Views / suggestion of PCKL on Consultation Paper on Terms and Conditions of Tariff Regulations for Tariff Period 01.04.2019 to 31.03.2024 has been brought out by CERC through public notice on 24.05.2018.

Sl.No.	Options for Regulatory Framework	Comments
	Thermal Generating Stations –Tariff Structure	
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.	Three part tariff structure for the generating plants proposed for the period 01.04.2019 to 31.03.2024 is a welcome move in the present scenario wherein Plant Availability Factor and the Plant Load Factor are widening.
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).	Guaranteed Rate of return may be 12% and incremental return above guaranteed return may be 2%. Further, Interset on working capital may be segregated in two part a. portion of O&M cost and maintenance spares may be included in the interest on working capital to arrive fixed cost b. Interest on working capital on receivable may be included in the Variable charges.
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.	***The concept paper doesn't specify the methodology for payment towards Variable Charges. The explanation is required along with illustration for clarity.***
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	Techno-Commercial study is required regarding considering the possible option as stated in concept paper. Therefore, it is suggested that Thermal station crossing 25 years needs Joint

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	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.	Techno-commercial study by CEA and technical consultancy (nominated by generating company) to be carried out and in consultation with stake holders, the best option may be opted.
	Hydro Generating Stations - Tariff Structure	
7.4.2	The fixed component may include debt service obligations, interest on loan and risk free return while the variable component may include incremental return above guaranteed return, operation and maintenance expenses and interest on working capital. The annual fixed cost can consist of the components of return on equity, interest on loan capital, depreciation, interest on working capital; and operation and maintenance expenses.	Normally, life of the hydro generating station is more than the specified life in the Tariff Regulation (35 years). Since life of the hydro generating station more than 35 years the fixed components and variable component structure to be modified by extending the obligation of debt service duration, revision of depreciation calculation, determination of O&M cost based on the MWs instead of original project cost as existing. The fixed rate of return may be included in the fixed component and the incremental return on equity may be included in the variable cost component.
	Inter-State Transmission System - Tariff Structure	
7.5.4	Transmission tariff can be on two-part basis, wherein the first part can be linked with the access service and second part can be linked with the transmission service.	
7.5.5	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	

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	(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.	The proposal in the concept paper regarding Transmission tariff may 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 is agreeable with certain modifications as below; “ The recovery of fixed component could be linked to the extent of access (Transmission Access Charge) and variable component could be linked to the extent of use, to be recovered in proportion to the power flow (Transmission Service Charge) **<u>and reliability”</u>**.
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.	
	Renewable Energy Generation – Tariff Structure	
7.6.3	There can be Two part tariff structure for renewable generation covered under Section 62 of the Act, which comprises fixed component (debt service obligations and depreciation) and variable component (equal to marginal cost i.e O&M expenses and return on equity) - fixed component as feed-in-tariff (FIT) and variable component equal to capacity augmentation such as storage or back up supply tariff.	In the proposed two part tariff either in the fixed component and variable component the interest in working capital is not factored. This requires examination.

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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;	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; **Comments:** Para 7.6.4(a) is not specified the quantum of renewable generation may be supplied at the existing tariff of thermal power plant. Hence % to be notified. **Suggestion:** The tariff of renewable generation shall be equal or lower than the energy charges of the Thermal Power Plant and it may be inline with **<u>Ministry of Power guidelines dated 17.07.2018 flexible in generation</u>**. Hence, proposal for recovery of tariff separately when both the plants locates in the same location and integrated. The tariff of renewable generation in case of replace the energy charges only if tariff of renewable generation equal or lower than the energy charges of the Thermal Power Plant and it may be inline with **<u>Ministry of Power Notification dated 5th April 2018 on Flexibility in Generation and scheduling of Thermal Power station to reduce emission.</u>** Further the net gain realized, if any from supply of RE power in place of thermal power under existing PPA may be passed on to the beneficiary in the ratio of 50:50 (Beneficiary : Generators) Para 7.6.4(c) proposal for recovery of tariff separately is not agreeable proposal when both the plants locates in the same location and integrated.

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	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;	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;
	Deviation from Norms	
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.	i) Generators has to specify the deviation norms in the petition for control period. ii) The better norms option may be provided in the regulation for parameters including financial and norms of operation parameters. iii) The better norms agreed by the Generators should be compared only to the control period instead of the entire life of the projects. The regulation may be provided for any untied capacity of the generating station whose tariff is determined under Section 62 can be sell to any of the distribution licensee under Short Term at a rate determined by the commission or lesser. However, the procurement of power is subjected to approval of the Procurer State Regulatory Commission. Slab wise the incentive and disincentive mechanism for different level of dispatch may be specified. The target dispatch may be 85% and over and above dispatch incentive shall be incentive
	Components of Tariff	
9.3	The question is whether the annual fixed charges and energy charges are to be determined to the extent of the capacity tied up under Section 62 of the Act or for the entire	Commission may continue to determine the Annual Fixed Charges and Energy Charges for entire capacity under Section 62. However restrict the tariff for recovery AFC to the extent of

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	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.	power purchase agreement on pro-rata basis and balance capacity will be merchant capacity may be tied up under Section 63 or under Section 62. In case the existing beneficiary or any distribution licensee willing to purchase under short term at the tariff determined under Section 62 with the approval of the Procurer State Regulatory Commission, may be incorporated.
10.3	**Optimum utilization of Capacity Coal based Thermal Generation**	
	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;	In principle, the option of flexibility provided to the generating company and distribution licensee to redefine the Annual Contracted Capacity (ACC) on yearly basis out of total Contracted Capacity as proposed.
	b) Such unutilized Capacity may be aggregated and bidded out to discover the market price of surplus capacity. The surplus capacity may be re-allocated to the distribution licensee at market discovered price.	The proposal of defining the Annual Contracted Capacity on yearly basis out of total Contracted Capacity may be agreeable. The proposal of unutilized Capacity may be aggregated and bidded out to discover the market price of surplus capacity. The surplus capacity may be re-allocated to the distribution licensee at market discovered price is agreeable.
	Hydro Generation	
	(a) Extend the useful life of the project up to 50 years from existing 35 years and the loan repayment period up to 18-	Proposal of Extend the useful life of the project up to 50 years from existing 35 years and the loan repayment period up to 18-

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	20 years from existing 10-12 years for moderating upfront loading of the tariff.	20 years from existing 10-12 years for moderating upfront loading of the tariff is acceptable. Further depreciation value is also reduce due to extension of project life.
	(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.	Para 10.5(b) provides for 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. Somepart 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 **is not acceptable proposals.** The rationale for not accepting this proposal is as below: ***Particularly, in Karnataka three main reservoir based Hydro Power Projects namely Linganamakki (1035 MW), Supa (900 MW) and Mani (460 MW) dam in Karnataka are being used for base load as well as peaking support. Total capacity from these three projects is 2395 MW. Hydro power is one of most flexible sources of electricity production. This offer easier integration of variable generation balancing the rich in renewable energy generation. Karnataka State is rich in Renewable energy.*** ***Hence, the proposal as per 10.5(b) is not acceptable. Further depreciation value is also reduced due to extension of product life.***

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	Gas based Thermal Generations	
10.7	Scheduling and dispatch of gas based generating station may be shifted to regional level with the primary objective of balancing. After meeting the requirement of designated beneficiaries, the regional level system operator can use it for balancing power at the rate specified by the generating companies. Alternatively, all the gas based generating station capacities may be pooled at regional level. After meeting the requirement of designated beneficiaries, the balance generation may be offered for balancing purpose as and when required.	The proposal of Scheduling and dispatch of gas based generating station may be shifted to regional level is acceptable.
	Capital Cost	
11.8	One of the options is to move away from investment approval as reference cost and shift to benchmark/reference cost for prudence check of capital cost. However, the challenge is absence of credible benchmarking of technology and capital cost.	
11.9	Higher capital cost allows the developer return on higher base of equity deployed. In the cost plus pricing regime, the developer envisages return on equity as per the original project cost estimation. The regulations allow compensation towards increase in cost due to uncontrollable factor so as to place the developer to the same economic position had this uncontrollable event not occurred. Therefore, in new projects, the fixed rate of return may be restricted to the base corresponding to the normative equity as envisaged in the investment approval or on benchmark cost. The return on additional equity may be restricted to the extent of weighted average of interest rate of loan portfolio or rate of risk free return. Further, incentive for early completion and disincentive for slippage from scheduled commissioning can	Inabsence of credible benchmarking of technology and capital cost, Commission has come out with benchmarking pricing mechanism based on technology prior to notify the Terms and Conditions for Tariff Regulation for control period. and this benchmark may be considered as a reference annul further till completion of control period it should be escalated / de-escalated as per the WPI and CPI composite index of WPI and CPI for energy subsequent year. Therefore, for the new projects the fixed rate of return may be restricted to base corresponding to the normative equity as envisaged in the bench mark cost. Further, the return on additional equity may be restricted to extent of weighted average of interest rate of loan portfolio or the rate of risk free return whichever is lower. The incentive for the early completion and disincentives for slippage from the

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	also be introduced.	scheduled commissioning can also be introduced.
	Renovation & Modernisation	
12.6	The R&M of transmission system could include Residual Life Assessment of Sub-Station and Transmission Lines, Upgradation of sub-station and transmission line, System Improvement Scheme (SIS) and replacement of equipment. The Commission may allow Renovation & Modernisation (R&M) for the purpose of extension of life beyond the useful life of transmission assets. Alternatively, the Commission may allow special allowance for R&M of transmission assets. Such provision will enable the transmission companies to meet the required expenses including R&M on completion of 25/35 years of useful life of sub-station/transmission line without any need for seeking resetting of capital base.	Provisions in the Tariff Regulation, 2009 in the form of special allowance to be allowed in lieu of R&M for coal/lignite based thermal power stations may be continued. The option as brought out in Para 12.6 modified as below; The R&M of transmission system could include Residual Life Assessment of Sub-Station and Transmission Lines, Upgradation of sub-station and transmission line, System Improvement Scheme (SIS) and replacement of equipment. The Commission may allow Renovation & Modernisation (R&M) for the purpose of extension of life beyond the useful life of transmission assets **based on techno-commercial study authorized by CEA.** 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.
14.	**Depreciation**	
	a) Increase the useful life of well-maintained plants for the purpose of determination of depreciation for tariff;	The useful life of the both thermal, Gas Hydro projects and Transmission assets may be upto the years specified as above.
	b) Continue the present approach of weighted average useful life in case of combination, due to gradual commissioning of units;	Treatment of weighted average useful life in case of combination, due to gradual commissioning of units should be continued
	c) Consider additional expenditure during the end of life with or without re-assessment of useful life. Admissibility of additional expenditure after renovation and modernization (or special allowance) to be restricted	**Modified proposal:** Consider additional expenditure during the end of life **with** re-assessment of useful life. Admissibility of additional expenditure after renovation and modernization (or special allowance) to be

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	to limited items/equipment;	restricted to limited items/equipment **which has to be specified by the Regulatory Commission in consultation with CEA. Further the guidelines for additional capitalization may be notified by CEA.**
	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;	**Modified proposal:** In case of any add cap, the effective life should at least be extended to the end of that control period. The assessment of every additional expenditure in line of accounting standard.
	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.	Extend useful life of the transmission assets required re-examination in view of and hydro station to 50 years and that of thermal (coal) assets to 35 years and bring in corresponding changes in treatment of depreciation as below; **Depreciation should be charged over the revised balance life of the assets along with the written down value up to 90% of revised GFA.**
	f) Reduce rates which will act as a ceiling	The reduce rates be treated as ceiling rates
	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).	**Modified proposal** The deprecation policy may be continue with change of useful life of the assets. The deprecation opted by the developer for lower than Notified rates may be considered for the computation of the tariff.
15	**Gross Fixed Asset (GFA) Approach**	
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.	The Gross Fixed Assets (GFA) approach may be continued with certain changes that **once the loan amount is repaid, the equity should be reduced in proportionate to the deprecation amount paid on every year.**

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16.	**Debt: Equity Ratio**	
16.4	For future investments, modify the normative debt-equity ratio of 80:20 in respect of new plants, where financial closure is yet to be achieved.	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 is acceptable
18	**Rate of Return on Equity**	
	According to CEA, the capacity addition is no more a major challenge and adequate installed capacity (along with currently under installation) exists to meet the demand for the next 8-10 years. Further, the rate of interest has also come down in recent times. Therefore, there is market dynamics which 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.	**Modified proposal** The existing Rate of Return on Equity for both existing and new project required reductions. The details as follows; There is an urgent need to define and quantify components on the basis of which the rate of return on equity is being determined. It is suggested that the level of return being earned by other business entities may be examined to determine the rate of return. The rate should be such that the investor may be able to earn at least the prevailing rate of interest being offered by the banks and additional component to counter the risk factor. The fixed rate of guaranteed return should be continued uniformly throughout the control period in order to have regulatory certainty along with provision of incremental RoE.
18.7	(a) Review the rate of return on equity considering the present market expectations and risk perception of power sector for new projects;	Guaranteed Rate of Return is 12% and incremental RoE linked to market maximum 2%
	(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;	Different RoE for the generation and transmission sector may be specified based on the life of project except hydro power plant and it should not be more than rate of return as specified in above para
	c) Have different rates of return for thermal and hydro projects with additional incentives to storage based	Different rates of return for thermal and hydro projects with additional incentives to storage based hydro generating projects

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	hydro generating projects;	may be allowed
	(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;	Keeping into consideration the location, construction methodology, time period required for construction, compliance requirements etc, the differential rate of returns should be decided and made applicable for Hydro and Thermal Power Projects. The hydro Power Projects should have more rate of return in comparison to the Thermal Power stations
	(e) Continue with pre-tax return on equity or switch to post tax Return on equity;	**Modified proposal** The tax paid by the generators/transmission utilities may not be reimbursed by the beneficiaries with whom Power Purchase agreement exists.
	(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;	Fixing different Rate of return for different size is may not necessary
	(g) Reduction of return on equity in case of delay of the project;	**Modified proposal** The reduction of return on equity may be allowed ie in case delay of project from the scheduled dated by more than 6 months, the ROE reduced by 0.5% and delay by 1 year the RoE may be reduced by 1% and so on.
19	**Cost of Debt**	
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	

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	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.	
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;	As far as existing projects, the existing method of working out cost of debt may be continued by considering weighted average rate of interest, calculated based on actual loan, actual interest rate and scheduled loan repayment. However, existing generators are to be switchover to present system of MCLR based lending rate. In case any difference between MCLR / average rate of interest limit to lower of MCLR or average rate of interest. The MLCR rate may not be more than SBI one year MCLR rate.
	a) Review of the existing incentives for restructuring or refinancing of debt;	The existing method sharing of financing gain needs to revise and Generators have to switchover to MCLR based funding rate.
	b) 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;	Benchmarking reference for cost of debt link to RBI policy rate repo rate is most viable option. It brings more discipline & efficiency in debt.
20	**Interest on Working Capital (IOWC)**	
20.3	a) Assuming that internal resources will not be available for meeting working capital requirement and short-term funding has to be obtained from banking institutions for working capital, whose interest liability has to be borne by the regulated entity, IWC based on the cash credit was followed during previous tariff period. Same	The non cash expenditure of depreciation and ROE may be

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	approach can be followed or change can be made.	excluded from the working capital requirement. The stock of fuel considered for working capital is very high. Even a week stock is not available. Hence, stock of fuel may be considered as 7 days. The most of the sub-element under administrative expenses and most of the sub-element under corporate office form part of the working capital along with O&M expenses in the existing methodology although these are not even remotely connected with the working capital requirement. Interest on Working Capital on fuel oil, gas and coal cannot be provided equal weightage as there is no time required for piping gas and oil but the coal required considerable time for transportation. Interest on working capital may be linked to yearly MCLR rates of SBI as on 1.4.2019 for existing projects and as on the date of commission of the projects for new projects. Normative availability factor for coal consumption may be reduced in view of renewable source as well as the low demand for thermal projects Hiding the gap between availability and dispatch
	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.	
21	**Operation and Maintenance (O&M) expenses**	
21.7	a) Review the escalation factor for determining O&M cost based on WPI & CPI indexation as they do not capture	

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	unexpected expenditure; Treatment of income from other business (e.g. telecom business) while arriving at the O&M cost.	The different O&M cost per MW/KM may be specified based on the actual cost excluding the wage revision and any other extraordinary items for new and old projects The charges included in the O&M cost needs to specified since there is disputes for whenever additional claims raised by the Generators. O& M cost for the imported coal based project exclusively having jetty may be specified separately since cost of handling of coal from jetty lesser than domestic coal. The O&M cost for the Hydro Project may be based on normative value per MWs basis inline with Coal based Thermal Project. Separate O&M cost for the plants like gas, Naptha and R-LNG based plants may be specified in the regulation. Separate norms for O&M expenses on the basis of vintage of generating station and the transmission may be provided
	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.	
22.	**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	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.

<table>
<tr><th>Sl.No.</th><th>Options for Regulatory Framework</th><th>Comments</th></tr>
<tr><td></td><td>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.</td><td>In the present scenario based on GCV range run of mine price of coal is fixed. There is 17 grade and different GCV range in each grade between higher value to lower value is 300 GCV. Therefore instead of limiting GCV loss, slippage of grade loss may be better option or more 300 GCV rate to be considered.

For imported coal- As per ISO and ASTM standard, the inter-lab tolerance of GCV, Ash and sulphur is as detailed below:

<table>
<tr><td>Parameters</td><td>As per ASTM</td><td>As per ISO</td><td>Umpire Analysis</td></tr>
<tr><td>GCV(ARB)</td><td>56 kcal/kg</td><td>72Kcal/kg</td><td>If discharge port results beyond inter lab tolerance</td></tr>
<tr><td>TM(ARB)</td><td>0</td><td>0</td><td>Only if discharge port results beyond rejection levels</td></tr>
<tr><td>Ash(ADB)</td><td>0.5%</td><td>0.3%</td><td>If discharge port results beyond inter lab tolerance</td></tr>
<tr><td>Sulphur(ADB)</td><td>0.1%</td><td>0.1%</td><td>If discharge port results beyond inter lab tolerance</td></tr>
</table></td></tr>
<tr><td></td><td>b) Similarly, specify normative GCV loss between “As Received” and “As Fired” in the generating stations.</td><td></td></tr>
<tr><td></td><td>c) Standardize GCV computation method on “As Received’ and “Air-Dry basis” for procurement of coal both from domestic and international suppliers.</td><td>The GCV at Generating station may be considered for calculation of energy charges. Therefore GCV at fired is not relevant to specify the GCV losses.

“Air-Dry basis” for procurement of coal both from domestic and international suppliers, may be introduced.</td></tr>
</table>

Sl.No.	Options for Regulatory Framework	Comments
23.	**Fuel - Blending of Imported Coal**	
23.6	Normative blending ratio may be specified for existing plant as well as new plants separately in consultation with the beneficiaries.	Normative blending ratio for existing plant is as per advisory of CEA dated 19.4.2011 ie blend ratio by weight of 30:70 imported /high GCV coal: indigenous coal. For new plants, blending ratio may be 50:50
24	**Fuel - Landed Cost**	
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; 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.	Each loaded wagon/ shipment may be supported by the document viz coal cost, transportation charges, taxes, GCV Any other charges, dues and arrears may be claimed separately in the bill for reimbursement. Any penalty/ revenue earned by generating companies from the any agencies may allowed as credit in the month. Imported coal. In case of imported coal based Generating plants using jetty for external coal handling, the costs associates with coal handling are as follows; 1. Stevedoring charges 2. Shore handling charges 3. Insurance, 4. LC establishment charges 5. Lease Rent 6. Railway bonus 7. Sampling analysis 8. License fee 9. Dredging Cost 10. loss of capacity charges , 11. Demurrage Charges 12. Annual Maintenance charges, 13. Land license and maintenance fee 14. 50% of Railway Marshalling Yard Charges

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		15. Ship related charges i. Port Dues ii. Pilotage charges iii.Water charges iv. Any other charges for the specific services requested and availed The landed cost of coal may include only FOB, Freight, Transportation and Custom duty and other cost incurred by the Generating stations may be reimbursed based on actual payment by them.
25	**Fuel - Alternate Source**	
25.2	(a) Stipulate procedure for sourcing fuel from alternate source including ceiling rate; (b) Rationalize the formulation keeping in view the different level of energy charge rates, as the fuel cost has increased since 1.4.2014.	In case of alternate source the price should not deviate from more than 5% of energy charge rate of the designated source during that period. In case the price deviation more than 5% approval of the procurer is mandatory subjected that aggregate capacity from the procurer may not be less that the technical minimum as specified in IEGC. All cases if it is in supply from alternate sources the generating company intimate to the Procurer with complete detail calculation. The generating company may declare the separate availability on domestic and imported coal so that beneficiary can make their planning and decide on the off take of power. Further, inefficiency on procurement of fuel (lower grade) should not be passed on to Discoms.
26.3.6	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 station and possible changes required in the existing norms given in tariff Regulation 2014-19	The existing project and new project commissioned prior to 2019 all parameters as per the applicable Tariff Regulation may be continued excluding Heat rate margin to be reduced from 4.5% to 3%. For new projects beyond 2019 the station heat rate has to be evolved based on the technology and unit size.

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26.3.19	Transit and Handling losses Comments and suggestion are invited from the stakeholders on the possible regulatory options discussed above and alternatives, if any.	For non-pit head stations the transit and handling losses should be linked to the distance of the power stations from coal mines and transit and handling losses should be determined separately for: (a) Imported Coal Plants (b) Plants required to use washed coal as mandated by MoEF
26.4	**Thermal generation** Comments and suggestions are invited from the stakeholders on the possible regulatory options discussed above and alternatives , if any	Actual data is not available for further comments/ suggestions on the norms for such coal rejects based power plants. Commission may circulate draft norms for such type of Coal Plants in case it decides to include the same in the Regulation.
26.5	**Transmission System 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;	The existing level of Annual Transmission Availability Factor (NATAF) needs revision based on the actual operational data to be furnished by Power Grid. These data may be shared with the stakeholders as the availability of transmission lines/auto transformers/reactors, etc., are much more than 95% and hence these need to be analyzed to arrive NATAF. With the likelihood of commissioning of more 765 kV transmission systems, HVDC systems operational norms and calculation of TAFM and NAFM need to be addressed. Computation of Transmission system availability may be based on voltage wise. For example, for recovery of full fixed charges for 765 kV availability factor is 100%. For 400 kV 99.80% and so on
	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	The availability of inter-regional links for the purpose of incentive may be certified by the importing region.

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	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;	The existing norms should be revised upward and factors should be modified to achieve higher efficiency. The incentive amount may be linked to ROE and fixed the ceiling.
27.	**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;	Linking of incentives to RoE instead of fixed charges as existing and vintage of the asset and life of the asset. Same level of incentive/kWh from new and old \stations irrespective of the vintage. • Incentive /kWh can be at a flat rate of 25 paise/kWh for generation in excess of normative level. • Incentive to be delinked with the recovery of fixed charges. • Incentive to be based on accumulative PLF/PAF achieved at the end of each month
	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	Different incentive may be provided for peak and off peak hours for thermal, hydro and transmission may be consider.
	c) Review the incentive and disincentive mechanism in view of the introduction of compensation for operating plant below norms.	Compensation for operating plant below norms may be linked to the Plant Load Factor (PLF) instead of giving a compensation as alternate proposal.
	d) Review the norms for availability of transmission system.	Incentive in no case be more than 10% of return on equity and the tax on incentive be paid by the generating company and the transmission licensee. The incentive must be linked to the ROE with a cap of 10%.
28 28.2	**Implementation of Operational Norms** Comments and suggestions of stakeholders are invited whether the operational norms of the new tariff period	The operational paramaters are to be implemented from the date effective of the regulation i.e. 1st April of the Tariff period.

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	should be implemented from the effective date of control period irrespective of issuance of the tariff order for new tariff period.	
29 29.1	**Sharing of gains in case of Controllable Parameters** 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	 The present method sharing of gains between generating company and beneficiary in 60:40 ratio on account of controllable factors such as Station Heat Rate, Auxiliary consumptions, secondary fuel oil consumption, refinancing of loan may be continued
29.2	The compensation mechanism introduced through IEGC entails the hedging of the risk of operating at low PLF. The compensation coupled with normative controllable parameters creates a buffer for generating companies. In view of this, the merit order operation can be linked with the PLF in such a way that the plants under Section 62 may be encouraged to compete for maximum PLF.	
29.3	Further, different generators adopt different methodology for sharing of gain, say on monthly or annual basis. Thus, procedure for the monthly reconciliation or annual reconciliation mechanism may need to be prescribed.	The different generator adopt different methodology hence Regulation may be provide for the clarity along with illustration. However, monthly reconciliation is the better option.
30	**Late Payment Surcharge & Rebate**	
30.1	The present regulatory framework provides for late payment surcharge at the rate of 1.50% per month for delay in	The late payment surcharge may be linked to monthly MCLR of SBI rates.

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	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.	
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.	The payment made within seven working days from the date of presentation of bill through hard copy, 2% Rebate may be allowed and 1% for the payment made within one month from the date of presentation of bill. The 2 days provided in the present regulation is too short
31	**Non-Tariff Income**	The existing norms should be revised upward
32 32.1	**Standardization of Billing Process** Presently, generating companies and the transmission licensees are following different practice for raising bills on the basis of tariff order. In order to avoid possible disputes in billing, it need to be consider as to whether standardization of billing process including formats, verification and timeline etc. may be done	The formats to be specified in respect of following; i) Monthly billing consist of capacity charges, energy charges, incentive. ii) Supplementary bill consist of any revision of orders / decision of the various Court / Tribunals iii) Supplementary bill for Income Tax payment iv) Any other bills should be submitted in the form of supplementary bill only
32.2	Some of the States are imposing electricity duty on the actual auxiliary consumption which may be higher or lower than the normative auxiliary consumption. Such electricity duty is passed on to the beneficiaries along with the monthly bill. Whether electricity duty is to be linked with actual auxiliary consumption or normative consumption or lower of the two, may need to be specified.	Normative or actual whichever is lower
33.	**Tariff mechanism for Pollution Control System (New norms for Thermal Power Plants)**	

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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.	Ministry of Power vide letter dated 30.05.2018 notified the mechanism for implementation of New Environmental Norms for thermal Power Plants supplying power to distribution licensee under concluded long term and medium term PPA. As per para 4 appropriate regulatory framework specifying mechanism or enabling guidelines for providing regulatory certainty about recovery of such additional cost through tariff.
	a) The principle of bringing the generator to the same economic condition if it is considered as change in Law.	
	b) Technical specifications based on the difference in actual emission and revised emission, proposed technology, construction period, phasing plan for shutdown during the construction period;	
	c) Feasibility of undertaking implementation of new norms with R&M proposal for plants having low residual life, say, less than 10 years.	
	d) Change in Auxiliary Consumption and operation and maintenance expenses due to implementation of pollution control equipments.	
33.4	Comments and suggestions are invited from stakeholders on a) Possibility of reducing funding cost through suitable change in debt: equity requirements. Relaxation in funding from equity may be introduced and the rate of return on equity may be aligned with the interest on debt;	Relaxation in funding from equity may be introduced and the rate of return on equity may be aligned with the interest on debt;
	b) Debt Service obligation during construction period and recovery of depreciation" may be provided with the condition that such depreciation may be adjusted during the remaining period;	The existing method may be continued for discharging debt service obligation
	c) As the level of emission is linked to actual generation, it would be appropriate to link recovery of supplementary tariff with the actual generation or availability or combination of both.	The emission is linked to actual generation and tariff may be recovered for the scheduled generation from the beneficiary

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34	**Renewable Generation by existing Thermal Generation Stations**	
34.4	Comments/ Suggestions Comments and suggestions are invited from the stakeholders on the possible options for bundling tariff, and alternative options, if any.	
35	**Commercial Operation or Service Start date** Comments/ Suggestions	
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;	In line with provisions under Standard Transmission Service Agreement, Indian Electricity Grid Code (IEGC) Regulations, 2010, Central Electricity Authority (technical Standards for Connectivity of the Grid) Regulation, 2007, Central Electricity Regulatory Commission (Grant of Connectivity, Long-term Access and Medium-term Open Access in inter-State Transmission and related matters) Regulations, 2009 and its Details Procedure, Applicant granted "Connectivity" will be required to sign "Connection Agreement" with CTU prior to the physical inter-connection. In case the connectivity is granted to the ISTS of an inter-State transmission licensee other than the CTU, a agreement may be signed between the applicant, the Central Transmission Utility and such inter-State transmission licensee, in line with the provisions of the Connectivity Regulations. <u>In the case of a generating plant seeking connection to the inter-state transmission system not owned by the CTU, a tripartite Connection Agreement would be signed between the CTU, the inter-State transmission licensee and the applicant, since the planning of the inter-State transmission system, insulation coordination, system studies, etc. are the responsibility of the CTU. The responsibilities of the three</u>

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		parties would be defined accordingly in the tripartite Agreement. Accordingly, parties may separately take up modalities for implementation of the works on mutually agreed terms and conditions. The scope of works, time schedule for completion of works, including the timelines for the various milestones to be reached for completion of works (PERT chart), may form an appendix to this agreement, and may form the basis for evaluating if the works by the parties is being executed in time. Penalties for non-completion of works in time by one party resulting in financial losses to the other party may be appropriately priced, as per mutual agreement, for indemnification of each other against losses incurred in this regard, and form a part of this Agreement. Similarly, for the regular O&M of the connection equipments owned by the applicants and located in the CTU's premises/switchyard, the parties may separately take up the O&M agreement on mutually agreed terms and conditions. After signing of the Connection/Tripartite Agreement, Nodal Agency will provide a copy of the same to concerned SLDC/RLDC. In case of where Generation and Transmission system are associated with each other, trial run or trial operation/COD of both may be interlinked. The coordination between the two may result in COD of both simultaneously by avoiding non-utilization of either of the one due to commissioning of other one. Further, it is recommended in case of associated Transmission

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	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 LongTerm Access Agreement respectively; f. Linking the commercial operation date of the transmission system with the commissioning of the	System, Transmission Charges needs to be linked to capacity of the Generation Station commissioned. Complete Transmission Charges can be allowed only on commissioning of the entire Generating Station in line with the schedule. If any deviation by one party resulting in financial losses to the other party may be appropriately priced, as per mutual agreement. In view of the above,: a. The trial run of generating station and trial operation for transmission element are coordinated in accordance with tripartite agreement in case where Generation and Transmission system are associated with each other. b. Must be in accordance with the Tripartite Agreement. Penalties for non-completion of works in time by one party resulting in financial losses to the other party may be appropriately priced, as per mutual agreement, for indemnification of each other against losses incurred in this regard, and form a part of Tripartite Agreement. c. Must be in accordance with the Tripartite Agreement. Penalties for non-completion of works in time by one party resulting in financial losses to the other party may be appropriately priced, as per mutual agreement, for indemnification of each other against losses incurred in this regard, and form a part of Tripartite Agreement. d. Must be made mandatory e. If there is any PPA entered the commercial operation date may be later of the schedule commencement date of Power Purchase Agreement or Date of Grant of Long Term Access. f. Must be in accordance with the Tripartite Agreement.

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	generating units or stations; g. Separation of the commercial operation date of the unit or stations, the transmission element or system from the service start date under the contract.	Penalties for non-completion of works in time by one party resulting in financial losses to the other party may be appropriately priced, as per mutual agreement, for indemnification of each other against losses incurred in this regard, and form a part of Tripartite Agreement. g. The present methodology of treating commercial operation date of the unit or element which commissions at last may be treated as commercial operation date of the Station/Transmission System.
36.	**Energy Storage System**	
36.7	Comments/ Suggestions Comments and suggestions are invited from the stakeholders on the possible options discussed above and alternatives, if any.	
37.2	**Alternative Approach to Tariff Design** The Annual Fixed Charge (AFC) is determined based on the admitted capital cost as on the Date of Commercial Operation (COD) after carrying out prudence check of the individual component of costs. In this process, the Commission examines vast data which is required to be submitted before it in respect of each of the components to arrive at permissible costs for recovery through tariff. Accordingly, substantial efforts are made towards determination of Annual Fixed Cost, which constitutes on an average 30% – 40% of total cost of generation. It has often been argued by various stakeholders at different fora, that such a system of elaborate examination of data to determine AFC needs a revisit. It is in this context that an alternate approach to tariff determination is proposed.	Prudence check linked to Benchmarked cost. However, Commission may lay down detailed procedure for transparent inviting and evaluation of bids and awarding contract packages through competitive bidding process . Out of the benchmark, the cost actually cost incurred upto COD may be considered. The annual account should be part of the petition /truing up petition.

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37.6	a) Would it be advisable to undertake econometric analysis to arrive at benchmark capital cost?	
	b) What are the variables that should be considered for the purpose of determining Capital Cost on normative basis? c) Any other methodology for benchmarking the capital cost for generation and transmission projects?	The financing cost, interest during construction, taxes and duties, right of way charges, cost of Rehabilitation & Resettlement etc. should be treated variables to benchmark cost.
37.21	a) Does the proposal of differential recovery of AFC by segregating into peak and off-peak periods balance the need for both the buyers and sellers? b) What could be the weightage factors for peak and off-peak periods along with the PAF for each segment? c) What could be other mechanisms to arrive at peak and off peak AFC tariffs?	1. **Normative Annual Plant Availability Factor** of the generating station may fixed on quarterly basis i.e. January to March 95%, April to June 85%, July to September 75% and October to December 85%. The fixed charges may be paid for the quarterly Annual Plant Availability factor not on yearly basis. The total capacity charge payable for a generating station may be divided on four quarters. Further, Annual Fixed Charges also may be on seasonal basis for example: For the month of January to March the fixed charges may be enhanced by 10% and during July to September the fixed charges may be reduced by 10%. The Regional Power Committee may be authorized for fixing seasonal based availability and pricing mechanism. The quarterly fixed cost may be higher during higher availability and lower during lower availability The same frame work may also apply mutatis mutandis for transmission project.
38	**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	Certification along with the documentary evidence for the claims may be provided

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	strengthening the existing system.	
39	**Relaxation of Norms**	
39.2	Comments/ Suggestions Comments and suggestions are invited on whether to continue with the practice or change the parameters during the intervening stage	Based on the recommendation of CEA, relaxed operational norms should be allowed for initial years, especially the plants where a new process technology or higher sized Unit is introduced for the first time. The relaxed norms can be permitted for a period of one year from the date of COD of the Units. The relaxed norms should cover all parameters - Normative Annual Plant Availability, Station Heat Rate, Auxiliary Power consumption and specific fuel oil consumption.
40	**Merit Order Operation**	
40.3	Comments/ Suggestions Comments and Suggestions are invited from the stakeholders for alternative approach, if any, for economic operation of merit order.	The fixed cost for the quantum tied for the generating station needs to be paid by the beneficiaries irrespective of the dispatch. Hence, for variable components related to dispatch scheduled to be considered. For, example variable cost per unit at ex-bus, Transmission charges, Losses and compensation charges etc
41	**Application for Tariff Determination: Review of Process in Case of Transmission System**	
41.4	Comments and suggestions of the stakeholders are invited on simplification of the process for disposal of tariff petitions	The tariff petition may be filed based on projected expenditure before 6 months to the date of COD. As such provisional tariff may be allowed. The final tariff may be fixed based on actual capital cost incurred after prudence check. The actual expenditure based on audited accounts may be trued up in the following control period. The penalty clause may be applied in case of over projected tariff exceeding 15% over the actual expenditure Any delay in filing for tariff determination, the ROE is reduced on slab wise. It is difficult to determine the tariff for transmission system on regional basis on the POC, availability and useful life for each

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		transmission system will be different. Also it will be difficult to account the additional capital expenditure if any to be incurred. Hence, it is suggested that the present practive of awarding tariff to each asset separately should be continued.
	Other issues	The benchmarks can be developed by a comparative analysis of performance over time across various plants/ stations after factoring for the differences on account of technology, vintage, fuel source, etc. Competitively discovered tariff can also be one of the factors to be considered for such comparison. Utilities should be incentivized to perform lower than the ceiling and penalized if they cross the same.
	Additional clarification required	Energy Charge Calculation: Form 15 does not specify the methodology for computation of closing stock a) Whether it shall be based on scheduled energy or actual energy generation b) Whether the monthly coal consumption shall be based on normative Gross Station Heat Rate and Auxiliary Consumption or Actual coal consumption maintained at generating station.

ADDITIONAL DIRECTORS (PROJECTS)
PCKL, BANGALORE