5873/2018/CRU-CERC

GMR Energy Limited

(44)

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31st July, 2018

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

Sub.: Comments on Consultation Paper: "Terms and Conditions of Tariff for the tariff period commencing from 1st April, 2019"

Dear Sir,

This is with reference to the Public Notice issued by CERC on 24th May'18 seeking comments on the consultation paper reg. "Terms and Conditions of Tariff for the tariff period commencing from 1st April, 2019.

On behalf of GMR energy Ltd. Please find enclosed the comments on the same. We hope that same would be considered while preparation of the regulations for the next tariff period.

Thanking you,

Yours sincerely,
For and on behalf of:
GMR Energy Limited

(ABANI PRASAD MISHRA)
Vice-President (Contracts and Regulatory)

01/08

Chief (Fin)

E.O/Secy
2/8/2018

DCERPJ/Fin
7/8/18

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<tr><td>1.</td><td>7.2.4-7.2.6
Thermal Generating Stations-Tariff
Offer procurers with 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.
Three Part Tariff:
Fixed Charges – depreciation, interest on loan, guaranteed return (risk free return), part of O&M expenses
Variable charges – incremental return over guaranteed return and balance O&M expenses
Energy Charges – Fuel Cost, transportation, duties & taxes on fuel
Recovery of Fixed Charges linked to target availability; variable component linked to difference between availability and dispatch and
Energy Charges linked with dispatch</td><td>a) Projects which were conceived and developed on the basis of Full recovery of all costs withy reasonable return and have achieved COD should be insulated from the structural changes being proposed in this consultation paper.

<u>Reason/Rationale:</u>
The project has been evaluated and accessed by lenders, Investors, Stakeholders on the certain premises which were already frozen while signing the PPAs and finalizing the tariff for the respective projects. On the basis of which lenders/investors have done the due diligence and have approved the funding on that premise. Therefore, any change which is being proposed now will have a material impact on tariff and economics of the project. This will add to already high level of NPAs in the country. In addition, Central Commission vide IEGC amendment Regulation, 2016 has already taken care of the issue of low demand from Discoms with appropriate compensation mechanism to generators

b) Following may also be explored for the projects which are being conceived Now and for which PPAs are not signed:
Three Part Tariff:
Fixed Charges – depreciation, interest on loan (short and Long term both), guaranteed return, full cost of O&M expenses.
Variable charges –Incentive over guaranteed return
Energy Charges – Fuel Cost, transportation, duties & taxes on fuel
<u>Reason/Rationale</u>
For inviting substantial risk capital (equity) we need to provide return which is more than the risk free return else investors will not be motivated to invest in power sector. Therefore, the fixed charges should cover a Guaranteed return which is risk premium Plus Risk free return. Conceiving and completing the projects involves considerable amount of uncertainty/ complexity and all such risks are taken by the investors who put in Risk Capital. Hence, they should be motivated to invest by way of providing some</td></tr>
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		risk premium over Risk free return and reasonable certainty in recovering all other costs.
2.	7.3.4 **Thermal Generating Stations-Older than 25 years** i. replacement of inefficient sub critical units by super critical units ii. phasing out of the old plants iii. renovation of old plants iv. extension of useful life	• Globally, all the leading countries are resorting to closure of Coal based plants on the grounds of environment sustainability. • Such older and inefficient plants should retire and give way to modern and environmentally sustainable generation. Specially in the context when there is a narrowing down of the gap between demand and supply leading to reduced PLF of thermal generating plants. • The revival options may only be put in practice if the overall projected demand is still unmet with existing untied capacities and upcoming generating capacities put together. • It is also advisable that for the capacities being revived after useful life, may only sell power through tariff based competitive bidding through short term and medium term only, which will test there improved efficiency.
3.	7.4.2 **Hydro Generating Stations - Tariff Structure** Reformulate two-part tariff structure • Fixed Component – return on equity, interest on loan, depreciation, interest on working capital, and O&M expenses. • Variable Component –incremental return above guaranteed return, O&M 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.	• **Recommended:** This should be implemented.
4.	7.5.4-7.5.6 **Inter-State Transmission System - Tariff Structure** Two-part tariff • 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	• **Recommended:** This looks to be more pragmatic in today's context.

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	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. • 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.	
5.	7.6.3-7.6.4 **Renewable Energy Generation – Tariff Structure** Two-part Tariff • Fixed Component (debt service obligations and depreciation) and variable component (marginal cost i.e. O&M expenses and RoE) - fixed component as feed-in-tariff (FIT) and variable component equal to capacity augmentation such as storage or back up supply tariff. **Bundling of renewable generation with thermal plant (coal/ lignite)** • Existing Thermal Tariff: Tariff of renewable generation may replace the energy charges • Renewable Tariff may be combined with two-part thermal tariff to the extent contracted capacity under PPA: Operational norms of thermal plant may be revised such as higher target availability for recovery of Fixed Charges, higher PLF for recovery of incentive. • Separate Tariff for renewable and thermal; separate operational norms	• Bundling of renewable with thermal plant may be permitted only for upcoming new plants and the plants which were built in last 10 Years. Bundling with older plants may lead to unreasonably high tariff for end consumers in additional to environmental sustainability issues. • If this benefit has to be given to Discoms and generators who have tied up long term PPAs through competitive Bidding Like Case-1, & 2 etc. • The operational Norms of the conventional plants need not require any revision such as High target availability because it's an additional benefit given to Discoms who would be able to meet RPO obligations with a reasonable cost and contracted capacity of the plant under the existing PPAs remains same but the renewable energy shall be provided under a separate arrangement. • Hence, Separate Tariff for renewable and thermal may be preferred over other two options.

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6.	8.4 **Deviation from Norms** • Develop Incentive and disincentive mechanism for different levels of dispatch • Specifying target dispatch expanding the scope of Regulation 48.	• The concept of Minimum off take guarantee may be introduced in order to ensure the minimum despatch from a particular plant. • If generator is desirous to get the despatch beyond the guaranteed level then it must be given flexibility to offer lower tariff in order to get the higher despatch schedules.
7.	9.3 **Components of Tariff (IPPs – PPAs under Section 62 & 63 + Merchant)** • Determine the tariff for entire capacity restrict recovery of tariff pro-rata to PPA and balance will be under merchant or under Section 63, as the case may be.	• **The existing practice being followed should be continued,** where capital cost is determined for the entire project is considered and applied in prorate to the capacity tied up under sec-62 is appropriate. • In case of specified component of the thermal station that is added after the cut-off date but is used to supply power to the beneficiaries under sec-62 of the act must also be considered for tariff purpose. Similarly, any component that is not used for supply of power under sec-62 its cost may be excluded from the capital cost.
8.	10.3 **Optimum utilization of Capacity** • Flexibility to Genco/ Discoms to redefine Annual Contracted Capacity (ACC) out of total Contracted Capacity (CC) depending on reduced utilization Capacity beyond ACC may be treated as Unutilized Capacity (UC), which discom will have a right to recall during next year and pay 10-20% of the fixed cost or to the extent debt service obligations • Such all UC may be aggregated and bid out to discover the market price of surplus capacity which may be allocated to discoms at market discovered price.	• Annual contracted capacity should remain constant over the period of the PPA. Discoms shall be obligated to pay the Generator the fixed charges based on the declared availability. However, Generator shall on be at effort basis to sell to third party as and when Discoms are failing to Despatch the contracted capacity. • TO the extent the Generator is able to earn over and above the energy Charge the same shall be used to mitigate the liability of the DISCOMS. • If the Generator is able to earn higher than t the total tariff, then such higher income to share with a ratio of 80:20 (Generator: Discom) • The proposed option lacks clarity in terms of recovery of 100% Annual Fixed Costs while generator is meeting normative availability. • The option is not different from Availability Based Tariff (ABT) concept wherein, the discoms overdrawing than the scheduled power is liable to pay UI charges. • The primary reason of moving to such an arrangement is reducing demand-supply gap/ energy deficit across nation. The option is premised on the assumption that there would be demand from other

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		discoms for such unutilized capacities. What if there would be no demand?
9.	10.5 **Hydro Generation** **10.5 (a)** Extend useful life of project up to 50 years from existing 35 years and loan repayment period up to 18-20 years from 10-12 years **(b)** Assign responsibility of operation of hydro and pumped mode operations at regional level; scheduling 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 for flexibility in scheduling and to address the difficulties of cascade hydro power station. 10-20% of the fixed charge liability against the use of flexible operation and pumped operations may be apportioned to the regional beneficiaries as reliability charges.	(a) **Not recommended:** For a private developer it's difficult to get a loan of tenure more than 10-12 years, especially for risky Hydro projects. Therefore, the current method should continue to invite the interest in Hydro Projects. In many of the Hydro Projects allotted through Bids or otherwise the implementation agreement is limited up to 25 years. Thereafter the project shall be owned by the state Govt. in such a scenario the promotes & IPPs need to recover all the costs before it goes back to state. The current life of 35 years should be reduced to reflect such restrictions under the implementation agreement so that lenders/investors and other stakeholders recover their dues before the implementation agreement expires. (b) **Seems more practical and is Recommended.** It is suggested that Reliability Charges shall be over and above the Annual Fixed Charges
10.	10.7 **Gas based Thermal Generations** a) Scheduling and dispatch may be shifted to regional level. After meeting the requirement of designated beneficiaries, the regional system operator can use it for balancing power at the rate specified by the generating companies. b) Alternatively, all the 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.	It is suggested that even the Gas plants without any PPAs should also be included in the regional Pool. Such plants including the Plant having PPAs should offer their respective reserve prices in the pool and depending on the competitiveness the capacity to be used at regional level
11.	11.8 **Capital Cost** a) Move away from investment approval as reference cost and shift to benchmark/ reference cost for prudence check b) 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.	a) Benchmarking of Technology and capital cost should be provided under the regulation. b) Incentive for actual project cost lesser than the benchmarked cost should be provided. c) Delayed commissioning due to reasons beyond the control of generator must not result into disincentive. After prudence check, if it is established that delay is not attributable to the generator, it should be

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	c) 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. d) Incentive for early completion and disincentive for slippage from scheduled commissioning can also be introduced.	deemed to have achieved scheduled timeline and hence, shall be appropriately incentivised. d) *The concept of Cut-Off Date should be dispensed with and utilities should be allowed to defer expenditure to the extent it is within the original scope of work.*
12.	12.6 **Renovation & Modernisation** a) The Commission may allow R&M for extension of life beyond the useful life of transmission assets. b) Alternatively, allow special allowance for R&M of transmission assets 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.	It is recommended that Special allowance may also be extended for Hydro projects which undergo R&M. **Rationale:** Hydro generating stations have the useful life of 35 years, affected by technological obsolescence, require R&M after useful life, takes longer time for R&M like any other type of generating stations, therefore, it is justified to allow similar allowance to hydro generating stations.
13.	13 **Financial Parameters** a) 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.	The current hybrid approach should be continued where all the controllable parameters should continue to be normative like O&M expenses, heat rate, aux consumption. Non-controllable parameters like rate of interest is linked to the financial performance of a company and can't be allowed on normative basis. Similarly, GCV of coal is very subjective where generators do not have any control on quality of coal received.
14.	14.6 **Depreciation** a) Increase the useful life of well-maintained plants for the purpose of determination of depreciation for tariff; b) Continue the present approach of weighted average useful life in case of combination, due to gradual commissioning of units; c) Consider additional expenditure during the end of life with or without reassessment of useful life. Admissibility of additional expenditure after renovation and modernization (or special allowance) to be restricted to limited items/equipment;	In many of the Hydro Projects allotted through Bids or otherwise the implementation agreement is limited up to 25 years. Thereafter the project shall be owned by the state Govt. in such a scenario the promotes & IPPs need to recover all the costs before it goes back to state. The current life of 35 years should be reduced to reflect such restrictions under the implementation agreement so that lenders/investors and other stakeholders recover their dues before the implementation agreement expires.

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	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).	For thermal generation all of the PPAs are typically bid out for 25 years even PPAs with 7 -15 years are also there in the name of Long term PPA. Before such tenure expires all the loans need to be repaid/investors need to get back their investments and recover all costs from the project. In view of this increasing the life of the project to more than 25 years would not help the generation projects. Residual life (if any) for generation projects then tariff shall be determined after the completion of the PPAs and the benefit of such reduced tariff in any way shall be passed on to Discoms. Hence no such life extension is necessary.
15.	15.2 **Gross Fixed Asset (GFA) Approach** 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.	**Not recommended.** Modified GFA approach is not advisable in infrastructure company having long term exposure taken by lenders and investors otherwise projects would not get funding.
16.	16.1-16.4 **Debt: Equity Ratio** 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.	**Not recommended.** It should be noted that 80:20 ratios are not available commercially in market as lenders are not keen to provide such comfort to generation projects specially when these projects are coupled with High risk exposure.
17.	17.1-17.4 **Return on Investment** The Commission had compared both the approaches viz. RoE and RoCE while framing the Tariff Regulations for 2014-19 and decided to continue with RoE approach.	**Recommended:** We agree with commissions analysis. RoE approach shall provide regulatory certainty to developers.
18.	18.1- 18.7 **Rate of Return on Equity:** (a) Review the rate of return on equity considering the present market expectations and risk perception of power sector for new projects;	a) For increasing the risk appetite there should be some premium over the debt cost. The premium should be sufficient enough to incentivize the risk capital. Further, to take care of loss of ROE during the construction period a 2% margin should be provided

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	(b) Have different rates of return for generation and transmission sector and within the generation and transmission segment, have different rates of return for existing and new projects; (c) Have different rates of return for thermal and hydro projects with additional incentives to storage based hydro generating projects; (d) In respect of Hydro sector, as it experiences geological surprises leading to delays, the rate of return can be bifurcated into two parts. The first component can be assured whereas the second component is linked to timely completion of the project; (e) Continue with pre-tax return on equity or switch to post tax Return on equity; (f) Have differential additional return on equity for different unit size for generating station, different line length in case of the transmission system and different size of substation; (g) Reduction of return on equity in case of delay of the project.	b) **Not recommended.** ROE on generation projects should be more as compared to transmission projects since the former is more risk intensive as compared to latter. Going by the CAPM approach, cost of equity is driving by systematic and unsystematic variables. Beta for companies in power sector will remain same due to undiversifiable nature of risks faced. Also market risk premium for a newer project may not be different from an older plant where the kind of risks – like coal shortage, receivable delays, etc. remains same. Therefore, there is no reason why any new project should have a different rate of return. c) **Recommended.** The rate of return for hydro projects should be higher than thermal projects due to higher level of risk exposure during construction. d) A nominal incentive of additional return to the extent of 0.1-1% may be provided. e) **Recommended.** Pre-tax RoE ensures that tax only on the related business is allowed to be recovered. We agree with this proposal. f) **Not recommended.** Rationale same as point (b) above. g) **Not recommended.** Infrastructure projects are often effected 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 of the generators. This would lead to make the sector riskier and less attractive for promoters and investors.
19.	19.1 -19.5 **Cost of Debt** (a) Continue 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;	**Not recommended:** Existing approach should be continued. Cost of loan should be allowed based on actual loan portfolio. **<u>Reasoning:</u>** Rate of interest on long-term loans are purely driven by the credit ratings received by the generating company. Therefore, any transition to normative rate of interest will greatly help the large sized organizations with strong parent company . Whereas smaller companies and companies with lower credit ratings will be impacted by under recovery of fixed cost and would be at a loss. This may lead to monopoly in the sector.

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20.	20.3 **Interest on Working Capital (IOWC)** a) Assuming that internal resources will not be available for meeting working capital requirement and short-term funding has to be obtained from banking institutions for working capital, whose interest liability has to be borne by the regulated entity, IWC based on the cash credit was followed during previous tariff period. Same approach can be followed or change can be made. b) As stock of fuel is considered for working capital, a fresh benchmark may be fixed or actual stock of fuel may be taken. c) While working out requirement of working capital, maintenance spares are also accounted for. Since O&M expenses also cover a part of maintenance spares expenditure, a view may be taken as regards some percentage, say, 15% maintenance spares being made part of working capital or O&M expenses.. d) For Hydro plants, Maintenance spares in IWC which is also a part of O&M expenses results in higher IWC for new hydro plants with time and cost overrun. For old hydro stations, the higher O&M expenses due to higher number of employees also yield higher cost for "Maintenance Spares" in IWC. Therefore, option could be to de-link "Maintenance Spares" in IWC from O&M expenses e) In view of increasing renewable penetration and continued low demand, the plant load factor of thermal generating stations is expected to be low. As per the present regulatory framework, the normative working capital has been provided considering target availability. In case of wide variation between the plant load factor and the plant availability factor, the normative approach of linking working capital with "target availability" can be reviewed.	a) Recommended; The same approach may be continued. b) **Not recommended:** 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. But reducing working capital because coal companies can't supply fuel is a counterproductive measure that will badly hit the financial / cash performance of generating companies. c) **Not recommended:** Current normative approach should be continued. **d) Not Recommended:** The current approach must be continued. **e) Not recommended:** 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 where as 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.

S. No.	Particular	Comments/ Suggestions
21.	21.1-21.7 **Operation and Maintenance (O&M) expenses** (a) Review the escalation factor for determining O&M cost based on WPI & CPI indexation as they do not capture unexpected expenditure; (b) Address the impact of installation of pollution control system and mandatory use of treated sewage water by thermal plant on O&M cost. (c) Review of O&M cost based on the percentage of Capital Expenditure (CC) for new hydro projects; (d) Review of O&M expenses of plants being operated continuously at low level (e.g. gas, Naphtha and R-LNG based plants). (e) Rationalization of O&M expenses in case of the addition of components like the bays or transformer or transmission lines of transmission system and review of the multiplying factor in case of addition of units in existing stations; (f) Have separate norms for O&M expenses on the basis of vintage of generating station and the transmission system. (g) Treatment of income from other business (e.g. telecom business) while arriving at the O&M cost.	(a) **Not recommended:** WPI & CPI is the best reflection of the increase in wholesale and consumer prices. This may be continued The unexpected expenses may be allowed separately on case to case basis after the prudence check. (b) **Recommended.** 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) (d) **Not recommended:** 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) (f) **Recommended:** The O&M expenses should be proportional to age of the Power station. Older the plant higher O&M is recommended. (g) Other income should be allowed as incentive to the generators rather than reducing the allowed O&M cost.
22.	22.8 **Fuel – Gross Calorific Value (GCV)** 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.	a) b) **Recommended**: This is a well-established fact that GCV losses to a great extent uncontrollable and therefore should be allowed on a normative basis to all power plants. Normative loss of 150 kcal/kg may be allowed from unloading point to firing in plant. This is in line with the recommendation of CEA and subsequent CERC notice for comment issued on 14.11.2017.

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	b) specify normative GCV loss between "As Received" and "As Fired" in the generating stations. c) Standardize GCV computation method on "As Received' and "Air-Dry basis'' for procurement of coal both from domestic and international suppliers.	**c) Recommended**
23.	23.6 **Fuel - Blending of Imported Coal** Normative blending ratio may be specified for existing plant as well as new plants separately in consultation with the beneficiaries.	**Not recommended:** **<u>Rationale:</u>** Each plant has its specific requirements hence can't be standardized. It is to note that one size fits all approach reg. blending is not practical. Blending of imported coal is dependent on several factors like GCV, Availability, Price, boiler design and other technical parameters etc. which cannot be standardized. Therefore, the blending of imported coal should be left with the generators to decide.
24.	24.5 **Fuel - Landed Cost** (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; (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.	a) **Not recommended;** The existing system of pass-through of landed cost should continue. Coal India varies its cost components time to time which may not be recoverable if some standard cost components are specified. Ex. Railways has introduced Coal Terminal surcharge in Aug'16 but removed in Jan'18. Coal India Ltd. Introduced Evacuation Facility Charges w.e.f. Jan'18. Therefore, all the components of coal cost or its transportation cost are not fixed Hence the proposed new system is not implementable. b) **Not recommended:** Generators are already struggling with cash flow issues and are under severe stress. The proposed changes shall further aggravate the situation and would accelerate the NPA status.

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25.	25.2 **Fuel - Alternate Source** (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.	a) **Not recommended**: Difficult to implement as it varies from source to source. Other than linkage coal, primary source of domestic coal is e-auction / spot auctions conducted by CIL subsidiaries. These auctions are purely driven by demand / supply scenarios and are biased towards a party which is logistically nearer to the source / mine. Therefore, putting any ceiling of such alternate coal prices will be very restrictive on generators it would lead to less Availability and loss of capacity charges. It is further suggested that the idea of taking prior consent of beneficiaries must be dispensed with as availability of coal is totally out of control of the generators and It is not possible to specifically schedule power from only domestic or imported power to any beneficiary.
26.	**26.3.19** **Operational Norms** a) **Station Heat Rate:** 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. b) **Specific Secondary Fuel Oil Consumption:** 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. c) **Auxiliary Energy Consumption:** Generating stations which have less auxiliary consumption than the norms, are able to declare 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	***a) …*** b) **Specific Secondary Fuel Oil Consumption*:*** This point very pertinently elaborates the difficulty of generating stations in renewable dominated generation. Based on CEA, NEP estimates significant renewable capacity is expected to be added in next few years. Considering the frequent start /stop operations expected under such scenario, there is a need to increase the normative SFC to at least 1 ml/kw from the existing level. c) **Auxiliary Energy Consumption*:*** Generator should be allowed to declare higher availability if they are able to operate at lower than normative aux power. No extra cost is being recovered from the customer if the generator is able to dispatch more than the normative ex-bus capacity. This is only the efficiency of a generator under which it may be able to sell some extra power in exchange / third party. This is should be allowed and encouraged. Also, the environmental norms specified by MoEFCCC would entail additional auxiliary consumption that should be allowed for. Further the AUX Norms have been set

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	declaring availability. Methodology of declaring availability after reduction of normative auxiliary consumption and colony consumption need elaboration. d) **Normative Annual Plant Availability:** 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; e) **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.	predominantly for based on performance of CPSU plants. With IPPs contributing around 40% of total thermal generation capacity, design parameters of all such IPPs shall also be considered. For e.g. there are many plants with design Auxiliary Power Consumption is 7.5 – 8.0%. However, the tariff norms provide for only 5.75%, which is not justified. d) **Normative Annual Plant Availability*:*** Plant availability factor must be firmed up only on annual basis and should not be reduced to a lower periodicity. One of the main reasons for keeping it annual is to ensure that generators get opportunity to meet the any shortfall (due to forced shutdown) over the year. It is pertinent to note that coal supply contracts /FSAs are also designed to keep supply levels of *25%, 22%,* 28%, 25% in respective four quarters of the financial year. Therefore, in a scenario where coal supplies is not uniform, there cannot be a monthly or quarterly limitation from fixed charge recovery point of view. e) **Transit & Handling losses:**
27.	26.4.2 **Thermal Generation (Coal washery rejects based)** • 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.	-
28.	26.5.5 **Transmission Availability Factor** • 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;	-

S. No.	Particular	Comments/ Suggestions
	• 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;	
29.	26.5.9 **Transmission Losses** • Introduce the norms for inter-state transmission losses based on factors within control and international benchmarks. • The existing approach for operational norms and level of Normative Annual Transmission Availability Factor (NATAF) may be reviewed. The weightage factor to be applied for arriving outage hours for calculating NAFM of transformer and switchable reactor of substation element may also be deliberated upon.	-
30.	26.6.3 **Hydro Generation** • Currently, Hydrology risk is to being 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. • The norms of auxiliary power consumption of hydro generating station vary from 0.7% to 1.2% based on rotational or static excitation system. The transformation losses are covered as a part of auxiliary consumption.	Recommended.
31.	27.5 **Incentive** (a) Review linking incentive to fixed charges in view of variation of fixed charges over the useful life and on vintage of asset - Need for different incentives for new and old stations; (b) Different incentive may be provided for off peak and peak period for thermal and hydro generating stations. Differential incentive mechanism for storage and pondage type hydro generating stations may also be considered.	It is suggested that Incentive scheme of 2009-14 tariff regulation linked to Availability must be re-implemented. **Rationale:** There is no incentive for Generator to be available if it has recovered its fixed cost based on Normative availability. Further in case of lower schedules the generator would not be able to get incentive for the reason beyond its control. Hence incentives must be liked to availability of the station rather than PLF.

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	(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.	
32.	28.2 **Implementation of Operational Norms** • 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.	**Not recommended:** **<u>Rationale:</u>** Unless tariff order is issued, there is no clarity on the critical plant specific operating norms like heat rate, SFC, Aux power. Therefore, plants should be allowed to bill as per existing order till the new order under new regulations is issued. Further there may be cases where a plant has pleaded for operation parameters greater than the norms. Therefore, in such a scenario the generator would be at a disadvantageous position.
33.	29.3 **Sharing of gains in case of Controllable Parameters** • 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.	The reconciliation should be done on annual basis to avoid billing complexities and multiple debit / credit notes and adjustments during the year if monthly system is introduced.
34.	30.1-30.2 **Late Payment Surcharge & Rebate** • 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. • For Rebate, Valid mode of presentation of bill, (email, physical copy etc.), authorised signatory, definition of two days (working days or including holidays) may need elaboration.	**Recommended.**
35.	31.1-31.2 **Non-Tariff income** • 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.	**Not recommended:** Additional revenue is earned after putting effort and money & Innovation etc. & people should be incentivised. Such sharing & reducing shall discourage people to go for innovations.

S. No.	Particular	Comments/ Suggestions
	• Presently, the revenue from telecom business is adjusted at the rate of Rs 3000/- per KM, which was fixed in 2007. It may need review.	
36.	32.1-32.2 **Standardization of Billing Process** (a) Whether standardization of billing process including formats, verification and timeline etc. may be done. (b) Whether electricity duty is to be linked with actual auxiliary consumption or normative consumption or lower of the two, may need to be specified.	**Recommended:** Standardized format may ease the billing complexities and disputes. Electricity duty is only a kind of reimbursement that generators are paying to their respective states. Therefore it should be allowed at actuals.
37.	33.3 **Tariff mechanism for Pollution Control System (New norms for Thermal Power Plants)** 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.	These expenses as already declared as Change in Law Ministry of Power, therefore actual cost incurred may be allowed as a pass-through. In addition, the costs associated with disposal of by-product of FGD system and cost incurred during the installation period of the FGD system in the form of Loss of Capacity Charges due to reduced availability of the plant is substantial which should also be considered for evaluation of the impact of FGD system on tariff.

S. No.	Particular	Comments/ Suggestions
	d) Change in Auxiliary Consumption and operation and maintenance expenses due to implementation of pollution control equipment.	
38.	34.2-34.3 **Renewable Generation by existing Thermal Generation Stations** 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. The scheduling and dispatch mechanism of renewable generation can be as per the thermal power generation. The target availability and dispatch level, in this case, maybe pre-specified which may be 2% higher for every 10% renewable capacity addition and the annual fixed charges for the thermal project and renewable project maybe combined for deciding the tariff. The rate of return, land cost, operation and maintenance cost for such renewable capacity can be specified separately.	In order to encourage the existing Thermal generators to setup Renewable generation there must be some incentive. Addition of renewable capacity may not help a generating station in increasing its dispatch and availability. Therefore there is no rationale to increase the target availability based on the new renewable plant in the same location.
39.	35.5 **Commercial Operation or Service Start date** a. Addressing the shortcomings in existing methodology for the trial run of generating station and trial operation for transmission element through appropriate regulatory mechanism;	**Following methodology may be adopted for COD declaration:** The period of trial run may be specified. For generating station, it is advisable 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.

S. No.	Particular	Comments/ Suggestions
	b. Issue of trial operation and commissioning of the project when a generating station is ready but cannot be operated due to non-availability of load or evacuation system; c. Issue of acceptance of COD of transmission line if the generating project or upstream/ downstream transmission assets are not commissioned; d. 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;	Upon furnishing the test certificate from the Independent engineer to concerned RLDC/SLDC the unit may be deemed to achieve Commercial Operation. 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. 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.
40.	36.7 **Energy Storage System** 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 storage facilities. 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.	**Recommended:** This is a rationale measure.

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	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 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 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. 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.	
41.	37.6 **Normative Tariff by Benchmarking of Capital Cost** 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?	Benchmarking can be used a thumb rule in prudence check of capital cost. Benchmarking also guides the new investor / developers in the sector to set their own targets in accomplishing the desired level of cost and therefore target returns. Though we strongly feel that benchmarking should not be limited only for hard cost. But it should be done package-wise / asset-wise like for BTG, Railways, Coal Handling Plant, chemical plant, cooling towers, preoperative expenses etc.
42.	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?	As elaborated above, there are various uncontrollable costs like interest on long-term loan, cost of coal & GCV (for working capital), which are completely beyond the control of a generator. Therefore, normative tariff by fixing AFC as a percentage of Capital cost may not be an appropriate measure to award AFC.
43.	37.17 **Normative Tariff by fixing each component of AFC as a percentage of total AFC**	**Not recommended.**

S. No.	Particular	Comments/ Suggestions
	a. Whether clustering the components of AFC based on their nature to increase/ decrease in order? Any other possible method to cluster the AFC components? b. What methodology should be adopted to determine the escalable (increasing)/ non-escalable (decreasing) factors? c. Whether escalable (increasing) / non-escalable (decreasing) factors should remain same for all plants/transmission systems (or) they be separate for each of the plants/transmission systems based on vintage / capacity / fuel type/ fuel linkages etc. d. Whether isolation of "Additional Capitalization" as a separate stream of revenue would provide for recovery of AFC on a normative basis in realistic terms? e. Alternatively, do you suggest any other methodology to treat "Additional Capitalization" for determination of AFC on normative basis? f. Whether applicability of change in tariff principles in each control period for the new plants would allow regulatory certainty to the existing plants? g. Alternatively, is there any other methodology to minimize the impact on AFC on account of change in control period?	**Reasoning:** As explained above tariff should not be allowed on a normative basis **by fixing AFC as % of Capital Cost**. Deviating in tariff principles drastically from the existing regulations, would not allow regulatory certainty to the existing plants; in fact, it would be otherwise, as the developers have considered the prevailing rules and regulations at the time of putting up the plant. The proposed methodology for tariff/ AFC should ensure recovery of costs and reasonable return to the developer. **If CERC still wants to go ahead with the option, a detailed approach paper should be floated clearly explaining the process.**
44.	37.20-37.21 **Principles of Cost Recovery - Approach towards Multi-Part Tariff** To introduce the system of differential AFC recovery linked to peak and off-peak periods in the following manner: - a. Off-peak component of AFC: The generating station has to declare a PAF of 80% for the year, which allows recovery of 80% of the AFC. Any slippage to meet the above norm would result in reduction in 80% of AFC in proportionate manner. b. Peak component of AFC: The remaining 20% of the AFC is recoverable from the beneficiaries, if the generating station achieves a PAF of 95% for the peak period, say of 4 months. During the currency of peak period, adherence to the norm of 95% PAF will be reconciled on monthly basis and slippages from this norm i.e. 95% up to the limit of 80%, would result in reduction in higher peak AFC for that month.	**The approach in its present form is not recommended.** **Reasoning:** As explained in earlier points, if a plant is forced to shut down during the peak period due to technical failures or circumstances out of its control like coal shortage or drought, it may lose the fixed charges corresponding to that period. 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.

S. No.	Particular	Comments/ Suggestions
	c. The peak and off-peak months for each generating station will be declared by the appropriate RLDC by considering load profile of beneficiaries. The proposed mechanism also seeks to provide for a higher peak price, say at 25% over the off-peak price. Accordingly, the weightage factors can be calculated by considering: i. Recovery of 80% of AFC, upon declaration of 80% PAF during the year and remaining 20% of AFC upon achieving 95% PAF during the peak period, say of 4 months. ii. Higher peak price (i.e. by 25% over the off-peak price) **37.21** • 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? • 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?	
45.	37.22 **Process flow for determination of normative tariff**	• **Step:2:** AFC may not be segregated into escalable/ no-escalable segments. • **Step: 5:** The present regulation provides for allowing add. Cap. and AFC is derived after giving effect to Add. Cap. Also, the Add. Cap. is allowed even after cut-off date for certain specific conditions as specified under the Tariff Regulations. It is recommended that the concept of cut-off date may be removed.
46.	38.1 **Transparency in Billing and Accounting of Fuel** • 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.	**More clarity required in the GCV measurement and allowance of normative GCV loss from unloading point to bunker.**

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47.	39.2 **Relaxation of Norms** • 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.	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.
48.	40.3 **Merit Order Operation** • 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.	Existing system is optimum to schedule the power with lowest marginal cost for a distribution company. This practice may be continued. Alternatively, the generators may be asked to declare their fuel cost on day ahead basis along with the availability and this data could be used by System operators to update the merit order on real time basis.
49.	41.4 **Review of Process in Case of Transmission System** • 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. • 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	-

S. No.	Particular	Comments/ Suggestions
	capital cost of individual elements. The true up maybe carried out on completion of the project based on balance sheet of individual project.	
50.	42.1 **Goods and Service Tax (GST)** • 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.

- **The consultation paper has not made any reference to the tariff determination for Cross-border projects. Regulations should define a process for determination of tariff for such projects.**

- **Any other taxes and duties levied by Central/State government should be allowed by CERC like Electricity Duty on Auxiliary consumption, entry tax etc., wherever applicable**