MBPMPL/ANP-I/CERC/2023-24/887 **29.07.2023**

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

Subject: ***Comments/ suggestions of MB Power (Madhya Pradesh) Limited on CERC Approach Paper on Terms and Conditions of Tariff for the period commencing from 01.04.2024***

Ref: ***CERC Public Notice(s) dated 26.05.2023 and 03.07.2023 on the subject matter.***

Dear Sir,

We write in reference to the above referred Public Notice(s) dated 26.05.2023 and 03.07.2023 issued by this Hon'ble Commission vide which comments/ suggestions of the various stakeholders have been invited on the CERC Approach Paper on Terms and Conditions of Tariff for the period commencing from 01.04.2024.

We, MB Power (Madhya Pradesh) Limited, are a Generating Company having an operational 1200 MW (2X600 MW) coal based Thermal Power Project in district Anuppur of Madhya Pradesh. We are hereby furnishing our detailed comments/ concerns/ suggestions on the said Approach Paper (enclosed herewith as ***Annexure-1***) for your kind consideration.

We hope you would acknowledge a genuine merit in our comments/ concerns/ suggestions and would consider the same favourably.

Thanking You,

Yours Truly

Abhishek Gupta
AVP (Regulatory & Commercial)
MB Power (Madhya Pradesh) Ltd.

1) **Section-4: Financial Aspects impacting Tariff.**

a) **4.3: Capital Cost for Projects acquired post NCLT Proceedings**

Our Comments: It has been proposed that for the projects acquired post NCLT proceedings having acquisition cost significantly lower than the historical cost, such an acquisition cost be considered for the purpose of tariff determination under Section-62.

This proposition may augur well for the projects where the entire Installed Capacity is tied-up under Long Term PPAs. However, as seen in the past, most of defaults in payments to creditors have been by those projects which have been not been able to secure revenues in absence of Long Term PPAs resulting in a substantial untied capacity. As such, the haircut taken both by the creditors and the project company is essentially on account of such non-revenue bearing untied project capacity.

For such projects which are already impaired due to a substantial untied/ open capacity and have a limited revenue stream in terms of a partial capacity tied-up under PPA, further reduction in their ongoing tariff stream on account of revision of the Project cost would further adversely affect their financial viability and sustained operability.

Accordingly, it is suggested that for the projects acquired post NCLT proceedings having Long term PPAs for less than 75% of the installed capacity, only the historical project cost (and not the acquisition cost) be considered for the purpose of tariff determination under Section-62.

b) **4.10.1: Normative Add-Cap – Thermal Generating Stations**

Our Comments: It has been proposed that for the existing Thermal Generating Stations, in-lieu of the actual Add-Cap, a normative yearly allowance may be allowed based on the unit sizes and vintage, which shall not be subject to any true-up and shall not be capitalized. Further, such an annual allowance be over and above the additional add-cap incurred by a thermal generating station on account of Regulation 26 to Regulation 29 of the CERC Tariff Regulations 2019-24.

This is a welcome measure which would further simplify and expedite the tariff determination/ true-up exercise and save considerable time and efforts required for exercising prudence check of actual add-cap by this Hon'ble Commission. **It is suggested that such an annual allowance be over and above the additional add-cap incurred by a thermal generating station on account of factors mentioned under Regulation 25 (1) in addition to Regulation 26 to Regulation 29 of the CERC Tariff Regulations 2019-24. Further for a Thermal Generating Station having a unit size of 500 MW and above which has been under operations for 10 years or more, a normative special allowance of 9.5 Lakhs/MW/Year i.e. at par with special allowance mention under Regulation 28(2) of the CERC Tariff Regulations 2019-24 be allowed in-lieu of actual add-cap.**

c) 4.12: O&M Expenses

Our Comments: While the normative O&M expenses cover the Employee Expenses, Repair & Maintenance Expenses and Administrative & General Expenses, however in the recent years, Ministry of Environment and Forests (MoEF) has issued various notifications from time to time for ensuring 100% Ash Utilization/ Disposal which necessitates incurring additional monthly charges towards Ash Utilization/ Disposal by the Thermal Generating Stations which are purely in nature of O&M Expenses.

A 1200 MW coal based Thermal Generating Station incurs almost Rs 120 Crs on Ash Utilization/ Disposal per year which interalia includes expenses on account of labor costs towards ash load and unloading, transportation (freight/ logistics) charges towards transportation of Ash by road and/or rail, incentives payables to various Ash off-takers, soil cover, compaction and green cover charges and other associated overheads etc. An illustration of the same on annual basis for a 1200 MW Thermal Generating Station operating at a normative PLF of 85% is as under:

A. Coal Requirement: 6 MTPA (Million Tonnes Per Annum)
B. Ash Generated: (@ ~ 35% of coal consumption): 2 MPTA

C. Operational Expenses towards Ash Disposal: Rs 600/ Ton (plus GST) as per the following breakup:
   - *Transportation Charges (including incentives to Ash Offtakers): ~ Rs 400-450/ Ton*
   - *Loading & Unloading Charges: ~ Rs 100-150/ Ton*
   - *Soil cover, Compaction and Green Cover Charges: ~ Rs 75-100/ Ton*

D. Total Operational Expenses incurred per Annum: B*C: Rs 120 Crs which roughly translates into Rs 10 Lacs/MW/Year (including GST).

Accordingly, it is suggested that over and above the existing normative O&M expenses, an additional normative O&M expenses component of Rs. 10 Lacs/MW/Year be allowed towards Ash Utilization/ Disposal. This shall not only simplify the tariff determination process but would also reduce the avoidable Litigations/ Petitions on account of claim of such expenses under "Change in Law". Further, this may also serve as a benchmark for pass through of such operational expenses under Section-63 PPAs where such expenses are claimable under Change in Law provisions.

Further, we are also in agreement with the Approach Paper's proposal to provide a suitable mechanism in the Regulations to capture impact of Change in Law events like taxes & duties etc. on the O&M expenses as this would save a lot of efforts involved with claiming the same separately through individual Petitions.

d) <u>4.13: Depreciation</u>

<u>Our Comments:</u> Under the prevailing Regulations, normative depreciation rates for initial 12 Yrs of operations of a Generating Station have been specified by this Hon'ble Commission with the objective to make adequate cash flows available to meet principal repayment obligations of the Project Company. This has been done considering loan period of 12 Yrs. However, it is now suggested that since currently the loans are available for a period of 15-18 Yrs, hence the depreciation rates may now be revised considering a loan period of 15 Yrs. instead on current practice of 12 Yrs.

While such a measure may serve its intended purpose of eliminating the front loading of tariff for the new projects and the projects who are yet to achieve the cut-off date. However, such a proposed methodology may prove counter-productive, for the projects which are under operations for a considerable time of more than 8-9 Yrs as these projects would continue to receive normative depreciation for another 6-7 Yrs (instead of balance 3-4 Yrs as per the current provisions).

Hence is it suggested that revised depreciation rates considering loan period of 15 Yrs be notified for only new projects or at best the projects which are under operation for a period of less than 5 Yrs as on 01.04.2024. Further, the existing projects which are under operation for a period of more than 5 Yrs as on 01.04.2024 were essentially conceived and financed as per the old financing norms wherein there the loan period was restricted to 12 Yrs. only and as such there should not be any revision in the existing Depreciation rates and methodology for such projects.

e) <u>4.15 & 4.16: Return on Equity.</u>

<u>Our Comments:</u> While we agree in view of tangible limitations and de-merits involved with RoCE and WACC, it shall be prudent to continue with RoE approach instead of RoCE approach, however any downward revision of current RoE @ 15.5% (post tax) shall be highly detrimental for the Generating Stations.

Further, as suggested in the approach paper, **we also agree with the concept of differential Rate of RoE for Generation and Transmission businesses given the risks associated with Transmission Business are significantly lesser than those associated with Generation Business on account of factors like high credit ratings, no risks related to fuel and power tie-ups, negligible risks associated with part-load operations as 100% tariff recovery is ensured even if a transmission asset is not operating at its full rated capacity. This has also been a recommendation of Forum of Regulators in its Report on *"Analysis of Factors Impacting Retail Tariff And Measures To Address Them"***

However, for a generation business, the prevailing normative Rate of RoE of 15.5% as per the CAPM methodology is resulting in under recovery of RoE as explained below.

The formula for computing the Rate of RoE (Re) based on CAPM is as under:

Re=Rf+β(Rm-Rf)

Where:

Rf = risk-free rate

β = equity beta

Rm-Rf = equity market risk premium

a. **Risk-free Rate (**Rf): It is proposed that average 10-Year GOI securities (G-Sec) rate over a one year horizon be considered as Rf which is almost 7.31% as elucidated in the Approach Paper.

b. **Equity Beta (**β): Equity Beta is proposed to be computed based on daily data on the Sensex and BSE Power Index for the last five years. The constituents of BSE Power Index, their respective line of business, Market Capitalization, Weightage in the Index and Beta are as under:

BSE Power Index *As on 27.07.2023*

S. No	Company Name	Industry	Mkt Cap (Rs. Crs.)	Weightage (%)	Beta
1	ABB India	Electric Equipment	93,307.50	7.61%	0.64
2	Adani Green Energy	Renewables	1,77,221.55	14.45%	1.17
3	Adani Power	Power Generation	97,619.12	7.96%	1.15
4	Adani Trans	Power Transmission	89,830.63	7.32%	1.44
5	BHEL	Engineering - Industrial Equipment	36,032.39	2.94%	1.04
6	CG Power	Electric Equipment	60,638.75	4.94%	0.8
7	JSW Energy	Power Generation	47,572.24	3.88%	1.58
8	NHPC	Power Generation	49,421.57	4.03%	0.71
9	NTPC	Power Generation	1,95,872.66	15.97%	0.67
10	Power Grid Corp	Power Transmission	1,74,804.85	14.25%	0.58
11	Siemens	Electric Equipment	1,33,545.10	10.89%	0.7
12	Tata Power	Power Generation & Distribution	70,553.10	5.75%	0.99
		TOTAL	**12,26,419.46**	**100.00%**	***0.90 (Weighted Avg.)***

As may be seen from above, BSE Power Index having a composite Beta of 0.90 comprises some of the companies (highlighted above) viz. ABB, BHEL, CG Power, Siemens, Adani Trans and Power Grid Corp. which are not which are not engaged in the business power generation/ distribution and are rather have a diverse line of business like Electric Equipment, Engineering, Power Transmission etc. As such, their respective Beta shall not be a true indicator of risks associated with power generation business and the same ought not be considered while computing Rate of RoE for generation business. This would be strictly in line with the concept of differential RoE for different businesses as proposed in the Approach Paper itself.

Accordingly, considering only those constituent companies of the BSE Power Index which are essentially engaged in the Power Generation & Distribution business, the Beta is computed as under:

S. No	Company Name	Industry	Mkt Cap (Rs. Crs.)	Weightage (%)	Beta
1	Adani Green Energy	Renewables	1,77,221.55	27.77%	1.17
2	Adani Power	Power Generation	97,619.12	15.29%	1.15
3	JSW Energy	Power Generation	47,572.24	7.45%	1.58
4	NHPC	Power Generation	49,421.57	7.74%	0.71
5	NTPC	Power Generation	1,95,872.66	30.69%	0.67
6	Tata Power	Power Generation & Distribution	70,553.10	11.05%	0.99
		TOTAL	**6,38,260.24**	**100.00%**	***0.988 (Weighted Avg.)***

As can be seen from the above, Beta of companies essentially engaged in Power Generation & Distribution is 0.988 vis-à-vis overall BSE Power Index Beta of 0.90. Further, this Beta gets further amplified on accounts of risks faced by power generating companies related to delayed/ non-payment of dues by the Discoms, which does not get captured in the BSE Power Index. As such, computation of Beta under the proposed methodology has inherent statistical error, which also needs to be accounted for.

c. **Market Risk Premium** (MRP=Rm-Rf): To calculate the Market Risk Premium, average of annual returns on BSE Sensex for the last 20 Yrs be considered as Rm as since 20 Yrs would be a right indicator to capture the developments in the Indian power market post promulgation of The Electricity Act 2003 and any period beyond 20 Yrs would not correctly represent the Rm associated with the private power generation companies.

Annual Returns on BSE Sensex since Jan' 2003 till Dec' 2022 (20 Yrs) is as under:

S.No	Year	BSE SENSEX		% Return
		Opening	Closing	
1	2003	3383.85	5838.96	72.554%
2	2004	5872.48	6602.69	12.434%
3	2005	6626.49	9397.93	41.824%
4	2006	9422.49	13786.91	46.319%
5	2007	13827.77	20286.99	46.712%
6	2008	20325.27	9647.31	-52.535%
7	2009	9720.55	17464.81	79.669%
8	2010	17473.45	20509.09	17.373%
9	2011	20621.61	15454.92	-25.055%
10	2012	15534.67	19426.71	25.054%
11	2013	19513.45	21170.68	8.493%
12	2014	21222.19	27499.42	29.579%
13	2015	27485.77	26117.54	-4.978%
14	2016	26101.5	26626.46	2.011%
15	2017	26711.15	34056.83	27.500%
16	2018	34059.99	36068.33	5.896%
17	2019	36161.8	41253.74	14.081%
18	2020	41349.36	47751.33	15.483%
19	2021	47785.28	58253.82	21.907%
20	2022	58310.09	60840.74	4.340%
AVERAGE (Rm)				**19.43%**

Based on the above, an illustrative computation of Rate of RoE is done as below:

Rf = 7.31%
β = 0.988
Rm = 19.43%

Rate of RoE, Re=Rf+β(Rm-Rf)

Re = 7.31% + 0.988 * (19.43% - 7.31%) = 19.28%

As evident from above, against the Rate of RoE of 19.28% computed using the CAPM, the current Regulations allow the normative Rate of RoE of 15.50% only which is resulting in a substantial under recovery by the project companies. **In view of the above, it is strongly suggested that normative Rate of RoE for power generation business during FY 2024-29 be increased to at-least 18% (post tax).**

f) 4.18: Interest on Working Capital.

Our Comments: We suggest the current mechanism of computation of Interest on Working Capital, being quite efficient and responsive to market conditions be retained. Since the integral components of Working Capital viz. Coal (and logistics) cost, receivables (consisting of both Fixed Charges and Energy Charges) etc. vary significantly from project to project and hence computation of the same on normative basis may lead to distortion of tariff i.e. over-recovery for certain projects and under-recovery for the others.

g) 4.19: Life of the Generating Stations.

Our Comments: It is earnestly requested that while the normative life of the existing Generating Stations be retained to 25 Yrs, however, the normative life of any new/ upcoming Generating Stations be increased to 30 Yrs. It may kindly be appreciated that the existing Generating Stations were conceived and developed considering the normative life of 25 Yrs only and accordingly, the entire planning and execution of the same involving technology adopted, equipment installed, commercial agreements towards land lease, coal supply (FSA) and power sale (PPA) etc. have all been done for the maximum period of 25 Yrs only. As such, any fresh impositions on the Generating Projects in terms of mandatory increase in their life would severely distort the existing dynamics and increase in uncertainties in power and fuel tie-ups post 25 Yrs of their operation, since the existing PPAs and FSAs are valid for a maximum period of 25 Yrs i.e. commensurate to existing life of the Generating Station of 25 Yrs. Further, such an onerous move shall also lead to under-recovery of depreciation (as it would now be spread across 35 Yrs instead of 25 Yrs), thereby leading to higher risks associated with an existing Generating Station becoming a NPA.

Accordingly, it is requested that any operations of an existing Thermal Generating Station beyond the current normative life of 25 Yrs may solely be on voluntary basis, in line with the current dispensation, and may not be made mandatory by way of any regulatory intervention.

2) Section-5: Normative Annual Plant Availability Factor (NAPAF)

a) 5.2: Peak and Off-Peak Tariff

Our Comments: We agree with the Approach Paper's observations operational difficulties are being faced by the Generating Stations supplying power to more than one State/ Region as the Peak demand period of one State does not converge with the Peak demand period. Such an operational difficulty becomes even more glaring for the generating stations which are supplying power to multiple States spread across multiple Regions due to non-uniformity in their respective power demand pattern. Accordingly, it is proposed that a National level peak and off-peak periods may be defined instead of having the same specified on State and/or Region level.

b) 5.8: Gross Calorific Value (GCV) of Fuel

Our Comments: We earnestly request to continue with the existing dispensation of considering GCV of fuel for the purpose of allowing Energy Charges on an as "received basis" plus an additional margin of 85 kCal/kg towards storage losses. It may kindly be appreciated that there is a considerable loss in GCV of coal during its transit from the billing point (Coal Mine) to the receiving point (Generating Station), which is solely on account of the factors which are beyond any control of the Generating Station. Hence by not allowing such a loss and/or mandating a Generating Station to partly bear such a loss would only amount to penalizing a Generating Station for absolutely no fault on its part.

Further devising any sharing mechanism to share such GCV losses amongst the coal company, railways and the Generating Station would only lead to spate of unwarranted litigations and especially when the coal companies and/or railways are not amenable to the jurisdiction of this Hon'ble Commission.

Accordingly it is requested that the current dispensation be allowed to continue without making any changes in the same.

c) <u>5.9: Blending of Coal</u>

<u>Our Comments:</u> In the recent past, Ministry of Power, vide its various directions from time to time, has directed the Generating Stations to mandatorily blend the domestic coal with the imported coal. However, such a blending results in a steep increase in the Energy Charges beyond 30% of the base Energy Charges, thereby necessitating a Generating Station to secure a prior consent of the beneficiary for import of coal as a part of existing regulatory requirement. Consequently, the Generating Stations face severe challenges as most of the times, the beneficiaries do not provide the timely consent and times no consent at all. In such a scenario, the Generating Stations are not able to comply with the Ministry of Power directions or suffer severely in terms of under recovery of Energy Charges.

Accordingly it is requested that this existing regulatory requirement may be suitably modified to allow a blending of domestic coal with upto 30% of imported coal without any prior consent of the beneficiary.

d) <u>5.7 & Addendum dated 03.07.2023 to the Approach Paper</u>

<u>Our Comments:</u> 4th Amendment to IEGC 2010 dated 06.04.2016 and Detailed Operating Procedure (DoP) thereof dated 05.05.2017 prescribed Technical Minimum limit for operations of Thermal Generating Station ("TGS") as 55% of MCR. Further, vide these notifications, a compensation mechanism was devised for payment of compensation by Discom(s) to a TGS in event of under-scheduling by Discom(s) resulting in Part Load Operations of such a TGS below normative level of 85% but above 55%. Subsequently, in terms of CEA (Flexible Operation of Coal based Thermal Power Generating Units) Regulations, 2023, CEA revised the Technical Minimum limit for operations of TGS from existing 55% to 40% of MCR. Thereafter, CEA prepared a compensation methodology for operating a TGS below the 55% and upto 40% of MCR (enclosed as Addendum to Approach Paper), wherein compensation in terms of both Fixed Cost (towards additional Capex on account of retrofitting for a TGS capable of operating at 40% of MCR and also O&M) and Variable Cost (towards increase in SHR, Oil Consumption etc.) on per unit basis has been indicated.

In this regard, we would like to submit the following:

a) All the existing TGS are not capable of achieving the Technical Minimum limit of 40% even after retrofitting. Further, as per the discussions of with the OEMs, the guaranteed operational parameters viz. SHR, AUX, Boiler & Turbine efficiency etc. would be severely affected if such TGS is made to operate at 40% levels, which would not only void the existing Guarantees provided by the OEMs but would also substantially reduce the life of the TGS.

   Even CEA has acknowledged that operating a TGS at 40% level would lead to reduction in the life of a TGS which is in stark contradiction to this Approach Paper's proposal to increase in the normative life of a TGS from 25 Yrs to 35 Yrs.

   In view of the above, it is requested that the existing Technical Minimum limit of 55% be retained and the TGS may be allowed to opt if it is capable of operating at 40% Technical Minimum limit. In event a TGS opts to operate at Technical Minimum limit of 40%, then it shall be allowed the CAPEX as a pass through under Change in Law under the PPAs. While CEA has proposed a capping on such CAPEX on a generating unit (under operations after 2004 onwards) @ Rs. 10 Crs, however no rationale has been furnished for such a capping. As such, imposing any such capping would only lead to under-recovery of CAPEX. **It is accordingly proposed to allow the entire CAPEX towards retrofitting as a pass through, subject to prudence check by the Hon'ble Commission and the same should be allowed to be recovered within a period of 5 Yrs from its commissioning as suggested by CEA.**

b) With respect to compensation on account of degradation of operating parameters (SHR, AUX and increased Secondary Oil Consumption) on account of Part Load Operations of TGS below normative level, two separate and distinct mechanisms exist as under:

- Compensation for Part Load Operations of TGS in the range of 85% to 55% - As per the DOP prepared by NLDC and issued by this Hon'ble Commission on 05.05.2017.
- Compensation for Part Load Operations of TGS in the range of 55% to 40% - As proposed by CEA under Addendum to this Approach Paper.

Both these methodologies are conceptually different in terms of underlying parameters, mode of computation and recovery of compensation, apportionment of payable compensation amongst various beneficiaries of a particular TGS etc. Accordingly their co-existence would only lead to ambiguity and uncertainties.

Further, the existing Compensation Mechanism stipulated in the DOP dated 05.05.2017 has matured over the last 6 Yrs. and is being undertaken by a statutory bodies like RLDCs who are competent to undertaking such an exhaustive exercise.

In view of the above, it is strongly proposed that the existing Compensation Mechanism stipulated in the DOP dated 05.05.2017 be further modified to cover the compensation for Part Load Operations of TGS in the range of 55% to 40% (applicable to only those TGS, who opt to operate at Technical Minimum limit of 40%) and this singular and unified Compensation Mechanism (for computation of compensation for Part Load Operations of TGS in the range of 85% to 55%) may be made a part of CERC Tariff Regulations 2024-29 as specified in the CERC IEGC 2022.