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Federation of
Indian Chambers
of Commerce and Industry

Federation House
Tansen Marg
New Delhi - 110001
T : +91 11 23738760 (11 lines)
F : +91 11 23320714 / 23721504
E : ficci@ficci.com
W: www.ficci.com
CIN : U99999DL 1956NPL002635
ISO 9001 : 2008 Certified

Vishal Dev
Additional Director

July 31, 2018

Shri Sanoj Kumar Jha
Secretary
Ministry of Power
Central Electricity Regulatory Commission (CERC)
New Delhi

01/08/18

Dear Shri Jha,

Comments on CERC Consultation Paper on Tariff Regulations for period 2019-24

Chief (Fin)

This has reference to the Consultation Paper on Tariff Regulations for period 2019-24 on which comments/ suggestions were invited by CERC to be submitted by 31st July 2018 vide notification no. L-1/236/2018/CERC dated 13-07-2018.

DC(RB)/Fin
7/8/18

In this regard, FICCI has extensively discussed the suggested provisions of this paper with all its members and compiled their comments as an input to CERC for kind consideration before finalization of Tariff Regulation for 2019-24.

Please find the hard copies of the comments enclosed here with the letter. The comments in soft have already been mailed on July 31, 2018.

We will further, be more than delighted to clarify or discuss any issue pertaining to the suggested provisions, if the need be.

With best regards,

Yours sincerely,

Vishal Dev

Vishal Dev

FICCI Representation on

‘CERC Consultation Paper on Terms and Conditions of Tariff Regulations

For Tariff Period

1.4.2019 TO 31.3.2024’

Submitted to:

Central Electricity Regulatory Commission

Section wise recommendations on 'CERC Consultation Paper on Terms and Conditions of Tariff Regulations for 1.4.2019 TO 31.3.2024'

A) A Consultation Paper on 'Terms and Conditions of Tariff Regulations for the period 1.4.2019 TO 31.3.2024 was published by CERC on 24th May 2018 vide notification no. L-1/236/2018/CERC. CERC had invited comments/suggestions from the stakeholders on the Consultation Paper due for submission by 31st July 2018.

B) In this regard, we have solicited the feedback of our industry members. Based on the feedback, FICCI recommends the following:

Para No.	Para	Comments / Suggestion
Thermal Generating Stations –Tariff Structure *Options for Regulatory Framework*		
7.2.4	The possible options for tariff structure could be to offer to the procurers having low demand a menu of options for ensuring dispatch by linking a portion of fixed charges with the actual dispatch and balance of AFC to availability. This will ensure optimum utilization of the infrastructure, as procurers will continue to procure power from the generating stations and the generator will get reasonable return without losing the demand.	We are not in favour of three-part tariff structure, rationale being: 1. It involves a radical departure from stated policy as well as standard practice, Tariff Policy having laid out a two-part tariff structure in Generation Sector to be aligned with Long and Medium-Term Contracts and to facilitate Merit Order Dispatch. A three-part tariff will destabilise the current market functioning. 2. The proposal seems to have been made out of the concern that part

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).	capacities are not utilised due to low demand, leading to low PLF. A lasting and futuristic solution would be to increase the depth of the market to provide for larger proportion of Short Term Contracts as well as choice of exchange traded products based on demand dynamics and appetite of buyers. Such mechanism will allow capacities to enter into both forward trades with lock-in of prices and spot sales aligned with demand sensitivities experienced by buyers. 3. In future, Long or Medium-Term Contracts should only be limited to capacities that can be tied up with beneficiaries to serve their base load, leaving balance capacities open to market operations. This will imply that regulated tariff and its recovery will apply to the capacity to be served under Long and Medium Term PPA, which is also one of the options given under Para 9.3. 4. In sum, market-based instruments of forward trades and even derivative products should provide the solution to flexible operations of unutilised capacities in the face of demand uncertainties rather than introducing an additional element of regulated tariff with associated complexities of constructing such tariff. Higher penetration of renewable energy will produce further capacity strain and hence, a market-based solution rather than a regulated tariff will be seen appropriate. The option of open market operation of unutilised capacity to provide flexibility to buyers and sellers has also been stated under Para 10.2. 5. Proposal of three-part tariff structure is fraught with complications involving apportionment of O&M costs under fixed and variable charges and realistic assessment of incremental return above guaranteed return under variable charge. Firstly, a rule-based system will be necessary to decide upon
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.	

		proportionate allocation of O&M expenses linked to dispatch and plant availability. Secondly, cost of equity to provide for both risk free and incremental return is to be established by application of Capital Asset Pricing Model (CAPM) and assessing the equity Beta (β) which will measure the relative riskiness of the sector compared to the market as a whole. Comparative data may not be available to permit such evaluation and there is also the case that equity return aligned with dispatch will be restricted only to the risk-free level if balance capacity under availability remains un-requisitioned or unutilised.
Thermal Generating Stations – Older than 25 years *Options for Regulatory Framework*		
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.	Decision should be on case to case basis and on merit to establish which option would be particularly suited in a given situation. For example, cost of ownership as well as improvement of efficiency parameters should be the guiding principle in replacing sub-critical units by super-critical units. A principal consideration for phasing out old units should be improvement of Station Heat Rate (SHR) as well as amenability to environmental compliance in accordance with the new norms of PM, NO_x and SO_x emissions and water consumption notified by MOEF&CC. In such cases, for plant modifications, retrofitting and new additions are to be kept in view based on techno-commercial analysis.

Hydro Generating Stations - Tariff Structure *Options for Regulatory Framework*		
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.	Our observations are as under: 1. We are of the view that a combination of policy measures, market intervention and tariff design, including ToD tariff and hourly pricing, would be necessary to enable optimum utilisation of hydel generation capacities. Particularly through adequate market design, hydro power can be made to serve peaking and balancing loads as well as provide ancillary services operation to meet the challenging task of firming up renewable energy generation, which will be both uncertain and variable / intermittent. Regulatory attention is necessary to develop such concept of market design. 2. The proposal of reformulation of fixed and variable charges could serve as an interim measure till a new market design as outlined above to compensate hydel projects with commensurate tariff is introduced. However, care is to be exercised to ensure that cost of equity finance is captured realistically applying Capital Asset Pricing Model and the risk free return is aligned with G-Sec yield on a dynamic basis based on market movements. 3. Clarity is lacking in that the components identified under 'annual fixed cost' are overlapping with those given under fixed and variable charges in the preceding sentence.

Inter-State Transmission System - Tariff Structure *Options for Regulatory Framework*		
7.5.5	The tariff for transmission of electricity on inter-State transmission system can consist of fixed components and variable components. a) The fixed components may consist of either (i) annual fixed cost of some of fixed transmission system designated for access and immediate evacuation, (ii) annual fixed cost of the evacuation transmission system or (iii) part of annual fixed cost of the entire transmission system consisting of debt service obligations, interest on loan, guaranteed return; b) The variable components may consist of either (i) common transmission system or system strengthening scheme excluding immediate evacuation transmission system, (ii) common transmission system excluding evacuation transmission system or (iii) sum of incremental return above guaranteed return, operation and maintenance expenses and interest on working capital.	We propose retaining the single part tariff structure and would observe as follows: 1. In case two-part tariff is introduced, either the Transmission Licensees shall be left with under recovery of their cost or some of the beneficiaries will end up paying more than their legitimate share. Example – Assume 2 x 500 MW customers seeking open access. Customer A is using the network for 20% energy transaction and Customer B for 80%. In this case, both will pay equal access charge but Customer B will bear more service charges even though there is no additional expenditure on this account. 2. The two-part tariff structure is complex and will be difficult to implement. The break-up suggested of fixed and variable components has overlapping terminologies of transmission systems that do not provide adequate understanding and calls for apportionment of costs on judgemental basis without defining a rule-based system. Secondly, splitting return on equity between fixed and variable components does not seem a sound proposition, transmission being both a sunk cost and shared asset. 3. Proposal will adversely affect financials of Transmission Licensees, as lenders will consider such change in methodology of recovery of transmission charges as increase in risk perception, leading to higher rate of interest and AFC. 4. Introduction of Two Part Tariff for Transmission will require amendment /
7.5.6	The recovery of fixed component can be linked to the extent 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.	change in PoC regulation / methodology. 5. The Transmission Licensee is responsible for maintenance of his line and makes it available for use, while actual usage of a particular transmission line and its loading is guided by Law of Physics and decided by System Operator, i.e. RLDC / SLDC. The transmission licensee owning a line has no control over use / non- use of his line and hence it is not justifiable to decide tariff based on usage of the line. 6. Further the system is designed in a manner that there is n-1 contingency and hence, full capacity of transmission system will never be utilized and consequently two-part tariff will lead to under-recovery of Tariff for Transmission Licensee. 7. Para 7.5.2 states single part tariff is suitable for long term open access but not medium and short-term transmission access on the reasoning that market participant may seek access but not necessarily avail the transmission service unless there is actual transaction. It is to reckon that both intermittency of renewable energy generation and demand uncertainties have reduced the dependence on Long-Term Contracts, which lock-in transmission capacities. Transmission network will be increasingly subject to changes in flow patterns and will require higher transmission capacity margins for short-term transactions and hence, greater flexibility in transmission corridor allocation. Rather than introducing a two-part tariff structure and distinguishing between access and usage charges, products such as Financial Transmission Rights and Physical Transmission Rights will seem appropriate consistent with a dynamic and real time market design to make transmission access flexible and reduce usage costs without

		compromising on reliability.
Renewable Energy Generation – Tariff Structure *Options for Regulatory Framework*		
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.	We would observe as follows: 1. In accordance with standard practice, as also followed internationally, we propose retention of single part tariff for solar and wind power generation under renewable energy and avoid mathematical complications of identifying the components under the notion of 'fixed variable charges'. In any case, return on equity as a variable component will provide wrong market signals. O&M expenses also are generally identified under fixed charge. Further, using the variable component so determined and taking it for comparison purpose with other generation sources under Merit Order Dispatch would be a theoretical exercise prone to subjective assessment. It is also the case that renewable energy plants enjoy the must-run status in terms of present policy and are not subject to Merit Order Dispatch. 2. Proposal of identifying capacity augmentation such as storage or back-up supply tariff under variable component is fraught with error of judgement as because such constituents will comprise balancing costs and cannot be termed as variable charge. Separate policy instrument is necessary to

		socialise such costs and ensure their recovery. 3. It is to reckon that renewable energy by definition will cover a wide range of generating plants apart from solar and wind, viz. Biomass, Biogas and small hydro etc. While small hydro follows single part tariff, the other two sources have different considerations applied for computation of fixed and variable charges. Thus, a blanket provision of introducing two-part tariff structure cannot be generalised for all sources of renewable energy generation and case by case approach is necessary.
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 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	We prefer option b) suggesting bundling of renewable energy tariff with the fixed and variable components of thermal generation in proportion of capacities utilised of the respective generation sources and supplied in terms of PPA. In terms of Para 9.3, recovery of regulated tariff of thermal plant will apply pro-rata to the capacity supplied under PPA. The capacity made spare because of substitution by renewable energy should be left to open market operations and offered to prospective beneficiaries. This will obviate the necessity of revising operational norms or providing safeguards against recovery of fixed charges, including return on equity.

	generation and thermal power generation may be recovered separately. The operational norms for recovery of tariff may have to be specified separately.	
8. Deviation from Norms *Options for Regulatory Framework*		
8.4	Possible option could be to develop for incentive and disincentive mechanism for different levels of dispatch and specifying the target dispatch expanding the scope of Regulation 48 above.	We would comment as under: 1. Development of incentive and disincentive mechanism for different levels of dispatch need not be part of regulation, being case-specific. Such provision can be made under a bilateral arrangement. 2. The said option would be contradictory since on one hand as per present Tariff Regulations, incentive is offered at higher PLF beyond Normative Availability and on the other hand there will be incentive / disincentive below target availability also.
9. Component of Tariff *Option for Regulatory Framework*		
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	As stated hereinbefore, it is suggested that appropriate regulatory commission should determine tariff for the power station / unit as a whole irrespective of the quantum of power contracted and subsequently, this tariff can be applied pro-rata to portion of power contracted under Section 62 while for the balancing capacity, tariff discovered through competitive bidding or market-based operations can

	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.	apply.
10. Optimum Utilisation of Capacity ***Coal based Thermal Generation*** *Option for Regulatory Framework*		
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 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	We would comment as under 1. Redefining Annual Contracted Capacity (ACC) and introducing the concept of guaranteed contracted capacity as its equivalent will lead to subjective interpretation of contractual terms and conditions and be detrimental to the interest of the generator. On the contrary, capacities should be contracted to the extent load demand is to be met leaving the residual capacity for market-based operation as stated under Para 9.3. Given the demand variations that will emerge out of economic outlook as well as higher penetration of renewable energy, capacities can be tied-up for delivery under forward trade mechanism and also as derivatives in a futures market. We are, therefore, not in favour of the proposal. 2. Providing distribution licensee, the right to recall Unutilised Capacity (UC) provides undue advantage to one of the parties, will give rise to Contract of Adhesion. As proposed, the provision of apportionment of fixed cost of 10-20% or alternatively, debt service obligations for recovering such right will lead to both approximation and subjective judgement not supported by

	capacity. The surplus capacity may be reallocated to the distribution licensee at market discovered price.	principles of cost recovery. 3. The proposal under Para 10.3 (b) is not workable, as it may not be right to assume that the capacity that will be bidded out to discover market price will remain open in the absence of buyers. It is also difficult to sustain bidders' interest if capacity is not offered to prospective buyers and put to bidding only for the purpose of price discovery. To assume that distribution licensee will have access to surplus capacity upon bidding and price discovery will not be realistic.
Hydro Generation *Option for Regulatory Framework*		
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.	We would observe as follows: 1. For a private developer, it is difficult to get a loan of tenure of more than 10-12 years, especially for risky Hydro projects. Therefore, the current method should continue to invite the interest in Hydro Projects. Also, for the Hydro Projects allotted through Bids or otherwise, the implementation agreement is limited up to 25 years. Thereafter the project is to be owned by the State Govt. In such scenario, the promoters & IPPs need to recover all the costs prior to handing over to State. The current life of 35 years should be examined in the context of the implementation agreement so that lenders/investors and other stakeholders recover their dues before the implementation agreement expires. 2. Reliability Charges shall be over and above the Annual Fixed Charges
10.5	(b) Assign responsibility of operation of the hydro	We would observe as follows;

	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.	1. Option 10.5 (b) seems practical, but it requires more deliberations. 2. Secondly, the provision should not be applicable for existing projects as investment in these assets have been made based on prevalent depreciation rates and any change in the same would affect their finances considerably and lead to higher risk rating which will in turn lead to higher interest rate. The gains accruing to the beneficiaries by reduced depreciation on account of increase in useful life will be offset by higher interest rate. 3. Further there is lack of clarity about the treatment of expenses made towards R&M, before the defined life.
Gas based Thermal Generations *Option for Regulatory Framework*		
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.	We propose scheduling and dispatch at regional level to enable consolidation of balancing loads arising out of variable renewable generation and undertake operation of gas-based stations on an aggregated basis. Such operation will essentially be short term that can also meet peaking loads and regulation services and will require real time market design with ToD and hourly pricing mechanisms.

	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.	
11. Capital Cost *Option for Regulatory Framework*		
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.	We would observe as follows: 1. As rightly pointed out, in the absence of credible benchmarking of technology and capital cost, prudence check may not yield the desired results. Instead, the due diligence done by lenders prior to sanctioning of loans could be a starting point for allowing provisional capital cost to be trued up subsequently on project completion. This will lead to hastening up the approval process and prevent duplication 2. There should not be any cut-off date for essential expenses. If there is prudent reasoning for any work be it originally envisaged or other-wise at any time during the tenure of the project, there is no reason to deny the same. 3. The Commission may include provision related to additional capital expenditure to meet exigency as well as efficiency requirements based on prudence checks. The Commission may define broad heads in this regard. 4. Control systems, system software etc. are prone to obsolescence due to rapid technological advancement and the same needs to be suitably

		allowed under additional capital expenditure.
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 commissioning can also be introduced.	We would observe as follows: 1. Variable factors in a generation plant or in transmission lines are so high that each plant is unique in itself, as far as design and investment is concerned and therefore, it is practically impossible to define the benchmark cost. 2. There is no regulatory sanctity for Benchmarking Norms or Investment Approval. The Commission has dispensed with the requirement of prior capital cost approval also. 3. Once prudence check has been performed and only legitimate costs are allowed, then such costs along with the costs related to its financing plan are to be also allowed. 4. For increase in capital cost due to uncontrollable factors, developer will have to incur the equity which otherwise would have earned the same return / higher return of equity from investment in other businesses (Cost of Equity). 5. It is to be appreciated that cost over-runs are not completely funded by debt. Proportionate equity has to be brought in by the Promoter. Equity has an opportunity cost. However, this cost does not get recorded in books of accounts. Though the Regulation allows compensation towards increase in cost due to uncontrollable factor so as to place the developer in the same economic position had this uncontrollable event not occurred but it is not clear that cost of equity (which is a universal concept) will be allowed as compensation also since it is not recorded in books of accounts and whatever is not recorded in the books of account will not be certified by Auditors and whatever is not certified by auditors might create dispute. 6. In any case, the cost overrun is allowed by the Hon'ble Commission only after due prudence check of the delay and after satisfactory demonstration of no fault from developer's side. In case the same is found attributable to the developer, the same is disallowed by the Hon'ble Commission. The

		developers do not earn any return on equity deployed for such disallowed investment. Hence, further reduction in reasonable return to shareholders for the cost overrun allowed by the Hon'ble Commission would imply imposition of penalty for no fault of the developer and is therefore not desirable. This would in turn reduce the cash flow to reserves for funding future growth 7. The incentive for early completion of the project from scheduled commissioning may be linked with an additional post-tax Return on Equity of 0.5% in line with the prevailing Tariff Regulations.
12. Renovation & Modernisation *Option for Regulatory Framework*		
12.6	The R&M of transmission system could include Residual Life Assessment of Sub-Station and Transmission Lines, Upgradation of sub-station and transmission line, System Improvement Scheme (SIS) and replacement of equipment. The Commission may allow Renovation & Modernisation (R&M) for the purpose of extension of life beyond the useful life of transmission assets. Alternatively, the Commission may allow special allowance for R&M of transmission assets. Such provision will enable the transmission companies to meet the required expenses including R&M on completion of 25/35 years of useful life of sub-station/transmission line without any need for seeking resetting of capital base.	We propose the option of providing R&M allowance for the purpose of extension of life for transmission assets. The exercise can be on case to case basis upon assessment of asset condition, residual life and recoverability. Suitable R&M norms should be developed to allow utilisation of assets beyond their useful life.
13. Financial Parameters		

13.1	The performance based cost of service approach, a combination of actual cost and normative parameters has been evolved for the Tariff regulations. Components like return on equity, operation & maintenance expenses and interest on working capital have been specified on normative basis whereas cost of debt has been allowed based on actual rate of interest on normative debt. The normative parameters are expected to induce operational and financial efficiency. While continuing with the hybrid approach, more weightage may be provided for normative parameters to induce greater efficiency during operation as well as in development phase.	We are in favour of continuation of present normative approach for specifying financial parameters with cost of debt being allowed on actual basis on normative loan component.
14. Depreciation *Option for Regulatory Framework*		
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	We would observe as follows: 1. Increasing the useful life after distinguishing 'well maintained plant' will be a subjective approach. 2. Concept of weighted average useful life in case of phased commissioning is both feasible and scientific and hence, should be continued with. 3. R&M projects should be admitted based on the technical reports and should not be restricted to limited items/equipment. Further, there may be requirement of additional capital expenditure on account of premature failure of equipment or to comply with the stricter statutory norms which

	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. 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).	may not necessarily ensure a life extension of the entire Project. Such schemes may be allowed based on their merit. 4. Depreciation allowed under the regulatory mechanism is a major component of tariff and assures the cash flow for the project. Frequent revision in depreciation will result in uncertain cash flows and this will create problem in arranging finance for the project. Therefore, it may not be desirable to reassess life and recompute depreciation at start of every tariff period. 5. Extension of useful life cannot be subjective but requires expert opinion and consultation with OEM. 6. With more RE sources coming into Grid, useful life of thermal power stations gets affected due to frequent cyclic loading, which induces fatigue. Further, frequent shutdowns due to Reserve Shut Down (RSD) and low PLF will also affect the useful life of the plant which may not be even 25 years. Hence the depreciation shall be maintained for 12 years. 7. Ideally, option g) seems the best, as it tends to protect the interest of the existing stakeholders; however, the residual value/scrap value may be changed to 5% instead of 10% in line with Companies Act, 2013. 8. Alternatively, depreciation may be linked to debt repayment rather than linking it to useful life of the asset since, loan tenure in most cases is such that a depreciation of 7-8% is needed to repay the loan ever year. Therefore, it is suggested to reassess the depreciation rate which needs to be enhanced and the salvage value considered at 5%. In consonance with Companies Act, 2013 9. Depreciation on additional capex should be allowed commensurate with the

<table>
<tr><td></td><td></td><td>residual life of the assets.

10. At the end of useful life of the assets, beneficiaries should be obligated to pay for the residual value.</td></tr>
<tr><td colspan="3">15. Gross Fixed Asset (GFA) Approach
Option for Regulatory Framework</td></tr>
<tr><td>15.2</td><td>An option could be to base the returns on the modified gross fixed assets arrived at by reducing the balance depreciation after repayment of loan in respect of original project cost.</td><td>We would observe as follows:

1. Referring to Para 15.1 that no new coal-based capacities will be required till 2027, National Electricity Plan of CEA suggests coal-based capacity of 47855 MW to be in pipeline between 2017-22 and an additional capacity of 46420 MW to be required during 2022-27. The statement needs correction.

2. Existing GFA approach should be continued as it incentivises equity investors for efficient operations and proper utilisation of assets.

3. Modified GFA approach is not advisable in Infrastructure Company having long term exposure taken by lenders and investors, as otherwise projects would not get funding.

4. We therefore, suggest to continue approach of RoE till the supply / service continues since:

○ Unlike debt, developer does not earn return on equity during</td></tr>
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		construction period. ○ Power Sector is going through critical phase and private investment has slowed down in generation and transmission projects. Also, existing projects, when conceptualized, were evaluated considering RoE till the supply/service continues. 5. Tariff Policy mandates regulatory certainty and any such move will demotivate the prospective investors. 6. During the past Tariff Regulations, the returns on modified GFA arrived at by reducing depreciation has not been used after elaborate discussion (ROE versus ROCE approach). 7. Accordingly, this proposal may be disregarded since all past implemented projects achieved financial closure assuming returns on GFA basis and not modified GFA. Altering the methodology will increase the perceived risk and banks will charge a higher interest rate which will be passed on to beneficiaries and thereby, negate the gains achieved by basing the returns on modified Gross Fixed Assets.
16. Debt: Equity Ratio *Option for Regulatory Framework*		
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.	We would observe as follows: 1. Proposal is in contravention of Tariff Policy which states "*For financing of future capital cost of projects, a Debt: Equity ratio of 70:30 should be adopted*." 2. It should be noted that 80:20 ratio is not available commercially in market as lenders are not keen to provide such comfort given the perceived riskiness of

		projects under power sector relative to the market.
17. Return on Investment		
17.4	Comment and suggestions are invited from the stakeholders on the continuation of fixed rate of return approach or alternatives, if any.	We agree with Commission's analysis. RoE approach shall provide regulatory certainty to developers.
18. Rate of Return on Equity *Option for Regulatory Framework*		
18.6	According to CEA, the capacity addition is no more a major challenge and adequate installed capacity (along with currently under installation) exists to meet the demand for the next 8-10 years. Further, the rate of interest has also come down in recent times. Therefore, there is market dynamics which favours reduction of rate of return. However, any such reduction will have negative impact on the equity already invested in the existing and under construction projects, creating further financial stress on such projects. Different rate of return for new projects (where financial closure is yet to be achieved), may be thought of, with different rates for generation and	Our view is that while the rate of interest has come down, the riskiness of the power sector as a whole has increased and led to financial stress impacting the banking sector. These risks have been beyond control of project sponsors and have been the result of policy, regulatory and operational uncertainties. Thus, whether or not the rate of return should be revised for new projects vis-a-vis existing ones requires careful consideration and proper judgement, considering that the cost of equity finance is higher and ROE should not be subject to downward revision in present market context.

	transmission projects.	
18.7	a) Review the rate of return on equity considering the present market expectations and risk perception of power sector for new projects;	We would observe as follows: 1. It is agreed that the rate of return on equity needs to be reviewed keeping in view market performance and overall risk perception of power sector for new projects. It is suggested that the Hon'ble Commission may determine the ROE based on the Capital Assets Pricing Model (CAPM), specifying the Rf (Risk free return), Rm (expected market return) and β (Beta for the sector) and publish the findings. This will also establish the efficacy of RoE prescribed for 2014-19 period.
	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;	2. Different rates can be specified for Thermal and Transmission projects only upon establishing their relative riskiness vis-a-vis the market. However, no distinction is to be made between new and existing projects since Beta (β) for companies in power sector will remain same due to undiversifiable nature of risks. Also, market risk premium for new and existing projects will be the same.
	c) Have different rates of return for thermal and hydro projects with additional incentives to storage based hydro generating projects;	3. The rate of return for hydro projects should be higher than thermal projects due to higher level of risk exposure during construction, with additional incentives allowed for storage-based projects. Hon'ble Commission has already specified different RoE for Thermal (15.5%) and Hydro (16.5%) in 2014-19 Tariff Regulations based on risks involved and the gestation period for commissioning the 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	4. On the contrary, because of higher risks involved, the allowable return at a higher and differential rate should be assured for hydro projects, and a commensurate incentive of 1% additional return should be considered against timely execution.

	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;	5. Pre-tax RoE ensures that tax only on the related business is allowed to be recovered. We agree with this proposal.
	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;	6. Rationale same as point (b) above.
	g) Reduction of return on equity in case of delay of the project;	7. Infrastructure projects are often affected by delays. CERC during the prudence check of capital cost, disallows all the expenditure resulting from delay in COD. Therefore, the claims under Annual Fixed Charges are already reduced. As such further reduction of rate of return will be a double impact on the project developers. This would lead to the sector being perceived riskier and less attractive for promoters and investors.
19. Cost of Debt *Option for Regulatory Framework*		
19.4	While allowing the cost of debt as pass through, options available for regulatory framework are either to consider normative cost of debt based on market parameters or actual cost of debt based on loan portfolio. As the tariff is determined for multi-year	1. The cost of domestic borrowing is high and is associated with credit rating of the project as well as developers that may not be same. Normative cost of debt on the basis of present debt market condition is not a viable option and we are in favour of adopting cost of debt based on actual loan portfolio as

	period and cost of debt varies based on changing market conditions, linking cost of debt to market parameters such as MCLR & G-sec will bring a degree of unpredictability. The regulatory approach evolved so far has been to allow the cost of debt based on actual loan portfolio. This does not incentivize the developers to restructure the loan portfolio to reduce the cost of debt. The current incentive structure may need review to encourage developers to go for reduction of cost of debt.	per present regulatory practice. 2. Given that the sector is facing financial strain and the loans are stressed and leading to NPAs, we do not see a new interest regime emerging to allow developers to have the flexibility of applying differential costs.
19.5	a) Continue with existing approach of allowing cost of debt based on actual weighted average rate of interest and normative loan, or to switch to normative cost of debt and differential cost of debt for the new transmission and generation projects; b) Review of the existing incentives for restructuring or refinancing of debt; c) Link reasonableness of cost of debt with reference to certain benchmark viz. RBI policy repo rate or 10 year Government Bond yield and have frequency of resetting normative cost of debt;	
20. Interest on Working Capital (IOWC)		

Option for Regulatory Framework		
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.	a) The same approach may be continued.
	(b) As stock of fuel is considered for working capital, a fresh benchmark may be fixed or actual stock of fuel may be taken.	b) Actual fuel stock should not be used for computing working capital requirements. It is a fact that most of the plants are today operating at less than 7 days coal stock, but that is because of lower coal supply by CIL and its subsidiaries. Generating companies face huge risk of un-planned shutdowns due to lower coal stock. Today there is a need to put clear responsibilities on the coal supplying companies to ensure that at least 1 month of coal stock is available for power companies so that they don't have to rely on auction / open market coal which increase the costs as well as working capital requirements.
	(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.	c) Current normative approach should be continued. Presumptive estimates in preference to established practice will lead to discretionary measures.

	(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.	d) The current approach should be continued. Time and cost over-runs are not always under developers' control and departure from established practice is not recommended in the absence of a deleterious cost impact.
	(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.	e) The current approach should be continuing. Linking the working capital requirement with the PLF is not advisable. A Generator has to make the arrangements of fuel etc. and make expenditure in advance to be available for the next day whereas PLF is a real time scenario. Therefore, linking the working capital requirement with the PLF may lead to reduced availability and consequently reduced PLF. In such a scenario generator would also be losing the capacity charges.
21. Operation and Maintenance (O&M) expenses *Option for Regulatory Framework*		
21.7	(a) Review the escalation factor for determining O&M cost based on WPI & CPI indexation as they do not capture unexpected expenditure;	(a) WPI & CPI is the best reflection of the increase in wholesale and consumer prices. This may be continued. The unexpected as well as unavoidable expenses viz. ash disposal charges, water charges etc. may be allowed separately on case to case basis after the prudence check.

	(b) Address the impact of installation of pollution control system and mandatory use of treated sewage water by thermal plant on O&M cost.	(b) The impact of installation of pollution control system and mandatory use of treated sewage water by thermal plant on O&M cost must be incorporated. O&M expenses must be reflective of increase in operation cost due to installation of pollution control system. A detailed study can be conducted to identify the increase in costs for such installations in India in view of MOEFCC directives to install these systems.
	(c) Review of O&M cost based on the percentage of Capital Expenditure (CC) for new hydro projects;	(c) May be taken up if rationale is established
	(d) Review of O&M expenses of plants being operated continuously at low level (e.g. gas, Naphtha and R-LNG based plants).	(d) O&M contracts are awarded for full year. Partial load operations are subject to availability of fuel and therefore linking O&M expenses to level of operation may not be optimum and cost reflective. This may lead to under recovery of O&M expenses.
	(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;	(e) At present, there are no rates defined for O&M of transformers and reactor bays. Separate O&M norms for these assets should also be defined.
	(f) Have separate norms for O&M expenses on the basis of vintage of generating station and the transmission system.	(f) The O&M expenses should be proportional to age of plant / equipment / apparatus. Older the installation, higher O&M is recommended.
	(g) Treatment of income from other business (e.g. telecom business) while arriving at the O&M cost.	(g) Other income should be allowed as incentive to the generators rather than reducing the allowed O&M cost. Such incentive can be shared with beneficiary on a proportionate basis to be decided.

	Additional Issues	Current Norms for O&M Expense do not take into account Reserve Shutdown (RSD). As pointed out in the consultation paper, due to low PLF on account of various reasons, incidence of RSD is expected to increase in future. Higher incidence of RSD results in higher O&M expense due chemical consumption for wet preservation of the boiler, circulation of DM water to restrict oxidation and corrosion in the Boilers etc. It will also result in higher wear and tear and reduced life cycle span.
22. Fuel – Gross Calorific Value (GCV) *Option for Regulatory Framework*		
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 losses to be booked to Coal supplier or Railways. 48 b) Similarly, specify normative GCV loss between "As	We propose different approach for raising of invoices by coal companies on 'as received basis' at the loading end as per standard international practice this is enumerated below: 1. International norms of coal pricing follow the practice of declaring GCV on 'As Received Basis (ARB)', being measured on-site at FOB loading end, and thereby, capturing Total Moisture content in coal. In contrast, GCV in India is being measured on equilibrated basis which takes into account moisture in coal sample conditioned at 60% RH and 40° C temperature. In practice, GCV measurement at site is either measured (or converted into GCV) on equilibrated basis for the purpose of checking grade compatibility and

	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.	subsequent invoicing. By converting in-situ GCV into equilibrated basis determined under laboratory conditions, approximations are introduced and should be best avoided for commercial billing. 2. To provide parity with international practice and avoid ambiguities, it is suggested that GCV measurement of CIL coal under third party sampling be undertaken on-site at the loading end under prevailing atmospheric conditions and declared on 'As Received Basis (ARB)'. It is to be ensured that such exercise of determination of GCV is completed within a prescribed time limit so that the sample represents the actual Total Moisture Content in coal and is not affected by the atmospheric conditions in the laboratory that is likely if it is kept for a prolonged time. GCV on 'As Received Basis', or 'GAR', will correspond to coal delivered against Rail or Road Receipt Challans at the Point of Sale. 3. 'As Fired Basis' should provide the datum for capturing the ultimate coal quality to be factored into Energy Charge calculations. For this purpose, we propose that regulatory norms be established based on experimental studies and historical records to provide yardstick norms of transit loss between loading point and generating station stockyard and subsequent stockyard loss between storage and boiler firing.
23. Fuel - Blending of Imported Coal *Option for Regulatory Framework*		
23.6	Normative blending ratio may be specified for existing plant as well as new plants separately in consultation with the beneficiaries.	We do not propose normative blending ratio as because: 1. Each plant has its specific requirements hence can't be standardized.

		2. Blending of imported coal is dependent on several factors like GCV, availability, price, boiler design and other technical parameters etc., all of which cannot be standardized. 3. Therefore, the blending of imported coal should be left with the generators to decide on a case to case basis.
24. Fuel - Landed Cost *Option for Regulatory Framework*		
24.5	(a) All cost components of the landed fuel cost may be allowed as part of tariff. Or alternatively, specify the list of standard cost components may be specified;	(a) We would suggest the landed fuel cost to be determined capturing all cost components for determination of tariff as per existing practice. Standardisation of these costs components is not feasible as there are additional charges, surcharges and levies that may be imposed from time to time
	(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.	(b) We do not prefer the arrangement as coal supply cannot always be secured under long term arrangement given the present shortage scenario to determine the parameters of sourcing, coal quality and distance of transportation on a predicated basis. Secondly, generators are being dependent on procuring coal from market sources, and hence such parameters cannot be ascertained in advance.

25. Fuel - Alternate Source *Option for Regulatory Framework*		
25.2	(a) Stipulate procedure for sourcing fuel from alternate source including ceiling rate; (b) Rationalize the formulation keeping in view the different level of energy charge rates, as the fuel cost has increased since 1.4.2014.	The premise that the earlier provisions were introduced in a shortage scenario still prevails. We would observe that: 1. Market procurement of coal is a necessity and hence neither its sourcing nor a ceiling rate can be specified. Also, other than linkage coal, primary source of domestic coal is e-auction / spot auctions conducted by CIL subsidiaries. These prices are driven by demand-supply scenario and are on 'as is where is' basis. Thus, applying a ceiling cannot be on predicated lines. 2. It may be considered if concept of SOP should be introduced to standardise sourcing so that prudent and auditable practices are followed. 3. Rationalising formulation of different levels of energy rates in a scenario where coal will be procured from multiple and varied sources is not a practical proposition.
26. Operational Norms **26.3 Thermal Generation (Coal based)**		
26.3.6	**<u>Station Heat Rate</u>** Approach for determination of station heat rate may need review including the criteria for specifying heat rate of old plants, continuation of relaxed norms for specific stations and possible changes required in the existing norms given in Tariff Regulation 2014-19.	We would observe as follows: 1. Heat Rate is a design parameter. Margin provided over Design Heat Rate depends upon variance in actual site conditions as compared to parameters considered while designing the machine. Once the margin is fixed for any machine based on COD, the same cannot vary. Therefore, Margin needs to be fixed based on COD and to be continued for entire useful life. 2. There is a need to factor in degradation in Heat Rate due to vintage/ wear &

		tear of the machine year over year. Suitable margin should be added in the heat rate. 3. Also, Station Heat Rate (SHR) being the ceiling norms, only actual SHR is considered in case the same is lower than normative SHR.
26.3.7	**Specific Secondary Fuel Oil Consumption** The existing norm for the Secondary Fuel Oil Consumption is 1.00 ml/KWh for lignite based CFBC technology with some exception in case of TPS-I and 0.50 ml/KWh for Coal based project with the provision for sharing of savings with the beneficiaries. Further reduction in specific secondary fuel oil consumption norms may adversely affect the boiler operations under different operating conditions including partial loading of units due to fuel shortage conditions. With contribution from renewable generation increasing in the grid, thermal power plants are facing frequent regulations of supply and operations at lower PLF up to technical minimum. The consumption of secondary fuel oil would change on account of nature of operations.	The norms of 0.5 ml/kwh does not capture the consumption of fuel related to frequent start-stop or higher oil consumption at low PLF. IEGC provides for compensation of start-stop only after 7 operations. Therefore, Secondary Fuel Oil Consumption (SFOC) norms may be increased to 1 ml/ kwh in order to take care of frequent switching operations and running at technical minimum.
26.3.10	**Auxiliary Energy Consumption** Generating stations which have less auxiliary consumption than the norms, are able to declare	While it will be beneficial to elaborate the methodology of declaring availability after setting off normative auxiliary consumption and colony consumption, we would draw attention to the following considerations that are also necessary: 1. Normative Auxiliary Energy Consumption (AEC) for any plant needs to be

	higher availability by making adjustment of difference between actual (lower) and normative auxiliary consumption. Further, colony consumption is not a part of auxiliary consumption w.e.f. 1.4.2014 and therefore, the same cannot be accounted for against auxiliary consumption while declaring availability. Methodology of declaring availability after reduction of normative auxiliary consumption and colony consumption need elaboration.	linked with COD of machine and once, it is fixed, there should not be any revision in such ceiling norms. 2. Saving in AEC needs to be shared with predominantly higher benefit to the developer in order to create more impetus. 3. Additional AEC and SHR may be considered for implementation of Environmental Norms. 4. Operational norms do not capture impact of Reserve Shut Down (RSD). During RSD, several auxiliaries would be running for equipment / system protection. Cooling water system of the Main TG Condenser, Lubricating Oil system of the Main Turbine, Turbine seal oil system, Turbine BFP, Lube oil system of Mills, Compressed air system, Control & Instrumentation system, HVAC system, Lighting system, Furnace Scanner Cooling air system etc. would be in service during RSD resulting into higher Auxiliary. Consumption. Such time bound increase in Aux. consumption cannot be made up on cumulative basis since the norms consider normal operation and not RSD. Hence, suitable compensation needs to be provided for the same. 5. Impact of Ageing may be considered additionally over current norms. 6. The norm for 800 MW should be fixed based on analysis of actual auxiliary consumption for installed units being operated under different conditions. Such measure is necessary since the operational experience of establishing norms and availability of data is limited, the units having been newly installed.

26.3.15	**<u>Normative Annual Plant Availability</u>** The existing norms of annual plant availability may need review by considering fuel availability, procurement of coal from alternative source, other than designated fuel supply agreement, shifting of fixed cost recovery from annual cumulative availability basis to a lower periodicity, such as monthly or quarterly or half yearly;	We would observe as follows: 1. Consideration of annual plant availability as a basis for fixed charge recovery is mainly considering the fact that generator requires continuous planned outages for no. of days for Capital Overhauling (COH) / Annual Overhauling (AOH) and if availability is to be considered monthly or quarterly, it will result in reduction of availability in such months. Moreover, prior permission of Discoms is taken before plants are subject to COH / AOH. Further, forced outages due to equipment failures, water availability, seasonal disturbances are unpredictable. 2. Above factors reduce availability considerably and if the periodicity is reduced to monthly or quarterly or half yearly, it will result in severe cash flow issues for Generators. 3. Therefore, Periodicity for availability cannot be reduced to any lower period than a year. 4. Also, bridging fuel gap by procuring coal from e-auction or imported sources does not offer a straitjacketed solution to generators. Such procurement is dependent on domestic coal being available in a supply-constrained scenario and price of imported coal being sustainable. Secondly, regulatory decisions of coal cost pass-through under alternative procurement have mostly been post-facto and not been timely, pre-empting generators to curtail their capacities in future time frames and reduce plant availability.

26.3.18	**Transit & Handling losses** A regulatory option could be that the generating station shall only pay for coal "As Received" at the plant plus normative transmission loss of GCV and quantity as per CERC norms. This can be addressed in the Tariff Regulation by indicating GCV as "As Received at plant end" and customization of Form- 15 regarding the GCV.	Our observation against Para 22.8 refers. In accordance with standard international practice, we suggest invoicing by coal company on GCV 'as received basis' at the loading end by following the procedure of GCV measurement as stated therein. For the purpose of determining Energy Charge, suitable norms may be established to factor in transit loss as well as yard loss so as to evaluate GCV of coal 'as fired'.
26.4Thermal 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 substantial amount of land at the mine site and storing of rejects for prolonged period is hazardous as it may lead to combustion.	Regulatory options are not clear. In our view, regulations to be framed in terms of Tariff Policy should take into consideration their applicability on a case to case basis, keeping in view that washery yield determining the reject quantity will depend upon coal quality and its ash content as well as plant design and technology deployed. These variations are to be appropriately allowed for so that optimum throughput is implemented by plant operator based on site conditions.
26.5Transmission System		
Transmission Availability Factor		
26.5.1	Availability of Transmission System/ elements is expected to increase with introduction of new technology like polymer insulators etc. Thus, the mechanism of payment of transmission tariff based on availability of transmission system may need review.	CERC has already fixed stretched norms for Transmission availability of AC system. Therefore, there is no scope of any further reduction. Introduction of polymer insulator would only help in maintaining the availability at current level. Further it is to be noted that Polymer insulators are not installed on all operational lines and even stability and reliability of silicon rubber insulator is not established. It is also observed that polymer insulators are susceptible to failure in a span of 7 to 8-year life cycle and cannot be considered the ground for increase of availability of

		transmission system.
26.5.5	(a) Existing approach for computation of Transmission system availability and weightage factors to be applied for outage hours for transformer and reactors; (b) Review of the incentive formula for HVDC bi-pole and HVDC back-to-back stations at par with AC system; (c) Specify appropriate region (import or export) for certifying the availability of Inter-regional links (AC and HVDC line) for the purpose of incentive and recovery of annual fixed charges; and (d) Review of the existing methodology or procedure for computation of availability, monthly availability and cumulative availability;	Incentive formula for HVDC system should not be at par with AC system for following reasons; the two systems being not like-to-like: 1. Line length of HVDC system is more than AC system (3 to 4 times length of AC line) and also line covers various regions / terrains / weather conditions. 2. HVDC is state-of-the-art technology which involves complex controls and logic function and cannot be compared with AC system. 3. In HVDC system, both terminal stations along with line are considered as one element. Hence, it should not be equivalent to AC system. 4. Specialised technology (valve hall, pole control and station control) is involved during maintenance activities which required longer outage period. 5. The incentive & tariff calculations need to be consolidated annually, and the final settlement is to be done on annual availability. 6. At present, it is very difficult to get Right of Way (ROW) for maintenance of transmission line, leading to hampering of regular maintenance activities. Therefore, present provision of loading of 12 hrs non-availability after second tripping needs to be revised to allow at least 4 tripping on annual basis, besides working out availability on Annual basis.
26.6 Hydro Generation		
26.6.1	The existing Operational norms of Hydro generation include norms for auxiliary consumption, transformation losses and normative annual plant	Regulatory option is not clear. However, we agree to the proposal that there is need for review of existing value of Normative Annual Plant Availability Factor NAPAF based on actual PAF data for last 5 years.

	availability factor. Capacity Index as a measure of plant availability was implemented by 57 the Commission during tariff periods 2001-2004 and 2004-09. It was 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.	
27. Incentive		
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	We would observe as follows: 1. Incentive represents the efficiency of the Generator and ought to be captured prudently. 2. Current regulation to provide incentive based on PLF for coal-based plants is not correct, since it is not in the control of the Generator and is based on the schedule decided by the Discoms. Therefore, incentive should be linked to

	generating stations. Differential incentive mechanism for storage and pondage type hydro generating stations may also be considered. (c) Review the incentive and disincentive mechanism in view of the introduction of compensation for operating plant below norms. (d) Review the norms for availability of transmission system.	availability. 3. As under earlier regime applicable between 2009-14, the incentive payable at the fixed charge rate for stations more than 10 years old and at 50% of fixed charge for stations upto 10 years old can be reinstated. 4. Differential incentive mechanism at a higher rate may be considered for peak period operations.
28. Implementation of Operational Norms		
28.2	Whether the operational norms of the new tariff period should be implemented from the effective date of control period irrespective of issuance of the tariff order for new tariff period.	Till the time operational norms are notified, there is no avenue of implementing the same. Therefore, retrospective implementation of the norms is not possible till the issuance of the tariff order.
29. Sharing of gains in case of Controllable Parameters		
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	We observe as follows: 1. Any gain and loss due to variation from the normative parameters shall be to the account of developer. This will be the true reflection of the spirit of defining normative parameters and the Commission will also be saved from the task of scrutinising the accounts, year after year. 2. At the time of fixation of existing norms, issue of lower PLF was not in existence and therefore, not factored in the norms. Considering the same, due to emergence of low PLF situation, the Commission has provided

	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.	compensation in degradation of operating parameters through IEGC. Therefore, the compensation under IEGC has no relevance with the ratio of sharing of gains. 3. Even otherwise, if CERC is inclined towards networking the share of gains, the same may be higher for Generators/ Licensee so as to keep them motivated to achieve the higher efficiency. 4. 29.2 – not understood 5. Sharing of gains may be reconciled on annual basis
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.	
30. Late Payment Surcharge & Rebate		
30.1	The present regulatory framework provides for late payment surcharge at the rate of 1.50% per month for delay in payment beyond a period of 60 days from the date of billing. In view of the introduction of MCLR, the rate of late payment surcharge may need to be reviewed. One option is to add some premium over and above MCLR.	We observe as follows: 1. Late Payment Surcharge (LPS) should act as deterrent for non-payment and hence, should be made more stringent. Accordingly, LPS @ 1.5% per month may be retained 2. It may also be noted that LPS is calculated on a simple interest basis while all the accounting is on compounded basis. Therefore, LPSC should be on higher side otherwise we will be incentivising the delays in payment. 3. Payment appropriation norm needs to be specified in the regulation. i.e. LPS

30.2	Further, as per the existing regulations, the rebate is provided if payment is made within 2 days of presentation of the bill, (email, physical copy etc.), authorised signatory, Valid mode of presentation of bill, (email, physical copy etc.), authorised signatory, definition of two days (working days or including holidays) may need elaboration.	followed by past dues followed by current dues.
31. Non-Tariff income		
31.1	The tariff determination under Section 62 of the Act follows the principle of cost of recovery which inter-alia provides the reimbursement of cost incurred by the generating company or the transmission licensee. The income on account of sale of fly ash, disposal of old assets, interest on advances and revenue derived from telecom business may be taken into account for reducing O&M expenses. Present regulatory framework does not account for other income for reduction of operation & maintenance expenses. However, in case of transmission licensee, the income earned from telecom business are adjusted in the billing separately. The principle of treatment of other income as applicable in case of transmission can be extended for the generation business.	We observe as follows: 1. Presently, O&M Norms for generating companies are fixed taking into account actual expenditure for past period. While doing so, revenue on account of disposal of old assets, interests of advances, revenue for telecom business etc. are already taken into account. 2. Disposal of fly ash is a new occurrence and Generators are required to incur the additional expenditure for utilization of Ash which is not covered under O&M Expense at present. Therefore, there is no avenue for reducing the same from O&M Expense. In fact, recently, CERC has issued orders granting additional expenditure as pass through in terms of MoC notification after netting off the revenue if any.
32. Standardization of Billing Process		
32.1	Presently, generating companies and the transmission	We observe as follows:

	licensees are following different practice for raising bills on the basis of tariff order. In order to avoid possible disputes in billing, it need to be consider as to whether standardization of billing process including formats, verification and timeline etc. may be done.	1. Standardized format will ease the billing complexities and disputes. 2. Electricity Duty needs to be considered at actual auxiliary consumption
32.2	Some of the States are imposing electricity duty on the actual auxiliary consumption which may be higher or lower than the normative auxiliary consumption. Such electricity duty is passed on to the beneficiaries along with the monthly bill. Whether electricity duty is to be linked with actual auxiliary consumption or normative consumption or lower of the two, may need to be specified.	
33. Tariff mechanism for Pollution Control System (New norms for Thermal Power Plants) *Option for Regulatory Framework*		

33.3	There is likelihood of significant impact on tariff on account of compliance with these norms. Supplementary tariff could be determined considering the followings. a) The principle of bringing the generator to the same economic condition if it is considered as change in Law. b) Technical specifications based on the difference in actual emission and revised emission, proposed technology, construction period, phasing plan for shutdown during the construction period; c) Feasibility of undertaking implementation of new norms with R&M proposal for plants having low residual life, say, less than 10 years. d) Change in Auxiliary Consumption and operation and maintenance expenses due to implementation of pollution control equipments.	We are in agreement with the steps enumerated in providing tariff compensatory mechanism for installation of Pollution Control System, broadly upholding the principle that the generator will be brought to the same economic condition as occurring under Change in Law. New regulations should introduce norms for recovery of capital and operating expenditure as well as impact on auxiliary consumption on the basis of benchmarking studies and established industry standards. A consideration that needs to be made is that installation of new Pollution Control System like FGD will lead to loss of capacity charges due to reduced plant availability and hence, earning income of generators. It is to be examined how generators are to be compensated as a result of such loss and secondly, how change in contractual terms under PPA resulting in lower off take by beneficiaries is to be addressed.
33.4	a) Possibility of reducing funding cost through suitable change in debt:equity requirements. Relaxation in funding from equity may be 61 introduced and the rate of return on equity may be aligned with the interest on debt;	a) While normative debt equity ratio can be followed for proper gearing innovation financing to reduce finding cost should be targeted by introducing cheaper options of sovereign low-cost fund of longer duration of, say, 25 years. Tax incentives provided to generators would also serve to restrict tariff escalation in the interest of meeting emission norms as well as policy goals.
	b) "Debt Service obligation during construction period and recovery of depreciation" may be provided with the condition that such depreciation may be adjusted during the	b) In terms of treatment of debt, we would suggest an extended moratorium so that both interest payments and principal repayments can be spread beyond the initial years of construction

	remaining period;	
	c) As the level of emission is linked to actual generation, it would be appropriate to link recovery of supplementary tariff with the actual generation or availability or combination of both.	c) Although the level of emission will be linked with actual generation, new addition Pollution Control System, including retrofitting, will be a foregone conclusion and sink costs, which will need to be recovered through adequate tariff compensation to the extent capacities are tied up under PPA and not applicable to actual generation. Para 9.3 states " *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*....".
34. 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 principles.	Options of regulatory framework have been suggested under Para 7.6.4 and should be synergised with the proposal made thereunder. Our comment under Para 7.6.4 that we suggest bundling of RE tariff (which will be single part) with the fixed and variable components of thermal generation holds good, all the three elements having been determined individually as per appropriate Tariff Regulations.
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	Attention is drawn to MoP Notification on "Flexibility in Generation and Scheduling of Thermal Power Stations to reduce emissions", dated 05-04-2018 that: a. *"Declared Capacity (DC) shall be declared by the existing Thermal generating station as per the extent regulations. Once the schedule for the next day is*

	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.	*received, the generating station shall have the flexibility of using its Thermal power or the generating company owned renewable power or procured RE Power to meet its generating station scheduled generation. Thus, the RE power shall replace the Thermal power of any of the thermal generating station of the generating company, wherever found feasible by the generating company".* This implies that the supply of renewable power is in substitution of thermal generation and will contribute to neither higher target availability nor dispatch level and will be contained within the Declared Capacity. Hence, there is no case to apply an empirical relationship of increasing target availability and dispatch level by 2% for every 10% renewable capacity addition. Secondly, combining renewable generation undertaken at off-site location with thermal generation will be feasible only when transmission corridors are available and thus suggesting higher target availability and dispatch level cannot be a blanket solution. Also, the resultant tariff will be a merged solution of two-part tariff under thermal generation and single part tariff under RE generation and not combination of annual fixed charges only as stated herein.
35. Commercial Operation or Service Start date		
35.5	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	Following methodology may be adopted for COD declaration: **<u>Generation:</u>** 1. The period of trial run may be specified. For generating station, it is advisable to hold a commissioning test. In order to monitor the tests, it is suggested to appoint an Independent Engineer by the parties who would certify that Unit has achieved all the test parameters successfully and is ready to put into commercial operation.

	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. Pre-requisite of completion of data telemetry and communication facilities for declaring COD of transmission system and operationalization of RGMO for declaring COD of generating station; 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 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.	2. Upon furnishing the test certificate from the Independent engineer to concerned RLDC/SLDC, the unit may be deemed to achieve Commercial Operation. 3. In case Unit is ready to for Commissioning test but it could not be performed due to any reason like Transmission constraint or low demand in the system then the Unit may be deemed to achieve the commercial operation and should start declaring the availability and get the capacity charges. 4. The commissioning tests may be performed as and when the Grid conditions are suitable. In the commissioning tests if a Unit fails then generator should be asked to refund all the capacity charges it recovered from beneficiaries along with LPS. **<u>Transmission</u>**: 1. The onus of formulating ISTS schemes lies with STU, CTU & CEA through various fora of consultative process viz. Empowered Committee, Regional Standing Committee of System Planning, Technical Coordination Committee (TCC) and Regional Power Committee (RPC). 2. Once a scheme has been approved through these forums, the SCOD of the project is also decided and agreed at these forums. The ISTS scheme is then bid out under TBCB or awarded under Sec 62 with targeted commissioning as of SCOD. Ideally, the transmission asset should be commissioned by SCOD and recovery of transmission charges from the

		pool/ beneficiaries begun irrespective of the status of upstream or down-stream element. 3. Transmission licensee does not have any control over functioning of RLDC /NLDC / SLDC and should not be made to suffer o account of any inefficiencies of RLDC / NLDC / SLDC. 4. Under the present system, TSA is signed between Developer & Long Term Transmission Customers while STU and Upstream/ Downstream Developers are not a party to TSA. So, no damages can be claimed or levied on these entities for the delay of ISTS element. In order to make a contractual document comprehensive, the Implementation Agreement forming a part of the Standard Bid Documents should be signed by the Nodal Agency before bidding/ award under cost plus. This would obviate the likely delays of signing of IA and other associate documents after selection and notification of the Developer. The provision of LD's for delay in completion of the project needs to be provided in one document, as penalties for one default cannot be recovered twice. Recovery of default payment of any entity should be the responsibility of the BPC and this may be deposited subsequently in Pool account. 5. The obligations of all the parties are well defined in TSAs and all commercial decisions should be in line with the provisions of TSA. Moreover, one person cannot be made to suffer on account of inefficiency of other persons, on whose action the first person does not have any control. In the past, there have been decisions wherein the defaulting parties have been asked to make payments beyond the provisions of TSAs, which is against the set doctrines of legal process.

		General 1. Further in case of mismatch between commissioning dates of generating unit or transmission lines, the gestation period of the affected party, i.e., the party which commission its assets earlier, increases. Therefore, the Hon'ble Commission may develop suitable mechanism for compensating the IDC accrued for the period of delay to the affected party. 2. The suggestion on pre-requisite criteria of completion of data telemetry and communication facilities by RGMO for declaring COD, may not be appropriate at this point of time. Power market is in developmental stage and is yet to be fully developed and under that scenario, such a mandate shall unduly constrain the developer and may also lead to delay in COD. 3. It is suggested that Scheduled COD should be linked to the SCOD appraised by the lender as finalized in the Common Loan Agreement. Further, there should also be a provision to revise Scheduled COD & start/zero date for reasons not attributable to the generator.
36. Energy Storage System		
36.3	The regulatory options available for implementation of the energy storage system for use are to combine the tariff with transmission and generation projects. Storage facility as a part of inter-state transmission system may be subjected to regulatory approval while storage facility as a part of the generating capacity may be as per the consent of the procurer for availing	The options for implementation of the energy storage system shall also be open for Independent system that may be developed, owned, operated and maintained by Independent Service Providers (ISP) who are meeting the requisite techno-commercial experience standards (e.g. transmission licensee). The tariff for such system may be treated just like transmission and generation projects.

	storage facilities.	
36.4	The annual fixed charges of energy storage system may be determined separately as per the pre-specified operational and financial norms by the Commission and may be recovered from the beneficiaries of the region as supplementary to the transmission charges. Energy storage at transmission level can be used for overall optimization of power from the grid, irrespective of the owner of storage capacity and may be dispatched when needed. Such dispatch can be added in the drawl schedule of all beneficiaries of the region on ex-post basis. Alternatively, the energy storage at transmission level can be used as ancillary support services. The specific operational procedure can be devised for transmission level grid storage.	For smooth implementation of energy storage at Transmission level, following 2 phase methodologies may be adopted. 1. **Phase-1 (2018-2021)**: Energy storage at transmission level will initially be a bundled service that can be used for overall optimization of power from the grid, irrespective of the owner of storage capacity and may be dispatched when needed. Additionally, the energy storage at transmission level can be used as ancillary support services. The specific operational procedure can be devised for transmission level grid storage. The LDCs will have complete control over the storage use and any benefits/revenue streams thereof. During this phase, the LDCs/CERC will monitor usage to identify which applications the storage system is being used for, how frequently and attempt to quantify the benefit. 2. **Phase 2 (2021 onwards):** CEA/ LDCs will issue RFPs (competitively bid or other market mechanism as determined by CERC) for one or more specific applications (identified in phase 1, called primary application). Independent Service Providers (ISP) of these applications will be entitled to any additional use/revenue streams from their assets, as long as the minimum requirements of the primary application are being met. This will incentivize market driven optimization of asset use thus bringing down bid prices for the primary application. Any performance deviation in the primary application will attract appropriate penalties.
36.5	The annual fixed charges of energy storage system may be determined separately as per pre-specified operational and financial norms by the Commission. The energy storage at generation level would be used	If the owners of renewable generators need to seek storage capacity in order to comply with regulatory requirements imposed on the generators (such as smoothing/ramping performance or balancing services), then the generator owners should be allowed the discretion to meet the requirements via either co-

	for storage of generation output. The supplier may use it for optimization of the generation dispatch specific to their designated beneficiaries within the power purchase agreement. The generating 64 stations may use it to avoid the flexible operations due to frequent regulations. The specific operational procedure can be devised for generation level grid storage.	locating a storage project dedicated to a particular generator or striking a contract for the appropriate level of pro-rata capacity (needed to satisfy the requirements) with a centrally located storage device owned and operated by an ISP and shared among multiple generators.
36.6	The annual fixed charges of the storage facility can be determined based on ramping rate, auxiliary consumption, Return on Equity (ROE), Interest on Loan, Depreciation, Operation & Maintenance cost and Interest on Working Capital.	The annual fixed charges of the storage facility should be determined both on operating parameters such as power capacity (kW), energy capacity (kWh), response time, (secs or msecs) ramping rate (kW/min), round-trip efficiency (%), auxiliary consumption required to counter degradation over contract period and financial parameters such as Return on equity (RoE), interest on Loan, Depreciation, Operation & Maintenance cost and Interest on Working Capital.
37. Alternative Approach to Tariff Design		
37.6	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?	Our comments against Para 11.8 and 11.9 refer stating the absence of credible benchmarking standards /metrics to undertake standardization of capital costs of generation and transmission projects on a universal scale. Project dynamics as well as physical, technical and financial parameters are also at variance to permit such standardization vis-a-vis benchmarking. We would therefore suggest continuation of the practice of determining tariff for generating station and transmission system as per current practice for carrying out prudence check of the individual components of costs. Although the process is elaborate, it provides sanctity of tariff determination as the factors of divergence are minimized. The rationale against following a benchmarking practice is also borne out of the statistical

		deviation that emerged out of distribution of capital costs examined for generating projects with sample size of 30. Such statistical analysis is absent for transmission projects to justify the adoption of benchmarking capital cost.
37.9	**Normative Tariff by fixing AFC as a percentage of Capital Cost** 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 relation between AFC and Capital Cost so that it meets the interests of both buyers and sellers?	1. The proposed methodology to determine AFC as a percentage of capital cost may not capture the true picture of the variation in the Fixed charges on account of components which are not related to the capital cost. Uncontrollable costs like interest on long term loan, interest on working capital, cost of coal vis-à-vis GCV pricing are not determinable in advance, so as to follow a relationship with capital cost 2. Further, the Capital Cost shall not remain constant throughout the useful life of the Project. Additional Capitalization is necessary based on the nature of requirement of the Project which would call for change in Capital Cost. The corresponding change in the FC may not reflect the actual impact of the addition/deletion in the Capital Cost. 3. Further, it is also essential to factor the escalation in the O&M Expenses to reflect the effect of inflation on the operational cost. Such increase is irrespective of the status of the Capital Cost of the Project. Therefore, the proposed methodology of linking AFC with normative Capital Cost will always result in under-recovery/over recovery for developers and interim reviews might not be sufficient to address cash flow issues of the developers. Thus, the present approach of linking normative O&M Expenses with installed capacity of the project may be continued.
37.17	**Normative Tariff by fixing each component of AFC as a percentage of total AFC** a. Whether clustering the components of AFC based	The present method of tariff determination based on prudence check of each and every component of the tariff may be continued. We would observe as follows:

	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? g. Alternatively, is there any other methodology to	1. Clustering of AFC components on the basis of escalable and non-escalable factors would evolve a scenario similar to earlier bid-based tariff structure under Case -1 projects. Such tariff structure may transform to a normative tariff approach as envisaged by the Hon'ble Commission. The shortcomings of such normative tariff approach have been elaborated in the above paragraphs and is not repeated herein for the sake of brevity. 2. It is not only the additional capitalization which affects the trend of tariff. Other important factors can be loan restructuring, variation in cost of working capital components and decapitalization. Incorporating all such changes in the normative tariff structure may lead to complications in determination of tariff and subsequent recovery. 3. Additional Capitalization is an integral part of the tariff as it impacts 4 out of 5 components of the fixed charges. Hence Additional Capitalization cannot be considered separate to the fixed charge stream on normative basis and should be considered at actual. Adoption of normative basis for determination of Additional Capitalization may disrupt the process of prudence check by the Hon'ble Commission. Hence the present method for tariff determination based on prudence check may be continued.

	minimize the impact on AFC on account of change in control period?	
37.21	**Principles of Cost Recovery - Approach towards Multi-Part Tariff** a. Does the proposal of differential recovery of AFC by segregating into peak and off-peak periods balance the need for both the buyers and sellers? b. What could be the weightage factors for peak and off-peak periods along with the PAF for each segment? c. What could be other mechanisms to arrive at peak and off-peak AFC tariffs?	1. In the absence of systematic study and data support, we are not in a position to comment on the efficacy of the measures proposed. Absent mathematical modelling and formula-based analysis, we are not clear how differential AFC recovery can be linked to peak and off-peak periods. We also see assumptions being made in applying the ratio of 80:20 for recovery of AFC against off-peak and peak usage while specifying a PAF of 95% under peak period. Whether such assumption represents market realities, which will be subject to both demand uncertainties and penetration of renewable energy, is to be put to test. We are also not clear whether a higher peak price of 25% would be commensurate with TOD pricing that should ideally apply to reflect the demand-supply scenario in the evolving power market. 2. Also, if a plant is forced to shut down during the peak period due to technical failures or circumstances out of its control like coal or water shortages, it may lose the fixed charges corresponding to that period. 3. The proposed system poses a risky scenario for the generators as the machine availability cannot be guaranteed by the generators. If this option is to be implemented there should be provisions for inclusion for such exigencies (as explained above) that may lead to reduced availability.

37.22	**Process flow for determination of normative tariff**	
	***Serial* No. 2** Components of AFC be segregated into “escalable / increasing” and “non-escalable/ decreasing” segments a. Segment -1 (Non-Escalable/ decreasing) comprising of RoE, IoL, IoWC, Depreciation b. Segment -2 (Escalable) comprising O&M	AFC may not be segregated into escalable/ non-escalable segments
	Serial 4 Cut-off Date‟ means 31st March of the year closing after two years of the year of commercial operation of whole or part of the project, and in case the whole or part of the project is declared under commercial operation in the last quarter of a year, the cut- off date shall be 31st March of the year closing after three years of the year of commercial operation	The concept of cut-off date may be removed.
	Serial 5 Add. Cap be isolated and the components of AFC be derived without giving effect to Add. Cap. (from Cut-Off Date onwards)	The present regulation provides for allowing additional capitalisation and AFC is derived after giving effect to additional capitalisation. Also, the additional capitalisation is allowed even after cut-off date for certain specific conditions as specified under the Tariff Regulations.
38. Transparency in Billing and Accounting of Fuel		
38.1	The regulatory approach of pass through of coal cost to the procurer directly on the basis of certification has been well adopted. Comments and Suggestions are invited for further strengthening the existing system.	Our comments against para 22.8 refer. We broadly agree to the basis of certification but would consider a few measures for further strengthening: 1. In line with international practice, invoicing of coal should be on ‘as received basis’ at the loading end. 2. To support the measure, third party sampling is to be undertaken by

		accredited agency and suitable laboratory infrastructure created at loading end 3. Experience based analysis is to be undertaken to establish normative GCV loss with tolerance limits in transit as well as at recipients' stock yard. 4. Finally, certification of coal and its GCV will be on 'as fired basis' based on allowances for transit and yard losses.
39. Relaxation of Norms		
39.1	The present regulatory framework provides for specifying normative operational parameters. However, there may be situations where the normative level due to the site-specific features such as FGD, Desalination plant, increase in length of water conductor system etc may lead to power consumption in excess of the norms. In such situations, the present regulatory framework provides for relaxation of norms.	1. It is not possible to foresee all events, conditions and circumstances which may lead to any hardship for the project developers to comply with the general operational and financial norms during the next five years. It is essential for the Hon'ble Commission to look into such cases to establish equitable treatment for all the stakeholders. Hence, it is necessary to continue with the provisions for relaxation of norms which may be exercised by the Hon'ble Commission to accommodate different features specific to a project etc. 2. Relaxation should be provided on case to case basis and after prudence check of the requirements. For specific features like FGD, having nation-wide implication, MoP vide its letter dated 30.05.2018, has already directed to CERC to develop appropriate regulatory mechanism to address the impact on tariff and certainty in cost recovery on account of additional capital and operational cost. Therefore, relaxation of norms shall compensate for actual cost increase due to such site-specific features.
40. Merit Order Operation		

40.1	Though merit order is a dispatch issue, scheduling/ non-scheduling has its impact on purchase cost. It is seen that in respect of certain old plants having low fixed costs, their power may not get dispatched as the merit order is based on variable cost, which may be high.	It is submitted that thermal projects complying with MOEFCC's notification with regard to emission control will have higher tariff which impacts the position in the Merit Order. Decreased ranking in the merit order has placed the environment friendly plants at a disadvantaged position. In order to address the above issue, suitable provision may be incorporated in the Regulations to consider fuel charges without the impact of new norms in the Merit Order Dispatch till 2022-23.
40.2	The merit order operation is important for economic operation of the plants and optimum despatch of economic resources. The consideration of other factors such as distance of transportation, secondary fuel oil consumption may provide the option to distribution utility to optimize the despatch. Present merit order is based on the fuel cost of the past data, with time lag of up to two-three months in billing cycle.	Currently SLDC's/TRANSCO's are backing down renewable power despite the latter enjoying 'Must Run' status in the name of grid security without any compensation. Additionally, generator may be forced to bear the additional cost of DSM charges during such unplanned back down, as there is little clarity about such scenarios in the regulations. A suitable mechanism is necessary so that renewable energy can be considered an essential extension of MOD regime and any back-down without technically or operational constraints would attract compensation.
41. Application for Tariff Determination: Review of Process in Case of Transmission System		
41.2	One alternative to simplify the process is to determine the tariff of existing assets based on actual capital expenditure instead of projected capital expenditure, so that two applications of existing assets can be reduced to one in each tariff period. Further, the tariff of new assets can be determined during tariff period after commissioning of the new assets.	We would be in agreement with the proposal of: a) Determination of the tariff of existing assets based on actual capex. b) Admission of single petition for the individual elements of new transmission assets commissioned within a year.

41.3	Further in case of new assets of transmission system, single petition may be admitted for all the individual elements of the project which have been commissioned within a year. Then annual fixed charges may be determined on consolidated basis and apportioned on proportion to the capital cost of individual elements. The true up maybe carried out on completion of the project based on balance sheet of individual project.	
42. Goods and Service Tax (GST)		
42.1	Goods and Services Tax (GST) has been introduced which has replaced various Central and State level taxes. Accordingly, prudence check of impact of pre-GST and post-GST taxation regime on the costs may be required for determination of tariff in the next control period.	These expenses are certified by cost auditors and may be evaluated for prudence check by CERC in next tariff period as well.
Annexure 1(B)		
	Cost of Coal as on 31.03.2018	Cost of coal and its impact on per unit cost of electricity needs to be captured considering the effect of change taxation regime to GST from 1st July 2017 and effect price increase vide CIL notification of 8th January 2018. The calculations for 2017-18 are shown below **<u>Cost of Coal (2017-18)</u>**

		<table><tr><th>Particulars</th><th>G12</th><th>Rs Per Unit</th></tr><tr><td>GCV Range (Kcal/KG)</td><td>3700-4000</td><td></td></tr><tr><td>Source</td><td>MCL</td><td></td></tr><tr><td>Basic Price Sizing/Crushing Chg Surface Transportation Charges</td><td>886.00 87.00 57.00</td><td></td></tr><tr><td>Sub Total (A)</td><td>1,030.00</td><td>0.65</td></tr><tr><td>Central Excise Duty Education Cess Higher Secondary Education Cess Royalty 14% on BC</td><td>- - - 124.04</td><td></td></tr></table>

		DMF @ 30% of Royalty	37.21	
		NMET @ 2% of Royalty	2.48	
		Vikasupkar	-	
		Clean Energy Cess	400.00	
		Paryavaran	-	
		Stowing Excise Duty	-	
		Sub Total (B)	563.73	
		Sub Total (C=A+B)	1,593.73	
		GST @ 5% of C	79.69	
		GST Compensation Cess	-	

		Sub Total (D)	79.69	
		Net Coal Cost (Rs/MT) (E=C+D)	1,673.42	
		Contribution of Taxes & Duties (E-A)	643.42	0.40
		Raliway Distance (KM)	**500**	
		Road Distance	**0**	
		Basic Freight (Rs/MT) Busy Season Surcharge (Oct-Jun) @15%	969.80 -	
		Sub Total	**969.80**	0.61
		Development Surcharge Originating Coal Terminal Charges	- -	

		Destination Coal Terminal Charges	-	
		GST @ 5%	48.49	
		Sub Total	**48.49**	0.03
		Net Freight (Inclusive of Tax) (Rs/MT)	**1,018.29**	

Operational Parameter		
Station Heat Rate	Kcal/KWh	2375
Auxiliary	%	5.25%
Specific Coal Consumption	Kg/KWh	0.627

Per Unit Cost	
Coal Price (ROM)	0.65
Taxes and Duties	0.40

		Coal Transportation	0.61	
		Taxes and Duties on transportation	0.03	
		Total (Per Unit Cost)	**1.69**	