Submission on draft Rajasthan Electricity Regulatory Commission (Terms and Conditions for determination of Tariff) Regulations, 2025

Prayas (Energy Group) *23rd December 2024*

The Rajasthan Electricity Regulatory Commission (henceforth the Commission or the RERC), has published the draft notification on the Tariff Regulations for the control period from 1st April 2025 to 31st March 2030, and invited public comments on the same.

The tariff regulations, and related processes, have implications on all sector stakeholders in the state for the next five years and beyond. Given this, it is crucial to further strengthen flexibility measures, target incentives, safeguard consumer interests and ensure clarity in tariff regulations. Prayas (Energy Group) has the following suggestions towards strengthening the proposed tariff regulations:

1. Power procurement, planning, and fuel supply

1.1. Treatment of new capacity

In the context of the on-going energy transition, the addition of new capacity, including bundled capacity, has widespread and longstanding impacts on the state's power sector. As per draft regulation 60(5), the capital investment plan should be accompanied by such information, particulars and documents as may be required showing the need and justification for the proposed investments. Accordingly, any new capacity addition must be justified. In addition to this, decisions regarding capital investment should be in line with power procurement planning and demand projections undertaken by the utilities. RE capacity additions should also be justified based on RPO targets in the states.

Given the long-term nature of typical PPAs, new cost-plus coal-based capacity additions with 25-year fixed cost commitments on beneficiaries pose a serious risk of long-term lock-ins. Further, the competitiveness of cost-plus coal-based projects is also suspect given other growing sources of generation (RE, RE+storage, and other hybrid sources of generation).

Instead of Section 62, the competitively bid Section 63 route, with due approval from RERC, should be encouraged for new capacity additions. This would aid with competitive price/tariff discovery, while also simplifying the tariff process and reducing the burden on the Commission. Thus, any new projects should only come up through the Section 63 route based on due approval from the Commission. Such Section 63 processes should be designed to encourage competition and adhere to the Standard Bidding Guidelines as issues by the Ministry of Power. Approval of any deviations from these guidelines by the Commission should be based on a public hearing.

If capacity addition through Section 62 is still allowed, transparent reporting of justification and approval of new capacity becomes crucial. Section 7.2 of the explanatory memorandum discusses the preparation and filing of a Capital Investment Plan (CIP). This is an important step towards providing clarity to sector actors about capacities and projects in the pipelines, along with the related costs and expenses over the coming control period. Given the implications of capacity addition on the consumer, CIP order approval should be subject to public consultations.

Capital investment has crucial impacts on all sector actors, including consumers, and the Commission should consider having regulations specifically for approval of Capital expenditure, as done by Maharashtra ERC.

Slippages and delays are a serious concern, which impact system costs and disrupt planning. The Rajasthan Electricity Regulatory Commission (Investment Approval) Regulations, 2006 provides formats for details that the entities/licensees are required to file towards the CIP. This should be modified to include that utilities report status of projects along with time and cost overruns and interest during construction incurred and reasons for delay, if any for each project. The Commission could also consider strictly penalising delays that are within the control of the utilities.

Any capacity addition undertaken should be transparent and justified. Thus, the Commission should develop a publicly accessible web-based portal for submission, review, approval and monitoring of capital investment schemes. It should also mandate online reporting of status of ongoing capex schemes and imposition of penalties in case of delays. This has been an approach proposed by the Gujarat ERC in its current MYT regulations.

Thus, we request the Commission to:

- Ensure any new capacity addition should be justified and in accordance with power procurement plans of the distribution utility
- Mandate any new capacity additions, including coal-based capacity addition, to be undertaken through the Section 63 route
- Ensure that approval of CIP orders, in the instance of Section 62 capacity addition, is subject to public consultation
- Penalise generating companies for delays in undertaking capital investment, as reported in the CIP order
- Ensure transparency in tracking and monitoring of capital investment through a publicly accessible web-based portal

1.2. Capping transfer price/landed price of coal

Rajasthan Rajya Vidyut Utpadan Nigam Limited (RRVUNL) has been allocated three coal blocks – Parsa East, Kanta Basan, and Parsa – for captive use in power generation. Draft regulation 11 (8) addresses the filing of a petition by any entity that owns or is allotted a captive mine or is granted land use rights for mining fuel for thermal power plants – for determining the transfer price or landed price of fuel if it is not determinable by the Government or Government approved mechanism or by fuel regulator. Ultimately, this transfer or landed price is passed on to consumers.

The draft regulations, however, do not stipulate a ceiling for the fuel transfer price. If coal from a captive mine were to be more expensive than CIL notified price for the same grade, then it would be better for consumers that the coal is procured from CIL. The reason for allotting captive coal mines 'free' to power companies is so that they could obtain coal at a lower price. Maharashtra ERC has recognised this in their second amendment to its 2019 MYT regulations. The Commission should cap the fuel transfer price of coal from captive mine to the CIL notified price for the corresponding grade of coal, to be consistent with the objectives of allotting coal mines for captive consumption under the Coal Mines (Special Provisions) Act, 2015 and related Rules.

Thus, we request the Commission to:

- Cap the fuel transfer price of coal from captive mines to the CIL notified price for the corresponding grade of coal

1.3. Coal washing

The draft regulation 50(4) account for washery charges as and when applicable in the landed cost of the fuel. Since this would impact fuel prices, and therefore consumer tariffs, it is important that details regarding coal washing are transparently reported.

Maharashtra ERC has set a precedent for this practice and requires the Maharashtra state generating company to '*carry out the proper cost benefit analysis of coal beneficiation after receiving the tenders and before going ahead for placing the contracts for coal beneficiation. MSPGCL should try to ensure that the effective landed price of washed coal at thermal Station in terms of Rs/Kcal is lower than the landed price of coal at thermal station in terms of Rs/Kcal*' – in MERC Case 296 of 2019.

The Commission could further strengthen this and require generators under its jurisdiction to report contract details, costs, GCV and quantities of washed coal, in addition to cost benefit analysis for the use of washed coal in the control period. RERC should require generators to validate that the effective landed cost of washed coal at thermal stations in terms of Rs/Kcal is lower than the landed price of (raw) coal at thermal station in terms of Rs/Kcal. Towards ensuring transparency and accountability such reporting and cost benefit analysis should be made available in the public domain. The Commission should further ensure that generating companies submit a detailed cost benefit analysis and validate reported improvements in GCV through coal beneficiation, and should not approve any associated costs until such details have been submitted and scrutinised.

Thus, we request the Commission to:

- Only approve costs associated with coal washing based on assessment of reporting and cost-benefit analysis carried out by the generating companies
- Ensure that generating companies report details of washed coal in the public domain, and that such reporting includes contract details, costs, GCV and quantities of washed coal, in addition to cost benefit analysis for the use of washed coal in the control period

1.4. Mandate fuel supply planning

Given the increasingly dynamic nature of the sector, it is good practise to ensure that the generating entity prepares a fuel utilisation plan on a periodic, say monthly/quarterly, basis, towards addressing shortfall/failure in supply from approved sources to some extent. As a precedent, Maharashtra ERC mandates the regular preparation and publication of a fuel utilisation plan in accordance with its MYT Regulations 2019. In addition to transparency in planning and ensuring an alternate arrangement for meeting shortage of fuel, such a fuel utilisation plan would help with optimum fuel utilisation (through allocation based on merit order/variable cost) and aid cost savings.

Such planning should be consistent with the likely demand for coal-based generation as projected by the distribution utility, and will enable generating companies to be better able to plan for its fuel procurement at least cost, even in instances of shortage. Towards this, the plan should also include alternatives for fuel procurement in case of sudden increase in demand or shortage of expected fuel supply – for example, prioritising e-auction coal or enhanced production from captive mines over imports, as they are a potentially cheaper alternative.

The Commission should require generating companies under its jurisdiction to prepare a comprehensive, station-wise fuel utilisation plan for the control period. A format for the same is suggested in Table 1.

Table 1. Suggested format for fuel utilisation plan to be prepared by the generating company

		Station/ Unit 1	Station/ Unit 2	…..	Station/ Unit n
Name of the unit					
Fuel Type					
Fuel Requirement of the unit (MT/MCM)					
Details of Contracted Source	Name of Source				
	Annual Contracted Quantity				
	Variable cost/unit				
	Estimated Availability				
	Expected Shortage				
Alternate Arrangement in case of Shortage	Name of Alternate Source				
	Expected Rate of Alternate Source				
	Impact on Variable Cost per unit				
Plan for swapping of Fuel Source for Optimizing Cost					
Net Cost Savings in Variable cost after optimum utilisation					

Source: Prayas (Energy Group)

The Commission should also require the generating company to publish on their website monthly/quarterly data on actual station wise performance of fuel utilisation with justification of deviations from the fuel utilisation plan submitted. The Commission should specify penalties in case the fuel utilisation plan is not submitted as per formats prescribed by the Commission.

Thus, we request the Commission to:

- Mandate that the generating entity should prepare a fuel utilisation plan in the suggested format on a periodic, say monthly/quarterly, basis and publish such plans on their website
- Ensure that such reporting is adhered to and the lack of compliance by generating companies should be appropriately penalised

2. Financial Parameters

2.1. RoE linked to performance parameters

As per draft Reg 20, RoE is to be computed at a rate of 14% for transmission licensees and SLDC; 15% for generating companies; and 16% for the distribution licensees.

Instead, RoE could be considered in two parts – Base RoE and Performance-based ROE. The Base RoE (of say 12.5% for transmission licensees and SLDC; 13.5% for generating companies; and 14.5% for the distribution licensees) should be allowed in accordance to the proposed regulation 20. The Performance-based RoE (of say, 1.5%) should be linked to actual performance. Given the importance of efficient and reliable operation in the fast-changing power sector, such treatment of RoE can be used to incentivise efficiency in actual operation and performance.

The Commission could link the Performance-based RoE to improvement in reliability and technical performance, such as:

- Reduction in Mean Time Between Failures by generating companies
- Reduction in transmission losses beyond norms by the transmission companies
- Reduction in DT failure rates by distribution licensees
- Reduction in feeder level outages by distribution licensees
- Ensuring timely submission of tariff petitions/true-up orders

The Performance-based RoE incentives/penalties provided should be considered in proportion to appropriate capacity and should collectively be subject to a ceiling not exceeding the total Performance-based RoE (of say 1.5%).

Such incentives, designed with careful consideration, will aid the needs of the sector with improved grid integration capability and more responsive, effective operation. Such an approach has been considered in the MYT Regulations of other states, such as Maharashtra, Gujarat, and Telangana.

Thus, we request the Commission to:

- Consider a two-part RoE (comprised of base RoE and performance-based RoE) with the recovery of performance-based RoE being linked to improvement in reliability and technical performance

3. Generation

3.1. Consideration of GCV 'As Billed' for ECR calculations

As per draft Reg 50 (2), the Rate of Energy Charge (REC) for Thermal Generating Stations is calculated based on GCV 'As Received' (at the unloading point) less 85 kcal/kg or GCV 'As Fired', whichever is higher. However, this approach raises certain concerns that need to be carefully considered and addressed.

In accordance with the model FSA (Para 7, 'Transfer of Title to Goods), the ownership of the coal is transferred to the generator at the loading point at the mine end, after which the procured coal is the responsibility of the generator. Thus, as per the FSA, compensation can only be claimed for the difference in grade as declared (or billed) by the coal company and as analysed (or procured) by the generator at the loading end, and the coal company is not responsible for any GCV loss during transit. The FSA and the SoP for third party sampling also only deal with measurement of coal quality/sampling at the billing/loading point, at the mine end, though it is good practice for the generator to also undertake sampling and quality checking at the receiving end. The consideration of GCV 'As Received', as in the draft regulations, results in any slippages during transit beyond the billing/loading point at the coal mine being passed on to the beneficiaries, with an additional allowance of 85 kcal/kg provided over and above these slippages.

Towards safeguarding consumer interests and ensuring operational efficiency from the generator, GCV 'As Billed' (with allowance for adjustment in moisture, and transit loss) is the appropriate measure for REC calculation. The Maharashtra ERC has adopted a similar approach.

When considering GCV 'As Billed' for REC computation, the adjustment for GCV methodology would address generator concerns regarding differing moisture levels. Towards balancing generator concerns with consumer interests, the Commission should require source-wise reporting of grade, price and quantity of coal procured at the mine end and at the generator end. This data should be hosted publicly on the generator's website. The Commission could then undertake a study to better understand the cause of slippages and ensure more efficient and prudent coal supply.

Moreover, no such slippages in GCV should be allowed for generating stations that use coal from an integrated mine. This treatment is consistent with CERC Regulations on the matter.

Thus, we request the Commission to:

- Consider GCV 'As Billed' in REC computation with the adjustment for moisture content.
- Require generators to record and publicly report grade, price and quantity of coal procured from each source, at the mine end and at the generator end
- Ensure no GCV slippages are allowed for generating stations that use coal from integrated mines

3.2. Availability linked weights for Fixed Cost Recovery and PLF incentives

As per Reg 51 (1) and 54(6) of the draft regulations, capacity charge recovery and application of PLF Incentive is carried out by treating availability uniformly for every hour and month of the year. Given the increasing variation in demand across the day and seasons, and the changing role of coal-based generation in meeting demand, this uniform consideration for availability does not reflect the realities of the sector or the responsiveness required in TPP operations. There will be increased need for flexible operation of coal-based TPPs, and robust incentive frameworks with broader applicability should be put in place. Table 3 suggests such a framework for the recovery of capacity charge.

Optimally, plants should be encouraged to be available and generate during periods of high demand for that type of plant, and incentivisation should be tapered for periods of lower demand. For coal-based generation, these periods are based on *net-load* rather than overall load, since that determines when coal-based plants are most or least required. Towards this, availability-linked weights for Annual Fixed Cost (AFC) recovery should be introduced in a targeted manner across peak/off-peak season and high/low demand months.

Table 3. Proposed consideration of availability-linked FC recovery

	Peak hours (net-load)	Off-peak hours (net-load)
High-Demand Season (net-load)	~2.5X weightage per hour for AFC recovery*	~1.2X weightage per hour for AFC recovery*
Low-Demand Season (net-load)	~1.2X weightage per hour for AFC recovery*	~0.8X weightage per hour for AFC recovery*

Source: Prayas (Energy Group)

*Note: *For example, if the high-demand season is defined as 3 months and each day is assumed to have 4 peak hours, then the four combinations of high-demand/peak, high-demand/off-peak, low-demand/peak and low-demand/off-peak would correspond to about 4%, 21%, 13% and 63% of the year, respectively. However, the AFC recovery for these periods as per the suggested approach would be about 10%, 25%, 15% and 50% respectively.*

Similar to the approach for recovering fixed charges, PLF incentive calculations should also be distributed unevenly, focusing on peak and off-peak seasons as well as high and low demand months. The highest incentives should be allocated for generation during high-demand seasons and peak hours, with no PLF incentives provided for low-demand seasons and non-peak hours.

The objective of providing greater weightage for availability and generation during high demand seasons/peak hours for TPPs is to encourage availability and generation at times when thermal capacity would be most required. Towards this, it is suggested that the definition of peak/off-peak hours and high/low demand seasons itself should be based on net load (i.e., after accounting for the must-run capacity such as solar and wind), rather than overall load.

Thus, we request the Commission to:

- Consider availability-linked AFC recovery in line with the approach suggested in Table 3
- Ensure peak/off-peak hours and high/low demand season for TPP operations is defined based on net load instead of overall load
- Consider varying PLF incentives across high/low demand season and peak/off peak hours based on net load.

3.3. Sale of surplus Power

In accordance with MoP's Electricity (Late Payment Surcharge and Related Matters) (Amendment) Rules 2024, generators are required to offer power which has been declared but not scheduled (i.e., un-requisitioned surplus (URS) power) in the power exchange, at a price not exceeding 120% of the ERC determined/adopted energy charges plus transmission charges. If a generator fails to do so, the URS power not offered on the power exchange (against the declared capacity) will not be considered for the payment of fixed charges.

In addition to improving utilisation of surplus power, this amendment to the LPS Rules will have significant impact on the cost recovery of the generators. Despite this, the draft regulations do not address this provision of the LPS Rules Amendment 2024. The Commission should amend the State Electricity Grid Code to include the impact of the LPS Rules Amendment 2024, with directions to sector actors in this regard. To avoid regulatory ambiguity, the Commission should also include appropriate regulatory provisions in the MYT regulations to account for the impact of the LPS Rules Amendment 2024 on AFC recovery.

Further, to facilitate the monitoring of such sale of URS power, the Commission should require generators to submit data tracking the treatment of un-requisitioned capacity. A format for such tracking is suggested below in Table 5.

Table 5. Proposed format for tracking of URS from each unit For each generating unit

	Contracted Capacity	Declared Capacity	Scheduled Capacity	Un-requisitioned capacity	Capacity offered for sale	Bid offered	Capacity sold
	A	*B*	*C*	*D=B-C*	*E*	*F*	*G*
	(MW)	(MW)	(MW)	(MW)	(MW)	*(₹/unit)*	(MW)
Block 1							
Block 2							
….							

Source: Prayas (Energy Group)

Such tracking should be reported on the generator's website periodically, say every month, and submitted to the Commission. Additionally, to ensure accountability, the generator should submit certification towards the capacity offered for sale, bid offered, and the capacity sold from the power exchange.

Thus, we request the Commission to:

- Introduce regulatory provisions to enable MoP LPS Rules Amendment 2024 and amend the State Grid Code accordingly
- Mandate generators to publish on their website the necessary information to track capacity declared available, scheduled and offered on the market as suggested in Table 5, and require that such data (with power exchange certification) be submitted to the Commission on a monthly basis

3.4. ECS cost impact and recovery

All Thermal Power Plants are required to comply with the emission norms as notified by the Ministry of Environment, Forest and Climate Change (MoEF&CC) and directions given by Central Pollution Control Board (CPCB) from time to time. For compliance to the emission norms, around 1,240 MW of capacity in the state falls under Category A, while around 7,660 MW is classified under Category C. The final compliance deadline for these, set for December 2026, falls well within the Control Period of these regulations. In light of this, it is crucial to give proper attention to the regulations regarding the implementation of the revised emission standards. Regulation 17 (6) of the draft discusses the additional capitalisation on account of implementation of revised emission standards. Admission of additional capitalization on account of implementation of revised emission standards and not merely installation is a good step. Towards ensuring proper operation of the Emission Control System (ECS), and to justify the intent of the related expenses, the cost of ECS should be reimbursed subject to achieving the purpose of incurring the ECS expenditure, i.e. adherence to the environmental norms. Neither operation of the plant, nor construction of the ECS is equivalent to the utilisation of the ECS and adherence to the norms.

Cost recovery of ECS through tariffs should, thus, be based on compliance to the norms. This could be done on the basis of the generator procuring suitable certification from the State Pollution Control Board for adherence.

> Thus, we request the Commission to:
>
> - Allow ECS cost recovery based on compliance to the norms, which can be linked to state PCB certification for adherence

4. Transmission

4.1. Separate regulation for transmission project implementation

Rajasthan, being RE rich state and having huge potential for solar and wind resources, is vital state for meeting 500 GW RE targets by 2030 and even net zero targets in future. To add such RE capacity, transmission network at both inter-state and intra-state level are important. Hence, a separate regulation is need of hour for regulating implementation of transmission projects in the state, as has been done in AP. The regulation shall deal with mode of implementation of project (RTM/ TBCB), project monitoring and data reporting in public domain.

> Thus, we request the Commission to:
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> - Formulate a separate regulation for implementing transmission projects in Rajasthan, encompassing project implementation modes (RTM/TBCB), monitoring mechanisms, and public data reporting, to support the state's pivotal role in meeting nationally Determined Contributions (NDCs)

4.2. Threshold limit for TBCB

The commission's decision to specify a threshold limit for the development of projects through the TBCB mode is a welcome step, as it is expected to promote competition in the transmission sector, ultimately reducing the burden on consumers caused by cost escalations and delays, as seen in RTM projects. However, we recommend that the Commission need to reconsider the proposed threshold for projects under the TBCB mode. TBCB has been successfully implemented in the ISTS transmission network for over a decade with a threshold limit of Rs. 100 crores.

Additionally, several states have adopted TBCB for their InSTS networks, also with a threshold of Rs. 100 crores, as listed on the India Transmission Portal[1].

We suggest that the proposed threshold of Rs. 250 crores by RERC is high and should be reduced to Rs. 100 crores, ensuring that more projects are eligible for the TBCB route, thus maximizing potential cost savings, as was previously decided by the commission. The Commission may also consider monitoring projects developed under both TBCB and RTM modes to assess which approach is more effective.

Additionally, we recommend that State Committee for Transmission (SCT) shall report data related to projects (like scope of work, estimated cost, mode of project implementation, name of developer, expected date of commissioning, etc.) in public domain and report same to Commission and STU every quarter. To strengthen this aspect of data reporting, Commission shall consider to assign data reporting function/ responsibility to SCT. In case that is not possible, STU shall be entrusted with this responsibility through these regulations.

Thus, we request the Commission to:

- Reduce the proposed threshold for projects under the TBCB mode from Rs. 250 crores to Rs. 100 crores to ensure broader eligibility and maximize cost savings
- Monitor and compare the effectiveness of projects developed under both TBCB and RTM modes
- Mandate the State Committee for Transmission (SCT) to report project-related data quarterly to the Commission and STU, and make it publicly available. Alternatively, entrust this responsibility to the STU if assigning it to the SCT is not feasible

4.3. NATAF and Incentive

The commission has specified the normative Availability of the Transmission System as follows:

a) High Voltage AC system: 98%

b) High Voltage DC bipole links & HVDC back-to-back stations: 95%

The actual availability of the transmission system for FY 2022-23, as certified by SLDC and approved by the commission, is 99.18%[2]. We suggest the commission to re-consider the value of normative availability somewhere between 98.5 to 99%. Additionally, to ensure the accuracy of the data, we suggest that an independent third-party verification of the data submitted by Transco, along with SLDC certification, be required for approval.

Thus, we request the Commission to:

- Reconsider the value of normative availability somewhere between 98.5 to 99%.

[1] https://indiatransmission.org/Commercial/TBCB%20Threshold%20in%20states

[2] True up for FY 2022-23 and Annual Revenue requirement & Tariff for FY 2024-25 of Rajasthan Rajya Vidyut Prasaran Nigam Ltd.

- Mandate independent third-party verification of data submitted by Transco, in addition to SLDC certification, for approval

4.4. Transmission Pricing Mechanism

Clause 65 (1) specifies that *"The Long-Term and Medium-Term Users of the transmission system shall share the transmission cost in such proportion as their contracted transmission capacity to the total transmission capacity contracted/agreed from the intra-State transmission system: Provided that the charges payable by the Long-Term and Medium-Term Users may also take into consideration factors such as voltage, distance, direction, quantum of flow and time of use, as may be stipulated by the Commission in its order passed under subsection (3) of Section 64 of the Act."*

National electricity policy states that *'for cost effective transmission of power across the region, a national transmission tariff framework needs to be implemented by CERC, sensitive to distance, direction and related to quantum of flow. As far as possible, consistency needs to be maintained in transmission pricing framework in inter-State and intra-State systems'*[3]. It also states that *"after the implementation of the proposed framework for the inter-State transmission, a similar approach should be implemented by SERCs in next two years for the intra-State transmission, duly considering factors like voltage, distance, direction, and quantum of flow"*[4].

Since the enactment of the EA 2003, the ISTS pricing mechanism has undergone several changes, transitioning from the postage-stamp method to POC, and now to GNA. However, states continue to use the postage-stamp method for calculating transmission pricing. It is strongly recommended that the intra-state transmission pricing mechanism be reformed to align with both the NEP and NTP guidelines.

Thus, we request the Commission to:

- Reform the intra-state transmission pricing mechanism to align with the National Electricity Policy and National Tariff Policy guidelines, ensuring consistency with the national transmission tariff framework

5. Distribution

5.1. Treatment of O&M expenses

We note that the draft Regulations in para 9(2) provides a non-exhaustive of controllable parameters including variations in (a) transmission losses, distribution losses and collection efficiency; (b) performance parameters such as Station Heat Rate, Coal Transit Losses, Auxiliary Consumption, Secondary Fuel Oil consumption etc. and (c) O&M expenses. Further, para 9(3) states that any gains or losses to the regulated entity on account of these factors shall be retained or borne by such entity, except for (a) and (b) which is subject to treatment as para 55 and 74 respectively. Para 74(5) enlists the gain/loss sharing mechanism for distribution losses as 2/3rd of

[3] National Electricity Policy, 2005
[4] Tariff Policy, 2006

gains and 1/3rd of losses shall be passed on to the consumers while the regulated entity retains the rest. While we note that this amendment has been brought in accordance with Electricity (Second Amendment) Rules, 2023[5], it is unclear as to the rationale for different treatment of gain/loss sharing mechanism for other controllable parameters such as O&M expenses.

O&M expenses under para 81 consist of three components of Employee, Administrative and General (A&G) and repairs and maintenance (R&M) expenses. While the first two components have a fixed rate for the first year of the Control period with an increase as per the escalation rate, R&M expenses are calculated based on the gross fixed assets along with the escalation rate and a constant 'k' as specified. This is a good practice which is also followed in several states including Maharashtra and Gujarat.

Due to the different treatment where the gain/loss are to be retained by the regulated entity, it may disincentivise higher spending on R&M since the losses would have to be borne by the entity. This is likely to impact on supply quality and network reliability. Instead, we suggest that the draft Regulations be amended to maintain a minimum percentage allocation of total O&M expenses on R&M, which is a practice being followed in Maharashtra.

Furthermore, due to skewness in existing network density and capital investments across, R&M expenses as a factor of the GFA and investments would also vary. This methodology may be suitable appropriate in urban and dense circles, but also result in reduced spending in R&M expenses in circles with lower investments and density. Therefore, we suggest circle-wise allocation of R&M expenses on pro-rata basis, such that the top 3 circles with the poorest performance and network spread in recent years should have a higher allocation of R&M.

Thus, we request the Commission to:

- Subject O&M expenses and other controllable parameters to the gain/loss sharing mechanism as outlined for distribution losses in draft Regulation 74(5)
- Specify a minimum % of total O&M for R&M
- Provide higher allocation of R&M expenses (through separate norms) for circles with poorest network spread and lowest capex investments in recent years. Adopt a circle wise approach to estimate O&M expenses

6. Amendment of Grid code

The draft regulations include amendments to reflect the changing realities of the state's power sector. Towards ensuring such measures are effectively rolled out, its crucial to bring in relevant amendments to the state grid code as well. Amendment of the state grid code to include the following measures should be considered:

- *For addressing impact of 40% technical minimum:* The Central Electricity Authority (CEA) has mandated a technical minimum load of 40% for thermal power plants (TPPs) and outlined a

[5] https://powermin.gov.in/sites/default/files/Electricity_Second_Amendment_Rules_2023.pdf

phasing plan to achieve this operational standard. According to the plan, units from power plants such as Chhabra, Suratgarh, and Kalisindh are included in Phase 1 and Phase 2, both of which fall within the control period of these regulations. In light of this, the state grid code should be amended to address how such operation is to be introduced, operationalized, and monitored.

- *For adherence to MoP LPS Rules:* Failure to adhere to Rule 9 of MoP LPS Rules Amendment 2024 could result in disallowance of fixed charges for the URS power not offered on the power exchange (against the declared capacity). Section 3.3 of this submission suggests a framework to ensure the Rule is implemented effectively. In addition to regulatory provisions in the MYT Regulations, amendment to the state grid code is also required to address the impact of MoP LPS Rules Amendment 2024 on generator operations.

- *For scheduling to improve resource utilisation:* Towards ensuring optimal utilisation of resources, the grid code should include amendments to improve scheduling by distribution utilities. Currently distribution companies (DISCOMs) carry out day ahead hourly average scheduling of their contracted power. This could be extended to mandate that DISCOMs provide a coarser schedule of their contracted power (say on an hourly basis, instead of block wise) but on a week/fortnight ahead basis. DISCOMs should carry out this advance scheduling based on past demand patterns and an understanding of their consumer base. This coarse schedule would serve as a constraint for the declaration of the DISCOMs day ahead block-wise schedule. This would provide the generators sufficient time to identify alternate buyers for their unscheduled power. It would also provide the distribution utility flexibility to identify more competitive sources of power purchase, if needed. A gain and loss sharing mechanism could be applied to ensure any profit earned by the generator through selling excess power based on the coarser schedule is shared with its beneficiaries.

> Thus, we request the Commission to:
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> - Amend the State Grid Code in line with suggestions listed above

7. Tariff-setting process and public participation

7.1. Technical Validation Sessions

Given the fast-changing sector, regulatory process and decision making should take place through transparent public processes to ensure legitimacy of institutional processes and decisions. Technical Validation Sessions (TVS) lend further reliability to the tariff process by ensuring data submitted by regulated entities are correct and complete. TVS should be treated as indispensable to the tariff determination process as important information and insights can be derived from clarifications and additional data provided by the companies and licensees. Thus, the following additions should be included in draft regulation 12 (4):

"Provided also that the Commission shall conduct a Technical Validation Session prior to admission of the Petition. The petitioner shall furnish a soft copy of the petition and data formats with consumer representatives, members of the State Advisory Committee, relevant stakeholders and sector experts who will also be added to the TVS.

Provided further that the petitioner shall ensure that the soft copy of the petition and data formats shared with these stakeholders shall be in text-searchable format or in downloadable spreadsheet format and showing detailed computations."

Thus, we request the Commission to:

- Include provisions (as suggested above) for a technical validation session before any tariff process with all utilities and some sector experts

7.2. Draft data formats available in the public for comments:

The draft Regulation in para 11(1) state that the formats for furnishing information shall be specified by a separate order of the Commission. We suggest that such technical formats should be made available to the regulated entities and interested stakeholders prior to the effective date of the Control Period, for comments and suggestions, and provide clarity and certainty to the stakeholders.

Thus, we request the Commission to:

- Make the technical formats available before the Control Period's effective date for stakeholder feedback, ensuring clarity and certainty.

7.3. Public hearings and accessibility

The draft Regulations in para 12(3) requires the regulated entity to publish a public notice in newspaper containing the salient features of the tariff/true-up petitions. However, there is no onus on the entity to invite comments and suggestions from the public. We suggest that a mechanism should be incorporated to encourage interested stakeholders to raise queries, and share comments on the tariff process. The public notice should be accompanied with a timeline and email address for sending feedback, details of the website where complete tariff petitions and related data are available and the date, time and venue for the public hearings to take place. Furthermore, the public hearings in the tariff determination and related processes should be conducted in hybrid format to maximise participation from all stakeholders. Public consultations, both written and oral should be strengthened in the tariff determination process.

Thus, we request the Commission to:

- Incorporate a mechanism for stakeholder consultations and public hearings in the tariff process.
- Ensure all tariff related processes are disposed off only after public consultation, both written and oral
- Conduct public hearings in a hybrid format to maximize participation from all stakeholders and strengthen both written and oral public consultations.

7.4. Ensuring availability of data in the public domain

At present, the draft Regulations in para 11(1) requires the regulated entities to submit the tariff/true-up petitions and data to the Commission. We suggest that this should be amended to mandate regulated entities to upload the complete tariff/true-up petition and other filings such as Capital Investment (as per para 72) and Power Procurement Plans (as per para 76) along with the data furnished in the stipulated technical /data formats on its regulated entity and Commission websites. Such filings and data formats should be in text-searchable and downloadable spreadsheet formats. Further, any additional filings or submissions made in response to queries raised by stakeholders or the Commission should also be uploaded. Such data should be made available on the regulated entities' websites even after the completion of the tariff/true-up process. The availability of such archives is a crucial resource to examine historical sectoral trends. We note that the Commission's website has a dedicated page for Archives which has records from 2019 onwards (available here). This is a good practice and should be continued, and making an amendment to the regulations as well would ensure the same.

Thus, we request the Commission to:

- Require regulated entities to upload complete tariff/true-up petitions and related filings in searchable formats on their own and the Commission's websites, with the data archived for public access after the process is completed.

We request the Commission to take this submission on record and allow us to make any additional submissions, if required.

Prayas (Energy Group)
Date: 23rd December 2024
Place: Pune