Ref: JPL/CERC/TP.19-24/2018(1) Dated: 30.07.2018

The Secretary
Central Electricity Regulatory Commission
3rd Floor, Chanderlok Building
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New Delhi – 110001.
(Email : secy@cercind.gov.in, secyskj@gmail.com)

Sub.: **CERC staff approach paper for finalization of Tariff Policy for the block 2019-2024**

Sir,

This has reference to Public Notice dated 24th May, 2018 seeking comments on CERC staff approach paper in respect of finalization of tariff policy for the block 2019-2024.

We hereby request the following broad issues to be addressed in the proposed tariff policy:

i) Tariff Policy 2014-19 (TP. 14-19) is common for both Generation and Transmission sector whereas number of provisions are applicable specifically for generation and transmission. Further, approach and basis of tariff for both sectors are totally different. Therefore, for sake of easy reference, understanding and clarity, **TP.19-24** should provide following sections :

Section-A : General (Applicable to all),
Section-B : Thermal Power Generation,
Section-C : Other Power Generation (Other than Thermal)
Section-D : Transmission and Sub-Stations

ii) Minimum changes may be carried out in existing tariff policy 14-19 while drafting new tariff policy 19-24 for smooth transition.

iii) O&M of Transmission Lines passing through hilly and snow bound terrain involve frequent patrolling through difficult logistics and access. That causes almost triple expenditure in comparison to that for lines in the plain terrain. Further, for a single asset company like JPL, establishment expenditure can not be distributed/ shared with other transmission assets whereas same is possible for large players. Therefore, O&M charges for such terrain should be atleast 2.5 times of the expenditure that may be fixed for the lines with similar conductor and voltage configuration passing through plain terrains.

iv) Transmission Majoration Factor is applicable to tariff of certain transmission lines set up in a particular period to attract investment from private sector. However, there is only one beneficiary, that too a JV of two giants- TATA and POWERGRID, to avail benefits of such factor. Approach paper is silent on this aspect. Therefore, provision for such majoration factor need to be abolished in TP.19-24 so that all Transmission Licensees are treated at par.

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v) Thermal Power Generating Units of 200/210/500 MW capacity, which have completed more than 15-20 years and are of sub-critical nature, have inherent inefficiency in operation wrt Heat Rate, APC etc. Same need to be shut down and replaced by coal consumption efficient Super Critical Units so as to provide better utilization by operating at higher PLF for optimum utilization of coal and power transmission capacity of existing assets as well. TP.19-24 should facilitate such arrangement and incentives.

vi) Provision for add-caps should be clear towards replacement and modernization of existing transmission assets like replacement of porcelain insulators by polymer insulators, construction of office/stores post COD of lines.

vii) Transmission Licensees terminate line bays at their own cost in the sub-station owned by other utilities. Transmission Licensees get O&M charges for such line bays through tariff as per norms fixed in Tariff Policy but on the other hand they are required to pay O&M charges to the owner of the sub-station because there is no other option and traditionally it is being practiced in this way. Being a bilateral issue, sub-station owner charges arbitrarily. For example, in case of JPL, it has to pay substantial charges to POWERGRID for the maintenance of those bays but obligations towards insurance, replacement of items, payment of charges to visiting engineers of equipment suppliers etc lies with JPL. In addition, GST is also paid by JPL on the amount paid to POWERGRID. That leaves only meager amount with JPL to fulfill its obligations. As both assets of Transmission Lines and Sub Stations are regulated assets, TP.19-24 should make provision to share O&M charges of line bays of licensees terminated in the sub-station of other utility in the ratio of 60: 40 :: Transmission Licensee(Bay owner): Sub-Station Owner for a fair and equitable treatment to transmission licensees and to avoid conflict among them on sharing issue.

viii) TP.19-24 is for a block of 5years. For stable policy, it is suggested that block period should be enhanced to at least 7 years instead of 5 years.

We shall be grateful for addressing aforesaid issues while finalizing tariff policy for the block 2019-2024.

Thanking you,

Yours faithfully,
Jaypee Powergrid Limited

(D P GOYAL) 30/7/18
Director

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JAIPRAKASH
POWER VENTURES LIMITED

July 6th, 2018

The Central Electricity Regulatory Commission
4th Floor, Chanderlok Building
36 Janpath
New Delhi 110 001

Sub: Staff Consultation Paper on Tariff Regulations commencing from 01.04.2019.

Dear Sir,

With reference to your letter no. 20/2017/CERC/Vol I/Tariff Regu/Fin dated 6th June 2018 on the subject, we had attended the meeting for interaction on Tariff Regulations scheduled on 28th June 2018 and verbally submitted our observations. A copy of the same is attached for your perusal.

In respect of O&M of Hydro Plant, we wish to submit that O&M is allowed @ 1.5% on the capital cost with annual escalation based on WPI & CPI. During the last 5 years escalation on O&M has been @ 2% p.a. approx. However Insurance of Hydro Plant has increased by nearly 100%, hence insurance cost which was 7-8% of O&M has been increased to 14-15%. This is primarily due to increased risk perception of Hydro projects as envisaged by the Insurance/Re-Insurance Companies. Actual data for the last five years of our Vishnuprayag HEP is as under:

Year	O&M received in Tariff (Rs Crs)	Insurance (Rs Crs)	% of Insurance on O&M
FY 2014	50.89	3.90	7.66%
FY 2015	54.06	5.04	9.32%
FY 2016	54.32	5.63	10.36%
FY 2017	55.19	7.07	12.81%
FY 2018	55.99	7.93	14.16%

In view of aforesaid, we request Hon'ble CERC to make provision of additional escalation in O&M of Hydro Plant or allow actual Insurance cost to the Hydro Power Plants.

Thanking you

Yours faithfully
for **Jaiprakash Power Ventures Limited**

(Ashok Shukla)
Authorised Representative

Encl: As above

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GROUP

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Observation on the consultation Paper on Terms and Conditions of Tariff Regulations

S.no	Page no	Option of Regulatory Framework	Observations
7.2.4-7.2.6	23	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 fixedcharges 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. 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). 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 andDispatch. Fuel charges could be linked with dispatch.	Except small portion of O&M (10-15%) , other expenses/ cash outflow is fixed hence even if the plant is operating at Lower PLF no reduction in AFC is possible. The reduction in AFC will impact the ROE of Investor which will further discourage investment/Finance in Power. If PLF is low on account of non availability of coal then the reduction in tariff will impact the ROE of investor for the reason beyond its control as the return in tariff guidelines are restricted and no profit is available on merchant sales.
7.4.2	24	The two part tariff structure of hydro generating stations seems adequate inpresent scenario. However, in view of large capital cost, hydro generatingstations often find it difficult to get dispatched due to resultant higher energycharges. In order to address this issue, for the hydro generating stations, thefixed charges and variable charges may need to be reformulated.	PLF of Hydro stations is fluctuating; it operates at 100% during monsoons and operates at 30% during winter. The energy charges need to be seen on annual basis not on monthly basis and long terms PPAs should be awarded to hydro plants via MOU route, to get further investment in Hydro Generations.
8.4	28	Possible option could be to develop for incentive and disincentive mechanismfor different levels of dispatch and specifying the target dispatch expanding the scopeof Regulation 48 above.	Lower production/ supply is beyond the control of generator due to non availability of coal or shut down by procurer, this disincentive mechanism will adversely impact the ROE of promoter.
9.3	28	The question is whether the annual fixed charges and energy charges are tobe determined to the extent of the capacity tied up under Section 62 of the Act or forthe entire capacity. One approach could be to determine the tariff of the generatingstation for entire capacity and restrict the tariff for recovery to the extent of powerpurchase agreement on pro-rata basis and balance capacity will be merchant capacityor tied up under Section 63, as the case	Annual fixed charges and energy charges are tobe determined forthe entire capacity and restrict the tariff for recovery to the extent of powerpurchase agreement. As revenue of balance capacity on merchant or otherwise cannot be estimated / presumed.

		may be.	
10.2	29	If the unutilized capacity of the generating station is allowed to be utilized by other distribution companies or through open market, the obligations of the distribution companies may reduce to the extent of utilization.	There should be a possible option of penalty mechanism for the Discoms after certain level (which needs to be specified) of unutilized capacity. Even if generators sell their power in open market there are no certainties in respect to power prices ,which will directly hamper the financial health of a generating plant
10.3	29	10.3 (a) Flexibility may be provided to the generating company and thedistribution licensee to redefine the Annual Contracted Capacity (ACC) onyearly basis out of total Contracted Capacity (CC), which may be based on theanticipated reduction of utilization. Annual Contracted Capacity (ACC) may betreated as guaranteed contracted capacity during the year for the generating company and the distribution licensee and the capacity beyond the ACC maybe treated as Unutilized Capacity (UC). The distribution licensee will have aright to recall Unutilized Capacity during next year and for securing such rights,some part of fixed cost, say 10-20% or to the extent of debt service obligations,may be paid; (b) Such unutilized Capacity may be aggregated and bidded out todiscover the market price of surplus capacity. The surplus capacity may be reallocatedto the distribution licensee at market discovered price.	As per the executed PPA and expected cash flow on the said PPA, Lenders/investor has invested in Project, if there is any change in contracted capacity and revenue thereon the same will impact the debt servicing and viability as there is no confirmed open market prices for the sale of power at profitable rates. The demand / rates in the open market are fluctuating in nature and cannot be relied for viability of project. Hence contracted period should not be disturbed
10.5 (b)	29	Assign responsibility of operation of the hydro power stations and pumpedmode operations at regional level with the primary objective for balancing. Forthis purpose, the scheduling of the hydro power operation (generation and pumped mode operation) may have to be delinked from the requirements ofdesignated beneficiaries with whom agreement exists. The power scheduledto the hydro generation can be dispatched to designated beneficiaries throughbanking 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 flexibleoperation and pumped operations may be apportioned to the regionalbeneficiaries as reliability charges.	The same has to be controlled by Government agencies after study of requirement of all beneficiaries. Individual generators and beneficiaries cannot decide on the said arrangements and it will involve central and state regulators for the fixed charges apportionment.
11.8	32	One of the options is to move away from investment approval as reference costand shift to benchmark/reference cost for prudence check of capital cost. However,the challenge is absence of credible benchmarking of technology and capital cost.	In Hydro Power, cost depends upon the Geological condition of the location and natural calamities; hence part of capital cost cannot be benchmarked. Further restructuring of Loans of stress power assets by the lenders has to be considered in Tariff Regulations.
11.9	32	Higher capital cost allows the developer return on higher base of equitydeployed. In the cost plus pricing regime, the developer envisages return on equity asper the original	

		project cost estimation. The regulations allow compensation towardsincrease in cost due to uncontrollable factor so as to place the developer to the sameeconomic position had this uncontrollable event not occurred. Therefore, in newprojects, the fixed rate of return may be restricted to the base corresponding to thenormative equity as envisaged in the investment approval or on benchmark cost. Thereturn on additional equity may be restricted to the extent of weighted average ofinterest rate of loan portfolio or rate of risk free return.	
13	34	The performance based cost of service approach, a combination of actual costand normative parameters has been evolved for the Tariff regulations. Componentslike return on equity, operation & maintenance expenses and interest on workingcapital have been specified on normative basis whereas cost of debt has beenallowed based on actual rate of interest on normative debt. The normative parametersare expected to induce operational and financial efficiency. While continuing with thehybrid approach, more weightage may be provided for normative parameters toinduce greater efficiency during operation as well as in development phase.	As on date Power Companies are under stress and lenders are charging higher rates in respect of Financing charges and Interest. In this scenario normative rates for Rate of Interest on Loans to be avoided.
14	34	Depreciation	Depreciation to be allowed upto 95% of the cost. Increase in useful life with depreciation linked with the same will impact cash flow of the project and it may discourage the lenders and Investors as they expect repayment of loans in a span of maximum of 10-15 years from COD as per the guidelines of RBI.
15	37	An option could be to base the returns on the modified gross fixed assetsarrived at by reducing the balance depreciation after repayment of loan in respect oforiginal project cost.	Generator must get cost plus ROE on the investment.
16.4	37	For future investments, modify the normative debt-equity ratio of 80:20 inrespect of new plants, where financial closure is yet to be achieved.	Guidelines and due to Stress in Power Sector, Lenders may not accept the same and will be discouraged to invest in power sector
18.7 (g)	41	Reduction of return on equity in case of delay of the project	This case should be applicable only, when default is in the account of project developer. Otherwise the same will impact developer health due to overrun cost and lower ROE. Projects already Stressed – Any reduction in RoE will further impact the Projects.
19.5	43	Continue with existing approach of allowing cost of debt based on actualweighted average rate of interest and normative loan, or to switch to normativecost of debt and differential cost of debt for the new transmission andgeneration projects;	Interest on loan is to be actual not normative.

20.3 (b)	44	stock of fuel is considered for working capital, a fresh benchmark may befixed or actual stock of fuel may be taken.	Normative period/ amount to be continued as other payments such as advance for stock etc which are actual cash out flow in working capital are not included hence the same will adversely impact.
20.3 (e)	44	In view of increasing renewable penetration and continued low demand, theplant load factor of thermal generating stations is expected to be low. As perthe present regulatory framework, the normative working capital has beenprovided considering target availability. In case of wide variation between theplant load factor and the plant availability factor, the normative approach oflinking working capital with "target availability" can be reviewed.	
21.7	46	O&M Expenses	Request to include T/L O&M Expenses for Dedicated T/L in Generation tariff.
22.8 (a)	47	Take actual GCV and quantity at the generating station end and addnormative transportation losses for GCV and quantity for each mode oftransport and distance between the mine and plant for payment purpose by the generating companies. In other words, specify normative GCV lossbetween "As Billed" and "As Received" at the generating station end andidentify losses to be booked to Coal supplier or Railways.	Coal is being sourced / transported from CIL/Railway; How CERC will ensure the recovery of the same from CIL/Railway under the monopolistic regime of CIL /Railway. Normative GCV loss should be between "As Billed" and "As Fired" at the generating station.
24.5 (b)	50	The source of coal, distance (rail and road transportation) and quality of coalmay be fixed or specified for a minimum period, so that the distributioncompany will have reasonable predictability over variation of the energycharges.	Due to shortage in supply from CIL against FSAs, Coal supply is not predictable and coal is being sourced from many sourced and cannot be fixed. Stringent regulatory possible options and penalty mechanism should be there, if coal companies fails to supply contracted coal quantity .
25.1	50	The present regulatory framework provides that the generators resorting the alternate source of fuel, other than designated fuel supply agreement, require prior consultation only if the energy charge rate exceeds 30% of the base energy charge rate or 20% of energy charge rate of the previous month. These provisions were introduced w.e.f. 1.4.2014 in view of the shortage of fuel at that time.	Alternate source of fuel cost should be completely pass through to the DISCOMS because this is a additional incurring cost for generators and it is putting extra stress on financial health of generators. Alternately allow DC for non-availability of Coal and change definition of Force Majure to include non availability of Coal.
26.3.18	54	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 andquantity as per CERC norms. This can be addressed in the Tariff Regulationby indicating GCV as "As Received at plant end" and customization of Form-15 regarding the GCV.	CIL is the major supplier and coal is procured after advance payment. This cannot be forced by IPPs.
29	58	Technical Minimum	The 4th Amendment to IEGC should apply to all TPS, irrespective of whether they are CGC / ISGS as the basis is Unit Capacity and not Type of Station.
31	59	The tariff determination under Section 62 of the Act follows the principle of costof recovery which inter-alia provides the reimbursement of cost incurred by thegenerating company	Against the Non tariff Income Generator has to bear additional expenses which are over and above O&M allowed in Tariff.

		or the transmission licensee. The income on account of sale offly ash, disposal of old assets, interest on advances and revenue derived fromtelecom business may be taken into account for reducing O&M expenses. Presentregulatory framework does not account for other income for reduction of operation &maintenance expenses. However, in case of transmission licensee, the income earned from telecom business are adjusted in the billing separately. The principle oftreatment of other income as applicable in case of transmission can be extended forthe generation business.	Payment of advances on which interest is received is not made from tariff income, same is made from the ROE, any income earned from the same is part of ROE. Hence interest on advances should not be considered.
32.2	60	ED on Aux	Should be on Actual Aux and not Normative.
34	61	The Revised Tariff Policy dated 28th January,2016 provides for setting up ofrenewable energy generation capacity by existing coal based thermal power generating station	Due to stress in power sector, IPPs may not be able to bring equity and lenders will also not give loan for the same.
37	65	Alternative Approach to Tariff Design – Normative Tariff by Benchmarking of capital cost / fixing AFC as a percentage of capital cost.	• Suitable for MOU route only • In case of force majure plant will be unviable • Land / water / coal not in control of generator, it may adversely impact. • Variable cost cannot be normative Each Plant has its own issues and peculiar conditions. Cost should not be on a Normative basis as a % of Capital Cost.
37.18	68		No Change from Existing
40.1	71	Though merit order is a dispatch issue, scheduling/ non-scheduling has its impact on purchase cost. It is seen that in respect of certain old plants having low fixed costs, their power may not get dispatched as the merit order is based on variable cost, which may be high.	MOD should also have possible regulatory option regarding technical minimum scheduling and safe operations for thermal power plants.

To provide for Dedicated Transmission Line O&M in the Generation Tariff.

To apply the 4th Amendment to IEGC to all Thermal Stations, irrespective of whether they are CGC / ISGS as the basis is Unit Capacity and not Type of Station.

Note on Terms & condition of Tariff Regulation.

As per the recent change in terms & conditions of Tariff Regulations in last two policies, the emphasis has been made to reduce the cost of generation and transmission to provide the power at minimum cost to the users.

In Power Sector a large sum has been invested by the Private Investors (IPPs) with the finance from financial investors and Banks/financial institution with an assured return / security of their investment. Some of the Government Policies / decisions in the past have adversely affected the IPPs and impacted the viability of the Project. This has not only resulted in the delay/ defaults in the debt servicing but has also discouraged future investment in the Power sector.

The major decision impacting the IPPs are, cancelation of coal mines, tariff calculation on the basis fired GCV in place of received GCV (as the only supplier is Government and there is no other source of coal), non materialization of FSA, Income tax gross up on equity, revision in scheduling without considering technical minimum etc.

We wish to submit that in line with the Tariff Policy and Electricity Act, the emphasis has to given to all parties related to the Power sector, i.e Generators, DISCOMs and Consumers.

As mentioned in the current staff paper at S. No 7.2.1-7.2.6 for revision in tariff structure on account of decrease in PLF, s.no 10 for unutilized capacity of station to be utilized by other distribution companies or open market etc will adversely impact the IPPs, as in the current scenario there is no stable merchant tariff market, even some time to operate at technical minimum the power has to be sold at lower than variable cost.

Further IPPs implement the project on the basis of finances from Lenders on assumptions of PPA/tariff guidelines, and any material change in the terms of PPA and /or Tariff Regulation not only impacts the viability of project resulting in NPAs, but also leads to erosion of equity of promoters and default of Banks and unutilized resources.

We submit that the any change in tariff regulation should not adversely impact the viability of stations and ROE as stated in regulations to be available to the promoters.