Submission on draft Chhattisgarh State Electricity Regulatory Commission (Terms and Conditions for determination of Multi-Year Tariff) Regulations, 2024

Prayas (Energy Group) *20th August 2024*

The Chhattisgarh State Electricity Regulatory Commission (henceforth the Commission or the CSERC), has published the draft notification on the Multi Year Tariff (MYT) Regulations for the control period from 1st April 2025 to 31st March 2030 on 2nd July 2024, 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 the MYT regulations. Prayas (Energy Group) has the following suggestions towards strengthening the proposed tariff regulations:

1. Power procurement, planning, and fuel supply

1.1. Power purchase and Resource Adequacy

Power purchase costs form a bulk of the DISCOM's ARR and significantly impact consumer tariffs. It is key to ensure that power procurement is carried out in a justified, transparent and prudent manner. As per para 7.3 (c) (iv) of the draft regulations, distribution companies are required to submit their power procurement plans to the Commission. However, the draft regulations do not specify any mechanism for the preparation and approval of power procurement plans.

The draft regulations also do not account for the CEA Guidelines for Resource Adequacy Planning 2023, which require that DISCOMs plan for sufficient and prudent power procurement – and that the Commission ensure adherence to such plan. Accordingly, we suggest that the Commission require the distribution licensee to prepare a plan for power procurement to serve the demand for electricity in its area of supply based on scientific demand estimation as envisaged in the Resource Adequacy guidelines; and that such plan be submitted by the DISCOM for each year of the control period. For the purpose of determining consumer tariffs and approving ARR, only the power procurement plan as approved by the Commission in line with scientific demand estimation as envisaged in the Resource Adequacy guidelines should be considered.

The Commission should also consider framing separate regulations for resource adequacy so that distribution licensees have a clear framework to estimate their demand in a scientific manner, as done by the ERC is Maharashtra, Punjab, and Madhya Pradesh.

Furthermore, given their impact on consumer tariffs, all hearings relating to power procurement and tariff adoption should be made public and undergo a public consultation process.

Thus, we request the Commission to:

- Mandate distribution licensees to submit detailed and scientific demand estimates as envisaged in the Resource Adequacy guidelines
- Prepare separate Resource Adequacy Framework regulations
- Ensure all power procurement and tariff adoption processes are subject to public consultation

1.2. 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 para 7.3 (b) of the draft regulations, 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, as discussed in section 1.1 of this submission. 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 CSERC, 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.

If capacity addition through Section 62 is still allowed, transparent reporting of justification and approval of new capacity becomes crucial. Section 7 of the draft regulations 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. Para 7.6 of the proposed regulations, provides a list of 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
- Come up with separate regulations to oversee capital investment
- 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

1.3. Capping input price of coal from integrated mines

Section 52 of the proposed regulations discusses the input price of integrated mines, as reflected in the ECR on account of input price of coal. Input price is based on the ROM costs, as computed in Section 53, but the draft regulations do not stipulate a ceiling for ROM costs. The input price of coal from integrated mines is eventually passed on to consumers. 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 RoM price of coal for integrated mines 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 RoM price of coal for integrated mines to the CIL notified price for the corresponding grade of coal

1.4. Coal washing

The draft regulations account for washery charges as and when applicable in the landed price of fuel and in consideration of the input price of integrated mines. 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. CSERC should require generators to validate that the effective landed price 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

1.5. 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. In addition, the regulations should also require the generator to publish the requisite data on their website on a monthly basis, in accordance to the format required 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 25, RoE is to be computed at a rate of 15.5% for generating companies, transmission licensees, distribution wires business and SLDC; and at a rate of 16% for the retail supply business. Instead, RoE could be considered in two parts – Base RoE and Performance-based ROE. The Base RoE (of say 14% for generating companies, distribution wires business and SLDC and 14.5% for retail supply business) should be allowed in accordance to the proposed regulation 25. 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 carefully 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

2.2. Retaining framework for pass-through of gain and loss

Draft Reg 13 amends the existent gain/loss sharing framework, and introduces different treatment for generating stations that supply their entire generation to state distribution licenses. In the EM, the varying control on components of ARR by the Commission, is stated as the reason for consideration of such treatment. However, this leads to varying impacts on the consumer tariffs, and also leads to dilution in accountability for generating stations that supply only to state DISCOMs. Such differentiated treatment could also prove ambiguous and invite litigation. Towards reducing the burden on the consumer, ensuring clarity of process, and encouraging accountability and efficiency from the generator, a standard gain and loss sharing framework be applicable to all entities – wherein, gains on account of controllable parameters should be shared in 2:1 ratio between the beneficiary and generator, reflected as a rebate in tariff; and losses should be shared in a 1:2 ratio between the beneficiary and generator, reflected as a hike in tariff.

Thus, we request the Commission to:

- Ensure a uniform gain and loss sharing framework is applicable to all entities
- Mandate sharing of gains on account of controllable parameters in a 2:1 ratio between the beneficiary and generator, reflected as a rebate in tariff; and losses in a 1:2 ratio between the beneficiary and generator, reflected as a hike in tariff

2.3. Treatment of interest on working capital borrowing

As per draft Reg 28.5, at the time of truing-up, the variation between the normative interest on normative working capital and *actual interest on actual working capital* incurred by the regulated entities shall be considered a controllable factor and therefore subject to the sharing mechanism of losses or gains. This is a significant change from the previous MYT Regulations 2021 which considered the working capital and interest on working capital based on the revised normative parameters at the time of true-up.

It is understood that working capital is necessary for the regulated entities to meet their day-to-day requirements of carrying out operations. From the DISCOM's audited financial accounts and Balance Sheet as on 31 March 2023, we observe that the working capital borrowings are approximately Rs. 2,609 Crore (assuming that the Working Capital Demand Loans have been taken to meet the working capital requirements). This far exceeds the working capital computed based on norms, which is Rs. 1,592 Crore, as per the CSERC True-up Order for FY 2022-23. Thus, working capital requirements calculated at actuals will imply a much higher pass-through to the consumers in the ARR. The rationale for the norm-based treatment of interest on working capital sufficiently recognises the requirement of working capital for the functioning of the regulated entity. Towards safeguarding consumer interests from procedural inefficiencies, the Commission should retain the normative frameworks for inclusion of the interest on working capital in the ARR.

Reporting of working capital on actuals is a significant parameter for assessing the financial efficiency and performance of the regulated entity and the Commission has taken a positive step in introducing the same within the tariff regulatory framework and reporting. However, the Draft Regulations do not provide any data/technical formats for the regulated entities to furnish this information specifically. A data format for the same is suggested in Table 2.

Table 2. Loan repayment and interest liability

Year: 2022-23							*(Figures in Rs. Crore)*
Sl. No.	Source	Opening Balance	Receipts	Repayment	Average rate of interest	Liability of interest during the year	Closing balance
1	PFC						
2	REC						
…	…						

Source: Prayas (Energy Group) compilation

Thus, we request the Commission to:

- Retain the normative framework for inclusion of the interest on working capital in the ARR
- Ensure that data formats for reporting of working capital are shared beforehand for timely submission of data from regulated entities.

3. Generation

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

As per draft Reg 45.6, the ECR of thermal generation is calculated based on GCV 'As Received' provided that when the arrangement for taking samples 'As Received' is not in place, GCV 'As Billed' is to be considered. While having such a proviso is a good measure, these considerations must be strengthened and there are some concerns the Commission must address.

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. Further, the slippages during transit beyond the point of billing at the coal mine end is already capped as per draft Reg 43.6 (Reg 43.3 of the extant CSERC MYT Regulations 2021).

Thus, GCV 'As Billed' (with allowance for adjustment in moisture, as calculated in draft Reg 45.6 (a), and transit loss, as already capped in draft Reg 43.6) is the appropriate measure for ECR calculation. The Maharashtra ERC has adopted a similar approach. Such a measure would ensure regulatory accountability, operational efficiency, and safeguarding of consumer interests.

When considering GCV 'As Billed' for ECR computation, the adjustment for GCV methodology (as discussed in draft Reg 45.6 (a)) 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 ECR computation with the adjustment for moisture content as given in draft Reg 45.6(a)
- 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

As per para 45.2 of the draft regulations, capacity charge recovery 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.

Considering daily peak and off-peak periods and high/low demand seasons are useful towards ensuring responsive operations from coal-based thermal power plants, which is increasingly necessary in the context of the energy transition.

Regulations must factor in such variability in the need for coal-based generation across seasons and over the time of day, to encourage coal-based capacity to be available when it is most needed. Para 45.4 encourages availability during peak hours only in instances of fuel shortage. Given the energy transition there will be increased need for flexible operation of coal-based TPPs, and robust incentive frameworks with broader applicability (than just during instances of shortage) should be put in place. Table 3 suggests such a framework.

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.*

The objective of providing greater weightage for availability during high demand seasons/peak hours for TPPs is to encourage availability at times when thermal generation 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.

Fixed charges impact the consumer and their electricity tariffs; hence it is crucial that prudence and accountability is ensured in its computation, Towards this, it should be made clear through the regulations that the availability linked recovery of fixed charges should be capped at AFC, and availability exceeding NAPAF will not result in recovery of costs in excess of the AFC, particularly since there are no stringent mechanism to verify the authenticity of declared availability. This practise is followed by the Maharashtra ERC towards protecting consumer interests and ensuring accountability in generator operations.

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
- Cap recovery of fixed costs across the year at AFC
- Remove Para 45.4 and instead encourage generators to operate effectively in response to demand, through the framework suggested in Table 3

3.3. Targeted incentive for PLF above the norm

Para 45.5 provides a flat rate incentive of 60 paise/kWh for generation in excess of that corresponding to the PLF norm. However, it is important to note that generators are fully compensated for all the costs incurred in generation (such as the cost of coal), and are paid the full AFC (subject to availability) to enable them to earn a good return on equity, service their debt, undertake O&M etc. Therefore, given merit-order based dispatch, the only purpose of providing a PLF incentive is to encourage generators to procure low-cost coal to improve their chances of getting scheduled, and thus lower the ECR for consumers. Providing a very high PLF incentive defeats this purpose of obtaining low-cost coal to reduce ECR. Since generation above NAPLF (particularly from expensive, typically non-pithead, plants) is only likely to be required during peak net-demand periods, PLF incentive should also be provided on the basis of high/low demand seasons and peak/off-peak hours based on net load. Moreover, given the arguments above, such an incentive – which is over and above all cost recovery and a handsome RoE – should be modest. Such a gradation is suggested in Table 4.

Table 4. Proposed consideration for application of PLF incentive

	Peak hours	Off-peak hours
High-Demand Season	Rs. 0.5/kWh PLF incentive	Rs. 0.25/kWh PLF incentive
Low-Demand Season	Rs. 0.25/kWh PLF incentive	No PLF incentive

Source: Prayas (Energy Group)

Note: High/low demand season and peak/off-peak hours should be defined based on national net load

Thus, we request the Commission to:

- Consider varying PLF incentives across high/low demand season and peak/off peak hours based on net load, in line with the suggestions in Table 4

3.4. 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

3.5. ECS cost impact and recovery

Section 45 of the draft Regulations also discuss the supplementary charges on account of emission control system. However, towards ensuring proper operation of 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. The Commission has a precedent of using a similar treatment of requiring certification for ensuring adherence, as seen in Para 53.4 where the generating company has to procure a certificate from the Coal Controller or the competent authority to ensure adherence to the Mining Plan.

Further, the final deadline for compliance with MoEFCC's revised emission norms (31st December 2026 for non-retiring plants and 31st December 2027 for retiring plants) falls within the upcoming control period. Towards protecting timely compliers, the Commission could exclude ECS related supplementary ECR for such units/stations from consideration for MoD till the final deadline (31st December 2027). After that, supplementary ECR can be included to decide MoD for all plants. In addition, generation from plants that have not installed ECS by the final deadline should be subject to a notional additional penalty after such deadline while considering MoD so that they do not gain an unfair advantage by being non-compliant to the norms. Operational incentives, such as the PLF incentive, should also not be applicable for such plants until they are able to comply with the norms. The proposed treatment of TPPs after the final deadline for adherence to norms is summarised in Table 6.

Table 6. Proposed treatment with regard to adherence to revised emission norms post final deadline

	If ECS CapEx is not incurred	If ECS CapEx is incurred
TPP is compliant	N.A.	ECS related costs (FC and VC) should be passed through
If TPP is not compliant	Apply notional additional penalty to compute MoD, so as not to give unfair advantage	Disallow ECS related FC and VC; Apply notional additional penalty to compute MoD so as not to give unfair advantage

Source: Prayas (Energy Group)

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
- Ensure timely compliers are protected by excluding ECS expenses from consideration of MoD till the final deadline
- Penalise non-compliance post the final deadline in accordance with the treatment suggested in Table 6, so as to avoid unfair advantage to non-compliers

4. Transmission

4.1. Accounting for revenue from short-term transmission charges

It is unclear as to how the revenue from short-term transmission charges is adjusted as a part of aggregate revenue requirement, for which an additional sub-clause may be added to clause 73.1 clarifying the above statement.

It is suggested that the revenue from short-term transmission charges as per open access regulations amended from time to time shall be projected based on audited figures and deducted from the ARR in order to reduce transmission charges for the long-term consumers, as quoted by GERC in its MYT Regulations, 2016 (Regulation 68), *"68.1 Aggregate Revenue Requirement of a transmission licensee shall comprise the following components, viz.* ……………

minus:

(g) Non-Tariff Income;

(h) ***Revenue from short-term transmission charges projected on the basis of latest audited figures; and***

(i) Income from Other Business, to the extent specified in these Regulations.

…… *"* ***(emphasis added)***

Thus, we request the Commission to:

- Add a sub-clause to clause 73.1 to clarify the treatment of revenue from short-term transmission charges
- Deduct revenue from short-term transmission charges from the ARR of the transmission licensee

4.2. Trajectory for transmission losses

The Commission shall specify a trajectory for reduction in transmission losses, for the control period as a part of MYT regulations, which will give a clear roadmap to transmission licensees in the state to work towards reducing the transmission losses over a period of time. This is aimed at improving the efficiency of the transmission system and reducing costs, which can benefit consumers by potentially lowering electricity prices or improving the quality of electricity.

Also, an incentive could be awarded for achieving transmission losses below a specified threshold, with the benefits being shared between the transmission licensee and the beneficiary. Any net gain on account of over-achievement in reference to the above set target shall be passed on to the beneficiary/consumer(s) and retained by the transmission licensee in the ratio of 1:1 or as may be specified in the Order of the Commission passed under this Regulation. Furthermore, there shall not be any pass-through of the net loss on account of under achievement in reference to the target set by the commission in this regard.

Thus, we request the Commission to:

- Specify a trajectory for reduction in transmission losses, for the control period as a part of MYT regulations
- Introduce incentives for achieving transmission losses below a specified threshold
- Ensure gains on account of over-achievement in reference to the set target are shared with beneficiaries, but losses are not passed through

4.3. Norms of operation for transmission licensees

Like the CERC Standard of Performance regulations for inter-state transmission licensees, the Commission may establish operational standards for various operational parameters like transmission system availability, transmission losses, restoration time, etc. and may specify the normative values. Further, the commission may come out with the norms for availing incentives on achieving values higher than the normative ones. While it will be good to have a separate regulation for this, we suggest to include these norms in the present regulation and can be removed once a separate regulation in this regard is formulated by the Commission. More detailed standards of performance parameters can be devised by the Commission, as done in the case of MPERC.

> Thus, we request the Commission to:
>
> - Establish operational standards for various operational parameters related to transmission and specify the normative values

4.4. Lower TBCB threshold for ISTS projects

TBCB has been implemented at ISTS Transmission network for more than a decade and various states have recently adopted TBCB for their InSTS network as well. The specification of threshold limit for InSTS by the Commission in the proposed regulation is a welcome step. As, many states have already determined threshold limit, however more information about the same and few other states can be found here on the India Transmission Portal. Determining the threshold TBCB limit for InSTS projects will promote competition in the transmission sector and thus reduce the burden on consumers due to cost escalations and time delays seen in RTM projects. This has been evident from the experience with ISTS projects developed under TBCB and RTM.

The TBCB threshold for ISTS projects is set at Rs 100 crore. Thus, the threshold of Rs. 250 crores as proposed by CSERC is much higher and should be lowered and set at Rs 100 crore so that most projects could be awarded under the TBCB route to maximize the benefits of cost saving. If needed, this can be revisited after two-three years based on the experience gained and the benefits accrued from shifting to TBCB after following the public consultation process.

Also, we suggest that an empowered committee (appointed by the state government) be created, which will be entrusted to assess the cost of transmission projects and decide the mode of implementation (TBCB or RTM). APERC has recently allowed the creation of an empowered committee for this purpose, similar to the National Committee on Transmission (at central level). Such a body in the state will promote better implementation and transparency of the TBCB framework. The empowered committee can also provide a broader platform to discuss the issues and challenges faced in development of transmission projects in the state.

In addition to this, the commission shall devise a framework to monitor the implementation of transmission projects in the state (either under RTM or TBCB mode) and make this data public, which can be utilized for further analysis/ benchmarking of transmission projects and related costs.

Thus, we request the Commission to:

- Lower TBCB threshold for ISTS projects to Rs. 100 Crore
- Devise a framework to monitor the implementation of transmission projects in the state and make this data public

5. Distribution

5.1. Treatment of O&M expenses

It can be noted that while the Draft Regulations 83.4 and 92.6 include HR expenses as part of the O&M, it is considered an uncontrollable factor and therefore not subject to normative parameters and gain/loss sharing mechanism. These expenses are passed on to the consumers at actuals. On the other hand, we note that O&M expenses (consisting of R&M and A&G expenses) are categorised as controllable factors. As per the recent CSERC True up Order for FY 2022-23 — the total O&M is Rs. 1,581.24 crores out of which HR expenses are Rs. 1,154.81 crores, indicating that approximately 73% of the total O&M is considered and passed through at actuals without adequate prudence checks by the Commission.

Based on this context, we strongly feel that this treatment of splitting O&M into controllable and uncontrollable defeats the purpose of incentivising the regulated entity to improve its efficiency and performance. Additionally, it goes against the principle behind the grouping of uncontrollable variables such as change in law events, force majeure, fuel prices, judicial pronouncements etc. which are beyond the control and cannot be mitigated by the regulated entity. Unlike such variables, HR or employee expenses have more predictable trajectories based on pay revisions and inflation and are not subject to a similar level of uncertainty.

In order to address the predictable increase required for HR expenses, the HR expenses norm can be linked to inflation but can also be parameterised to number of consumers. Thus, the norm itself can be specified on a Rs/ lakh consumer basis. With such indexation, the HR expense norm will increase with increase in number of consumers while retaining the variable as a controllable expense.

Alternatively, the norms can be revised at the end of the Control period based on the actual figures of the last year of the Control period. This kind of approach is followed in Maharashtra.

To address this, the Commission should make the following amendments to Draft Regulations 11.1 and 11.2 as below -

i. Delete (i) Human Resource (HR expenses) in 11.1 on uncontrollable factors and

ii. Delete (d) Maintenance & General (M&G) expenses and replace with Operation and Maintenance (O&M) expenses (which includes HR expenses) in 11.2 on controllable factors.

iii. Norms for HR expenses can be specified which are linked to inflation and change in change in number of consumers. Alternatively, norms can be revised at the end of the control period based on actual expenses for the last year of the previous control period.

Thus, we request the Commission to:

- Amend draft Regulations 11.1 and 11.2 as indicated above to ensure prudent and accountable treatment of HR expenses

5.2. Repair and Maintenance expenses

Since the supply and service quality, existing network density and planned capitalization would vary across different circles of the DISCOM, the R&M expenses can be further estimated and allocated circle-wise on a pro-rata basis to correct for the existing skewness in network investments and density. Therefore, the top 3 circles with the poorest network spread and lowest investments in recent years should have a higher allocation of R&M. In more urban circles, the Commission can also consider reducing the norm for R&M expenses over time to incentivize efficiency improvements.

As R&M expenses impact supply quality and network reliability, the Commission can specify a minimum % of total O&M towards R&M expenses. This is also the case in Maharashtra.

Thus, we request the Commission to:

- 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
- Specify a minimum % of total O&M for R&M

5.3. Performance-based RoE for distribution licensees

Towards the implementation of two-part Roe discussed in section 2.1 of this submission, the Commission should mandate the DISCOM to report circle-wise (a) DT failure rates, and (b) planned and unplanned Feeder outages within a period of 2 months from the notification of the Draft Regulations. This mandate can be implemented easily since the DISCOM already reports month-wise data on feeder scheduled outages, and can be extended to DT levels. Over time with improvement in the metering system, the performance parameters can be linked to SAIFI-SAIDI.

Based on this reporting of data, the Commission can specify the trajectory for reducing the failure rates and outages over the duration of the Control Period. Accordingly, the Commission can allow ROE based on the following-

- If the DISCOM meets or exceeds the performance parameters => Allow Higher ROE
- If the DISCOM fails to meet the performance parameters => Allow Base ROE
- If the DISCOM fails to report data within the stipulated timelines and formats => Disallow a % from the Base ROE

Thus, we request the Commission to:

- Mandate the DISCOM to report circle-wise (a) DT failure rates, and (b) planned and unplanned Feeder outages within a period of 2 months from the notification of the Draft Regulations
- Specify the trajectory for reducing the failure rates and outages over the duration of the Control Period, and link such performance to RoE as suggested above

5.4. Metering and other TOTEX expenses as a separate category

Draft Regulation 7(c)(v) requires the DISCOM to submit plans for the installation of meters as part of the capital investment plan. We note that such expenses towards the installation of smart meters, cloud services, customer care centre, demand forecasting, GIS mapping, network analysis etc. do not squarely fall within the scope of O&M or capital expenditures but as a separate category of TOTEX. Such expenses by their nature constitute elements of Capex as well as O&M, therefore treating such expenses as O&M subject to efficiency norms is unwarranted.

TOTEX expenses by their very nature have capex components as well as O&M components. Therefore, treating them as part of the O&M expenses where there is a norm-based approach for cost-passthrough is unwarranted. Instead like other capex schemes, the expenses should be evaluated for their efficacy, expected benefits and life-cycle costs and should be passthrough subject to prudence check by SERCs. Expenses for GIS mapping, software licenses, customer cases, SMS systems etc., can also be treated as separate OPEX schemes. For certain specific TOTEX schemes, specific guidelines for prudence checks can be evolved to ensure that cost-passthrough is contingent on state benefits and performance.

Thus, we request the Commission to:

- Consider TOTEX expenses under a separate heading and subject to evaluation for their efficacy, expected benefits and costs, and life-cycle assessments prior to cost pass-through to the consumers
- Issue separate guidelines for prudence checks of such 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 CEA has mandated a technical minimum of 40% for TPPs, and has also put forth a phasing plan towards ensuring such operational performance. 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 3.4 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 block-wise 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:

- 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 5.6:

"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. Mid-Term Review of tariff

As per draft Reg 5.7, regulated entities are required to file a multi-year ARR petition at the beginning of the year, followed by annual true-ups. A Mid-Term Review process, at the end of the first two years of the control period, could be considered to ease the burden of regulators and utilities, while ensuring timely, public tariff processes and regulatory certainty for consumers and investors. The trajectories for tariffs and operational parameters introduced during the MYT process and revised during the MTR (if needed), provide important signals for efficiency and performance; while also providing an avenue for mid-term course correction and scrutiny.

Thus, we request the Commission to:

- Consider a Mid-Term Review process during the control period to revise tariffs/tariff design if necessary and true-up the first two years

7.3. Provision of data and data formats in the public domain

Draft Regulations 38.1, 73.1, 93.14 and 105.1 refer to formats for furnishing information in the tariff determination and true-up process. However, the draft regulations do not have such data/technical formats appended to them. Specification of the formats, before the effective date of the Control Period, provides clarity and certainty to the stakeholders.

To make the MYT process more effective, the Commission formats could also require detailed information on the following, in addition to the existing formats:

- Actual working capital borrowings from DISCOMs to provide a clear picture of the financial strain faced by the DISCOM (as referenced in Table 2, Section 2.2 of this submission)
- Category-wise status of metering (including % of consumers where meter is AMI, pre-paid, capable of energy accounting in ToD slots etc.)
- Details of the number of employees based on the cadres and within each cadre the grade and technical and non-technical number of employees
- Unit-wise monthly availability for each regulated generating unit and applicable incentives/penalties

It is suggested that such formats be shared by the Commission and finalised based on stakeholder comments within three months of the notification of the regulations.

Further, Draft Regulations 6.3 and 106.2 state that the tariff petition and information received in formats shall be uploaded on the petitioner and Commission's websites. This is a good measure, and should be strengthened by requiring the entities to ensure availability of petitions and related data on their website even after the tariff/true-up process is completed. The availability of such archives is a crucial resource to examine historical sectoral trends. This practice is followed in other states such as Rajasthan, where all petitions of the utilities are available on their websites from 2014-15.

Towards this, the Commission should include the following revisions to the draft regulations (additions indicated as underlined text):

6.3 The Tariff Petition and the information furnished in the stipulated data/technical formats, including any additional information, regulatory filings, particulars or documents including queries raised and addressed at the time of the TVS shall also be uploaded on the Petitioner's website and the Commission's website in text-searchable and downloadable spreadsheet format showing the detailed computations for easy accessibility to all stakeholders.

Provided also that the web link to the information mentioned in this Regulation shall be easily accessible, archived for downloading and be prominently displayed on the Petitioner's internet website. The Petitioner shall ensure that the [it is not deleted for a period]

Explanation – For the purpose of this Regulation, the term "downloadable spreadsheet format" shall mean one (or multiple, linked) spreadsheet software files containing all assumptions, formulae, calculations, software macros and outputs forming the basis of the Petition.

6.5 The generation company, STU/ transmission licensee, distribution licensee, and SLDC shall publish the summary/gist of the proposals, as approved by the Commission for publication, highlighting the salient features of the Petition that are of interest to various stakeholders, on its website and in at least three newspapers, two in Hindi and one in English, having wide circulation in the State or in the area of the Petitioner:

6.6 The Petitioner shall publish the gist of the order including the approved tariffs, on its website and in at least three daily newspapers, two in Hindi and one in English, having wide circulation in its area of supply:

106.2. Display of information
The information received in the formats from the generating companies or the licensees or SLDC shall be posted on the website of the Commission ~~/~~and generator / licensee / SLDC. Such text-searchable and downloadable spreadsheet format showing the detailed computations for easy accessibility to all stakeholders. The provisos and Explanation to Regulation 6.3 shall be applicable here as well.

Similarly, the Capital Investment Plan must also be made available in the public domain, uploaded in accessible formats on the petitioner's website.

Further, draft Reg 7 provides for the filing and approval of a capital investment plan by the petitioner – and as per Regulations 25(9) and 29(3) of the CSERC (License) Regulations 2004, transmission and distribution licensees are required to submit a Business Plan, which would be updated annually. Towards ensuring clarity, the requirements under the Capital Investment Plan and Business Plan should not be at odds, and must also account for the provisions under the Resource Adequacy guidelines.

> Thus, we request the Commission to:
>
> - Make the formats for reporting under tariff and true-up process available in the public domain in a timely manner
> - Amend proposed regulations 6.3, 6.5, 6.6 and 106.2 along the lines suggested above to ensure public reporting of tariff petitions and related data on the petitioner's website during and after the tariff/true-up process
> - Ensure Capital Investment Plan is made available in the public domain and that such planning is in line with other statutory provisions

7.4. Public hearings and accessibility

Para 6.4 of the draft Regulations states that the Commission shall hear such persons it deems appropriate before deciding on tariff-related proposals. This provision must be strengthened, in the interest of public participation, and disposal of tariff/true-up related processes must be contingent on public consultations, both written and oral.

Given the implications of these regulations, the finalisation of the MYT regulations itself must be subject to public hearings, conducted in a hybrid manner to maximise participation from all stakeholders.

Further, the public notice inviting comments to the draft MYT Regulations 2024 do not provide clarity on how to submit the comments to the Commission. While the last date for submissions (and related extensions) is clearly stated, the email id to send soft copies and/or address to send hard copies was not mentioned. This deters wide public participation and should be corrected.

> Thus, we request the Commission to:
>
> - Ensure all tariff related processes are disposed off only after public consultation, both written and oral
> - Finalize multi-year tariff regulations subject to public hearings
> - Provide clear information regarding submission of public comments to ensure wide spread public participation

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

Prayas (Energy Group)
Date: 20th August 2024
Place: Pune