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Ref No: RCD18/1A/LT00492 No 09173

Date: 31.07.2018

31 JUL 2018

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

Sub: Comments and suggestions on the Consultation paper regarding Terms & Conditions of Tariff for the tariff period 2019-24.

Ref:
1) CERC Consultation Paper on Regulations 2019-24
2) Public Notice no. L-1/236/2018/CERC dated 24th May, 2018
3) Public Notice no. L-1/236/2018/CERC dated 13th July, 2018

Respected Sir,

Hon'ble Commission has invited comments and suggestions on the Consultation paper regarding Terms & Conditions of Tariff Regulations for the Control Period 01-04-2019 to 31-03-2024 vide Public notice under reference above.

MSPGCL is submitting herewith the comments regarding the subject matter as attached herewith.

It is requested to accept MSPGCL's comments.

It is also requested to allow MSPGCL to submit additional comments, if any, in the matter at latter stage.

Submitted please.

Thanking you.

Yours faithfully,

31/07/18

Chief Engineer
Regulatory & Commercial Dept.

Encl.: MSPGCL's comments on Consultation Paper

+ 2 copies

MSPGCL is submitting the comments on the Consultation Paper in two parts. Firstly, there is broad analysis of key initiatives and then tabulation for specific point wise comments.

Broad analysis:

As per MSPGCL, under the Consultation Paper there are 4 major deviations from the provisions in earlier Regulations. These key initiatives proposed and MSPGCL's comments thereof are as below:

A. Introduction of Three-part tariff in place of prevailing Two – part tariff:

Extract of proposed provisions:

In the low despatch scenario, fixed cost burden for the unscheduled capacity is increasing. The situation of low PLF due to low despatch is expected to prevail till FY 2021-22.

The two-part tariff system structure is suitable when the demand for power ensures utilization of capacity or around the target availability, i.e. Two-part tariff operates well in power deficit scenario. In view of decreasing PLF of the thermal generating stations, the Central Electricity Regulatory Commission (CERC) is re-looking the current two-part tariff structure and has introduced three parts tariff-

1. Fixed component of prevailing AFC as fixed charge (for recovery of fixed cost consisting of depreciation for repayment, interest on loan and guaranteed return to the extent of risk free return and part of operation and maintenance expenses) recovery for which will be linked to availability.
2. Variable component of prevailing AFC as variable charge (incremental return above guaranteed return and balance operation and maintenance expenses) recovery for which will be linked to the difference between availability and dispatch
3. Energy charges (fuel cost, transportation cost and taxes, duties of fuel) recovery for which will be linked to dispatch.

MSPGCL's comments:

Though the situation of low demand / despatch is prevailing for a long time, it is not by virtue of generating companies. Higher demand growth projections and correspondingly tied up PPA capacities and subsequent drop in actual demand coupled with increase in generation capacities have resulted in the supply surplus situation. So, even if it is understood that fixed costs burden in such low despatch situation leads to increase in overall tariff, the proposed bi-furcation of fixed charges is in a way taxing the generating companies for an uncontrollable event.

In this regard MSPGCL would like to highlight the observation in the Consultation Paper itself that "*the cost of purchase of power that constituted about 71% (=341*100/476) of the cost of supply of electricity in 2009-10 has come down to 63% (=438*100/691) in 2015-16. This implies that other costs viz. the operational cost of distribution utilities, including AT&C losses, have increased at a higher rate.*" The reduction in % contribution of power purchase cost in average of cost of sales clearly indicated that there is cost of generation is reducing or growing slowly.

Despite of such drop, cost of sales is not reducing and ultimately recoveries of Distribution companies are not improving resulting in huge outstanding dues to Generation companies. So efforts from generating companies needs reciprocation from Distribution companies also and carry out timely payment of Generation companies dues. So MSPGCL is of the opinion that the proposed provisions are aimed only at helping the Distribution companies and are detrimental to generating companies and hence MSPGCL opposes the same.

B. Reduction in regulated returns

Extract of proposed provisions:

On the assumption of declining yields, inflation and low capacity addition requirement in the medium term & recognising the risk of a return cut on existing and under-execution projects, it is proposed to maintain the existing RoE for projects that have achieved financial closure.

MSPGCL's comments:

This can be a positive for existing assets as earnings from their existing asset portfolio is preserved and also for the projects which are already under construction. However, for the projects yet under finalisation, this may impact the feasibility.

C. Option/view on increasing extension of useful life for very old thermal power plants:

Extract of proposed provisions:

The capacity of coal based thermal power plants more than 25 years old is about 37,453 MW, out of which around 35,506 MW capacities pertains to state / central sector, as on March 2016 according to Central Electricity Authority (CEA). Accordingly, CERC has proposed the option / view on increasing extension of useful life for very old thermal power plants,

MSPGCL's comments:

This provision may give a hope for a new lease of life to several power units. However, extension of useful life through renovation is one of the suitable options only if cost benefits are substantial. Otherwise for efficient usage of available coal resources, the option of phasing-out and replacement with higher capacity super critical plants is more appropriate.

D. Introduction of concept of annual contracted capacity

Extract of proposed provisions:

Presently the total capacity as per PPA is considered as annual contracted capacity. Against this it is proposed that flexibility may be provided to the generating company and the distribution licensee to redefine the Annual Contracted Capacity (ACC) on yearly basis out of total Contracted Capacity (CC), which may be based on the anticipated reduction of utilization. Annual Contracted Capacity (ACC) may be treated as guaranteed contracted capacity during the year for the generating company and the distribution licensee and the capacity beyond the ACC may be treated as Unutilized Capacity (UC). Such unutilized Capacity may be aggregated and bidded out to discover the market price of surplus capacity.

MSPGCL's comments:

This provision appears to have been made with intent to help Discoms to reduce their input costs. However, this will be detrimental for the Generators, increasing their risk in the business and could impact the whole sector, as increased risks may result in higher Capital cost of project, which will ultimately translate to higher cost of generation and ultimately result in higher cost for end consumers.

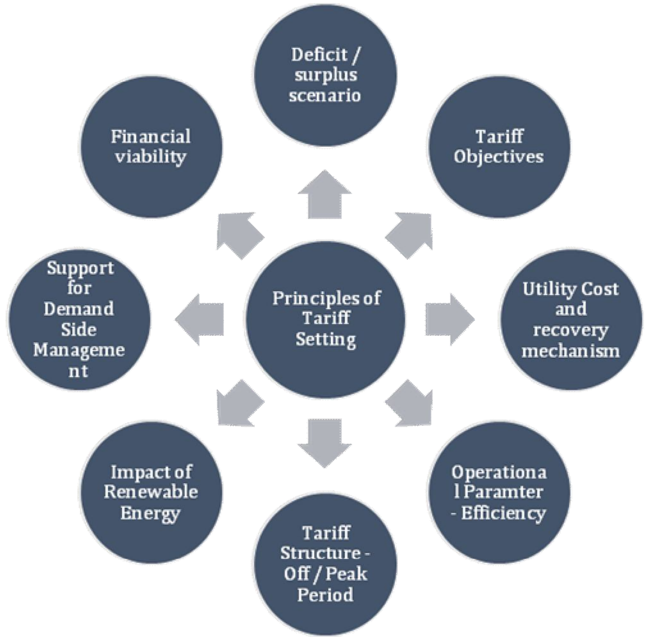
Even though the Power Purchase Cost over the past 3-4 years has increased, a large portion of the increase could be attributed to reasons beyond the control of Generating Stations - such as: imposition of clean coal cess, significant price hikes taken by Coal India, wage revisions, high spot power prices, cross-subsidisation of renewable energy transmission costs, etc.

The Generation sector is already struggling due to NPAs and stranded capacities. Hence, the Commission should not further techno-commercially weaken the Generation sector.

Point –wise comments from MSPGCL:

As per MSPGCL, while framing regulations, there is a need to consider the factors such as transparency, availability of past data with actual operational parameter, expected capacity addition (w.r.t thermal and renewable), Clarity about institutional roles and the process of tariff determination, Opportunity for stakeholder comments and inputs into the tariff-setting process, etc.

Considering the current market scenario, following factors are required to be considered while setting the principles of tariff setting mechanism:



This consultation paper can be used as input for formulating Terms and Conditions of Tariff commencing on 1.4.2019. Hence understanding the impact of the paper on various stakeholders vis-à-vis tariff and other parameters is necessary. MSPGCL has tried to discuss and comment on the point wise recommendation / options given in the paper as under:

MSPGCL'S COMMENTS ON CERC CONSULTATION PAPER FOR TERMS & CONDITIONS OF TARIFF REGULATIONS FOR 2019-24

Sr. No.	Proposed Option	Comments
1.	**Some key challenges – B. Coal based Thermal Generation**	
	5.2.13 Presently, thermal generation is being used for balancing requirements of the grid. The variability of renewable energy generation causes frequent regulations of thermal generation which adversely affect the plant & machinery in terms of reduced life, higher maintenance expenditure, higher down time and lower efficiency (Heat Rate, Auxiliary Power Consumption and Specific Oil Consumption).	• Considering the adverse impact on performance parameters, adequate additional compensation may be provided apart from compensation already provided under IEGC Fourth Amendment to the thermal generating units which need to undergo frequent regulations. • The impact of frequent regulation may be prominently observed on the units which are positioned on top of the MOD stack.
2.	**Some key challenges – C. Gas based Thermal Generation**	
	5.3.1 The gas based thermal generating stations offer greater capability of ramping up and ramping down. Thus, gas based generating station can provide alternative source for balancing power to address the intermittency of renewable generation. However, the gas based generating stations having concluded PPA are facing problem due to shortage of supply of gas from domestic source. The alternative may be to source costlier gas either from spot market or R-LNG.	• Due to the high ramp-up/ ramp-down rate, the gas-based generation may prove very critical for grid balancing, during peak demand hours as well as during sudden supply variations expected with envisaged renewable capacity addition. • In order to improve availability of gas-based units in the grid, special consideration may be given for utilization of Spot market purchase of R-LNG during peak hours and such generation may be excluded from MoD principle / separately ranked in MOD stack. This will enable the Discoms to plan for purchase of such higher cost power for short duration depending on market rates and also may result in increased overall unit availability of gas-based power in the grid.

MSPGCL'S COMMENTS ON CERC CONSULTATION PAPER FOR TERMS & CONDITIONS OF TARIFF REGULATIONS FOR 2019-24

Sr. No.	Proposed Option	Comments
3.	**Thermal Generating Stations –Tariff Structure**	
	7.2.5 The tariff for supply of electricity from a thermal generating station could comprise of three parts, namely, fixed charge (for recovery of fixed cost consisting of the components of debt service obligations allowing depreciation for repayment, interest on loan and guaranteed return to the extent of risk free return and part of operation and maintenance expenses), variable charge (incremental return above guaranteed return and balance operation and maintenance expenses) and energy charges (fuel cost, transportation cost and taxes, duties of fuel). **7.2.6** The recovery of fixed component could be linked to target availability, whereas variable component could be linked to the difference between availability and dispatch. Fuel charges could be linked with dispatch.	• **While the power purchase cost has increased over the past 3-4 years, a large portion of it could be attributed to reasons beyond the control of generating companies such as increased burden of fixed charges in low demand – high supply situation, imposition of clean energy cess, significant price hikes taken by Coal India, wage revisions, shortage of fuel, high spot power prices, cross-subsidization of renewable energy transmission costs, etc.** • **So as per MSPGCL, the proposed changes are aimed only at reducing the burden on distribution companies and are detrimental to generation companies.** • **It is further to submit that any Change in tariff structure needs to be considered post revision of definition in Availability whereby fuel and water unavailability may be considered as uncontrollable event and accordingly loss of availability on account of such shortage (without any fault of generator) needs to be considered as deemed availability. This will ensure the recovery of cost to service the Debt service obligation and reduction in NPA.** • **Apart from debt servicing expenses, major part of O & M costs is also fixed in nature. Amongst the Employee costs and Administrative costs are the major factors, contributing respectively @ 60 % and 5% of total O & M costs. As Employee costs and administrative costs are independent of operational level, O & M costs**

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		should not be considered as variable. • **Only interest on working capital can be considered in variable component which purely depends on efficiency and running hours of plant.** • As per the proposal, the fixed component of prevailing AFC can be linked to availability and variable charge to be linked to difference between availability and dispatch (PLF). • **Also, while computing PLF for recovery of variable component, proper factoring of loss of generation due to backing down on account of low demand should also be done or otherwise the generator will be unnecessarily penalised for lower PLF on account of uncontrollable factor of lower demand.**
4.	**Thermal Generating Stations – Older than 25 years**	
	7.3.4 A clear policy / regulatory decision are required in view of a number of thermal stations crossing the age of 25 years. Possible options could be: (i) replacement of inefficient sub critical units by super critical units, (ii) phasing out of the old plants, (iii) renovation of old plants or (iv) extension of useful life etc. It is worth to note that performance of a unit does not necessarily deteriorate much with age, if proper O&M practices are followed.	• The option of continuation of the plant needs to be considered post 25 years of life based on the condition and efficiency parameter for which a proper structural audit is required to be undertaken. In case the plant is efficient enough to run for another 10 years, then extension of useful life to 35 years for plant with proper O&M are highly efficient even after 25 years of age as the debt service cost will be negligible. • However, the recent experiments under EE- R&M (Energy Efficient –Renovation & Modernization) scheme are not found to be encouraging. The costs are not commensurate to the benefits arrived.

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		• **So, based on the audit report & Cost benefit analysis report, renovation of the plant may be considered if economically feasible and if common amenities are in better position, or otherwise replacement of inefficient sub critical units by higher capacity super critical units will be more appropriate from efficient coal usage point of view .**
5.	**Hydro Generating Stations - Tariff Structure**	
	7.4.2 The fixed component may include debt service obligations, interest on loan and risk free return while the variable component may include incremental return above guaranteed return, operation and maintenance expenses and interest on working capital. The annual fixed cost can consist of the components of return on equity, interest on loan capital, depreciation, interest on working capital; and operation and maintenance expenses.	• This may be a positive for Hydro generators as fixed cost component may become greater than 50% of AFC. • The debt service obligation needs to be linked with the total availability whereby the definition needs to be amended such that water unavailability due to uncontrollable measure may not be considered. • **Amongst the O&M expenses, employee costs and Administrative costs are the major factors, contributing respectively @ 60 % and 5% of total O & M costs. As Employee costs and administrative costs are independent of operational level, O & M costs should not be considered as variable. O&M goes for the plant as a whole and not for the tied-up capacity separately**.
6.	**Inter-State Transmission System - Tariff Structure**	
	7.5.4 Transmission tariff can be on two-part basis, wherein the first part can be linked with the access service and second part can be linked with the transmission service. **7.5.6** The recovery of fixed component can be linked to the extent	• This may be positive for Generation companies as it will reflect the actual charges for the energy actually transmitted. • However, it is submitted that such variable charge needs to be added to the energy charges of Generating

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	of access (Transmission Access Charge) and variable component can be linked to the extent of use, to be recovered in proportion to the power flow (Transmission Service Charge). The fixed component may be linked to evacuation system or on normative basis based on aggregate transmission charges of the identified transmission system under the contract. The variable component may be linked with yearly transmission charges based on actual flow or actual dispatch against long term access.	Station to decide on dispatch under MoD principle.
7.	**Renewable Energy Generation – Tariff Structure**	
	7.6.3 There can be Two-part tariff structure for renewable generation covered under Section 62 of the Act, which comprises fixed component (debt service obligations and depreciation) and variable component (equal to marginal cost i.e. O&M expenses and return on equity) - fixed component as feed-in-tariff (FIT) and variable component equal to capacity augmentation such as storage or back up supply tariff.	• The modalities for such two-part tariff are not getting clear from the proposal. The process for determination and recovery of variable component could not be understood. • Also, the return on equity is the only incentive to the developer in case of renewable energy. So, considering it as variable may result in reducing the attractiveness of such renewable projects from investor point of view. • So, the fixed component should include the return on equity also.
	7.6.4 In case of integration of the renewable generation with the coal / lignite based thermal power plant, the following may the alternatives. a) The renewable generation may be supplied through the existing tariff for the contracted capacity of thermal power plant under PPA. In this alternative, the tariff of renewable generation may replace the energy charges; **b)** Tariff of renewable generation may be combined with the fixed and variable components of the thermal generation to the	• Considering the lower tariff being achieved under bidding and the volatility in the coal price, it's necessary to safeguard the financial viability of the plant whereby proper availability will also help the plant to operate efficiently. • Therefore, blending of tariff may not be a viable option for scheduling of a thermal power as the variable cost of Thermal plant based on domestic fuel is between Rs. 1

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	extent of contracted capacity under PPA. The operational norms of conventional plants may require revision such as higher target availability for recovery of fixed charges, higher plant load factor for recovery of incentive; **c)** The tariff for supply of power from renewable generation and thermal power generation may be recovered separately. The operational norms for recovery of tariff may have to be specified separately.	to 3/- per unit and Solar is in the range of Rs. 2.50 to Rs. 4.5 per unit. So, there is a probability that variable cost of thermal plant may increase resulting in affecting the MoD list. • Since renewable power at present come under Must run mechanism, the operation of the plant may not get affected and for thermal power plant, to retain efficiency, its necessary to have ongoing operation. • Therefore, the tariff may be separate for both the source with a flexibility with generator to schedule and declare the capacity with a combination so as to achieve the normative availability.
8.	**Components of Tariff**	
	9.3 The question is whether the annual fixed charges and energy charges are to be determined to the extent of the capacity tied up under Section 62 of the Act or for the entire capacity. One approach could be to determine the tariff of the generating station for entire capacity and restrict the tariff for recovery to the extent of power purchase agreement on pro-rata basis and balance capacity will be merchant capacity or tied up under Section 63, as the case may be	• The proposal put forward by the Commission that Fixed charges and energy charges should be determined to the extent of the entire capacity and restrict the tariff for recovery to the extent of power purchase agreement on pro-rata basis is acceptable. • However, it is necessary for the Commission to undertake audit for exclusion of certain CAPEX undertaken by Generator for the units tied up U/s. 63 and such principles need to be undertaken only in case of common facilities is under use.
	10.3 (a) Flexibility may be provided to the generating company and the distribution licensee to redefine the Annual Contracted Capacity (ACC) on yearly basis out of total Contracted Capacity (CC), which may be based on the anticipated reduction of	• This provision appears to have been made with intent to help Discoms to reduce their input costs. However, this will be detrimental for the Generators, increasing their risk in the business and could impact the whole sector,

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	utilization. Annual Contracted Capacity (ACC) may be treated as guaranteed contracted capacity during the year for the generating company and the distribution licensee and the capacity beyond the ACC may be treated as Unutilized Capacity (UC). The distribution licensee will have a right to recall Unutilized Capacity during next year and for securing such rights, some part of fixed cost, say 10-20% or to the extent of debt service obligations, may be paid; **(b)** Such unutilized Capacity may be aggregated and bidded out to discover the market price of surplus capacity. The surplus capacity may be reallocated to the distribution licensee at market discovered price.	as increased risks may result in higher Capital cost of project, which will ultimately translate to higher cost of generation and ultimately result in higher cost for end consumers. • The Generation sector is already struggling due to NPAs and stranded capacities. Hence, the Commission should not further techno-commercially weaken the Generation sector. • Such provision needs to be made applicable only in case the Generating company is able to tie-up for the unutilized capacity for the said period, otherwise the reduction in annual contracted capacity will also result in lower fixed charges and issue with debt servicing. In the said case the option of selling to third party for unutilized capacity will remain with the Generator. • However, in the said case of Section 62, in case there is over recovery from the said arrangement whereby unutilized capacity is sold to third party, the same may be shared equally with the beneficiaries.
9.	**Hydro Generation**	
	10.5 (a) Extend the useful life of the project up to 50 years from existing 35 years and the loan repayment period up to 18-20 years from existing 10-12 years for moderating upfront loading of the tariff.	• This may bring down the tariff of Hydro stations and will be more saleable, however, other parameters such as O&M etc may have to be looked into. • However, this may also result in mismatch between the actual loan repayment and normative loan repayment for the generator.

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	10.5 (b) Assign responsibility of operation of the hydro power stations and pumped mode operations at regional level with the primary objective for balancing. For this purpose, the scheduling of the hydro power operation (generation and pumped mode operation) may have to be delinked from the requirements of designated beneficiaries with whom agreement exists. The power scheduled to the hydro generation can be dispatched to designated beneficiaries through banking facility so that flexibility in scheduling can be achieved for balancing purpose and to address the difficulties of cascade hydro power station. Some part of fixed charge liability to the extent of 10-20% against the use of flexible operation and pumped operations may be apportioned to the regional beneficiaries as reliability charges.	• Currently there is no central level regulation on procedure or charges for banking and de linking of designated beneficiaries from existing agreements which might lead to legal disputes for the generators. Even State Government approval is required for the said option as usually the State Government has a free share in such power and also some of such plant is regulated by irrigation department. • However, a priority of scheduling of such power to the designated beneficiary is required to be provided. • This may help balance the grid, however a secure mechanism needs to be put in place to that they must receive the tariff equivalent to approved/tied-up PPAs and must not suffer losses in the name of balancing the gird. • Additional reliability charges may be allowed to be retained by the Generating Company.
10.	**Gas based Thermal Generations**	
	10.7 Scheduling and dispatch of gas based generating station may be shifted to regional level with the primary objective of balancing. After meeting the requirement of designated beneficiaries, the regional level system operator can use it for balancing power at the rate specified by the generating companies. Alternatively, all the gas based generating station capacities may be pooled at regional level. After meeting the requirement of designated beneficiaries, the balance generation may be offered for balancing purpose as and when required.	• This is a welcome step, as operating a gas based generating station has almost become unviable due to unavailability of fuel. • The pooling of gas based at regional level, after meeting the requirement of designated beneficiaries, the balance generation may be offered for balancing purpose as and when required to help balancing the grid better. However, the mechanism of recovery of expenditure for the generators needs to be looked into.

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11.	**Capital Cost**	
	• **11.8** One of the options is to move away from investment approval as reference cost and shift to benchmark / reference cost for prudence check of capital cost. However, the challenge is absence of credible benchmarking of technology and capital cost. • **11.9** Higher capital cost allows the developer return on higher base of equity deployed. In the cost plus pricing regime, the developer envisages return on equity as per the original project cost estimation. The regulations allow compensation towards increase in cost due to uncontrollable factor so as to place the developer to the same economic position had this uncontrollable event not occurred. Therefore, in new projects, the fixed rate of return may be restricted to the base corresponding to the normative equity as envisaged in the investment approval or on benchmark cost. The return on additional equity may be restricted to the extent of weighted average of interest rate of loan portfolio or rate of risk free return. Further, incentive for early completion and disincentive for slippage from scheduled	• For shifting to benchmark costs / reference cost for prudence check capital cost, it will be difficult to define benchmarks as each plant may have a different design parameter which also includes BTG (Chinese / Indian), Technology, efficiency improvement measures, water from Sewage Thermal Plant (STP) with different length, railway infrastructure, etc. Such issues are required to be addressed while identifying the benchmark of the generating plant. Therefore, a component wise benchmark of a power plant rather than opting for overall thermal plant benchmark based on the size of the plant. • Otherwise, the original investment approval, which also takes into consideration the site specific issues, may be taken as a reference cost and prudence check needs to be undertaken for any deviations. • **Limiting of ROE on additional CAPEX may discourage the Generator as certain equity is always required to be funded from additional equity as 100% debt proposition may not be available. RoE is always on a higher side as its own fund of the shareholders which has been invested with a risk and therefore cost of equity is always higher than cost of debt. Any curtailment may result in delay in additional capex to be undertaken as generator will seek 100% tie-up for fund which may take its own time. Considering the volatility in the power sector**

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	commissioning can also be introduced.	**and regulatory risk, it's necessary to provide the current RoE for generator to carry out the additional capitalisation.** • Further, incentive for early completion and disincentive for slippage from scheduled commissioning can also be introduced, subject to prudence check and allowance of uncontrollable factors.
13.	**Depreciation**	
	14.6. a) Increase the useful life of well-maintained plants for the purpose of determination of depreciation for tariff; b) Continue the present approach of weighted average useful life in case of combination, due to gradual commissioning of units; c) Consider additional expenditure during the end of life with or without reassessment of useful life. Admissibility of additional expenditure after renovation and modernization (or special allowance) to be restricted to limited items/equipment; d) Reassess life at the start of every tariff period or every additional capital expenditure through a provision in the same way as is prescribed in Ind AS and corresponding treatment of depreciation thereof; e) Extend useful life of the transmission assets and hydro station to 50 years and that of thermal (coal) assets to 35 years and bring in corresponding changes in treatment of depreciation. f) Reduce rates which will act as a ceiling. g) Continue with the existing policy of charging depreciation.	• In case of increase of useful life of well-maintained plant, depreciation must not be changed as most of the depreciation must have been recovered due to spreading over after 12 years. Hence, whatever depreciation recovery is left, that can be spread over the remaining period (i.e. new useful life). • Considering the review of depreciation exercise on a yearly basis may result in unnecessary increase in administrative and audit work and therefore, in case the same is thought for, the review of the life of the plant needs to be undertaken post structural audit every 10 years and accordingly the depreciation can be revised.

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	However, the Tariff Policy allows developer to opt for lower depreciation rate subject to ceiling limit as set by notified Regulation which causes difficulty in setting floor rate, including zero rate as depreciation in some of the year(s).	
14.	**Debt: Equity Ratio**	
	16.4 For future investments, modify the normative debt-equity ratio of 80:20 in respect of new plants, where financial closure is yet to be achieved.	• The Debt: Equity ratio may be considered as 80:20 or actual, whichever is low for new plants.
15.	**Rate of Return on Equity**	
	18.7 (a) Review the rate of return on equity considering the present market expectations and risk perception of power sector for new projects; **(b)** Have different rates of return for generation and transmission sector and within the generation and transmission segment, have different rates of return for existing and new projects; **(c)** Have different rates of return for thermal and hydro projects with additional incentives to storage-based hydro generating projects; **(d)** In respect of Hydro sector, as it experiences geological surprises leading to delays, the rate of return can be bifurcated into two parts. The first component can be assured whereas the second component is linked to timely completion of the project; **(e)** Continue with pre-tax return on equity or switch to post tax Return on equity; **(f)** Have differential additional return on equity for different unit size for generating station, different line length in case of the transmission system and different size of substation; **(g)** Reduction of return on equity in case of delay of the project;	• ROE for all plants, new and old must remain same i.e. 15.5% as per CERC tariff regulations 2014. Any reduction will have negative impact on the equity already invested in the existing and under construction projects, creating further financial stress on such projects. • However, different RoE can be thought for Hydro and Thermal Power plant with RoE of Hydro to be on a higher side. As suggested, RoE can be bifurcated into 2 parts i.e. assured and incentive. • RoE to be considered based on Pre-Tax with Income tax on actual (after excluding the impact of income from other business).

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17.	**Interest on Working Capital (IOWC)**	
	20.3(a) Assuming that internal resources will not be available for meeting working capital requirement and short-term funding has to be obtained from banking institutions for working capital, whose interest liability has to be borne by the regulated entity, IWC based on the cash credit was followed during previous tariff period. Same approach can be followed or change can be made. **(b)** As stock of fuel is considered for working capital, a fresh benchmark may be fixed or actual stock of fuel may be taken. **(c)** While working out requirement of working capital, maintenance spares are also accounted for. Since O&M expenses also cover a part of maintenance spares expenditure, a view may be taken as regards some percentage, say, 15% maintenance spares being made part of working capital or O&M expenses. **(d)** Maintenance spares in IWC which is also a part of O&M expenses results in higher IWC for new hydro plants with time and cost overrun. For old hydro stations, the higher O&M expenses due to higher number of employees also yield higher cost for "Maintenance Spares" in IWC. Therefore, option could be to de-link "Maintenance Spares" in IWC from O&M expenses. **(e)** In view of increasing renewable penetration and continued low demand, the plant load factor of thermal generating stations is expected to be low. As per the present regulatory framework, the normative working capital has been provided considering target availability. In case of wide variation between the plant load factor and the plant availability factor, the normative approach of linking working capital with "target availability" can be reviewed.	• In the current volatile situation, it is a necessity for plant to maintain the working capital requirement; IWC need not be changed and be worked on the same approach as in 14-19 period. • It is submitted that over and above the said factor, there is also a need to reconsider the formula for receivables which is considered for 2 months. However, many DISCOM has been paying dues in part and parcel with delay of more than 2 months which affects the working capital. Therefore, the period of receivables to be considered while calculation of working capital needs to be actual so that Generator doesn't suffer with regards to the increase in such working capital requirement due to delay. • Also, the working capital need to be linked to Plant availability factor as the working capital used by the Generator is based on its availability and not based on what it has generated. In case the availability is reduced, this may affect the plant load factor in future as well as lower normative availability. Considering the fuel stock position, the plant needs to be available based on the availability of coal and therefore, the stock is required to be maintained at that level.
18.	**Operation and Maintenance (O&M) expenses**	

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	21.7 (a) Review the escalation factor for determining O&M cost based on WPI & CPI indexation as they do not capture unexpected expenditure; **(b)** Address the impact of installation of pollution control system and mandatory use of treated sewage water by thermal plant on O&M cost. **(c)** Review of O&M cost based on the percentage of Capital Expenditure (CC) for new hydro projects; **(d)** Review of O&M expenses of plants being operated continuously at low level (e.g. gas, Naptha and R-LNG based plants). **(e)** Rationalization of O&M expenses in case of the addition of components like the bays or transformer or transmission lines of transmission system and review of the multiplying factor in case of addition of units in existing stations; **(f)** Have separate norms for O&M expenses on the basis of vintage of generating station and the transmission system. **(g)** Treatment of income from other business (e.g. telecom business) while arriving at the O&M cost.	• The escalation factor considered based on WPI & CPI is required to be reviewed as though O&M expenditure witness an increasing trend, WPI and CPI Index has witness a downward trend in past resulting in under recovery in O&M expenses. A combination of past period CAGR and index may be considered for proper estimation. • **Amongst the O & M cost components, the Employee expenses have nearly 60% weightage. Accordingly for determination of CPI: WPI weightage should be 60 % : 40 % .** • However, the option of determining O&M cost based on operation basis can be considered as Plant with Lower PLF / PAF may have a lower O&M Cost. But this may be only if such event is in continuous in nature for more than a tariff period and not to be considered for one year period. • The review of O&M expenses are required and impact of some new equipment's/components in the plants and related O&M needs to be encountered in the norms e.g. FGD, mandatory use of treated sewage water.
19.	**Fuel – Gross Calorific Value (GCV)**	
	22.8 (a) Take actual GCV and quantity at the generating station end and add normative transportation losses for GCV and quantity for each mode of transport and distance between the mine and plant for payment purpose by the generating companies. In other words, specify normative GCV loss between "As Billed" and "As Received" at the generating station end and identify	• This may be a positive step; however, the Commission needs to do a proper study to formulate the normative loss of GCV during each mode of transport and distance between mine and plant. • With third party coal analysis (CIMFR) it is observed that there are major grade slippages in the declared

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	losses to be booked to Coal supplier or Railways. **b)** Similarly, specify normative GCV loss between "As Received" and "As Fired" in the generating stations. **c)** Standardize GCV computation method on "As Received" and "Air-Dry basis'' for procurement of coal both from domestic and international suppliers.	grade and grade at loading end itself. Since the billing is done on declared grade, the "As billed" GCV will not give true picture. Hence the billing (including related taxes and duties) needs to be done as per loading end coal analysis report from CIMFR . • Also, booking of such losses to coal supplier and railways approach will provide the transparency and accountability in occurrence of loss for which the Generator would not be blamed for. However, the modalities for actual recovery of such losses are not clear. Any change in this regard needs consent from these independent agencies/organizations. Also it will need necessary changes in the related agreements (i.e. FSAs or Rail Transportation Agreements) between these agencies Whether this will be notional booking or will it be dealt through special approval of respective ministry, along with a mechanism to avoid any dispute in future or otherwise will there be Coal Regulator and Railway Regulator to sort out these concurrent issues, needs to be clarified. • Also, it is required to define the proper methodology for sampling method so as to identify the GCV at each mode of transport. Preferably BIS should be specified so that the sampling will be more representative and hence coal analysis will be more proper.
20.	**Fuel - Landed Cost**	
	24.5 (a) All cost components of the landed fuel cost may be	• Currently, complete fuel costs are allowed as pass

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	allowed as part of tariff. Or alternatively, specify the list of standard cost components may be specified; **(b)** The source of coal, distance (rail and road transportation) and quality of coal may be fixed or specified for a minimum period, so that the distribution company will have reasonable predictability over variation of the energy charges.	through, the same practice may be continued as the generator has no control over the coal availability and cost. Standardization of cost would further increase risk for generators. • Also, there is a need to redefine the transit loss based on the distance and mode of transportation of coal.
21.	**Auxiliary Energy Consumption**	
	26.3.8 The existing norms of auxiliary consumption of coal based generating station varies from 5.25% for unit size of 500 MW and above to 8.5% for 200 MW series units with steam driven boiler feed pumps and electrically driven boiler feed pumps and relaxed norms for specific generating stations of smaller size. Auxiliary consumption for gas based generating station varies from 1.0- 2.5% depending on open or combined cycle operation. The existing norm of auxiliary consumption of lignite based generating station is 0.5% more than coal based generating station with electrically driven feed pump and 1.5% more if the lignite fired station is using CFBC technology. The auxiliary consumption does not include colony power consumption and construction power consumption. **26.3.9** Presently, the auxiliary consumption of 800 MW is fixed based on 500MW sets. The auxiliary consumption of 800 MW sets may vary depending on the size of the unit and economies of scale.	MSPGCL submits that Auxiliary consumption % primarily depends on design considerations at the time of installation and subsequently on the operating PLF. The design considerations like factor of safety considered, spare and redundant capacities considered results into some specific auxiliary size selection. Further as each project is different in respect of its geographical needs, auxiliary capacities especially Balance of Plant auxiliaries varies from project to project. This will result in different base auxiliary consumption for different projects even for same capacity. Thus, once unit is installed and commissioned, this design Auxiliary consumption or auxiliary consumption guaranteed by the OEM can be considered as reference and the same would increase based on the degradation of the units. By means of additional capitalization/R & M, it may be at best possible to retain the base/design levels. MSPGCL would like to bring it to the notice of Hon'ble Commission that in case of Station Heat Rate, the Regulations provide for consideration of the guaranteed

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		heat rate (which would vary from station to station) and further a deterioration factor of 4.5% has been provided to cover possible real time operational variations and constraints. Thus, MSPGCL submits that in case of upcoming units, instead of fixing a specific auxiliary consumption norm, the design auxiliary consumption or guaranteed auxiliary consumption with a further operational margin of 4.5% should be recognized as a norm for that unit.
22.	**Thermal Generation (Coal washery rejects based)**	
	26.4.2 The Tariff Regulations, 2014 provides operational norms for thermal power plant based on coal washery rejects. Coal rejects exhibit distinguished characteristics. Coal rejects cannot be stacked as it would require a period is hazardous as it may lead to combustion. Comments / Suggestions **26.4.3** Comments and suggestions are invited from the stakeholders on the possible regulatory options discussed above and alternatives, if any.	Many of the existing generating utilities have been allotted Coal blocks as per the Coal Mines (Special Provisions) Ordinance, 2014. MSPGCL submits that currently the Tariff Regulations do not specify the treatment of coal rejects from such mining operations. However, MSPGCL understands that the said realized value will be reduced from the overall cost of coal and will therefore reduce the landed cost of coal at the end use power station. MSPGCL requests the Hon'ble Commission to provide necessary guidelines regarding factoring the economic benefit of reject coal in landed cost of coal for the end use power station.
23.	**Hydro Generation**	
	26.6.1 The existing Operational norms of Hydro generation include norms for auxiliary consumption, transformation losses and normative annual plant availability factor. Capacity Index as a measure of plant availability was implemented by the Commission during tariff periods 2001-2004 and 2004-09. It was	• Review of existing values of NAPAF based on actual PAF data for last 5 years may be positive as with increased technology PAF have improved. • Also, it needs to be considered that the Hydro plant NAPAF is also based on natural conditions and any

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	based on the concept that hydrology risk has to be borne by beneficiaries all the time. After consultation, capacity index concept was modified with the new concept of Normative Annual Plant Availability Factor (NAPAF) during 2009-14 and continued during 2014-19 based on actual data. However, in case of a few hydro plants the same was revised. This is based on the premise that hydrology risk is to be shared by the generator & the beneficiary in the ratio of 50:50. There may be need for review of existing values of NAPAF based on actual PAF data for last 5 years.	non-availability of water will also affects the Availability of the Plant.
24.	**Incentive**	
	27.2 At present there is same incentive for availability during peak and off peak period. There may be a need for introducing differential incentive during peak and off peak periods. On the same consideration, there may also be a need for higher incentive for the storage and pondage type hydro generating station providing peaking support. At present, generation beyond the design energy is paid at 80 Paise / kWh in case of hydro generating station, which may also need review. **27.5 (a)** Review linking incentive to fixed charges in view of variation of fixed charges over the useful life and on vintage of asset - Need for different incentives for new and old stations; **(b)** Different incentive may be provided for off peak and peak period for thermal and hydro generating stations. Differential incentive mechanism for storage and pondage type hydro generating stations may also be considered.	• Introduction of any incentive to supply power during peak period or peak season will definitely bring in more competition and encourage plants to supply power.
25.	**Sharing of gains in case of Controllable Parameters**	

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	29.1 The present regulatory framework provides for sharing of gains between generating company and beneficiaries in 60:40 ratio on account of improvement in controllable factors such as Station Heat Rate, Auxiliary consumptions, secondary fuel oil consumption, refinancing of loan and the true up of primary fuel cost. Subsequent to above, the compensation mechanism has been introduced for operation in CERC (Indian Electricity Grid Code) (Fourth Amendment) Regulations, 2016. The compensation mechanism aims to provide compensation if generating plant is operated at improved norms than ones specified in the amended IEGC Regulations of 2016. In view of the compensation mechanism, it needs to be considered as to whether the ratio of sharing of benefit may be reviewed. **29.2** The compensation mechanism introduced through IEGC entails the hedging of the risk of operating at low PLF. The compensation coupled with normative controllable parameters creates a buffer for generating companies. In view of this, the merit order operation can be linked with the PLF in such a way that the plants under Section 62 may be encouraged to compete for maximum PLF. **29.3** Further, different generators adopt different methodology for sharing of gain, say on monthly or annual basis. Thus, procedure for the monthly reconciliation or annual reconciliation mechanism may need to be prescribed	• As there has been amendment in IEGC which entails the hedging of the risk of operating at low PLF, the compensation coupled with normative controllable parameters creates a buffer for generating companies. • However, sharing of gains should be computed on annual basis • Also, plant with Low PLF affects the efficient parameter and therefore in case of any plant working on a lower PLF, then reconsideration of normative parameter is required.
27.	**Tariff mechanism for Pollution Control System (New norms for Thermal Power Plants)**	
	33.1 As per the new Environment norms notified by Ministry of	• Pass through of cost of FGD, ESP and other equipment's

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	Environment, Forest and Climate Change, the TPPs would be required to install or upgrade various emission control systems like Flue-Gas desulfurization ("FGD") system, electrostatic precipitators ("ESP") system etc. to meet the revised standards. Recovery of the investment made during operation period in the form of additional capitalization through redesigning or retrofitting of plant and related operational costs require a mechanism in the tariff regulations. **33.2** Several generating companies have filed petition for approval of additional capital expenditure under "change in law" for complying the revised standards of emission for thermal power projects. CEA may be required to specify and benchmark appropriate technology and costing norms, apart from preparing phasing plan for shutdown during installation of emission related retrofits/ equipment. The generating companies would be required to select suitable technology at competitive rates through the process of transparent competitive bidding to minimize the impact on tariff in the power supply agreement.	mandated by MOEF and other entities must be considered as part of capital cost and allowed as pass through as generators have no other option but to install them and spend the capital. • However, a definite principle is required to be identified, to undertake such activities.
28.	**Renewable Generation by existing Thermal Generation Stations**	
	34.2 One of the options is to install renewable project at the same location using the common facilities and land and bundle RE power with the conventional power prior to delivery point i.e. before ex-bus bar. Other option is to establish the renewable project at different location and pool the generation capacity on external basis beyond the delivery point. In both the cases, the annual fixed charges for thermal project and renewable project may be determined separately, based on separate set of tariff	• An option can be provided to Generator to set up the renewable project at the same location or at other location based on the available space, infrastructure, evacuation system, etc. • The annual fixed charges for thermal project and renewable project may be determined separately, based on separate set of tariff principles to avoid any disputes later on.

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	principles. **34.3** The scheduling and dispatch mechanism of renewable generation can be as per the thermal power generation. The target availability and dispatch level, in this case, maybe pre-specified which may be 2% higher for every 10% renewable capacity addition and the annual fixed charges for the thermal project and renewable project maybe combined for deciding the tariff. The rate of return, land cost, operation and maintenance cost for such renewable capacity can be specified separately.	• However, the Generator can have a right to blend the power to match the schedule so as to avoid any impact on availability.
29.	**Commercial Operation or Service Start date**	
	35.5 Comments and suggestions are invited from the stakeholders on possible options for dispute-free and practical mechanism for declaring commercial operation date. Comments and suggestions are also invited on the following. **a.** Addressing the shortcomings in existing methodology for the trial run of generating station and trial operation for transmission element through appropriate regulatory mechanism; **b.** Issue of trial operation and commissioning of the project when a generating station is ready but cannot be operated due to non-availability of load or evacuation system; **c.** Issue of acceptance of COD of transmission line if the generating project or upstream/ downstream transmission assets are not commissioned; **d.** ………………………….. **e.** Linking of commercial operation date with schedule commercial operation or schedule commencement date of the Power Purchase Agreement or Long Term Access Agreement respectively; **f.** Linking the commercial operation date of the transmission	• For this, all entities i.e. generators, STU / CTU and beneficiaries must work together in a coordinated manner to achieve COD and all the entities must be invited at the trial runs and must give consent for the same. • For the issue of one entity being ready and other not i.e. Issue of acceptance of COD of transmission line if the generating project or upstream/ downstream transmission assets are not commissioned or vice-versa, even after the coordinated efforts, the entity (upstream/downstream) which is responsible for the delay must bear and compensate the others for the possible delay in COD i.e. Scheduled COD to Actual COD in line with the PPA so as the Utility without any default remains revenue neutral. • Commercial Operation date of transmission system exclusively associated together with the generating station/unit should be linked so as to enable completion

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	system with the commissioning of the generating units or stations; **g.** Separation of the commercial operation date of the unit or stations, the transmission element or system from the service start date under the contract.	of both in a well-coordinated and timely manner.
30.	**Alternative Approach to Tariff Design**	
	37.6 Views and comments are therefore being solicited on the following questions: **a.** Would it be advisable to undertake econometric analysis to arrive at benchmark capital cost? **b.** What are the variables that should be considered for the purpose of determining Capital Cost on normative basis? **c.** Any other methodology for benchmarking the capital cost for generation and transmission projects?	• An econometric analysis may be undertaken to arrive at the benchmark capital cost (hard cost). However due to different technology being used by different generator, the component wise analysis is required to be undertaken. • Benchmarking of cost of each component/equipment of the power plant (including new equipment i.e. ESP, FGD etc) must be done. Further, total capital cost based on this can be used to calculate AFC. This will reduce the efforts of Regulators in doing prudence of each components cost unless there are some uncontrollable situation, apart from that benchmarking of certain generic uncontrollable and controllable factors affecting delay and capital cost of plant may be thought of. • Variation from benchmark may be allowed only under Force Majeure conditions.
31.	**Normative Tariff by fixing AFC as a percentage of Capital Cost**	
	37.9 In this regard, views/ comments are solicited on the following:- **a.** Whether it is a good idea to determine AFC as percentage of Capital Cost on normative basis? **b.** What could be the possible methodology to establish the	• Capital Cost cannot be only factor to determine AFC as the plant design, technology may differ for different generator. O&M expenses may be higher in initial years for the advanced plant for stabilization of the technology (AMC type) and for other plant the O&M

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	relation between AFC and Capital Cost so that it meets the interests of both buyers and sellers?	may be higher later on.
32.	**Normative Tariff by fixing each component of AFC as a percentage of total AFC**	
	37.17 In this context comments/ observations of stakeholders are invited on the following points. **a.** Whether clustering the components of AFC based on their nature to increase/ decrease in order? Any other possible method to cluster the AFC components? **b.** What methodology should be adopted to determine the escalable (increasing)/ non-escalable (decreasing) factors? **c.** Whether escalable (increasing) / non-escalable (decreasing) factors should remain same for all plants/transmission systems (or) they be separate for each of the plants/transmission systems based on vintage / capacity / fuel type/ fuel linkages etc. **d.** Whether isolation of "Additional Capitalization" as a separate stream of revenue would provide for recovery of AFC on a normative basis in realistic terms? **e.** Alternatively, do you suggest any other methodology to treat "Additional Capitalization" for determination of AFC on normative basis? **f.** Whether applicability of change in tariff principles in each control period for the new plants would allow regulatory certainty to the existing plants?	• Benchmarking of cost of each component/equipment of the power plant (including new equipment i.e. ESP, FGD etc) must be done. Further, total capital cost based on this can be used to calculate AFC. This will reduce the efforts of Regulators in doing prudence of each components cost unless there are some uncontrollable situation, apart from that benchmarking of certain uncontrollable and controllable factors affecting delay and capital cost of plant may be thought of.
33.	**Principles of Cost Recovery - Approach towards Multi-Part Tariff**	
	37.20 The proposition is to introduce the system of differential AFC recovery linked to peak and off-peak periods in the following manner:- **a.** Off-peak component of AFC: The generating station has to	• **MSPGCL agrees that there is need for duality in approach so that generators can conserve resources during off-peak period/season and take maximum efforts to give maximum generation during peak**

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	declare a PAF of 80% for the year, which allows recovery of 80% of the AFC. Any slippage to meet the above norm would result in reduction in 80% of AFC in proportionate manner. **b.** Peak component of AFC: The remaining 20% of the AFC is recoverable from the beneficiaries, if the generating station achieves a PAF of 95% for the peak period, say of 4 months. During the currency of peak period, adherence to the norm of 95% PAF will be reconciled on monthly basis and slippages from this norm i.e. 95% up to the limit of 80%, would result in reduction in higher peak AFC for that month. **c.** The peak and off-peak months for each generating station will be declared by the appropriate RLDC by considering load profile of beneficiaries. The proposed mechanism also seeks to provide for a higher peak price, say at 25% over the off-peak price. Accordingly, the weightage factors can be calculated by considering: **i.** Recovery of 80% of AFC, upon declaration of 80% PAF during the year and remaining 20% of AFC upon achieving 95% PAF during the peak period, say of 4 months. **ii.** Higher peak price (i.e. by 25% over the off-peak price)	**demand period / season. However MSPGCL seems that the suggested approach of differential AFC recovery is less effective.** • This is so because taking into consideration the loss of Availability on account of planned and forced outages and also considering the coal supply related difficulties during rainy season, generating companies (especially coal based thermal plants) can't maintain PAF above 80% for about 3 months of a year and thus to achieve the annual target of 80% need to anyhow maintain AVF more than 80% during the balance year. However, achieving AVF may not necessarily mean achieving the higher Plant Load factor, as is desired. • **Thus MSPGCL is of the opinion that differential AFC will not yield too much in respect of reduction in peak period/season gap.** Also consistently achieving 95% PAF for the peak period may not be possible for all thermal units owing to many reasons like technology issue. • **Instead MSPGCL suggests <u>to discontinue the incentive provision on Target Annual Plant Load Factor and introduce higher incentive on peak period PLF and disincentive /(negative incentive) on lower PLF during Peak period, similar to UI charges.</u> This will act as a motivation to achieve higher PLF during the need of the grid.** • **The peak period and the threshold for peak demand will vary from state to state. Hence peak demand**

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		period and the peak demand threshold for ensuing year may be fixed by the State Regulator, on the basis of historical data. e.g. in Maharashtra , the average of maximum demand for MahaDiscom licensee area (State Discom) during March to May period for FY 17-18 & FY 18-19 has been apprx. 20000 MW. So for MahaDiscom area, one peak period slot will be March to May with peak demand threshold fixed at 80% of the average max. demand i.e. 16000 MW. Thus, if a generator supplying power to MahaDiscom maintains PLF above 90%, it should be made eligible to get incentive for such higher generation, say at 75 paise unit. However, if the generator maintains PLF below 80% during such period it should be made liable to disincentive, say at *minus* 25 paise (- 25 paise) per unit. So this will help to achieve the desired higher actual generation during the need of the grid.