MAHAVITARAN
Maharashtra State Electricity Distribution Co. Ltd.
(A Govt. Of Maharashtra undertaking)
CIN : U40109MH2005SGC153645

स्वातंत्र्याचा अमृत महोत्सव

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Ref. No: MSEDCL/CE/PP/ No 2 2 8 4 8 Date: 28 JUL 2023

To,
The Secretary,
Central Electricity Regulatory Commission,
3rd & 4th Floor, Chandralok Building,
36, Janpath, New Delhi – 110 001.

Subject: Comments on Approach Paper on Terms and Conditions of the Tariff Regulations for tariff period 1.04.2024 to 31.03.2029.

Reference:
1) CERC's letter L-1/268/2022/CERC dated 26.05.2023
2) CERC's letter L-1/268/2022/CERC dated 3.07.2023
3) CERC's letter L-1/268/2022/CERC dated 13.07.2023

Dear Sir,

Central Electricity Regulatory Commission vide letters under reference has sought the comments of the Stakeholders on the Approach Paper on Terms and Conditions of the Tariff Regulations for tariff period 1.04.2024 to 31.03.2029. MSEDCL welcomes CERC's steps with positive gestures for publishing approach paper and involving DISCOMs with other stakeholders.

The suggestions are sought as to how the present system of hybrid mechanisms of tariff determination 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. Accordingly, two possible options have been proposed.

It is to submit that Approach 2 may be preferred over Approach 1 as benefit of the prudence check will be missed and generating/ transmission companies even if have ability to keep actual parameters better than normative, may not opt for it as normative mechanism does not provide motivation to generators/ transmission companies to perform better. Further, if the actual cost is less than normative, actual cost shall always be taken into account while determination of tariff.

Furthermore, some restrictions are necessary to be imposed on generators and transmission licensees so that the asset is developed with optimised cost. Any extra cost above normative shall be borne by the generating company or the transmission licensee and an additional penalty on account of exceeding normative cost may be imposed.

One of the prime objective of the Electricity Act -2003, Sec.73 (a), National Electricity Policy and Tariff Policy, is to ensure availability of the electricity to the consumers at reasonable and competitive rate. Thus, MSEDCL submits that while formulating/simplifying any regulation, care needs to be taken to avoid any undue burden on end consumers while incentivizing generating/transmission companies.

The detailed comments are enclosed herewith as **Annexure-A.** It is kindly requested to consider our views before finalization of the draft proposal.

Thanking you,

Yours faithfully,

Encl:A/A

Chief Engineer (Power Purchase)

Copy s.w.rs. to:
The Director (Commercial), MSEDCL, Prakashgad, Mumbai – 51.

Annexure - A

MSEDCL Comments on CERC Approach Paper on Tariff Regulations

	Proposed Clause	MSEDCL Comments
2.4	*Key aspects have been considered while preparing this Approach Paper* *1) Attracting fresh Investments to meet the growing demand.* *2) Preserving and augmenting existing capacities – Incentivising life extension, R&M, and efficient old generating stations.* *3) Providing the necessary push so that the same encourages private investments through Assured Returns, Mitigation of Risk Perception and Regulatory Certainty.* *4) De-risking construction - Removal of current Bottlenecks faced during project execution, especially for Hydro Stations.* *5) Incentivising efficient plant operations and sustainable development.*	It is submitted that one of the key aspects that has been considered by CERC in this Approach Paper is to provide 24x7 power supply at affordable rates to end consumers, which is also the intension of the Electricity Act. Currently due to various factors, such as increase in demand, shortfall of coal etc., the power purchase cost to Distribution Licensees have become exorbitantly high. Hence, an attempt through this approach paper needs to be made to bring down the power purchase cost of Distribution Licensee so that end consumers can get the benefit of it.
2.5	*However, it is imperative that the focus be on efficient plant operations; and norms for old as well as new generating stations, need to be evaluated.* *The objective of moving towards sustainable generation mix can be achieved by incentivising generation with a lower carbon footprint, such as hydro generating stations, while also incentivising efficient operations of thermal generating stations including gas-based power plants*	It is submitted that gas based stations are currently not operational/scheduled due to its high cost of fuel and are resulting in negligible PLFs. Further, it is submitted that since the gas stations are also included in the scheme developed by MoP for pooling of stations, it is affecting the overall polling cost of all stations. Going ahead, it seems difficult for gas prices to drop drastically, at least for the next Control Period. Keeping these factors in mind, the focus for incentivising the power stations can be more on Hydro Stations than gas generating stations.

		Due to high fuel cost, there is very less that can be done for these stations to operate. Further, gas stations are being used for Ancillary services and therefore the gas stations are getting the desired benefits even though they are not available at all times. Hence, there is no need to incentivise gas stations by any means as it will only give additional burden to end consumers.
2.8	*The generating stations that cannot be operated economically or the generating stations that cannot comply with environmental norms have no other option but to decommission. It is to be noted that during the period 2017-22 around 10.048 GW of thermal capacity has already been decommissioned.* *However, the generating companies in the past have argued that most of the old generating stations have been well maintained and are operating efficiently, so supporting provisions such as the current dispensation under special allowance may be continued*	It is submitted that a benchmark can be decided based on certain operational parameters to ascertain which power stations can be termed as efficient and which can be termed as inefficient. It is observed that not all plants that have completed their useful life are running efficiently. For such plants, history can be studied whether R&M activities are carried out in the past or not. If R&M has been done before, how effective have been the R&M work and to what extent it has been proved to be fruitful. Based on this analysis of individual plants, a decision can be taken to continue running the plant or decommission the same.
2.10	*Further, it can be argued that increasing variability in demand requires more flexibility in generation with frequent ramp up and ramp down requirements, which may lead to degradation of operational norms, and therefore such an impact needs to be considered while determining the norms.* *It is therefore important that appropriate mechanisms be provided so that not only the norms can be made more efficient, but the generating companies are also incentivised to generate economically without compromising on regulatory certainty.*	It is submitted that the sole purpose of the Approach Paper shall not be to incentivise the generating companies so that they run efficiently. It shall also focus on penalty mechanism for generators so that they can be penalised as and when performance parameters are not met. A penalty mechanism can be devised with more stringent penalty to newer plants and less stringent penalty to older plants in the Regulations so that generating companies are kept on their toes to perform and operate as per the given norms.

		It is submitted that the focus shall be more on improving PLFs and generation from the existing and upcoming capacity to meet the overall demand of the Country. Also for those plants whose PLFs are already on higher side, normative PLFs may be increased to a higher level depending on the historical trend observed so that generators are encouraged to achieve even higher PLFs.
2.11	*It is also observed that due to the increasing number of assets whose tariff needs to be determined under the Regulated Tariff Mechanism (RTM), the tariff determination process has become complex and cumbersome.* *Further, considering the future growth that is required to sustain the economy, the tariff determination process is required to be simplified and aligned with future requirements. Therefore, simplification of the tariff determination process is the core idea that shall drive the terms and conditions of tariff determination for the period FY 2024-25 to FY 2028-29.*	It is a welcome move to simplify the Tariff mechanism in the next Control Period, however focus is also needed on the fact that Discoms should not be burdened in the process.
2.11	*Simplification of the process has been envisaged for the following key activities that, over time, have become complex and time consuming.* *1. Exploring the option for determination of tariff on a normative basis.* *2. Modifying the existing approach to allow more parameters on a normative basis.*	It is submitted that though the intension is to move towards a simpler mechanism, it shall not lead to compromise in cost/tariff for the beneficiary.
3.1	*In view of the above, 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*	It is submitted that Approach 2 may be preferred over Approach 1. Though moving towards normative is a passable move, shifting all the cost on normative basis will not be a healthy

	options could be as follows. *1. Approach 1: Shift to a normative tariff, wherein, once capital costs are approved on an actual basis after prudence check, all other AFC components are determined on normative basis.* *2. Approach 2: Further simplification of the existing Performance Based Hybrid Approach, wherein on the basis of admitted capital cost, AFC components can be approved based on actuals or norms as may be specified for the control period. Further, additional capitalisation may be allowed on certain counts on a normative basis*	move for the power sector. Benefit of the prudence check will be missed and generating/transmission companies even if have ability to keep actual parameters better than normative, may not opt for it as normative mechanism does not provide motivation to generators/transmission companies to perform better. Hence, normative parameters shall be made stringent. It is submitted that if the actual cost is less than normative, such actual cost shall always be taken into account while determination of tariff. However, if Hon. Commission feels it appropriate to adopt option1, then following points needs to be considered. It is submitted that the capital cost for generation and transmission assets needs to be approved based on the normative or actual cost whichever is lower. It is observed that since the enactment of the Act, generators and transmission licensees have gained enough experience in development of assets and therefore some restrictions are necessary to be imposed on generators and transmission licensees so that the asset is developed with optimised cost. It is therefore essential that only the cost which is lower (actual or normative) needs to be passed to Discoms/consumers for overall benefit of the Sector. Further, it is submitted that if the capital cost is on higher side than normative, then in addition to considering the normative value of the capital cost, a penalty may be

		imposed on the generating company or the transmission licensee for incurring higher cost than normative. This penalty shall be given as a rebate to Discoms/consumers while deciding the tariff. Under no circumstances the generating company or the transmission licensee shall exceed the normative expenses. Any extra cost above normative shall be borne by the generating company or the transmission licensee and an additional penalty on account of exceeding normative cost may be passed as benefit to Discom/consumers. Generating company or the Transmission licensee always has the option of funding this increase in cost above normative through its RoE. It is further submitted that True-up is an essential activity to check whether the generating company or the transmission licensee has actually incurred the cost or not and to verify whether the expenditure towards the capital cost was done in a prudent manner or not. As discussed earlier, lower of the normative and actual needs to be considered to determine the actual True-up and needs to be continued in the upcoming Tariff Regulations also. Any benefit which is on account of actual lower cost incurred by generating company or the transmission licensee needs to be passed on to the Discoms/consumers. Therefore, True-up shall be continued to be done for all the years of the Control Period. True-up of

		expenses will also give an idea on the estimation/ projections/ escalations that needs to be considered by the Hon. Commission for future years. Hence True-up of a particular asset may not be done only for initial 5 years but may be continued till the de-commissioning of the asset. Also it is submitted that based on the True-up of every year the escalation factor for O&M expenses and other than O&M expenses needs to be reviewed for the Control Period and then accordingly may be decided by the Hon. Commission. This would enable Discom/consumers to get the benefit of reduction in material cost/labour/inflation/other economic factors and tariff may be adjusted accordingly rather than ascertaining the tariff on normative basis. In addition to this variable cost (fuel and other supporting cost) may also be Trued-up at the end of the Control Period. Since fuel cost is one of the largest component in Discoms tariff, it becomes very essential to verify the fuel cost and ascertain if the fuel cost claimed is actually incurred or not mainly through audited statement or by verification through third parties. Therefore, variable cost shall also be part of the True-up exercise which needs to be taken up by the Hon'ble Commission. The existing Regulation has provision for submitting station wise audited accounts along with the Tariff Petition which needs to be continued and strictly followed in the new Regulation to maintain better transparency.

3.2	*1. Post COD, there are some variations in the components of AFC mostly due to the impact of additional capitalisation pertaining to balance capital works post COD, commissioning of subsequent units. From the past data, it is observed that major works are incurred primarily in the first 4-5 years, and therefore there is some aberration in AFC in the first 5 years post COD* *2. The near parallel trend lines for various generating stations suggest that though the behaviour of AFC components is similar, the quantum differs owing to different costs of funds, funding patterns, depreciation rates and other plant specific peculiarities*	It is submitted that similar to capital cost, AFC components shall be decided on normative parameters after taking into account additional capitalisation post COD. Additional capitalisation to be allowed shall also be based on certain parameters and the number of times it shall be allowed needs to be restricted. Further, any deviation on account of uncontrollable parameters may be allowed as an adjustment in tariff in the subsequent year. This can be made similar to FAC mechanism that is carried out for energy charge adjustment.
3.2	*From the past data, it is observed that there are variations in some of the cost determinants, and if a normative regime is to be adopted, the impact on account of the following factors needs to be duly accounted for from time to time so that the AFC components can be fine-tuned to incorporate the impact of additional capitalisation and changes in market dynamics.* *1. Weighted average rate of Interest* *2. Interest on Working Capital* *3. Additional Capitalisation*	It is submitted that interest rate can be kept as a variable parameter and tariff can be adjusted every year based on the revision in interest rates in the Country. In case the interest rate in normative tariff is decided to be linked to MCLR then the variation in MCLR every year can be allowed in tariff of generating company/transmission asset. The adjustment can be both ways, positive or negative. In case of additional capitalisation, CERC to come up with a norm stating under what conditions additional capitalisation can be allowed and these conditions may not be relaxed under any circumstances. Further, it is observed that generating Companies claim additional capitalisation several times in the useful life of the plant and the benefit of this additional capitalisation needs to be confirmed. the number of times additional capitalisation that can be allowed to a particular generating company/ transmission asset can be

		fixed by CERC and accordingly any additional capitalisation beyond this may be disallowed
3.2	*In order to achieve the dual objectives as flagged above, for existing generating stations and transmission systems whose cut-off date shall be over by 31.03.2024, the gross fixed assets as approved as on 31.03.2024 may be considered for projecting base year AFC i.e., for the first year of the Control Period (FY 2024-25). Subsequently, fixed charges for future years may be approved on the basis of indexation that may be specified for each generating station/ transmission system by the Commission from time to time* *In the case of new generating stations and transmission systems, as observed earlier, there is variation in the first 4-5 years causing aberrations, therefore, it is proposed that once the capital cost is approved on an actual basis as on cut-off date (5 years post CoD) after carrying out detailed scrutiny, all components of fixed charges may be determined on a normative basis from the sixth financial year (Base Year)* *Further, with regard to Energy Charges, for both new and existing generating stations the same may be approved based on actual fuel cost and normative performance parameters as currently allowed*	It is submitted that benchmark cost can be decided for existing and new/upcoming generating companies. Accordingly, AFC can be ascertained based on normative parameters. In case of upcoming plant, the benchmark cost can be determined after taking into account the additional capitalisation required. Further, it is to submit that the cut-off date may be continued as thirty-six months from the date of commercial operation of the project as envisaged in existing Regulations.
3.2	*1. Existing projects* *a) For existing generating stations/transmission systems that have been in operation for more than five years as on 31.03.2024, the capital cost as on 01.04.2024 is proposed to be considered for the determination of the tariff for FY 2024-25. Based on the norms to be specified in the CERC Tariff Regulations 2024, Annual Fixed Charges (AFC) for the first year of the next tariff period, i.e., FY 2024-25 are proposed to be determined. The AFC components for the base year*	It is a welcome move to restrict the AFC parameters to only two components. 1) AFC excluding O&M expenses 2) O&M expenses It is further submitted that the indexation that is to be approved for both the above parameters shall be on the basis of true-up activity that is proposed to be conducted for the

	(FY 2024-25) can be determined individually and then clubbed under the following two categories. *1) AFC excluding O&M expenses* *2) O&M expenses* *Once the above two major components of AFC are determined for FY 2024-25 (Base Year), the above two components for the rest of the years of the tariff period shall be determined for the project based on specified indexation.* *b) The indexation specified can be with regard to the previous year, i.e., AFC component as computed for the N th year/AFC component as computed for the N-1 th year.* *c) Post expiry of each tariff period, the Commission shall call upon relevant data (on weighted average rate of interest and Interest on Working Capital, Working Capital) and revise only the indexation factor pertaining to "AFC excluding O&M component" approved at the time of tariff determination for each Project for each year. There shall be no revision to the indexation with regard to O&M expenses pertaining to the past tariff period.* *d) Through the same exercise, the Commission can also specify the indexation factor, for the above two categories for the next tariff period (2029-2034).* *e) The Commission may issue a combined Order specifying the station wise revised indexation factor and based on the revised indexation of the past tariff period, generating station or transmission licensees can refund/recover the differential amount as done presently.* *f) Further, in case any additional capitalisation is incurred or is required, the petitioner may file a separate petition seeking approval of capital expenditure, and once such capital expenditure is allowed,*	Control Period. Further, the truing-up of both the components of AFC should be on basis of actual relevant data only in line with existing practice. Indexation can also be linked to the benchmark index approved by competent authorities

	the variation on account of additional capitalisation on the AFC can be serviced by first computing the impact on the AFC and then adjusting the same through the same indexation mechanism as specified above. Such an adjustment can be carried out from the date of capitalisation of such additional capitalisation. The various possible options of allowing additional capitalisation post COD have been discussed in detail in Section 4 of this Approach Paper. *g) For future tariff periods, the AFC of the existing projects, including servicing of additional capitalisation shall continue to be governed as per the CERC Tariff Regulations, 2024.* *h) Energy Charges are already allowed based on normative performance parameters and actual fuel costs and are proposed to be continued.*	
3.2	*2. New projects (COD on or after 01.04.2024 or projects that are yet to complete operations for 5 years as on 01.04.2024)* *a) The capital cost can be approved on actual basis up to cut-off date. Further, additional capitalisation post cut-off date can be allowed on normative basis and has been discussed in detail in Section 4 of this Approach Paper.* *b) The tariff components of AFC shall be determined and trued up on actual basis till the financial year in which the cut-off date of such generating stations ends. The AFC for each station can be determined under the following two categories for the first financial year post cut-off date. 1. AFC excluding O&M expenses 2. O&M expenses c) Thereafter, from 6th financial year onwards, the above AFC categories can be determined based on indexation mechanism as proposed for the existing projects.* *d) The current practice of approving Energy Charges can continue in*	The clustering the components of AFC based on their nature to increase/ decrease is a welcoming move however, indexation mechanism should be purely on basis of actual data after prudent check by Hon. Commission. Further, the impact of additional capitalisation should be allowed through a separate revenue stream as being carried out presently.

	the case of generating stations *In this context, comments/ observations from stakeholders are invited on the following* *points:* *1) 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?* *2) What other methodology can be adopted to determine the increasing/ decreasing factors?* *3) Whether the impact of additional capitalisation can also be allowed through the same indexation mechanism or through a separate revenue stream?*	
3.3.1	*Generation Tariff* *In the case of generating stations, although O&M expenses, Depreciation, Return on Equity are specified on a normative basis, the following components, as per the present Regulations require consideration of actual values.* *1. Energy Charge – Fuel cost and GCV to be considered.* *2. Working Capital – Actual fuel costs keep varying and affect total receivables.* *3. Interest rate on loans and interest rate on Working Capital* *With regard to Energy Charge, it is observed that the Commission has already specified an adjustment mechanism wherein Energy charges are claimed on an actual basis, however, the possibility of specifying working capital requirements on a normative basis which can factor in the variations due to actual fuel prices and interest rates to be considered for computing interest on working capital on a normative basis, needs to be explored.*	It is submitted that Working Capital requirement can be continued with the existing provisions of the CERC Regulations as the same is derived after detailed deliberations and stakeholder consultations. Similarly, Interest on working capital shall be linked to the variation in interest rates prevailing in the market.

3.3.1	*Transmission Tariff* *As per the current Tariff Regulations governing the determination of transmission charges, the following components of the tariff are already allowed on a normative basis:* *1. O&M expenses* *2. Depreciation* *3. Return on Equity* *4. Working Capital requirement and interest thereon* *The Regulation at present only allows interest on normative loan capital at the actual weighted average rate of interest. It is to be analysed whether this interest rate can also be fixed with linkage to the reference rate.*	It is submitted that the normative interest rate shall not be linked to the weighted average interest rate of the generating/transmission company. It is submitted that the interest rate at which funds are made available to the generator/licensee for asset creation is based on the financial performance of the company. A debt ridden company may acquire funds at a high interest rate and therefore if the interest rate is linked to the actual weighted average rate of interest, the burden on high interest rates gets passed on to the consumers/DL. It is submitted that the inefficiency of the generator/licensee shall not be passed on in tariff and therefore the interest rate shall be linked to market indices and not weighted average rate of individual companies.
4.2.1	*The approval of capital costs is one of the most important aspects of the tariff determination process, as almost the entire fixed charge throughout the life cycle of the project depends upon it. In the process of tariff determination, the Commission has been approving the capital cost of the projects on a case- to- case basis, which is dependent on the actual expenses incurred, duly certified by the auditors, and after carrying out due prudence on the reasonability of the expenses incurred. The CERC Tariff Regulations, 2009, introduced an enabling provision that allows utilities to seek approval of the capital cost of new projects on an anticipated basis, which helps utilities minimise the time gap between the commissioning of the project and the generation of cash flows by means of tariff.*	As discussed earlier, determination of capital cost may be done on case to case basis, on the basis of their actual cost. CERC to come up with a benchmark cost for determination of capital cost along with a sharing mechanism. Further, any uncontrollable factor can be adjusted in the capital cost provided it falls in the purview of the Regulations and is prudent.

	The provision 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	
4.2.2	*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*	All works under regulated tariff mechanism shall be mandated to be awarded under competitive bidding. Also any delay on account of achieving COD shall be on account of the developer and may not be passed on the beneficiary.
4.2.3	*For a thermal generating station, it is observed that there are several differences with regard to site conditions, water handling, coal handling systems, etc., and one benchmarked cost may not be a true representation of all such plants on the basis of which actual costs can be disallowed. These issues are even more profound in the case of hydro generating stations, as the costs significantly depend on several aspects such as choice of technology, design, reservoir based/Pondage/ROR, etc.* *With regards to transmission systems, the cost is affected by tower design, terrain, soil type, and wind zones, and therefore it is generally argued that benchmarking will serve a limited purpose and may not be a better alternative to current project specific Investment Approvals.* *Comments and suggestions of stakeholders are invited on other efficient reference costs other than Investment Approval costs that can be considered for prudence checks.*	It is therefore suggested that benchmark cost may be different for various conditions taking into account all the factors as mentioned herein. More variations are observed in hydro stations hence multiple benchmark cost can be determined for Hydro. In case of transmission, the benchmark cost can be determined based on the demographics at which the asset is set up.
4.2.4	*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*	It is submitted that any legitimate expense that needs to be allowed can be passed as an adjustment in capital cost/tariff provided the same is acceptable under the Regulations

	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" *Comments and suggestions are further sought from stakeholders on ways to expedite the development of hydro generating stations especially the construction phase, and increase their commercial acceptability*	It is observed that Hydro generating stations are commissioned with a delay of almost 5-10 years from the SCOD due to various obstacles. Due to this delay the overall actual cost of hydro stations is exorbitantly high as compared to the cost envisaged at the time of DPR/approval stage. It is therefore submitted that some incentives need to be introduced for early completion of hydro projects so that developers will take extra efforts for getting the additional incentive. Further, a timeline of such delay should also be defined beyond which the developers should be penalized. It is submitted that Govt. has issued HPO for promoting large hydro stations as the effective cost would be beneficial than thermal generators. However, if projects are coming up with such delays, then the target HPO would not be met forcing DISCOMs to buy additional Hydro power to meet its HPO obligation or to buy corresponding amount of Hydro Energy Certificate to meet the non-solar hydro renewable purchase obligations. Therefore, it is necessary to introduce incentives as well as penalties to all upcoming Hydro stations.
4.2.4	*1. Ways to expedite the construction phase by adopting alternate ways of awarding construction contracts.* *2. Contract to execute the project to be awarded only when all the required clearances and permits are available as on zero date.*	It is submitted that, the generators shall get the desired incentive if he is able to complete the project in time and save cost as compared to the benchmark cost. The generator may be allowed to keep 50% of the benefit with him for

	3. Creation of Special Purpose Vehicle (SPV) for obtaining all mandatory approvals *4. Focus on quality and the implementation schedule.* *5. Higher return on investments/equity for projects completed in a timely manner.* *6. Higher return for dam/reservoir based projects and Pumped Storage Projects.* *7. Levelized Tariff based one-time determination of tariff to remain uniform for useful life.* *8. Escalable tariff adjusted for year-on-year inflation.* *9. Possibility to further increase the useful life.* *10. Consideration of expenses towards Local Development/ infrastructure for public outreach for better project acceptability as pass through in capital cost or one time reimbursement.* *Comments and suggestions are sought from stakeholders to incentivise the developer if it executes the project faster/ or ahead of schedule and vice-versa if it delays.*	taking such initiative and completing the project before time. Further, a timeline of such delay should also be defined beyond which the developers should be penalized.
4.3	*Comments and suggestions are sought from stakeholders on the following issues:* *1. Historical Cost or Acquisition Value whichever is lower should be considered for the determination of tariff post approval of Resolution Plan.* *2. 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.*	It is submitted that the historical cost or acquisition cost whichever is lower may be considered for tariff determination process. It is submitted that since the asset is under NCLT, the benefit of being stressed assets needs to be accounted for in tariff.
4.4.1	*In view of the above, it has been argued that the provision can be modified so as to allow proportionate IDC upto SCOD or upto the date of delay condoned on the basis of total IDC worked out till actual*	It is submitted that IDC in case of delay needs to be restricted even when the delay is condoned by the Hon'ble Commission.

	COD *Comments and suggestions are sought from stakeholders on the following options for allowing IDC:* *1. Existing mechanism wherein the pro-rata deduction (based on delay not condoned) is done on IDC beyond SCOD.* *2. Pro-rata IDC may be allowed considering the total implementation period wherein the actual IDC till implementation of the project is pro-rated considering the period upto SCOD and period of delay condoned over total implementation period.* *3. IDC approved in the original Investment Approval to be considered while allowing actual IDC in case of delay* *Illustration: Consider an asset that was supposed to be implemented in 36 months but suffers a delay of 12 months. Further, suppose IDC up to SCOD is Rs. X and IDC beyond SCOD till actual COD is Rs. Y, and the Commission has condoned a delay of 4 months then the IDC allowable under the above two scenarios (mentioned at Sr. No. 1 & 2) shall be as follows.* *Under Option 1 above the allowable IDC shall be Rs. X + [Y*(4/12)], i.e., only IDC pertaining to delay is pro-rated.* *Whereas,* *Under Option 2 the allowable IDC shall be Rs. (X+Y)*[(36+4)/48] wherein the total IDC is pro-rated based on the SCOD and delay condoned vis-à-vis the actual implementation period of 48 months.*	The proportion in which the IDC is to be disallowed needs to be decided based on the time period of condonation which may be allowed by the Hon'ble Commission. The IDC may be disallowed in the following manner 1. Delay of up to 6 months - 50% of IDC for delay period may be disallowed 2. Delay of 6 months to 12 months - 75% of IDC for delay period may be disallowed 3. Delay of above 12 months – 100% of IDC for delay period may be disallowed Further, it is submitted that commissioning of any asset which is before SCOD may be incentivised and commissioning of asset which is after SCOD even after condonation of delay needs to be penalised Further, price variation after SCOD needs to be restricted and accordingly, IDC may be reduced to that extent It is further submitted that delay after SCOD may be compensated through the LD clause in the EPC contract and not by recovery from beneficiaries/consumers.
4.4.2	*In addition to above, it is further observed that in the CERC Tariff Regulations, 2019, difficulties have been faced in ascertaining the amount of liquidated damages (LD) to be retained by the generating stations and transmission licensees from the additional capitalisation*	It is submitted that the amount of LD that is received by the generating company/transmission licensee from their vendors due to delay in execution of the work, shall be adjusted in Tariff.. The delay effectively affects the beneficiary/Discom,

	claim made subsequently as the amount of LD is being adjusted by these utilities from the balance payable and payment is made on net basis to such vendors. In the absence of such clarity in the tariff forms without being supported with auditor certificate there may be chances of double deduction, i.e., first in the form of deduction in IDC and then LD which was supposed to be retained by the utilities which gets adjusted in additional capitalisation. In such cases, utilities are required to declare such adjustments upfront to avoid any double accounting. In order to address this issue, it is proposed that the additional capitalisation forms need to be tweaked so that such information is submitted along with the tariff petition. In view of the above, comments and suggestions are sought from stakeholders on necessary changes in tariff forms and regulations, if any, to provide further clarity on the adjustment of LD	as the beneficiary/Discom is not able to get the benefit of the asset in the given time. Hence this LD amount shall be passed on to the beneficiary/Discom as a compensation for not delivering the asset in time.
4.5	*Therefore, for allowing price variation, the utilities may be mandated to submit the statutory auditor certificate along with the petition duly certifying the price variation corresponding to delay and the same may be allowed on pro-rata basis corresponding to the delay condoned. Further, a separate form may also be specified to submit the relevant information pertaining to price variation*	It is submitted that price variation needs to be assessed by CERC that who would be responsible for the variation in price and accordingly recovery shall be made from the responsible person. If price variation is due to the errorneous decisions of the generating company/transmission licensee, then they should bear the differential amount, rather than allowing it to recover from the beneficiary/discom. If the price variation is due to vendor's inefficiency the price variation shall be recovered from the vendor and to that extent LD shall be increased. In case the price variation is beyond everyone's control, then only after prudence check, it may be passed on to the beneficiary
4.6	*In view of the inherent benefits of undertaking R&M as against going for fresh capital investment, the current provisions may be continued.*	It is submitted that competent authority needs to conduct a study of the R&M activities that have carried out by

	Further, utilities that opt for a special allowance for the first year of the tariff period shall have to continue with the same for the rest of the tariff period. Comments and suggestions are sought from stakeholders on continuation of the existing provisions and on the above suggestion of continuing with Special Allowance, if opted at the beginning of the tariff period for the rest of the tariff period.	generators in the past and the benefits derived from them. Through this study CERC may ascertain that whether R&M activities really help in boosting the operational performance of the stations. It is therefore necessary for CERC to come up with a study to continue supporting R&M activities in the new Regulations. Further, the proposal of R&M activities that are proposed to be taken up by the generators needs to be vetted by CEA. It is further submitted that in addition to the above due diligence, Cost Benefit Analysis needs to be also taken into account before deciding for going for R&M activities with respect to the cost which would be incurred. In case the overall tariff after R&M activities is turning out to be more costly than the cost of alternate sources of available power, Hon. Commission may disallow the R&M proposal of the generator. Hence, Hon. Commission may take up the proposal of R&M independently and decide on the same on case to case basis.
4.7	*In view of the above, a single norm can be considered for each of the following classes of transmission assets:* *1. Transmission Lines, including HVDC lines* *2. Substations (including HVDC S/s)* *3. Dynamic Reactive Compensation devices* *4. Communication Systems* *5. Underground cable*	Separate norms can be determined for each of the assets specified. Further, the norm can be different for different voltage levels and the type of terrain in which the asset is planned to put up.

	Comments and suggestions are sought from stakeholders on the above proposed approach and alternative options to standardise and simplify the norms for initial spares	
4.8.1	*In view of the same, delays on account of forest clearances can also be considered for inclusion as uncontrollable factor provided that such delays are not attributable to the generating company or the transmission licensee. Comments and suggestions are sought from stakeholders on continued inclusion of delay on account of land acquisition as an uncontrollable factor and on the further inclusion of delay on account of forest clearances as an uncontrollable factor.*	MSEDCL strongly objects against the consideration of delay in getting forest clearance and land acquisition for all cases as uncontrollable factor Enough forest clearances have been sought from developers in the past and therefore developers are aware of the tentative time which is taken to achieve a forest clearance and such time can be accounted for in the commissioning of the project rather than claiming as an uncontrollable factor. It is submitted that e-governance site and single window clearance system is now being developed for various activities including forest clearance. The aim of these initiatives is to get early clearances than normal time. If Government is taking such initiatives to get faster approval for forest clearance, then there is no point in categorising forest clearance as uncontrollable activity. It is pertinent to state that Govt. has already defined a timeline for processing of forest clearance proposals at different levels. Furthermore, there would be no efforts taken by generation companies/transmission licensees to get faster approval for clearances as delay is being treated as uncontrollable. This

		would result in the project delay and increase in project cost. Hon. Commission may consider delay in forest clearance and land acquisition on case to case basis.
4.9	*In order to encourage rigorous pursuit of such approvals, even if delay beyond SCOD is condoned for any reasons, some part of the cost impact (Say 20%) corresponding to the delay condoned may be disallowed.*	It is submitted even if the delay is condoned, however it may be the case that the delay could have been avoided by the developer then in such case entire 100% of cost increase due to delay shall be disallowed. CERC to decide on the disallowance percentage on case to case basis based on the circumstances faced by the developer and may not fix to only 20%.
4.9	*1. To encourage rigorous pursuit of such approvals from statutory authorities, even if delay beyond SCOD on account of clearances and approvals that are condoned, some part of the cost impact (Say 20%) corresponding to the delay condoned may be disallowed.* *2. Alternatively, RoE corresponding to cost and time overruns allowed over and above project cost as per investment approval may be allowed at the weighted average rate of interest on loans instead of a fixed RoE.* *3. The current mechanism of treating time overrun may be continued, considering that utilities are automatically disincentivised if the project gets delayed*	Even if delay is condoned, Time and Cost overrun shall be made accountable to the developers. The impact of time and cost overrun shall not be allowed in the tariff. It needs to be assessed whether the generators/transmission companies could have avoided such a delay by taking necessary actions in the given time. Further, it is submitted that no RoE shall be allowed on cost overrun on account of delay in commissioning of the project. ROE shall be restricted to the original capital cost only. Further, it is submitted that in case generators/ transmission companies gets RoE on differential cost due to delay, then in that case no efforts will be made by generators/ transmission companies to complete the asset within the stipulated time. All the developers will not take necessary steps for early

		commissioning as there is no pinch to these generators/ transmission companies even if they delay the project.
4.10	*However, there are no enabling provisions under which a generating station can seek approval of costs pertaining to Railway Infrastructure and its augmentation for transportation of coal up to the receiving end of the generating station (excluding any transportation cost and any other appurtenant cost paid to railways) that are not covered under the above provisions that may result in better fuel management, can lead to a reduction in operation costs, or shall have other tangible benefits. Therefore, in order to have an enabling provision under which such additional capitalisation can be allowed with prior approval, a provision may be introduced to existing Regulation 26 to allow such expenses if they are found to be beneficial/essential for continued operations*	Cost benefit analysis for such investment needs to be done and such expenses may be allowed only if they are found to be beneficial/essential for continued operations.
4.10	*However, additional capitalisation under Sr. No. 2 are generally not substantial but recurring in nature, and it has been observed that the same, for one reason or another have been recurring time and again, which is one of the prime reasons for which the entire exercise of tariff determination of hundreds of assets is done twice in the same tariff period. As the entire exercise does not have big impact on tariffs, possible options, if any, need to be explored to eliminate the need for such an elaborate exercise.*	Additional capitalisation may be capped to the number of times such additional capitalisation can be carried out by the generating company
4.10.1	*For generating stations that have already crossed the cut-off date as on 31.03.2024, the additional capitalisation for such generating stations can be considered as per the following.* *1. Thermal Generating Stations – Based on the analysis of actual additional capitalisation incurred by such generating stations in the past (15-20 years) and co-relating such expenses to different unit sizes*	It is submitted that special compensation may be allowed only if the same has proven to be beneficial to beneficiaries. Therefore, a cost benefit analysis shall be carried out for the additional capitalisation incurred by the generator to decide special compensation to be allowed.

	such as 200/210 MW series, 500/660 MW Series and different vintages (5-10, 10-15, 15-20, 20-25 years post COD), a special compensation in the form of yearly allowance may be allowed based on unit sizes and vintage, which shall not be subject to any true up and shall not be required to be capitalised. *2. Hydro Generating Stations – As each hydro generating station is unique owing to various factors, additional capitalisation of such generating stations may not bebenchmarked as can be done for thermal generating stations. However, in the case of a specific hydro generating station, the additional capitalisation is recurring in nature, and hence station wise normative additional capitalisation may be approved in the form of special compensation which shall not be subject to any true up and shall not be required to be capitalised* *3. While determining such special compensation for a thermal or hydro generating station, costs incurred towards works presently covered under Regulation 26 to Regulation 29, wherever applicable, may not be included as these expenses may be allowed separately.* *4. Further, any items that cost below Rs. 20 lakhs that may be in the nature of minor items such as tools and tackles, and those pertaining to Capital Spares may be allowed only as part of O&M expenses and may not be considered as part of additional capitalisation in case of both thermal and hydro generating stations.* *5. Further, discharge of liabilities of works already admitted by the Commission as on 31.03.2024 may be allowed as and when such liability is discharged*	Further, on completion of the activity, true-up shall be done so as to assess how much benefit was actually achieved against the estimated and accordingly adjustment in cost/ tariff shall be passed on to the consumers. Incentive/penalty mechanism may be implemented for such additional capitalisation
4.10.1	*Further, for generating stations whose cut-off date falls in the next tariff block (2024-29), or are expected to achieve COD after 31.03.2024, the following approach can be adopted.*	It is submitted that there needs to be capping of number of years for allowing the additional capitalisation after achievement of CoD. It is submitted that the current capping

	1. By extending the cut-off date from the current 3 years to 5 years, which shall allow time to close contracts and discharge liabilities and eliminate the need to allow additional capitalisation post cut-off date unless in the case of Change in Law and Force Majeure. *2. However, based on past data of similar existing generating stations, if there is a need to allow additional capitalisation that may be legitimately required post cut-off date other than those presently allowed under Regulation 26 to 29, the same may be allowed as special compensation as proposed in the case of existing station that have crossed the cut-off date.* *3. While determining special compensation for a thermal or hydro generating station, costs incurred towards works presently covered under Regulations 26 to 29, wherever applicable, may not be included as these expenses may be allowed separately* *4. Further, any item that costs below Rs. 20 lakhs that is in the nature of minor assets, including Capital Spares below Rs 20 lakh, can be allowed only as part of O&M expenses and may not be considered as part of additional capitalisation in case of both thermal and hydro generating stations. Further, any major capital spares costing above Rs. 20 lakh may form part of the special compensation.* *5. Further, discharge of liabilities of works already admitted by the Commission as on 31.03.2024 may be allowed as and when such liability is discharged.*	of three years may be continued. It is submitted that 3 years' time is sufficient for any generator/transmission licensee to do the additional capitalisation and no relaxation in this regard may be allowed to the generators/transmission licensee. Further, it is submitted that intermittent additional capitalisation may not be allowed and any proposal after the period of three years from the date of CoD may be allowed on case to case basis only. Additional Capitalisation may be only allowed in case the actual expenditure is incurred by the generators/ transmission licensee. The submission of additional capitalisation shall be supported with the audited statements of expenses for verification. Further it is submitted that Cost Benefit Analysis (CBA) needs to be carried out by the Hon. Commission when proposal for additional capitalisation is put up by generators/ transmission licensee. CBA shall be part of the prudence check that will be conducted by the Hon. Commission.
4.10.2	*Therefore, 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*	It is submitted that additional capitalisation may be allowed on case to case basis only after prudence check with cost benefit analysis.
4.11	*Increasing the Investors confidence by ensuring assured returns is*	• It is submitted that the allowing AFC components on

	important, and further considering the recent spikes in power tariffs in power exchanges indicating shortage of power availability, investment in Power sector needs a boost, and therefore the existing GFA approach, being a balanced approach, may be continued. However, comments/ suggestions are invited on alternate approaches, i.e. GFA/ NFA/ Modified GFA approach	Gross GFA needs to be revised to Net GFA. • It is submitted that depreciation allowed to generators reduces the book value of assets and therefore Net GFA is the correct picture of the value of the asset after reducing the accumulated depreciation. Hence the approach may be shifted from Gross GFA to Net GFA. • It is submitted that as the asset nears its salvage value, the interest and Return on Investment needs to show a reducing trend and therefore the Net GFA approach may be adopted in the proposed Regulations.
4.12.1	*O&M norms may be specified under the following two categories.* *1. Employee Expenses* *2. Other O&M Expenses comprise Repair and Maintenance and Administrative and General Expenses* *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.*	It is submitted that O&M may be allowed in the similar manner as it has been allowed in the existing Regulation. It is further submitted that the impact of pay revision may be allowed on the basis of actual and hence only during the True-up the impact of pay revision may be passed on in tariff and no such element shall be allowed while projecting tariff for future years.
4.12.2	*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.*	Norms can be separate for HVDC lines of similar nature..
4.12.3	*In view of the above, comments and suggestions are sought from stakeholders on whether additional O&M expenses can be given for*	MSEDCL welcomes the Commission's move of additional O&M expenses for transmission assets being operated in the

	transmission assets being operated in the North Eastern and Hilly Regions and the manner in which such additional costs can be considered.	North Eastern and Hilly Regions.
4.12.4	*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 and suggestion are sought from stakeholders on the above suggested approach and alternatives, if any, to streamline the approval process for spares*	Capital spares can be allowed on normative basis based on standard quantum of spares that are required by any generating unit. The norms can be separate for different size of the unit and fuel used by the unit for generation.
4.12.5	*Comments and suggestions are therefore sought from stakeholders on whether to include any provisions with regard to allowing impact of a change in law on O&M expenses*	It is submitted that O&M is a regular wear and tear activity and is driven by inflation. Hence there is no need to include 'Change in Law' component on O&M expenses.
4.13	*In view of the above, a depreciation rate may be specified considering a loan tenure of 15 years instead of the current practice of 12 years. Further, additional provisions may also be specified that allow lower rate of depreciation to be charged by the generator in the initial years if mutually agreed upon with the beneficiary(ies).* *Comments and suggestions are therefore sought from stakeholders on the above proposal and any modifications required, if any*	It is observed that useful life of unit/transmission asset is way beyond 25 years. Usually thermal unit has a useful life of 30 to 35 years after which its performance starts deteriorating. Similarly, for hydro stations the life is beyond 40 years. In view of above, it is submitted that the useful life can be revised to 30 years for thermal generating units, 40 years for transmission assets and 50 years for hydro/PSS stations. Hence, the depreciation and repayment of loan can be increased to 15 years instead of 12 years so that the front

		loading of tariff can be reduced. It is further submitted that the lower rate of depreciation in initial years shall not allowed.
4.14.1	*To simplify the approval of interest on loans, the weighted average actual rate of interest of the generating company or transmission licensee may be considered instead of project specific interest on loans. Further, the cost of hedging related to foreign loans be allowed on an actual basis, without allowing any actual FERV* *Comments and suggestions are sought from stakeholders on the above suggestions and alternatives, including in respect of treatment of FERV/cost of hedging*	• It is submitted that present practice of considering project specific interest on loans to be continued. • It is submitted that overall company specific approval will lead to extra benefit to some developers and injustice for some developers. • It is further submitted that normative value for interest on loans may be determined and actual interest on loans to be capped as per such normative value. • Incentives may be allowed if interest on loans is found to be lower than the normative value. • It is submitted that the cost of hedging may be allowed on actual basis without allowing actual FERV. • However, if there is a benefit which is arising out of the Foreign Exchange Rate variation then the same may be passed on to the beneficiary. • Further, it is submitted that with respect to interest on loans, any benefit due to refinancing activity carried out by the generating company or transmission licensee shall be entirely passed on to the beneficiary. In the current Regulation the benefit is shared in 50:50. Instead of sharing the benefit the benefit may be entirely adjusted in tariff of Discoms.

4.15	*RoE v/s RoCE Approach* *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 and suggestions are, however, sought from stakeholders on the continuation of the RoE approach*	It is submitted that RoE approach may be continued as the same provides clarity to investors on the returns of its investments
4.16.4	*1. 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.* *2. Whether the revised rate of RoE to be made applicable to only new projects or to both existing and new projects?* *3. Whether timely completion of hydro generating stations can be incentivised to attract investments?* *4. Merit behind approving different Rate of RoE to thermal, hydro generation and transmission projects with further incentives for dam/reservoir based projects including PSP.* *5. Merit in allowing RoE by linking the rate of return with market interest rates such as G-SEC rates/MCLR/RBI Base Rate.*	RoE on account of additional capitalisation due to Change in Law and Force Majeure shall not be allowed. It is submitted that the revised rate of RoE shall be applicable to all assets. It is submitted that Return on assets provides the risk that is involved in doing the business. Since setting up a thermal plant has different risk as compared to setting up a hydro plant, the RoE for both shall be different. Similarly, for transmission assets RoE may be different. It is submitted that RoE may be determined in the following manner 1. Thermal – Lowest RoE (Low risk) 2. Transmission – Medium RoE (Medium Risk) 3. Hydro – Highest RoE (Highest Risk) Further, only Hydro stations shall be incentivised for timely completion as the difficulties faced for completion of hydro stations are much more and extra efforts taken by the generator for timely completion may be awarded.

4.16.4	*The formula for computing the return on equity based on CAPM is as under:* *Re = Rf + β × (Rm − Rf)* *Where: Rf = risk-free rate* *β = equity beta Rm-* *Rf = equity market risk premium* *There are different ways of estimating the above parameters. However, the following approaches are proposed for the estimation of the above parameters:* *Keeping in view the international approaches to regulated rates of return, the average 10-year GOI securities rate over a one-year horizon may be considered a risk free rate* *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* *Keeping in view the international approaches, the 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. Alternatively, MRP may be computed using any other method, including the Survey Method*	It is submitted that generation and transmission business is a regulated business and therefore the returns in this business shall also be regulated. The approach of CERC to determine rate of RoE linked to the capital asset pricing model is appropriate. However, the ROE shall not be completely market driven and may be allowed at some discount rate .
4.16.5	*Possible options to encourage higher availability and generation from old generating stations can be as follows. 1) Allowing additional incentive in the form of paise/kWh apart from those currently allowed may be allowed to such generating stations against generation beyond the target PLF.* *Comments and suggestions are sought from stakeholders on various possible alternatives that incentivises generation from these efficient*	It is submitted that thermal stations are already getting incentives for achieving PLFs higher than normative. Further, there are incentives for also achieving availability above target availability. It is observed that all pithead stations are already getting the incentives as they are always able to achieve actual PLFs and

	old generating stations.	availability higher than normative PLFs and availability. Since most of the older stations are pit head stations, there is no need to provide additional incentive of any kind for running the old station/unit for additional number of years.
4.17	*In view of the above discussion and recent amendments to the Income tax regime, a domestic company shall fall under one of the following brackets, and the maximum tax amount that shall be payable is limited by the tax rates notified for the relevant category. Therefore, Base Rate of RoE may be grossed up as follows:* *1. At MAT rate (If not opted for Section 115 BAA)* *2. At effective tax rate (if not opted for Section 115BAA) subject to ceiling of Corporate Tax Rate; or* *3. At reduced tax rate under Section 115BAA of the Income Tax Act or any other relevant categories notified from time to time subject to ceiling of rate specified in the relevant Finance Act. Further, tax shall be allowed only in cases where the company has actually paid taxes as under no circumstances tax can be allowed to be recovered if the company has not paid any tax for the year under consideration. In view of the above discussion, comments and suggestions are sought on the above and any other alternative(s).*	It is submitted that Income Tax shall be allowed only on the basis of actual and only after the completion of the financial year when the actual tax is paid by the Company. No liability of tax may be created while estimating cost for ensuing years of the Control Period.
4.18.1	*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*	Existing norms for working Capital may be continued
4.18.1	*It is further observed that CEA has revised coal stocking norms for coal based thermal generating stations with effect from 06.12.2021 and CEA has suggested disincentives for thermal power plants in the event the availability of any coal based power plant is lower than the normative availability (as per prevailing CERC Regulations/Norms,*	The same may be incorporated in the Regulations.

	as applicable) due to a lower stock of coal maintained by the power plant as compared to the norm specified by the CEA. A Staff Paper titled "Methodology for Computing Deterrent Charges for maintaining lower coal stock by coal based thermal generating stations" was issued in May 2022 wherein the methodology for determining deterrent charges was proposed. In this regard, comments and suggestions were invited from generating stations and stakeholders. Various generating stations and stakeholders have submitted their responses, however, any further suggestions on the issues flagged therein may be submitted for consideration.	
4.18.1	*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*	It is submitted that actual generation above normative PLF by gas based plant may be linked in the normative working capital requirement.
4.18.2	*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.*	Interest on Working Capital shall be equated to MCLR rate without any mark-up of 350 basis points. It is submitted that the Actual Interest on Working Capital may also be taken into consideration and the Hon. Commission shall allow Interest on Working capital on actual rate or MCLR rate whichever is lower
4.18.3	*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*	As stated above
4.19	*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. As the need for higher repairs will still be required, the current dispensation of allowing a special*	It is a welcome move to increase the useful life of power stations and transmission assets. It is submitted that the useful life can be revised to 30 years

	allowance or provision of R&M may be continued after 25 years	for thermal generating units, 40 years for transmission assets and 50 years for hydro/PSS stations. This would significantly reduce the front loading of tariff. Also, the tariffs of existing stations and transmission assets may also be adjusted accordingly. Special Dispensation may be allowed after 25 years' subject to CBA and prudence check. It shall be allowed on case to case basis. Also, True-up of this special dispensation must also be done and any benefit that is not achieved may be adjusted in tariff accordingly.
4.20	*It is observed that so far the Commission has received a couple of petitions for the determination of the input price of coal and therefore not much actual data is available to review the current operational norms and other provisions. In view of no compelling reasons to revisit the current terms and conditions for the determination of the input price of coal, it is proposed that the current provisions be continued* *Comments and suggestions are sought from the stakeholders on any modifications that may be required to current tariff provisions with regard to the determination of the input price of coal and lignite from integrated mines*	It is submitted that current provisions for determination of input price may be continued. Based on the data available with CERC, benchmark input price needs to be determined and accordingly this benchmark shall be capping or ceiling price for input pricing. Further, it is submitted that this ceiling price as determined above shall be lower than the rates published by Coal India Limited from time to time or the rates at which coal is provided to generators through FSA. It is necessary that the input price mechanism should be such that it will ensure some benefit over the normal coal procurement made under FSA.
4.21	*It is observed that both generating companies as well as transmission utilities have considerable resources in the form of assets such as land banks and other enabling infrastructure and human resources that can be utilised to increase non-core revenues through lease, data centres, eco-tourism, etc., which should be explored, and in order to*	Generating/Transmission Company to come up with a plan before CERC to increase non-core revenues. Incentive mechanism to be introduced so that Generating/ Transmission Licensees can be encouraged to come up with a plan.

	generate such lateral revenue opportunities, the utilities need to be incentivised *Comments and suggestions are sought from the stakeholders on the following:* *1. Ways to increase non-core revenues through optimal utilisation of available resources.* *2. Any modification in the sharing mechanism that may be required*	CERC to implement all such avenues in the Non-Tariff Income of the Generating Company/Transmission company so that the benefit of the same shall be passed to consumers.
4.22	*To avoid such situations, the principal amount may be capitalised and the interest amount may be allowed to be recovered in instalments from the beneficiaries. However, such a recovery of interest may also involve carrying cost. Comments and suggestions are sought from stakeholders on the above approach and alternative ways, if any.*	It is submitted that the interest amount may not be charged from the date of arising of dispute. After issuance of the Order by appropriate forum, the liability is arising and therefore, any interest if any to be charged shall be from the date of issuance of Order.
4.23	*In order to streamline the rate of interest on the differential amount, the current practice of allowing a simple interest rate as per Regulation 10(7) in the 2024-29 tariff block may be continued. Further, interest may be allowed to be charged on the differential amount by the utility only until the issuance of the order, and no interest may be allowed during the recovery in six equal monthly instalments* *Comments and suggestions are sought from stakeholders on the above approach and alternative ways, if any*	It is a welcome move. It is submitted that the interest may be allowed only till the time the revenue gap is acknowledged by the SERC/CERC, which is done while issuance of Tariff Order. Hence, the interest rate shall not be allowed till the final recovery of the amount.
5.1.1	*In view of the above, the existing norms of NAPAF may need review by considering past years' PAF, the procurement of coal from alternate sources, other than designated fuel supply agreements, changes in hydrology, etc.* *Further, it is observed that current Regulations, although specifies the mechanism for computing PAF of storage based hydro generating stations, do not specify a methodology for computing PAF of Run-of*	It is submitted that ensuring coal availability is the responsibility of the Generator. MoP has also come up with the guidelines for keeping minimum coal stock for efficient operation of the plant. PPAs also have provision for alternate fuel sources when primary sources are not available. Therefore, it is submitted that non-availability of coal may not be termed as force majeure event and therefore actual

<table>
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<td></td>
<td>River (ROR) Plants. There is a need to specify a mechanism for the same, and based on such a specified mechanism, the current NAPAF value may need reconsideration.
One option can be to re-introduce the methodology that was being adopted in the CERC Tariff Regulations, 2004. Based on Regulation XI (b) under Chapter 3 of the Tariff Regulations, 2004, the methodology can be specified as follows
In case of purely run-of-river power stations, declared capacity means the ex-bus capacity in MW expected to be available from the generating station during the day (all blocks), as declared by the generating station, taking into account the availability of water, optimum use of water and availability of machines;
Comments and suggestions are sought from stakeholders on the above suggested option and any other methodology that can be considered for the computation of plant availability for ROR based hydro generating plants</td>
<td>PAF shall be calculated.

Stakeholders in the power sector needs to accept some responsibility rather than merely claiming compensation for its inability to deliver.

Further, it is submitted that seasonal NAPAF to be determined and shall be made applicable to the plants/units supplying to a particular region. For e.g. stations/units supplying power to Western Region states may have to adhere to seasonal variation observed in western region. Therefore, they shall not be allowed to take outage in high demand season of the western region. Accordingly, payment shall be based on the declared capacity during high and low demand season.

It is further submitted that NAPAF and incentive mechanism shall be revised as per below for pit head and non-pit head stations:

<table>
<tr><th>Particulars</th><th>NAPAF</th><th>For Incentive</th></tr>
<tr><td>Pit Head Stations</td><td>90%</td><td>95%</td></tr>
<tr><td>Non-Pit Head Stations</td><td>85%</td><td>90%</td></tr>
</table>

It is submitted that historically pit head stations have been able to show better performance that non-pit head stations hence the NAPAF and incentives shall be higher for pit head as compared to non-pit head station.</td>
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5.1.2	*It is observed that in the current mechanism, recovery of 50% of AFC is linked to actual generation, and in the event of any shortfall in actual generation below the saleable design energy, the same is allowed to be recovered as per Regulation 44(7).* *As the hydrological risk is eventually passed on to consumers, the usefulness of a two-part tariff may need to be reviewed. The existing provisions of the shortfall in recovery of AFC are leading to complications in the recovery process, wherein the affected generating company has to file petitions seeking such recovery.* *Comments and suggestions are sought from stakeholders on ways to simplify the tariff recovery process for hydro generating stations*	It is submitted that existing methodology of two part tariff to be continued. The recovery of fixed cost may be distrusted over a period of 50 years for hydro stations to reduce the AFC. However, fixed cost recovery shall be linked to the actual PLF achieved by the hydro station. Any event where hydro station cannot achieve the desired PLF due to lack of water availability can be taken up on case to case basis by CERC. Higher PLF may also be provided some incentive. It is to submit that the Discoms are doubly affected by non-availability of power from hydro stations as Discoms has to pay the AFC on declared capacity and also, purchase power from market at higher rate to cater its demand at peak hours.
5.2	*It is observed that though the segregation of recovery through peak and off-peak periods has brought in more accountability, there have been some operational difficulties while declaring high demand and low demand season which need to be taken care of. The current provisions require the Regional Load Despatch Centres (RLDCs) to notify in advance the months of high demand season and low demand season so that overhauling can be planned by the generators accordingly. The following issues have been brought before the Commission in this context:* *1) The actual period of high demand did not coincide with the forecast, and the generators had to postpone overhauling considering the sudden increase in demand. In some cases, such deferment has led*	It is to submit that the primary objective of EA, 2003 & National Tariff Policy is to provide 24x7 power supply and to ensure uninterrupted supply of quality power to all consumers. Thus, the variation in demand season and peak hours to be considered as per consumer point of view rather than generator's. Though recovery of reasonable costs is of prime importance for any infrastructure sectoral growth, there should not be any undue burden on the end consumers Further, power stations can plan for outages during the

	to forced outages, thereby impacting the recovery of the AFC. *2) The period of high demand and low demand is not the same for all the States in the Region, so declaring the common high and low demand period for all the States has its own challenges. For example, in Northern Region, the high demand season for hilly States such as Uttarakhand and Himachal Pradesh is the winter months, whereas for adjacent Punjab the same lies in the months of August-September and for Delhi it is the summer months.* *3) Some of the generating stations have beneficiaries in different regions, which again increases the diversity of demand. Therefore, declaring common high and low demand period is practically not possible. For example, Kahalgaon STPS and Farakka STPS have allocations to beneficiaries that belong to all five regions; therefore, in such cases, the objective of devising the above mechanism is rendered ineffective and may require tweaking of existing practice by RLDCs.* *4) While States have been demanding availability from the generators coinciding with State Peak, the generators have difficulty meeting this requirement due to the wide diversity of peak in different States.* *5) On the other hand, suggestions have also been received for a 'National' level Peak Period in view of the fact that the grid is integrated and India has a National market in operations.* *As recovery of reasonable costs is of prime importance for any infrastructure sectoral growth, comments/suggestions are sought on the possible interventions/modifications required to address the issues highlighted above. Specific suggestions are also sought on the following.*	common low demand season of the regions, whenever beneficiaries belong to multiple regions. In our Country generally the low and high demand season is observed in the months of November to Feb and Mar to May respectively. Hence, the low demand- high demand seasons for all the regions is bound to see some overlapping. Accordingly, generating companies can plan their outage and can still take the benefit of incentives to operate in high demand season at full capacity. It is further submitted that if the availability is found to be below 80% in the peak period, then there shall be no offset given against this reduced availability during off-peak period. Generators have to maintain the desired availability in peak periods or else may have to face penalty. Similarly, when the availability is below 80% during high demand season there shall be no offset given against this reduced availability during low demand season.

	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*	
5.3	*As these generating stations are operating at a much lower PLF, the actual performance data will also have a degradation impact. Further, as the generating stations are separately allowed degradation impact due to low load operations, it is felt that the norms may be fixed considering the ideal loading of generating units*	No comments
5.4	*For those generating stations that have not been operating efficiently in the past and for which the Commission has been considering actual achievements to fix relaxed norms, in the interest of limited resources, such relaxation of norms may need re-consideration. This is necessary as the coal/lignite is limited resource that needs to be consumed efficiently and can be re-allocated to more efficient plants. Comments and suggestions are sought from stakeholders on the option to do away with relaxed norms currently allowed on the basis of actual performance for various efficiency norms of generating stations*	It is a welcome move to do away with the relaxation of norms and re-allocate the fuel which is scarce to the plants that can operate more efficiently. It is submitted that over the years, enough dispensation through R&M and other capex has been claimed and recovered by generating companies to upgrade their performance. However, even after incurring such huge capex, the generating company is not able to deliver on the operational parameters then in such case, the power stations shall be directed to discontinue and the coal allocated to such plant may be assigned to other efficient plants which are not operational or having low PLF due to unavailability of coal.
5.5	*1. Station Heat Rate – To be approved on a case-to-case basis.* *2. Auxiliary Energy Consumption – 10%* *3. Secondary Fuel Oil Consumption – 2ml/kWh* *4. NAPAF – 75% (First three years from COD) and 80% thereafter* *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 and suggestions are sought from stakeholders on the above*	It is submitted that, once a norm is defined for particular set of units, the same shall be applicable to all units. Bifurcation can be made on the basis of the age of the units. Age beyond 25 years can have separate norms than the one with less than 25 years. Hence, SHR, Aux, SFOC and NAPAF shall be determined

	proposal.	through norms and no relaxation may be provided in any case.
5.6	*As adequate actual operational data were not available, the Commission in the Principal Regulations only provided for in-principle approval of additional capital expenditure, admissibility, and tariff structure (Supplementary Energy Charges and Fixed Charges) and stipulated the operational and financial norms subsequently through the first amendment to CERC Tariff Regulations, 2019, which were based on inputs from CEA and various other stakeholders.* *As only very few of such emission control systems have been commissioned, and in the absence of sufficient data on actual operational performance and its impact on auxiliary consumption, the current tariff norms may be continued for the next control period. However, comments and suggestions are sought from stakeholders on the continuation of the existing norms, or is there a need to modify the same* *Further, as considerable expenses have been incurred to reduce the adverse impact on the environment, suggestions are also sought on ways to incentivizing proper operation of such emission control systems so that the very purpose of incurring such huge expenses can be achieved and accounted for* *Implementation of an emission control system also requires the determination of supplementary energy charges, which impacts the power plant's standing on merit order. The Commission, considering that most of the generating stations are yet to install these systems, ruled that these supplementary energy charges shall not be considered while preparing merit order. In view of the earlier approach and*	It is submitted that partial cost of ECS can be recovered from State/ Central Govt. for installation of such devices so that entire burden of the same is not passed to consumers. Further, generators shall be made accountable if desired results are not achieved after installation of ECS.

	considering that most of these generating stations are still in the process of implementing such systems, the current practice of excluding such expenses while preparing merit order may be continued. Comments and suggestions are sought from stakeholders on whether the current mechanism to exclude these expenses may continue until these generating stations equip themselves with emission control systems as per the MoEF&CC notification dated 31.03.2021?	
5.7	*It is observed that currently the impact is being allowed considering the norms or actuals, whichever is lower. This mechanism results in operational gains being passed on to the beneficiaries, while any losses are borne by the generator. The mechanism may need a review wherein either normative norms are followed, or compensation is limited to actuals. It is further observed that there have been instances where the actual PLF of plants has been even below 55%. The current provisions for compensation do not cover operating PLF below 55%, and therefore, devising a compensation mechanism to govern such cases may also be required. With regard to the compensation norms, an Expert Committee has already been constituted; however, in view of the above discussion, comments and suggestions are sought from stakeholders on the earlier norms and any changes that may be required to compensate the generators to operate the plants in a flexible manner to support the Grid*	Present practice to be continued. No need to devise new compensation methodology, as it will increase burden on end consumers.
5.8	*It is observed that the loss in GCV from "as billed" to "as received" has been allowed on an actual basis. As mentioned earlier, even though the loss in GCV "as received" vis-à-vis "as billed" has reduced, one can argue that as the actual loss has been allowed in the past, there have not been considerable efforts made by generators in*	It is submitted that the GCV shall be continued to be done on 'as received' basis as per this existing Regulations. The loss between GCV "as received" vis-à-vis "as billed" needs to have a ceiling/ capping beyond which the loss of

	minimising the loss. Comments and suggestions are sought from stakeholders on ways to reduce the gap between GCV "as billed" and "as received	GCV shall not be considered. If the actual loss is lower than the ceiling loss, then only the actual loss shall be allowed. Hence normative or actual whichever is lower is to be considered while deciding on the GCV loss between the two. Further, it is proposed that the billed GCV needs to be verified in an appropriate manner. It is observed that manual sampling is still being done to arrive at "GVC billed". It is submitted that latest technology and various other sampling techniques are now available to arrive a correct "GCV as billed".
5.9	*Staff of the Commission, in June 2022, published a paper analysing the impact of blending of coal on the energy charges and noted that even when blending of coal is less than 10%, the 30% ECR threshold limit gets breached. In view of the same and considering that the shortage situation may recur, following can be analysed.* *Linking the consent of beneficiaries with the percentage blending of imported coal instead of an increase in ECR may enable a swift response to an increase in demand by the generating company. Procurement of such coal (other than linkage coal) has to be done through a transparent competitive bidding process* *Comments and suggestions are sought from stakeholders on the above proposal and any other alternative, if any*	It is submitted that the threshold limit shall be continued to be on the increase in ECR and shall not be linked to blending of coal to avoid tariff shock to the consumers. It is submitted that due to high prices of imported coal, even a small blending percentage have a significant impact on ECR, Owing to the above factors, it is submitted that the consent of the Distribution Licensee shall be linked to increase in ECR and not to the percentage of blending.
5.10	*However, 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. This will result in increased generation from such plants and will also benefit beneficiaries.*	It is submitted that in case of Hydro, the AFC is paid in full amount even though RTC power is not made available by Hydro Stations. It is therefore submitted that there is no need of any additional incentives to be provided to Hydro for excess NAPAF. The full recovery of AFC is an incentive in itself.

	Comments and suggestions are sought from beneficiaries on the above proposal and any other alternative options, if any	For pit head stations target PLF/NAPAF norms to be increased, so that increased generation will be available and there will not be any additional impact on consumers. Further, old pit-head generating stations are already being incentivized.
6.1	*However, it is observed that there is a need for a more enabling framework or incentive mechanism for dam/reservoir based generating stations to operate as peaking plants. Considering the anticipated increase in peaking loads, these stations may be incentivised to operate as peaking plants. One way to do so is by providing additional incentives for energy supplied during peak periods* *Comments and suggestions are sought from stakeholders on the above proposal and any alternative solutions, if any.*	It is submitted in case of Hydro the AFC is paid in full amount even though RTC power is not made available by Hydro Stations. It is therefore submitted that there is no need of any additional incentives to be provided to Hydro for excess NAPAF. The full recovery of AFC is an incentive in itself.
6.2	*As not all generating stations have installed the emission control system, and most of these works are in the execution stage, therefore the existing tariff recovery mechanism may be continued. However, comments and suggestions are sought from stakeholders on alternatives to the existing tariff mechanism for recovering the impact of the installation of emission control systems.*	As discussed earlier, 50% of the cost of ECS may be funded by the State/Central Govt. and 50% may be passed to the Distribution Licensee provided the generating company is able to establish that the desired results are achieved through the asset being put up.
6.3	*One approach could be that the net profit/loss post decommissioning and disposal of assets may be adjusted in one go from the beneficiaries, duly factoring in the un-recovered depreciation admissible under the Tariff Regulations.* *In view of the above, comments and suggestions are sought from stakeholders on the possible approaches to recover or refund the impact of decommissioning costs in case the generating*	It is submitted that post de-commissioning the salvage value of the asset recovered may be adjusted in the new capital cost which would be put up by the generating/transmission company and accordingly, reduce the cost of the new capital expenditure proposed. By these means, the benefit of the de-commissioning of asset would be passed on the beneficiaries.

	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.	
6.4	*Comments and suggestions are invited from stakeholders for simplifying the existing tariff formats.*	It is submitted that all the tariff formats as per the existing Regulations may be retained by the Commission. The tariff formats provide detailed insights of the information which is not available in the Petition. The tariff formats also ensure transparency between the stakeholders. Therefore the detailed tariff formats are requested to be continued as per the current Regulations.
6.5	*A transmission line can be considered as an inter-State transmission line in three circumstances, as mentioned under Section 2(36) of the Act. It is observed that many of the State transmission licensees are claiming tariff of the transmission lines either due to the creation of LILO on the existing transmission lines or systems or the construction of new transmission lines and intra-state lines converted into inter-state lines due to the bifurcation of a State. It is further observed that State transmission licensees are not taking any prior approval from the Commission, for the implementation of new transmission lines and also many of the State transmission licensees are claiming tariff for the transmission lines without submitting any approvals of SCM and RPC. In view of the above, 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 transmission lines carrying inter-state power.*	It is submitted that any activity/works that is carried out in the transmission sector is being done after due approval of the respective SERC or CERC. Thus, for intra-state line construction is outside the preview of CERC. However, due to some modification of establishing links between two lines may change intra-state line to inter-state lines. In such cases only, concern transmission licensee shall approach CERC.
6.5	*The transmission charges of such Intra-State transmission lines*	Present practice may be continued.

	(carrying inter-state power) of the State transmission utilities are determined based on the benchmark capital cost derived on the basis of the average cost of CTU lines for old transmission lines or based on the auditor's certified cost, in accordance with the CERC Tariff Regulations, 2014 and the CERC Tariff Regulations, 2019, as the case may be. 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.	
6.6	*Representations have been received regarding the non-recovery of the full capital cost of the assets, on account of de-capitalization due to upgradation or modification of existing transmission assets, much before the completion of their useful life. It is observed that a large number of projects that involves upgradation and modification have already been planned and assigned to transmission licensees for implementation, therefore appropriate provisions may be required to be included in the upcoming tariff regulations. In view of the above, comments and suggestions are invited from stakeholders regarding the treatment of unrecovered depreciation*	It is submitted that post de-commissioning the salvage value of the asset recovered may be adjusted in the new capital cost which would be put up by the generating/transmission company and accordingly reduce the cost of the new capital expenditure proposed. By these means, the benefit of the de-commissioning of asset would be passed on the beneficiaries
6.7	*Stakeholders may comment on whether to continue to consider the gross value of the asset being de-capitalized, by de-escalating the gross value of the new asset @ 5% per annum until the year of capitalization of the old asset, or may suggest any other methodology to compute assumed deletions.*	The present methodology may be continued.
6.8	*Further, commercial mechanisms and terms & conditions for transactions between a generator and beneficiaries are governed by the long term PPAs executed between them, which are generally valid through the life of the PPA. It is noted that a number of generating*	It is submitted that the Approach Paper discusses that the useful life of the plant can be increased to 35 years. Further, Draft PPA issued by MoP for procurement of power defines the tenure of the long term PPA to be reduced to 10 to 15

	stations, at times, operate beyond the tenure of the PPA, and that such extended operations should also be governed by the PPA as in the case of the original PPA period, and any interventions in the PPA through tariff Regulations, that too, every five-year, including such a unilateral exit clause, may not be desirable as it may violate contract sanctity and could be inequitable. *In view of the above, 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 and suggestions are sought from stakeholders on the above*	years. Hence it is submitted that power stations can have multiple PPAs in its tenure. So a new plant can sign PPA twice for a period of 15 years and thrice for a period of 10 years in its useful life However, as Long Term PPA have a typical duration of 25 years, DISCOMs should have an option to enter into medium or long term PPA which would enable Distribution Licensees to not get into contractual obligation for a very long period and accordingly structure its Power Purchase Agreements after a tenure of 10 to 15 years Further, it is submitted that the PPA shall supersede the provisions of the Regulations and accordingly, Regulations 17(2) of the Tariff Regulations can be dealt. Under no circumstances violation of PPA shall be done on account of provisions of Tariff Regulations. Furthermore, MoP has notified scheme for Pooling of Tariff of those plants whose PPAs have expired wherein a pool of generating stations who has completed 25 years is formed without confirming whether DISCOM is interested in extending the PPA or not. Thus, in view of MoP's notification, the continuation of Regulations 17(2) is questionable.
	Compensation for low load operation below 55% minimum power load. Impact to be allowed on actual or normative basis	It is submitted that as no actual data is available, considering such a huge amount of Rs. 30 Crore per unit for old stations commissioned before 01.01.2004 and Rs. 10 Crore for units commissioned on or after 01.04.2004 may be reviewed.

	In case of old units (commissioned before 01.01.2004) which have not upgraded their plant control and instrumentation previously, capex requirement may around Rs. 30 Crore per unit *It is estimated that the measures essential to operate at 40% load may require an estimated capital expenditure of around Rs. 10 Crore for each unit commissioned on or after 01.04.2004 except for units covered under para 3 (a) (iv)* *Therefore, measures/retrofit are not required in these units for operation up to 40% load. However as per OEM few measures are required to be implemented for regular 40% load operation of subcritical units though the same 40% was demonstrated during PG test. Considering above it is proposed a maximum capital investment of Rs. 6 Crore may be allowed to the subcritical generating units where investment approval received on or after 01.01.2011*	Further, the capital investment of Rs. 6 Crore proposed in this clause has no basis, hence such amount to be reviewed. . It is further observed that the O&M expenses escalation has been proposed to be increased up to 20% for part load operations at 40%. This is exorbitant. MSEDCL proposes 7%, 10% and 14% in place of 9%, 14% and 20% respectively. It is also necessary to look into the actual cost which would be incurred by the generator for operating at part load operations @40% and accordingly, on case to case basis the capital expenditure required or the O&M escalation required may be determined rather than deciding a normative number. Further, the increase in O&M cost should be considered on basis of in which bracket of % loading generator was operated for maximum no. of days out of total no. of flexible operations days. Furthermore, compensation of variable charges may be continued as per present practice which take care of all the parameters including Net Heat Rate rather than any percentage increase.