed through IPTC/JV route; and

(c) The transmission licence (under Section 27C of the Indian Electricity Act, 1910) should be obtained up to 31.03.2004.

Once the above eligibility criteria are fulfilled, the right of enjoyment of TMF becomes absolute, vested and is unconditional and not subject to any further embargoes or conditions or to any review.

1.10 Considering the above, Tata Power Company Ltd. and Power Grid Corporation of India Ltd. formed a Joint Venture ("**JV**") i.e. the Petitioner. The Petitioner was granted a Transmission Licence by this Hon'ble Commission on 13.11.2003 for a period of 25 years in terms of Order dated 22.10.2003 in Petition No. 40/2023 filed by the Petitioner for a grant of Transmission License. The Petitioner, being the only company in such JV route, became eligible to avail the above proposed TMF.

1.11 At this juncture, it is apposite to highlight that various amendments were carried out by this Hon'ble Commission in the Tariff Regulations but the useful life of 35 years for transmission lines specified in Tariff Regulations, 2001 was not altered. Therefore, the Petitioner proceeded with the assurance that its Project would be entitled for TMF for the entire useful life of 35 years.

1.12 Further, in 2004, this Hon'ble Commission promulgated the Tariff Regulations 2004 which did not contain the provision of TMF. Hence, the Petitioner specifically moved a Petition before this Hon'ble Commission seeking clarification on the availability of the TMF for the life of the Project as envisaged earlier. This Hon'ble Commission had, while clarifying the availability of such TMF for the entire life of the project, also noted the settled legal position that the expiry of a temporary statute does not obliterate the rights or obligations under that statute. In view of the above, the necessary clarification as provided by this Hon'ble Commission through the Order dated 01.07.2004 in Petition No. 51/2004 is reproduced below:

> *" 7. For an answer to the question raised, we consider the background leading to incorporation of Regulation 4.10A in the notification dated 26.3.2001. The Regulation 4.l0A notified on 21.9.2001 was preceded by the Commission's order dated 29.5.2001 in Petition No.23/2001. The Commission recognised the fact that private investors in transmission had to incur additional liabilities in their efforts compared to long standing transmission utilities like Power Grid Corporation of India Limited. Accordingly, in respect of the projects executed by private investors, the Commission allowed 10% mark up (pre-tax) on transmission charges as Transmission Majoration Factor. The Commission directed that the Transmission Majoration Factor would be available to new entrepreneurs only for the period up to 31.3.2004,* ***which implied that the benefit of Transmission Majoration Factor would continue to be available during the entire life of the project in respect of investors who entered the transmission sector up to the period 31.3.2004.***
>
> ......
>
> *8. When seen in the light of above background, in our considered opinion, Regulation 4.10A ibid has conferred a substantive right on the petitioner to claim Transmission Majoration Factor. Therefore, despite the fact that no provision for payment of Transmission Majoration Factor is made in the 2004 Regulations, the petitioner shall be entitled to claim the Transmission Majoration Factor throughout the period of licence, which is 25 years from the date of issue."*

[***Emphasis supplied***]

1.13 The Hon'ble Commission, therefore, made it clear to Petitioner that even if there is no provision in the Tariff Regulations 2004, it is eligible to claim TMF as per Regulation 4.10A of the Tariff Regulations, 2001.

1.14 It is further submitted that investment in Generation and Transmission Projects are conceived only after evaluation of the risks and return based on projections and available statutory assurances/clearances/consents. This would define the projected IRR which helps the investor to make its decision on the investment. The assurance of availability of the TMF for the entire life of the Project was one such key factor which attracted the Petitioner to invest into a Project extending for a life of 35 years. The IRR of the Project as envisaged initially considered the TMF for the entire lifetime of 35 years for the Project and decision to invest laid entirely on expected returns based on such assurance.

1.15 It is pertinent to note that the objection with respect to allowance and continuation of TMF has been taken by beneficiaries right from the first Tariff Order passed for the Petitioner. In this respect, this Hon'ble Commission has consistently relied upon Regulation 4.10A of Tariff Regulations 2001 (under which the Petitioner was entitled for recovery of TMF for entire life of the Project of 35 years) to uphold Petitioner's entitlement to TMF.

Re. The need for seeking clarity

1.16 Despite there being a clear understanding regarding applicability of the TMF throughout the entire life of the Project, this Hon'ble Commission *vide* its Notification dated 30.01.2019 issued the CERC (Terms and Conditions of Tariff) (Second Amendment) Regulations, 2019 and amended the Tariff Regulations, 2014. The Hon'ble Commission *vide* this amendment inserted a new regulation (49A) after the Regulation 49 of Principal Regulations viz. Tariff Regulations 2014 and restricted the applicability of TMF to a period of 25 years from the date of issue of transmission licence. The relevant extract has been reproduced below:

> *"49A Transmission Majoration Factor: Transmission Majoration Factor admissible for the transmission projects executed through JV route in terms of Regulation 4.10A of the Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2001 shall be available for a period of 25 years from the date of issue of the transmission licence."*

1.17 Further, the above provision has been carried forward while framing Tariff Regulations, 2019 in Regulation 75 notified on 7.03.2019 as well which provides that:

> *"75. Transmission Majoration Factor: Transmission Majoration Factor admissible for the transmission projects executed through JV route in terms of Regulation 4.10A of the Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2001 shall be available for a period of 25 years from the date of issue of the transmission licence."*

1.18 The premise under which the above amendment was introduced (which was carried forward in Tariff Regulations, 2019) has been explained by this Hon'ble Commission in its Statement of Reasons to the CERC (Terms and Conditions of Tariff) (Second Amendment) Regulations, 2014 as follows:

> "*6.0.* ***Regulation 4.10A in the 2001 Tariff Regulations specifies that the TMF will be available for the entire life of the transmission project. The life of a transmission line was specified as 25 years in the 2001 Tariff Regulations and accordingly, transmission licence was granted vide order dated 22.10.2003 in Petition No. 40/2013 to Powerlinks for a period***

> ***__25 years__***. *However, the useful life of the transmission line has been specified as 35 years in 2009 and 2014 Tariff Regulations.* ***In our view, the promotional scheme of TMF should be confined to the useful life specified in the 2001 Tariff Regulations and the transmission licence granted to Powerlinks.*** *Accordingly, the incentive of TMF granted to Powerlinks shall be available only for a period of 25 years from the date of issue of licence. This aspect needs to be clarified as the useful life of the transmission assets has been subsequently enhanced from 25 years to 35 years. The Commission has decided to issue second amendment to the 2014 Tariff Regulations clarifying the period for which TMF would be available.*"
>
> [***Emphasis supplied***]

1.19 It can be seen from the above that this Hon'ble Commission had inadvertently considered the useful life of transmission line as 25 years under the Tariff Regulations, 2001. Whereas, as elaborated hereinabove, the useful life of transmission line under the said Regulations is 35 years. Therefore, the Hon'ble Commission has inadvertently considered 25 years instead of 35 years for the purpose of allowance of TMF. The above submissions are also substantiated by the following:

(a) This Hon'ble Commission, in its Order dated 12.12.2002 in Petition No. 25/2002 – *PGCIL v. BSEB & Ors*. has itself observed that the useful life of a transmission line as per Tariff Regulations, 2001 is 35 years. Following are the relevant extracts from the said Order:

> "*27. One asset is in operation for about 8 years and three assets for about 7 years. Therefore, on an average entire assets of the project are in operation for about 7 years as on 1.4.2001*. ***As per the notification dated 26.3.2001, the useful life of the transmission line at 66 kV and above is 35 years****…*"
>
> [***Emphasis supplied***]

(b) Further, the observation of this Hon'ble Commission that since the useful life specified under the Tariff Regulations, 2001 was 25 years and hence the Transmission Licence for 25 years was granted to the Petitioner is erroneous and the same is evident from the following:

i. This Hon'ble Commission in its Order dated 14.06.2001 in Petition Nos 111/2000 and 118/2008 in the matter of grant of Transmission License – Procedure, Terms and Conditions of License, etc., *inter alia*, while deliberating on the issue of term of transmission licence observed that the transmission licence should be consistent with the useful life of the transmission asset. In this regard, this Hon'ble Commission made the following findings:

> "*32. … The two major equipments used in transmission are transformer and lines, the fair life of transformer is 25 years and that of transmission line is 35 years. However, in actual practice, the life of these equipment is may be more than this. We are of the opinion that the term of the license should be relatable to life so that normally no major capital investment is required on replacement of the equipment during the license period.* ***Accordingly, we direct that the term of the License should appropriately be 30 years***."
>
> [***Emphasis supplied***]

ii. It is pertinent to state that the transmission licence granted to the Petitioner was for 25 years only on account of the fact that the licence was granted by this Hon'ble Commission to the Petitioner on 13.11.2003 (i.e. after promulgation of the Act) in terms of the Order dated 22.10.2003. The term of 25 years is in accordance to Section 15(8) which prescribes that '*a licence shall continue to be in force for a period of twenty-five years unless such licence is revoked.*'.

iii. Further, the above understanding has been recorded by this Hon'ble

Commission in the Explanatory Memorandum to CERC (Procedure, Terms and Conditions for grant of Transmission Licence and other related matters) (Amendment) Regulations, 2010 wherein it was, *inter alia*, observed that:

> "*The Central Commission while considering the applications by various project developers for grant of transmission licence have observed that while the useful life of the transmission asset is normally considered as 35 years, transmission licences are issued for a period of 25 years under the provisions of Section 15 (8) of the Electricity Act, 2003 (the* Act)..."

(c) From the above, following emerges for consideration of this Hon'ble Commission:

i. The useful life of a transmission line under the Tariff Regulations, 2001 was 35 years instead of 25 years; and

ii. The term of licence granted to the Petitioner for 25 years was not on account of the useful life being 25 years rather it was in accordance to Section 15(8) of the Act.

1.20 In light of the foregoing submissions, it is evident that even this Hon'ble Commission while framing the above regulations has appreciated the benefit granted *vide* Regulation 4.10A of the Tariff Regulations, 2001. However, while considering the useful life for determining the period for which TMF can be availed, this Hon'ble Commission inadvertently considered useful life as 25 years instead of 35 years as provided under the Appendix II of the Tariff Regulations, 2001.

1.21 Accordingly, the following submissions may kindly be considered and according clarification may kindly be provided that TMF for Powerlinks had been granted for entire life of the project:

(a) The Petitioner was granted the benefit of TMF in terms of Regulation 4.l0A notified on 21.09.2001 which was preceded by the Hon'ble Commission's Order dated 29.05.2001 in Petition No. 23/2001.

(b) The applicability of the above TMF has been upheld by this Hon'ble Commission in its Order dated 01.07.2004 in Petition No. 51/2004. This Hon'ble Commission recognised that the Petitioner's entitlement to TMF is a vested right which has been granted under Tariff Regulations, 2001 and it ought not be revoked. In this regard, the Hon'ble Commission delved deep into the meaning of vested right to decide the above matter by relying upon the following:

i. The term "vested right" is defined in Black's Law Dictionary (7th Edition) at page1324 as:

> *"A right that so completely and definitely belongs to a person that it cannot be impaired or taken away without the person's consent."*

ii. Further, the term "vested" (adj.) is defined in Black's Law Dictionary (7th Edition) at page 1557 as:

> *"That has become a completed, consummated right for the present or future enjoyment; not contingent; unconditional; absolute. A co-joint reading of the above reveals that a vested right is a right independent of any contingency and it cannot be taken away without consent of the person concerned."*

iii. The word "vest" is normally used where an immediate fixed right in present or future enjoyment in respect of a property is created. With the long usage the said word "vest" has also acquired a meaning as "an absolute or indefeasible right" ref. *Howrah Municipal Corpn.* v. *Ganges Rope Co. Ltd.*, (2004) 1 SCC 663.

(c) In view thereof, TMF was being allowed to the Petitioner in subsequent tariff periods also. However, the difficulty arose when this Hon'ble Commission instead of allowing the TMF for the entire useful life of the Project i.e. 35 years, restricted the same to 25 years for the period of licence.

(d) The above restriction to 25 years was done on the basis that Tariff Regulations, 2001 prescribes useful life for Petitioner's Project as 25 years. Whereas, as demonstrated herein above, the useful life under Tariff Regulations, 2001 is 35 years. Further, it was incorrectly inferred that license was granted for 25 years on the basis of life being 25 years.

(e) The clarification becomes all the more necessary after notification of the Electricity (Amendment) Rules, 2005, which make the license renewal automatic after 25 years.

(f) Therefore, the above difficulty may be appreciated by this Hon'ble Commission as otherwise the entire purpose of TMF granted to the Petitioner under Tariff Regulations, 2001 would be rendered otiose.

1.22 It is submitted that in case, the instant submission is not allowed then grave prejudice would be caused to Powerlinks which will have a direct bearing on the viability and feasibility of the Project.