Objections, suggestions, comments of WBSEDCL on the Consultation Paper Consultation Paper on
TERMS AND CONDITIONS OF TARIFF REGULATIONS
For Tariff Period
1.4.2019 TO 31.3.2024

It has been observed that over the years, investment in Generation and inter-state transmission is incentivised through higher return and several tariff incentives, normative expenditures in cost plus tariff mechanism only to protect interest of those Generators and inter-state transmission utilities without proper periodical analysis of requirement of end consumers and effect of different Govt. Policies related to energy conservation, captive generation etc. Resultant effect of such investment now becomes burden of the Country, to be more specific to end consumers because of low dispatch and low utilisation of inter-state transmission system.

The situtaion was further aggraveted due to inclusion of large capacity of RE generation in the light of ambitious target of MoP, GoI to achieve it within a very short period of time. Such RE generation is mostly infirm in nature for which thermal Power Plants cannot be operated at optimum level due to frequent Ramping up and ramping down. This has also increased agony of stranded thermal asset and also of end consumer who are ultimately paying off all those expenditure without getting benefit out of such expenditure. As a distribution licensee, it is experienced that cost of such incentivized Generation, Transmission as well as infusion of large RE capacity, cost of power has increased significantly in many cases beyond the capacity of end consumers due to poor economic status which becomes major reason for increase of commercial loss in distribution sector. Moreover, such increase of power cost has resulted in reduction of demand growth.

Considering the situation stated above, it is hightime to formulate the proposed regulation keeping priority on cost reduction so that end users are relieved from existing burden.

If suitable corrective measure is not taken forthwith, entire power sector of the country will face its consequencecs. However, our observations in respect of the consultation paper on CERC's Tariff Regulation for 2019-24 are as follows:

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1	23	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.	Proposal for such three part tariff structure appears to be beneficial to end users since it will lead to reduction in cost However, inclusion of variable cost with energy cost may be considered for merit order dispatch mechanism as both are variable in nature.
2	23	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).	
3	23	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.	
4	24	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.	–Phasing out/ Renovation & Modernization/ Extension of Life programme of such plants may be dealt with case to case basis after detailed cost-benefit analysis so that consumer burden does not increase –In case of phasing out programme as proposed, modus operandi for existing PPAs with such older plants should be devised beforehand in consultation with existing beneficiaries

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5	24	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.	Proposed option of Two-part Tariff appears to increase financial burden to end user and hence the proposal is not in the benefit of consumers. Presently, as per state Regulation Hydro power purchase does not fall under Merit Order principle (Must Run) However, if the option of two-part tariff as proposed is kept, minimum dispatch value based on design energy should be linked with fixed component
6	25	7.5.4	Transmission tariff can be on two-part basis, wherein the first part can be linked with the access service and second part can be linked with the transmission service.	Issues related to Slab Rate in PoC Mechanism and Reliability Charge are under challenge before Delhi High Court which should be taken care of Region-wise pricing methodology may be introduced for the 'Common system' as proposed in part (b) of 7.5.5 because as a beneficiary, WBSEDCL should not pay any charge like HVDC, which does not exist in its region –In case regional pricing methodology is considered, options at (i) & (ii) under the sub-clause (a) & (b) of clause 7.5.5 appears to be beneficial to the end users in case the litigation in the Court of Law is resolved Under clause 18 of CERC's Grant of Connectivity Regulations 2009, the provision of relinquishment of access right on a stranded capacity is required to be addressed accordingly
7	25	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.	
8	26	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.	
9	26	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.	–Presently, for RPO fulfilment as per State Regulation, distribution licensees are purchasing RE power through competitive bidding route at DISCOM bus to minimise the power purchase cost –Proposed Tariff determination under sec 62 of the Act seems not beneficial to end users Scheduling of RE power should be separated from thermal power generation in case of bundled power mode as proposed
10	26	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;	

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	27		c)The tariff for supply of power from renewable generation and thermal power generation may be recovered separately. The operational norms for recovery of tariff may have to be specified separately.	
11	28	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.	Seems beneficial to the end users as the Generators has scope to reduce variable cost to come under merit order dispatch and thereby increase dispatch resulting in ultimate reduction in power purchase cost
12	28	9.3	The question is whether the annual fixed charges and energy charges are to be determined to the extent of the capacity tied up under Section 62 of the Act or for the entire capacity. One approach could be to determine the tariff of the generating station for entire capacity and restrict the tariff for recovery to the extent of power purchase agreement on pro-rata basis and balance capacity will be merchant capacity or tied up under Section 63, as the case may be.	Shall have no impact on Distribution segment since in both the scenario propotionate cost shall be paid by the Distribution Licensee
13	29	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;	Seems beneficial to the end users as the Distribution Licensee has scope to reduce contracted capacity for a year to reduce its fixed cost burden
			(b) Such unutilized Capacity may be aggregated and bidded out to discover the market price of surplus capacity. The surplus capacity may be reallocated to the distribution licensee at market discovered price.	
14	29	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.	Seems beneficial for end users as there will be reduction in depreciation and debt service.
			(b) Assign responsibility of operation of the hydro power stations and pumped mode operations at regional level with the primary objective for balancing. For this purpose, the scheduling of the hydro power operation (generation and pumped mode operation) may have to be delinked from the requirements of designated beneficiaries with whom agreement exists. The power scheduled to the hydro generation can be dispatched to designated beneficiaries through banking facility so that flexibility in scheduling can be achieved for balancing purpose and to address the difficulties of cascade hydro power station. Some part of fixed charge liability to the extent of 10-20% against the use of flexible operation and pumped operations may be apportioned to the regional beneficiaries as reliability charges.	Seems acceptable if the requirement of Distribution Licensee's as per their declared schedule is met. Also the overall power purchase rate should not exceed the rates available to the licensees as per their tied-up capacity after considering the benefits of extended life and longer repayment period
15	30	10.7	Scheduling and dispatch of gas based generating station may be shifted to regional level with the primary objective of balancing. After meeting the requirement of designated beneficiaries, the regional level system operator can use it for balancing power at the rate specified by the generating companies. Alternatively, all the gas based generating station capacities may be pooled at regional level. After meeting the requirement of designated beneficiaries, the balance generation may be offered for balancing purpose as and when required.	

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16	32	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.	–Option 11.9 for Regulatory Framework seems to be acceptable subject to cost overrun due to uncontrollable factor, which should be shared amongst Generators/Transmission Utility and beneficiaries –Provided relevant CERC/CEA project guideline/Norms is adhered and consent on cost overrun taken from respective beneficiaries •In a business, risk and return are to be shared between the parties in a transaction. Risk of cost overrun due to uncontrollable factor may be shared in the same principle to place the Generators/Transmission Utility and consumers on the same risk footing
17	32	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.	
18	33 & 34	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 34 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.	R&M may be allowed for the purpose of extension of life beyond the useful life of Transmission Asset afterRsidual Life Assessment (RLA) study because equipments attached with transmission line are usually installed in different period of time as per requirement and hence computation of such special allowance for R&M of transmission asset in general may also burden end users
19	36	14.6	a) Increase the useful life of well-maintained plants for the purpose of determination of depreciation for tariff; b) Continue the present approach of weighted average useful life in case of combination, due to gradual commissioning of units; c) Consider additional expenditure during the end of life with or without reassessment of useful life. Admissibility of additional expenditure after renovation and modernization (or special allowance) to be restricted to limited items/equipment; d) Reassess life at the start of every tariff period or every additional capital expenditure through a provision in the same way as is prescribed in Ind AS and corresponding treatment of depreciation thereof; e) Extend useful life of the transmission assets and hydro station to 50 years and that of thermal (coal) assets to 35 years and bring in corresponding changes in treatment of depreciation. f) Reduce rates which will act as a ceiling. g) Continue with the existing policy of charging depreciation. 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).	•Options A) , D) & E) is acceptable for setting up of Regulatory Framework for Depreciation –As extension of life has been considered through reassessment procedure
20	37	15.2	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	•Option at 15.2 modified Gross Fixed Asset arrived at by reducing the balance depreciation after repayment of loan in respect of original project cost shall be beneficial to end users and should be adopted •ROE instead of ROCE approach seems reasonable in view of options suggested in respect of 14.6 & 15.2 above
21	37	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.	•Option at 16.4 shall be beneficial to end users and should be adopted –It shall rationalize the interest component

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22	40 & 41	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 Figure 9: Plant load factor (thermal) Figure 10: Trend in interest rate & G-Sec yield Figure 8: Installed capacity of renewables 41 recent times. Therefore, there is market dynamics which favors 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 transmission projects.	•Risk free return should be at par with Govt. Bond (G-Sec) –Since there is more risk factor in Generation, •For Generation segment, ROE should be higher than Transmission segment •Premium return should be linked with prevailing market with some weightage according to risk involvment. Considering return from market (as 100% risk) & return from Govt. Bond (G-Sec) (as min risk), overall ceiling of ROE should not be more than 11% with 50-60% risk factor considering the present scenario of more than 40000 MW stranded generation and corresponding stranded transmission capacity –Furthermore, in respect of Generation segment, Hydro option 18.7 (C) seems reasonable considering peak support –In no case existing ROE should increase, in contrary ROE should be reduced linking with the performance of Generators
23		18.7	(a) Review the rate of return on equity considering the present market expectations and risk perception of power sector for new projects;	
			(b) Have different rates of return for generation and transmission sector and within the generation and transmission segment, have different rates of return for existing and new projects;	
			(c) Have different rates of return for thermal and hydro projects with additional incentives to storage based hydro generating projects;	
			(d) In respect of Hydro sector, as it experiences geological surprises leading to delays, the rate of return can be bifurcated into two parts. The first component can be assured whereas the second component is linked to timely completion of the project;	
			(e) Continue with pre-tax return on equity or switch to post tax Return on equity;	
			(f) Have differential additional return on equity for different unit size for generating station, different line length in case of the transmission system and different size of substation;	
			(g) Reduction of return on equity in case of delay of the project;	
23	43	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 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.	•Options elaborated in 19.5 (C) seems acceptable as it will lead to reduction in cost of debt for the end users
24		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;	

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25	44	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.	–Those spares which may take long time to consume (Runner, Motor, Spares for Governor etc.) should be excluded from the Working Capital [Option 20.3 seems acceptable] –However, it is proposed to charge the beneficiaries, on normative or actual basis, whichever is lower, in the interest of the consumer. Moreover, normative parameters should be downsized considering modernization and use of efficient operational norms.
	44		(b) As stock of fuel is considered for working capital, a fresh benchmark may be fixed or actual stock of fuel may be taken.	
			(c) While working out requirement of working capital, maintenance spares are also accounted for. Since O&M expenses also cover a part of maintenance spares expenditure, a view may be taken as regards some percentage, say, 15% maintenance spares being made part of working capital or O&M expenses.	
			(d) Maintenance spares in IWC which is also a part of O&M expenses results in higher IWC for new hydro plants with time and cost overrun. For old hydro stations, the higher O&M expenses due to higher number of employees also yield higher cost for “Maintenance Spares” in IWC. Therefore, option could be to de-link “Maintenance Spares” in IWC from O&M expenses.	
			(e) In view of increasing renewable penetration and continued low demand, the plant load factor of thermal generating stations is expected to be low. As per the present regulatory framework, the normative working capital has been provided considering target availability. In case of wide variation between the plant load factor and the plant availability factor, the normative approach of linking working capital with “target availability” can be reviewed.	
26	46	21.7	(a) Review the escalation factor for determining O&M cost based on WPI & CPI indexation as they do not capture unexpected expenditure;	–The options may lead to increase in O&M Cost and subsequent burden on end users –However, it is proposed to charge O&M expense to the beneficiaries, on normative or actual basis, whichever is lower, in the interest of the consumer
			(b) Address the impact of installation of pollution control system and mandatory use of treated sewage water by thermal plant on O&M cost.	
			(c) Review of O&M cost based on the percentage of Capital Expenditure (CC) for new hydro projects;	
			(d) Review of O&M expenses of plants being operated continuously at low level (e.g. gas, Naptha and R-LNG based plants).	
			(e) Rationalization of O&M expenses in case of the addition of components like the bays or transformer or transmission lines of transmission system and review of the multiplying factor in case of addition of units in existing stations;	
			(f) Have separate norms for O&M expenses on the basis of vintage of generating station and the transmission system.	
			(g) Treatment of income from other business (e.g. telecom business) while arriving at the O&M cost.	

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27	47 & 48	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	•As per fuel supply agreement (FSA) of generation station with coal supplier, ownership of the coal get transferred at coal mines end. Therefore, it is the responsibility of the generating company to take preventive measures so that grade slippage issue which leads to drop in GCV around 800-1000 Kcal/kg can be addressed. –Impact: Reduction of energy charge to the tune of ₹ 0.60/ KWH
			b) Similarly, specify normative GCV loss between "As Received" and "As Fired" in the generating stations.	•Excerpts of CEA report: Loss in GCV has been quantified between wagon top at unloading point and the point of firing of coal in boiler
			c) Standardize GCV computation method on "As Received' and "Air-Dry basis'' for procurement of coal both from domestic and international suppliers.	–Observation: •CEA report on loss of GCV value of coal is very partial in nature as the report is not analyzing the GCV of the coal at different point of journey of the coal upto the boiler. Therefore GCV loss cannot be addressed properly. •Blanket GCV compensation of around 70-80 kcal/kg for all season is not acceptable •Therefore, there is a drop of GCV--between coal mines to Wagon Top unloading point between Wagon Top unloading point to 'as fired' during the storage of the coal. Option for Regulatory framework:- Insert the definition of the following:- 'as received at coal mines end' 'as received at power station end' 'as fired' Drop in GCV at mines end ('as received at coalmines end') and power station end ('as received at power station end') should be quantified on percentage basis and generator should be directed to reduce the GCV loss in phased manner and it should be the parameters of performance of generating companies. Curtailment of ROE for Generator should be linked with their performance similar in line with non-achievement of normative distribution loss in case of DISCOM
28	48	23.6	Normative blending ratio may be specified for existing plant as well as new plants separately in consultation with the beneficiaries.	Seems reasonable
29	50	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;	•Lack of transparency –Linkup between the invoice claimed by coal companies, transportation charge claimed by the transporter, quality of the coal, quantum of the coal and the price of the coal claimed by coal companies reflected in the Form 15 (which is customized by the generator) should be transparent to the beneficiaries.
			(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.	
30	50	25.2	(a) Stipulate procedure for sourcing fuel from alternate source including ceiling rate;	Price should not impact energy cost due to sourcing of coal through alternate sources
			(b) Rationalize the formulation keeping in view the different level of energy charge rates, as the fuel cost has increased since 1.4.2014.	

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	51	26.3	Thermal Generation - Comments and suggestions are sought on auxiliary Energy consumption, Transit & handling loss and normative annual plant availability factor	Generally, Generating Stations are drawing power in two ways i.e. one from Generating bus and another from respective DISCOM (which is not used generally and acts as a Standby Power). Therefore, most of the time, load of the Township (which is not considered as Auxiliary Consumption as per Regulation) remains on the Generating Bus and is embedded in Auxiliary Consumption. In this context, our submission is that power for colonies including market complex & different establishment in the complex , should only be taken from the supply of discom and such cost should not be considered in AFC. Strict monitoring should be in place for the purpose with required authentication by discom otherwise it will create burden for end consumer. Regarding Normative Annual Plant Availability, norms should be linked with peak period and peak season (March to October in West Bengal) when generator can be allowed to realize full Per Unit (PU) fixed cost of proposed 3 part tariff based on declared PAF. In other period & other season, such PU realisation will be less, say 70-75% of Per Unit FC.This philosophy will regulate Fixed charge per unit throughout the year with minimum deviation. The proposal has been conceptualised considering present Buyer's Market scenario. Regarding Transit & handling loss , it should be transparently shown in the bill & such loss

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31	56	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;	For transmission substation, power supply from discom should be taken for colonies if any in the complex and such cost should not be considered in AFC. Strict monitoring should be in place for the purpose with required authentication by discom otherwise it will create burden for end consumer. Regarding Normative Annual Plant Availability, norms should be linked with peak period and peak season (March to October in West Bengal) when Inter state transmission licensee can be allowed to realize more fixed cost of proposed 2 part tariff based on Availability. In other period & other season, such realisation of fixed cost should be less. However, the impact on HVDC system should not fall upon non-users of the same and so region-wise approach might be preferable.

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	56	26.5.6	Presently, there is no regulatory framework on specifying the norms for transmission losses. Transmission loss comprises primarily of technical losses, which consists mainly of power dissipation in electricity system components such as transmission line, transformers and measurement systems. The transmission losses are dependent on the best operational practices, efficient planning, level of power flow and avoidance of circular flow. The operational strategies and practices adopted by transmission network operator and system operator impact the transmission losses.	Considering utilization of advanced technology in Trnasmission system and related investment thereof which are borne by end users, total(injection & withdrawal) CTU loss reduction trajectory should be incorporated say, below 1%. Furthermore, such loss component beyond normative should result in proportionate reduction in ROE which is presently prevailing in DISCOM as per State regulation where Distribution loss target is linked with Return on Equity component of Tariff
			The transmission losses considered in the present scheduling framework is about 4.5-5% for inter-state transmission system and 4-4.5% for intra-state transmission system. As a result, the net power delivered to the distribution periphery is reduced by about 9-10%, which has an impact on the cost of supply. An option could be to 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.	
	57	26.6	Hydro Generation - comments has been sought on auxiliary consumption, transformation losses and normative annual plant availability factor	For Hydro power station, power supply from discom should be taken for colonies including market complex & different establishment in the complex and such cost should not be considered in AFC. Strict monitoring should be in place for the purpose with required authentication by discom otherwise it will create burden for end consumer. Regarding Normative Annual Plant Availability, norms should be linked with peak period and peak season (i,e Monsoon) when generator can be allowed to realize full PU fixed cost of proposed 2 part tariff based on declared PAF. In other period & other season, such PU realisation will be less.
32	58	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;	Considering utilisation of advanced technology in Generation & Trnasmission sector and related investment thereof, borne by end users, incentive mechanism should be discarded henceforth. Furthermore, it may be mentioned that present CTU charge/unit is abnormally high.
			(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.	
			(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.	

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33	58	29.1 to 29.3	29.1 The present regulatory framework provides for sharing of gains between generating company and beneficiaries in 60:40 ratio on account of improvement in controllable factors such as Station Heat Rate, Auxiliary consumptions, secondary fuel oil consumption, refinancing of loan and the true up of primary fuel cost. Subsequent to above, the compensation mechanism has been introduced for operation in CERC (Indian Electricity Grid Code) (Fourth Amendment) Regulations, 2016. The compensation mechanism aims to provide compensation if generating plant is operated at improved norms than ones specified in the amended IEGC Regulations of 2016. In view of the compensation mechanism, it needs to be considered as to whether the ratio of sharing of benefit may be reviewed	–Gain sharing ratio may be considered as 40:60 i.e 40% for Generator & 60% for beneficiaries
			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.	–Proposed mechanism on PLF linked merit order operation needs elaboration.
			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.	–Quarterly reconciliation is preferable to accommodate the requirements of quarterly accounts compilation as per statute
34	59	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.	MCLR based LPSC option seems preferable in view of its linkage with the existing debt market
		30.2	Further, as per the existing regulations, the rebate is provided if payment is made within 2 days of presentation of the bill. Valid mode of presentation of bill, (email, physical copy etc.), authorised signatory, definition of two days (working days or including holidays) may need elaboration.	Definition of Two days for 2% rebate on presentation should consider two working days
35	60	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.	Already clean Cesses, different duties are now in vogue like clean coal cess, environmental cess etc. that are now being paid by consumers which may be used for funding in pollution control system with out further burdening to consumers
			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.	

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	62	35.5	Comments and suggestions are invited from the stakeholders on possible options for dispute-free and practical mechanism for declaring commercial operation date. Comments and suggestions are also invited on the following. a. Addressing the shortcomings in existing methodology for the trial run of generating station and trial operation for transmission element through appropriate regulatory mechanism; b. Issue of trial operation and commissioning of the project when a generating station is ready but cannot be operated due to non-availability of load or evacuation system; c. Issue of acceptance of COD of transmission line if the generating project or upstream/ downstream transmission assets are not commissioned; d. 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	Recovery in expenditure which is not possible due to delay in Commissioning from target COD of Generation or Transmission shall be absorbed by the party who is responsible for such delay and shall not be passed on to the end consumers. Thus to get benefit of generation by the end consumer, the date of COD of generation project and associated transmission system for evacuation of power which ever is later, COD should be considered for billing purpose.
	63	36.4 & 36.5	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. 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 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.	At this stage where Country is facing low despatch from thermal power station coupled with stranded asset, further investment for energy storage system may increase burden of end consumers if not such investment is borne by generators to save its equipment from frequent ramp up and ramp down.
	65	37.9	Views/ comments are solicited on the following:- a. Whether it is a good idea to determine AFC as percentage of Capital Cost on normative basis? b. What could be the possible methodology to establish the relation between AFC and Capital Cost so that it meets the interests of both buyers and sellers?	To protect the interest of end consumers for whom Power Purchase Agreement is being executed based on levelized tarif on DPR. Variation of DPR value should be restricted due to time over run & cost over run as based on capital cost, AFC is determined. In case AFC is made as % of capital cost, it may lead to increase of capital cost which will burden end consumers.

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36	68	37.18	37.18 The Commission introduced Availability Based Tariff (ABT) in the year 2000. Under the Availability Based Tariff (ABT), the annual bulk power tariff for supply of electricity from a generating station of a generating company as determined by the Central Commission comprises two components, viz. Annual Fixed Charges (AFC) and Energy Charge (EC). The fixed charges are payable fully on achieving the plant availability factor as per the benchmark level specified by the Commission. All the generating stations regulated by CERC are required to follow the scheduling and dispatch mechanism specified by the Commission. The generating station has to declare availability on daily basis. The failure to achieve the target plant availability factor leads to dis-incentive in terms of reduction of the fixed charges on proportionate basis, and there is a provision for incentive for actual generation above the target availability factor.	The new approach of AFC based on peak & off-peak period consideration is recommended which may improve efficient operation of Generators and shall also be beneficial to end users
	69	37.21	comments of stakeholders are invited on the following points. 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?	Option (a)& (b) seems favouable considering requirement of the consumers where Generator can be allowed to realize full PU fixed cost of proposed 3 part tariff based PAF in peak period and peak season (March to October in West Bengal). In other period & other season, such PU realisation will be less, say 70-75% of Per Unit FC.
37	71	38	Transparency in Billing and Accounting of Fuel 38.1 The regulatory approach of pass through of coal cost to the procurer directly onthe basis of certification has been well adopted. Comments and Suggestions are invited for further strengthening the existing system.	–Linkup between the invoice claimed by coal companies, transportation charge claimed by the transporter, quality of the coal, quantum of the coal and the price of the coal claimed by coal companies reflected in the Form 15 (which is customized by the generator) should be transparent to the beneficiaries. For better transperancy, reconciliation of coal stock at generator end vis-a-vis invoice quantity of coal supplier needs to be undertaken periodically (preferably on monthly basis). Simultaneously, cost and GCV of coal should be reconciled with coal supplied and coal stock at Generator end. In the POC bill there is no transperancy regarding realisation of Fixed Charge of different Transmission Lines even after realisation of depreciation and repayment of loan
	72	41.3	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.	Seems acceptable where those new transmission asset are put to use for end consumers and cost of such project has not increased significantly.