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Abhinav Jain
Associate Fellow & Area Convener
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9 August 2018

The Secretary
Central Electricity Regulatory Commission (CERC)
3rd and 4th Floor
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36, Janpath, New Delhi- 110001

Dear Sir,

Please refer to CERC public notice dated 25th May 2018 and 13th July 2018 inviting comments and suggestions on the consultation paper.

The consultation paper seeks to examine a change from two-part tariff to three-part tariff in respect of thermal generation and from single part tariff to two-part tariff in respect of inter-state transition system and renewable energy generation stations. It is not clear whether the proposed changes are to be applicable for the new thermal and renewable energy generation and transmission systems or the new as well as existing systems. In order to provide regulatory certainty to the existing assets, the proposal should be applicable only for the new system. Applying these changes to the existing systems will adversely impact the existing generation and transmission.

It is also proposed that the Commission may consider introducing a capacity market to address the issues with three-part tariff for thermal generating stations or two-part tariff in case of hydro generating stations. The capacity market will create long-term price signals for all, new and existing, generating resources that can mitigate the issue of risk associated with recovery of variable component of fixed cost as the power plants would receive compensation for capacity through the market.

In addition to the above, Para-wise observations/suggestions are annexed.

Yours faithfully,

Abhinav Jain.

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13/08/18

Consultation Paper on Terms and Conditions of Tariff Regulations for Tariff Period 1.4.2019 To 31.3.2024

Observations/ Suggestions of The Energy and Resources Institute (TERI)

Para No.	Options for regulatory framework	Observations/ Suggestions
7.2.6 Thermal Generating Stations – Tariff Structure	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.	It is not clear whether that the proposed three part tariff is for new generating stations or for the new as well as existing stations. It is suggested that the three part tariff may be considered only for the new ISGS; applying the same for the existing power stations would negatively impact the existing stations. In the three part tariff, full O&M charges should be considered as part of fixed component of Fixed Charges in order to avoid any dilution in proper operation & maintenance of generating stations. A) Adopting three part tariff for the new generating stations may encourage financially constrained DISCOMs to go for long term PPAs. B) However, this may distort merit order operation of thermal generating stations as the DISCOMs may consider variable component of Fixed Charges as an additive to the Variable (energy) Charges.
7.3.4 Thermal Generating Stations – Older than 25 years	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)	Environment compliance and operating efficiency should be the guiding principle for the thermal generating stations rather than the age. The plants units should be compliant with the operating

	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.	efficiency (such as unit heat rate less than 2500 kcal/kWh at 70% load). Operating efficiency parameters such as Heat Rate & Auxiliary Power Consumption (APC) being equal, the plants having high variable cost should be potential candidates for replacement / retirement.
7.4.1 Hydro Generating Stations - Tariff Structure	The two part tariff structure of hydro generating stations seems adequate in present scenario. However, in view of large capital cost, hydro generating stations often find it difficult to get dispatched due to resultant higher energy charges. In order to address this issue, for the hydro generating stations, the fixed charges and variable charges may need to be reformulated.	The main issue highlighted in regard to hydro generating stations is that these stations often find it difficult to get dispatched due to high energy charges. Reformulation of fixed and variable charges has been proposed to address this. Since the tariff of hydro generating stations is of the nature of fixed cost and is split between capacity charges and energy charges on 50:50 basis for sharing of risk between generator and procurer. In order to address the issue of dispatchability of hydro generation stations, total fixed cost of these stations between Capacity Charges and Energy charges for recovery purposes could be to keep the Energy Charge Rate of hydro generating stations as 90% of lowest Variable (energy) Charge of pit head thermal generating station in the region in which beneficiaries of the hydro generating stations do exist. The tariff design could consider extending the useful life of hydro stations from 35 years to 50 years and spreading loan repayment to a longer period as compared to prevailing period. Tariff could also be made back loaded, to address the difficulty of hydro power station in scheduling in the short run mentioned in the consultation paper. There does not seem to be

		any necessity of evolving a suitable regulatory framework to make these stations flexible (para. 5.5.5) as they are inherently flexible.
7.4.2 Hydro Generating Stations - Tariff Structure	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.	The narrative of the para does not make it clear whether the Annual Fixed Cost of these stations would also have a fixed and variable component or only reformulation of split between fixed charges and variable charges is contemplated.
7.5.5 and 7.5.6 Inter-State Transmission System - Tariff Structure	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. The recovery of fixed component can be linked to the extent of access (Transmission Access Charge) and	The cost component in respect of ISTS forming basis of tariff proposal to move away from single part tariff consolidating all the costs of providing access to the generating stations or the distribution licensee and transmission service (para7.5.1) to two part tariff comprising fixed and variable components (with a few alternatives in respect of the fixed as well as variable component) linking to access service and transmission service needs in depth examination in the light of problems / concerns / issues having been raised by generators and drawing utilities. Further, the recovery of fixed and variable component of tariff has been proposed at para7.5.6 of the Consultation paper. In this context it is mentioned that sharing of transmission charges of ISTS is presently governed by a separate regulation, namely CERC (Sharing of inter-state transmission charges)

	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.	Regulations, 2010, which is based on principle outlined in the Tariff Policy, which in turn, stems from the National Electricity Policy. The National Electricity Policy mandates that the national transmission tariff framework should be sensitive to distance, direction and related to usage. Any change proposed in regard to sharing of charges of ISTS may please be seen in this backdrop.
7.6.3 Renewable Energy Generation – Tariff Structure	There can be Two part tariff structure for renewable generation covered under Section 62 of the Act, which comprises fixed component (debt service obligations and depreciation) and variable component (equal to marginal cost i.e. O&M expenses and return on equity) - fixed component as feed-in-tariff (FIT) and variable component equal to capacity augmentation such as storage or back up supply tariff.	The entire tariff of renewable is of the nature of fixed cost; there is no fuel cost and O&M cost (like cleaning of solar panels, oiling of wind turbines, etc.) is marginal. In order to avoid any dilution in O&M of RE plants, full O&M charges should be allowed. This would then leave only the differential ROE as the variable component, which may come in the way of promoting RE generation projects. Further, CERC (Terms & conditions for tariff determination from RES) Regulation, 2017 govern the Tariff of RE. The control period or review period under the regulation is three years starting from FY2017-18. As per these regulations, the tariff for RE technologies shall be single part tariff. It is therefore contemplated to review the aforementioned CERC Tariff Regulations, 2017 for RE. Further, currently most of

		the RE projects are being set up based on competitive bidding and their bids are single part bids.
7.6.4.(a) Renewable Energy Generation – Tariff Structure	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	
8 Deviation from Norms	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.	Some of the generation capacity tied up by distribution licensee remaining un-dispatched over large part of the year has been rightly flagged in the Consultation paper. Expanding Regulation 48 of the CERC MYT Regulations for 2014-19 which specifically provided for deviation from the norms, the norms being the ceiling would be useful. Analysis based on available data would help in arriving at the right prescription.
10 Optimum Utilisation of capacity – Coal based thermal generation	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	Utilisation of capacity not utilised by a DISCOM, by other DISCOMs could certainly be attempted. However the first option in such cases may be given to sale of unutilised capacity to beneficiaries beyond the original ones (having PPA) at the existing tariff of the generating station. Sale of power of such capacity at market determined tariff may be kept as second option for consideration. However, it needs to be made clear

	recall Unutilized Capacity during next year and for securing such rights, some part of fixed cost, say 10-20% or to the extent of debt service obligations, may be paid; (b) Such unutilized Capacity may be aggregated and bidded out to discover the market price of surplus capacity. The surplus capacity may be reallocated to the distribution licensee at market discovered price.	that in the event of full unutilised capacity not getting buyers, the fixed charge liability for such part would continue to rest with the original beneficiaries.
10 Optimum Utilisation of capacity – Hydro generation	10.5 (a) Extend the useful life of the project up to 50 years from existing 35 years and the loan repayment period up to 18-20 years from existing 10-12 years for moderating upfront loading of the tariff. (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.	The proposals to extend useful life and loan repayment period are in order. Assigning responsibility of operation of hydro stations and pumped storage stations at regional level appears to be desirable. However, concurrence of states to lend their plants for this is the real issue.
10 Optimum	10.7 Scheduling and dispatch of gas	Assigning responsibility of

Utilisation of capacity – Gas based Thermal generations	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.	operation of gas stations at regional level would also need concurrence of states to lend their plants for this.
14.6. Depreciation	a) Increase the useful life of well-maintained plants for the purpose of determination of depreciation for tariff; b) Continue the present approach of weighted average useful life in case of combination, due to gradual commissioning of units; c) Consider additional expenditure during the end of life with or without reassessment of useful life. Admissibility of additional expenditure after renovation and modernization (or special allowance) to be restricted to limited items/equipment; 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	A decision in regard to extending useful life of transmission and hydro stations to 50 years and that of thermal plants to 35 years on the basis of data analysis would be in order. The useful life of all the plants not only that of well-maintained plants needs to be extended since responsibility to maintain the plant lied with the developer.

	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).	
16.4 Debt : Equity Ratio	For future investments, modify the normative debt-equity ratio of 80:20 in respect of new plants, where financial closure is yet to be achieved.	Changing the normative debt: equity ratio from 70:30 to 80:20 depending on the credit appraisal of the utilities may not be in order in view of experience in regard to credit appraisals in the past. Lending institutions / banks are at liberty to use lower equity as the 70 : 30 normative debt : equity ratio is for tariff purposes only.
18 Rate of Return	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 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. 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	The basic reason while adopting same rate of return on equity for thermal, hydro and transmission projects was to keep all the segments equally attractive for the investors. Different rate of ROE for thermal, hydro and transmission projects may be taken based on risk analysis in regard to these projects. The prevailing regulations in respect of storage type hydro projects already provide for additional ROE of 1%. In case of timely completion this needs to be continued to promote development of hydro projects. The prevailing dispensation in case of additional ROE of 0.5% for timely completion of projects should be continued.

	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;	
19 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; 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;	The existing approach of allowing actual cost of debt and normative loan provides a good tool and should be continued.
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	In order to avoid loss of generation due to coal shortage, which may be on account of inadequacy of coal availability or the constraints in the coal transportation due to unforeseen reasons, normative

	has to be borne by the regulated entity, IWC based on the cash credit was followed during previous tariff period. Same approach can be followed or change can be made. (b) As stock of fuel is considered for working capital, a fresh benchmark may be fixed or actual stock of fuel may be taken. (c) While working out requirement of working capital, maintenance spares are also accounted for. Since O&M expenses also cover a part of maintenance spares expenditure, a view may be taken as regards some percentage, say, 15% maintenance spares being made part of working capital or O&M expenses. (d) Maintenance spares in IWC which is also a part of O&M expenses results in higher IWC for new hydro plants with time and cost overrun. For old hydro stations, the higher O&M expenses due to higher number of employees also yield higher cost for "Maintenance Spares" in IWC. Therefore, option could be to de-link "Maintenance Spares" in IWC from O&M expenses. (e) In view of increasing renewable penetration and continued low demand, the plant load factor of thermal generating stations is expected to be low. As per the present regulatory framework, the normative working capital has been provided considering target availability. In case of wide variation between the plant load factor and the plant availability factor, the normative approach of linking working capital with "target availability" can be reviewed.	stock of coal should be allowed.
26 Normative Annual Plant	26.3.13 As per present regulatory framework, the recovery of annual fixed charges is based on cumulative	Giving higher weightage to availability during peak load hours is desirable.

Availability	availability during the year. There may be a chances of declaring lower availability during the peak demand period when the beneficiaries may be required to resort to procurement from short term market to meet their demand. However, during low demand period, the generating station may declare higher availability so as to achieve the target cumulative availability on annual basis to recover the full annual fixed charges. In this process, the beneficiaries may not get the electricity when required at the time of high demand.	
26 Transit and handling Losses	26.3.18 A regulatory option could be that the generating station shall only pay for coal "As Received" at the plant plus normative transmission loss of GCV and quantity as per CERC norms. This can be addressed in the Tariff Regulation by indicating GCV as "As Received at plant end" and customization of Form15 regarding the GCV	As mentioned in para 26.3.2, the decision to shift to GCV "As Received" for purpose of computation of energy charge for 2014-2019 was as per advice of CEA. A decision in this regard may therefore be taken in consultation with CEA.
27 Incentive	27.2 At present there is same incentive for availability during peak and off peak period. There may be a need for introducing differential incentive during peak and off peak periods. On the same consideration, there may also be a need for higher incentive for the storage and pondage type hydro generating station providing peaking support. At present, generation beyond the design energy is paid at 80 Paise/kWh in case of hydro generating station, which may also need review.	Higher weightage to availability of generating stations during the peak load hours is desirable as mentioned with reference to para 26.3.13 herein earlier. We do not find any need for an incentive beyond the same.
33 Tariff mechanism	33.3 There is likelihood of significant impact on tariff on account of	The capital investment to comply with new environmental norms

for Pollution Control System (New norms for Thermal Power Plants)	compliance with these norms. Supplementary tariff could be determined considering the followings. a) The principle of bringing the generator to the same economic condition if it is considered as change in Law. b) Technical specifications based on the difference in actual emission and revised emission, proposed technology, construction period, phasing plan for shutdown during the construction period; c) Feasibility of undertaking implementation of new norms with R&M proposal for plants having low residual life, say, less than 10 years. d) Change in Auxiliary Consumption and operation and maintenance expenses due to implementation of pollution control equipments.	should be treated as 'change in law'. An appropriate tariff framework for recovery of operational costs needs to be specified.
36 Energy Storage System	36.2 In the paper, two different uses of energy storage for regulatory framework were considered, one as a part of the inter-state transmission system and other as a part of inter-state generation station. The grid level storage system established by the transmission system owner has similar characteristics to that of transmission because it acts as intermediary for conveyance of the electricity from generator to the procurer covered within the Section 79 (c) of the Act. When the storage facility is used by generator to optimize the value of generation output and hedging purpose, it can be construed as a primary generator covered under Section 79 (a) and (b) of the Act.	Battery energy storage at distribution level (downstream of the network) is also one of the plausible options to flatten the demand curve or to provide reliability support or sale of power as part of distribution obligation or provide storage services to others. Same could be covered under Section 86 (Functions of the State Commission) of the Electricity Act 2003.

36 Energy Storage System	36.3 The regulatory options available for implementation of the energy storage system for use are to combine the tariff with transmission and generation projects. Storage facility as a part of inter-state transmission system may be subjected to regulatory approval while storage facility as a part of the generating capacity may be as per the consent of the procurer for availing storage facilities.	The transmission licensees may provide storage service as a facilitator and may own the infrastructure of storage facility without claiming the title of the stored energy.
36 Energy Storage System	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. 36.6 The annual fixed charges of the storage facility can be determined based on ramping rate, auxiliary consumption, Return on Equity (ROE), Interest on Loan, Depreciation, Operation & Maintenance cost and Interest on Working Capital.	The proposed mechanism seems to be in order.
37 Alternative Approach to Tariff Design	37.2 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	Regulatory regime in the country being in existence in the power sector for about 20 years, a robust benchmark cost data may pave the way for an alternative. Specifying benchmark capital cost may

	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.	provide efficiencies in utilisation of resources as well.
37 Alternative Approach to Tariff Design	37.6. b) What are the variables that should be considered for the purpose of determining Capital Cost on normative basis?	Benchmarking may be attempted in respect of major heads such as capital cost of equipment depending on technology, cost of land depending on locations / area, capital cost of mines (in case of integrated mines), administrative building and other assets, etc.
39 Relaxation of Norms	39.1 The present regulatory framework provides for specifying normative operational parameters. However, there may be situations where the normative level due to the site specific features such as FGD, Desalination plant, increase in length of water conductor system etc may lead to power consumption in excess of the norms. In such situations, the present regulatory framework provides for relaxation of norms. … Whether to continue with the practice or change the parameters during the intervening stage.	The current practice of relaxation of norms for taking care of new site specific features should be continued.