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Comments and suggestions from Prayas (Energy Group) on the Draft Telangana State Electricity Regulatory Commission (Multi Year Tariff) Regulation, 2023

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1. Process and specification for MYT Tariff Process

1.1 Framework for MYT and need for MTR process

This important Regulation has to be implemented by the licensees of Telangana. Therefore, their inputs to this process and owning up of the Regulation is crucial. We hope that the Hon'ble Commission would ensure that comments are provided by the licensees on the draft Regulation and also on the comments by the objectors.

In the draft Regulation, the Commission defines a 'Control Period' for five years, and discusses a MYT framework in section 5 of the proposed regulations. Para 6.2 (a), (b), and (c) of the draft document outlines the submission required by the utilities as part of such MYT process. The MYT process aims to provide tariff certainty and cost and performance trajectories over the duration of the control period. This goes a long way in not only providing regulatory certainty and clarity for all sector actors, but could also aid in easing the intensive burden of annual filings.

Unlike the stipulations for the generating entity, the transmission licensee, the distribution licensee (wheeling business), and the SLDC, the retail supply business of the distribution licensee is only required to submit the revenue from retail sale and consumer-wise tariffs for the first year of the control period, even under the MYT framework. Further, Para 6.2 (d), (e), and (f) proposes the submission of annual petitions by all utilities after the first year of the control period, which includes revision of tariffs for the ensuing year.

It is submitted that an annual true-up process weakens the objective of the multi-year tariff process toward providing tariff certainty as well as cost and performance trajectories over a medium-term. Annual revision via true-ups imply that medium-term cost and performance benchmarks have no meaning and that tariff and tariff design is revised each year.

Provision of clarity in regulatory frameworks and certainty in charges is of paramount importance towards a consumer-centric and investor-friendly power sector. Trajectories for tariffs and charges also provide important incentives for adherence to performance trajectories. However, the need for course correction and mid-term scrutiny is also necessary toward ensuring accountability and prudence in utility operations.

Towards this, the Commission should introduce a Mid Term Review (MTR) process. This would ensure certainty for consumer and investors, while also providing an avenue for timely course correction if needed. The MTR process should occur at the end of the first two years of the control and should include the true-up for the first two years of the control period and revised (if needed) forecasts for the upcoming three years. It should be aimed at evaluating performance parameters, controllable costs, revenue trajectories etc. Tariffs and tariff design can also be revised in this process. The MTR process, like other tariff-related processes, should be subject to public consultations.

It is suggested that:

- Inputs are taken from the licensees and consultations held so that the licensees own up this Regulation
- The retail business of DISCOMs, like other utilities, should also have revenue and tariffs for the control period announced as part of the MYT petition. This will provide certainty in tariff structure, tariff trajectories and tariff design.
- Instead of true-ups happening annually, MTR process should be conducted to evaluate performance parameters, controllable costs, revenue trajectories etc. Tariffs and tariff design can also be revised in this process.
- True-ups are to take place at the start of the control period, during MTR and at the end of the control period/beginning of the next control period.
- At the end of each year there should be public reporting of DISCOM performance, sales, revenue and audited accounts which will highlight trends and any major challenges for the utility. This will ensure data availability on status and performance of DISCOMs despite having a Mid Term Review process after a two year interval.
- In addition, the tariffs for all LT consumers with consumption less than 300 units should be linked to inflation so as to prevent such consumers from facing undue tariff shock. This can be codified in the regulations for the control period.

Such a framework strongly aligns with the broad objectives of regulatory certainty, financial viability and operational efficiency as elucidated in Section 2.1 of the Explanatory note.

Also, the proviso of the proposed para 6.2 (c) requires that the MYT petitions for the control period beginning from 1st April 2024, should be filed by 30th December 2023. Given that the regulations are yet to be finalised as on 14th December 2023, the date for such filing could be reconsidered, and extended to 31st January 2024.

1.2 Ensuring Technical Validation Sessions

Technical Validation Sessions (TVS) are an effective tool towards early identification of data gaps and errors, and facilitating more meaningful regulatory engagement. To ensure a rigorous and diligent TVS, the SAC, sector experts, consumer groups or consumer representatives (appointed by the Commission as suggested in Section 94 (3) of the Electricity Act[1]) should be included in the process.

It is suggested that:

- The Commission should conduct TVS prior to the admission of all tariff-related petitions, subject to consultation with sector representatives and experts. The same should be codified within the MYT regulations.

[1] Section 94 (3) of EAct: The Appropriate Commission may authorise any person, as it deems fit, to represent the interest of the consumers in the proceedings before it.

1.3 Hosting regulatory filings

The second proviso of the proposed para 9.5 mandates the petitioner to host downloadable spreadsheet formats with all regulatory filings, information and documents on its website, which is a welcome move. The Commission has a good practice of hosting yearly filings on its website for easy access to the same for stakeholders. The regulation should specify that such filings, submitted by the licensees in a machine-readable format, will also be hosted on the Commission's website. Further, the regulations should clearly specify that the queries raised during the technical validation session as well as the data provided to the commission should also be available on the website. The objections raised and replies given should also be made available.

It is suggested that:

- Accessible versions of the tariff fillings, and related documents and data (such as responses to the tariff filings, and queries raised and response received during the TVS process) should be hosted on the Commission's website. Such provision should be mandated by the Regulations.

1.4 Data formats for tariff process

The second proviso of para 9.4 in the proposed regulations says that the Commission may stipulate different formats for details to be submitted by the Petitioner for assessing ARR and determining the tariff. The required formats should be shared by the Commission and finalised based on stakeholder comments soon after the notification of the regulations. Specification of the formats, before the effective date of the control period, provides clarity and certainty to the stakeholders.

For example, in addition to the existing formats, to make the MYT process more effective, the formats should also specify detailed information on:

- Consumer Category-wise subsidy accounting and annual reconciliation of category-wise booked and paid subsidies as well as pending payments
- Actual working capital borrowings from DISCOMs to provide a clear picture of financial strain faced by DISCOMs
- Project-wise expenditure for Energy Efficiency (EE) or Demand Side Management (DSM) measures incurred by the DISCOMs
- Annual average availability and PLF across contracted capacity by DISCOMs to assess the extent of backing down in past years
- Data on short-term transactions from DEEP, TAM, G-TAM, I-DAM and RTM contracts with details of each transaction given separately.
- Extent of actual energy (conventional and RE) wheeled for open access and off-site captive consumption and extent of on-site captive consumption on an annual basis.
- Category-wise status of metering (including % of consumers where meter is AMI, pre-paid, capable of energy accounting in ToD slots etc.)
- Month-wise Hours of supply based on feeder data

- Detailed information of project/ scheme specific, general loans and working capital with details on loan amounts, tenure of loan, moratorium period and interest rates across utilities.

Some such formats suggested for such data capture can be found in this 2018 Prayas publication, https://energy.prayaspune.org/our-work/research-report/bricks-without-clay-crucial-data-formats-required-for-effective-tariff-processes.

It is suggested that:

- The Commission publish the formats for tariff filing by the utilities and finalise the same based on public consultation.
- The utilities be mandated to furnish data in accordance with the formats published by the Commission
- Such data related to tariff filings be published on the ERC website to enable more transparency and public accountability

2. Need for improved planning

2.1 Regulatory framework for resource planning

The Commission has taken important steps towards improving planning by requiring the distribution licensee to prepare a power procurement plan which includes short, medium and long term arrangements, as per section 17 of the draft regulations. Para 17.3 of the proposed document discusses the preparing of forecasts based on past data.

While requiring such forecasting is a step in the right direction, the process should be further strengthened with a regulatory framework for load forecast and resource planning over a longer time horizon of 10 years. Recent load forecast and resource plan petitions were submitted on the basis of earlier regulations which were brief and dated. It is important that the Commission take up a process of revising these old Regulations and Guidelines. This exercise can take into account CEA's resource adequacy guidelines, demand forecast guidelines, planning code in the revised Indian Electricity Grid Code and FOR model regulations on resource adequacy. In addition to meeting the projected demand, cost optimisation of power purchase should be taken up and expected improvements in network performance parameters should be quantified. Such planning should be based on production cost and capacity expansion modelling exercises to ensure different scenarios of demand and supply are assessed and considered in decisions regarding power procurement, while ensuring prudence in costs.

As per the CEA Resource Adequacy Guidelines, the resource adequacy framework should cover:

- Demand assessment and forecasting
- Generation resource and procurement planning
- Monitoring and compliance

We bring to notice the model Regulations for resource adequacy framework prepared by the Forum of Regulators (June 2023) and the draft framework for Resource Adequacy recently published by MPERC[2].

It is suggested that:

- Existing guidelines and regulations for resource planning and load forecast be revised to reflect requirements stipulated in documents such as CEA's resource adequacy guidelines, demand forecast guidelines, planning code in the revised Indian Electricity Grid Code, and FOR model regulations on resource adequacy
- The Commission mandate the use of modelling tools for demand forecasting and resource planning, such that multiple scenarios are assessed for long term planning and cost prudence

2.2 Rigorous Demand forecast mandate and load research

With regard to power procurement planning, proposed Regulation 17.2 and Regulation 87.1 cover sales forecast – which specify category wise quantitative sales forecast for long-term and monthly duration for the Control Period. As per the proposed Regulation 87.2, "*the sales forecast shall be consistent with the load forecast prepared as part of the power procurement plan and shall be based on past data and reasonable assumptions regarding the future*".

Toward this, there should be a clear and explicit mandate for the submission of load forecasts for the short, medium and long-term horizons. The distribution licensee should submit data in the same format as the 10 year annual rolling plan requirement under the CEA Resource Adequacy guidelines. In addition, the demand forecasts should capture the change in DISCOM demand due to open access, captive, behind the meter generation and proposed energy efficiency measures.

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The Commission, in Regulation 17.2 (a), has specified the need for the forecast to be stated separately for peak and off-peak periods. For this, load research studies need to be conducted periodically. To operationalise this, from the first year of the control period, the Commission should mandate DISCOMs to report hourly consumer demand profiles at least for each year of the control period to aid demand assessment. This can be based on AMI metering of agricultural/ urban feeders/ DTs, SEM data of open access/ off-site captive consumers, AMI metering of HT consumers and eventually smart meter data of LT consumers.

Regulation should initiate steps to improve the estimation and forecast for unmetered agriculture consumption. The current method of using a small sample of DTs to estimate 30-35% of the total sales is grossly in-adequate. DISCOMs should be given month-wise targets to complete metering of DTs which supply power to agriculture. Loss in LT feeders should be re-estimated based on sample measurements at pumpset locations. Census of pumpsets should be taken up once in a

[2] FOR: https://forumofregulators.gov.in/Data/Reports/Model%20Regulation-Resource%20Adequacy%20Framework.pdf, MPERC: 6ba006cd845c254f839825055afe58cb.pdf (mperc.in)

control period. TSERC could set up a separate Committee to prepare the methodology of estimating agriculture consumption.

Rigour in forecasting major loads like Lift Irrigation and HT industrial also need to improve. In addition to taking inputs from the respective departments, the distribution utilities and the Commission should take up independent assessment of demand growth.

For the demand forecasts, the DISCOMs should submit the data and methods used to arrive at the final forecast, along with the justifications. TRANSCO, as the STU should consolidate the forecasts of the DISCOMs.

Regulation 12.2 (d) mentions that sales is an uncontrollable parameter, and 12.2 (k) that Revenue from sale of power is uncontrollable. These provisions discourage efforts to increase rigour in load forecasting. As for sales, only actual metered sales could be uncontrollable, so that power purchase true up can be taken up, with approved agriculture consumption and approved losses. Revenue from sales should not be made uncontrollable. Even for metered sales, we request the Commission to examine this issue and explore if variation up to certain percentage of sales (say upto +/- 10%, depending on consumer category) could be considered uncontrollable, but variation beyond this threshold would not be eligible for true-up.

It is suggested that:

- Load forecasts should be mandated for the short, medium and long term. Data for such demand forecast should be submitted in accordance with the 10 year annual rolling plan requirement under the CEA Resource Adequacy guidelines.
- The distribution utilities should report hourly consumer demand profiles at least for each year of the control period to enable analysis of the load, and ensure reliable forecast for peak and off-peak periods, as proposed in para 17.2 (a).
- The Commission should set up a Committee to prepare the methodology of estimating agriculture consumption to improve the estimation and forecast for unmetered agriculture consumption. Clear targets to be set for achieving the metering of DTs which supply power to agriculture.
- The distribution utilities should take up the assessment of demand growth and use resources such as modelling (for multiple scenarios) in order to ascertain reliable demand profiles . Data and methods used should be reported. TRANSCO should consolidate the forecasts of DISCOMs
- Revenue from sales should not be considered uncontrollable. Only metered sales, which can be assessed during true up, should be categorised as uncontrollable (with limits on such consideration).

2.3 Mandated Fuel Utilisation Plan

Para 19.2 discusses conditions under which the distribution licensee may enter into additional agreement for power procurement in the event of electricity shortage – which could be caused due to insufficient supply from contracted sources. To address the shortfall/failure in supply from approved sources to some extent, the generating entity should be required to prepare a fuel utilisation plan on a periodic, say monthly/quarterly, basis. 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 as projected by the Telangana DISCOMs, and will enable TSGENCO to be better able to plan for its fuel procurement at least cost. 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 over imports, as they are a potentially cheaper alternative.

The Commission should require TSGENCO 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.

It is suggested that:

- The generating entity should be required to prepare a fuel utilisation plan in the suggested format on a periodic, say monthly/quarterly, basis and publish such plans on their website

2.4 Sale of surplus power

Given sector realties of RE additions, significant thermal capacity additions, and varying demand profiles, it is likely that backing down of contracted capacity will be required. In the interest of optimal resource utilisation, the Commission should encourage utilities to minimise such backing down by utilising options for sale of surplus generation. DISCOMs have the provision to operate as traders, and should explore options of selling surplus power on market platforms and/or through the surplus power portal (PushP). Similarly, generators could also explore alternate/market avenues to sell excess power, subject to scheduling obligations.

It is suggested that:

- Utilities should be encouraged to minimise backing down by utilising existing provisions for sale of surplus generation, toward ensuring optimal resource utilisation

2.5 Flexible contracting

Given the transition, even conventional capacity will have to operate in an increasingly flexible and responsive manner, to most optimally address demand and system needs. Thus, contracting of new capacity should be done innovatively, and not just on a rigid long-term basis. Such flexible and non-RTC hybrid contracts are already emerging in the RE procurement space. Non-RTC contracts should also be explored for non-RE procurement based on demand- supply assessment.

It is suggested that:

- Any new capacity should be sufficiently justified and innovatively contracted

3. Framework for Capital Investment Schemes

3.1 Better planning and approval process

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 changing sector, and to avoid imposing unnecessary financial burdens on procurers over long periods of time, regulated mandates for capital investment planning are crucial. If any regulated capacity addition or expansion is undertaken, it should be carried out transparently and with sufficient justification, as recognised in para 7.6 of the draft regulations. Decisions regarding capital investment should be in line with power procurement planning and demand projections undertaken by the utilities. In addition to tariff orders published for a control period, a CIP order should also be approved for all utilities for each control period, subject to public consultations. Given the crucial impact of capital investments on all sector actors, including consumers, the Commission could also 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. For instance, around 4000 MW of TSGENCO capacity that is still under construction was projected to be commissioned in 2019 as per the state's Power For All document. 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.

The proposed para 7.11 specifies the limit for prior approval of capital investment as 50 crores for Transmission, 10 crores for Distribution and 1 crore for SLDC. However, there has been no distinction specified for what qualifies as Detailed Project Report (DPR) and non-DPR schemes. The Commission must specify a threshold for schemes to qualify as DPR, and must draft a detailed approval and prudency procedure for the same.

The Commission should develop a 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 non-compliance. This has been an approach proposed by the Gujarat ERC in its recently notified draft MYT regulations.

It is suggested that:

- The Commission should notify a detailed framework and set of regulations for the approval of capital investment schemes.
- As part of the CIP utilities should also report status of projects along with time and cost overruns and interest during construction incurred and reasons for delay, if any, for each project. Penalties should be considered for delays on account of the utility.
- Prudence checks and scrutiny should be carried out for all capital investment schemes
- Online reporting and monitoring of capital investment schemes and their approval through a dedicated portal should be mandated toward ensuring accountability and to minimise delays.

3.2 Mandate for circle-wise investment plans for distribution licensees

With decentralised generation options and consumer choice of supplier, it is important that network planning takes place in a disaggregated manner. In addition to scheme-wise details, it is suggested that for DISCOMs, circle-wise, DPR/ scheme-wise capital expenditure and capitalisation data is reported for each year in the capital investment plans. Such detailed reporting is provided in Madhya Pradesh and Tamil Nadu.

It is suggested that:

- The distribution utilities report the annual circle-wise, DPR/ scheme-wise capital expenditure and capitalisation data as part of their CIP

3.3 Discouraging new Section 62 projects and Threshold TBCB limit

5080 MW of TSGENCO capacity has recently come online or is in advanced stages of construction. Such capacity has come online as per dated capacity additions plans, without sufficient review of its requirement. These projects are resource intensive and have long gestation periods and lifetimes. Given this, along with the increased penetration of RE and variation in demand profiles, such capacity addition without sufficient consideration could result in stranded assets and locked-in resources. [3]

Any new capacity addition should be scrutinised, and its need should be sufficiently justified before it is allowed. As recognised in para 16.3 of the proposed regulations, all future procurement should be undertaken only through tariff based competitive bidding, as per Section 63.

In the interest of accountability and transparency, the process of allowing any future capacity additions, whether under Section 62 or 63, should be subject to public consultation and scrutiny.

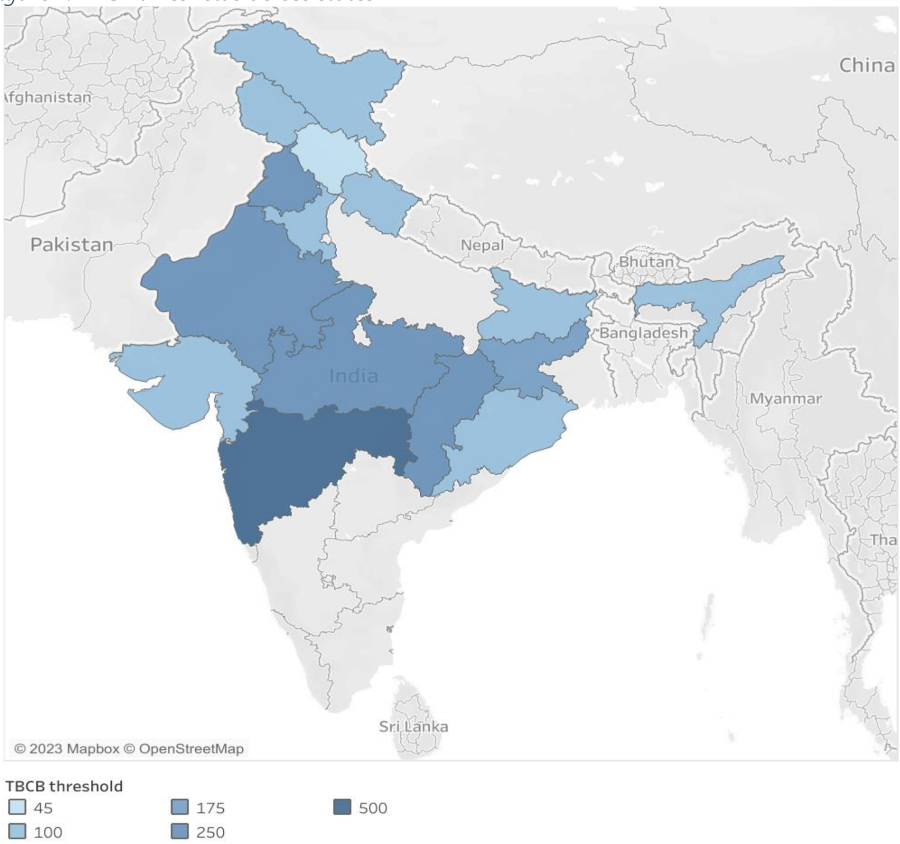
In order to further competition in the transmission sector, Tariff Based Competitive Bidding (TBCB) is being adopted by various states as per the recommendation of the National Tariff Policy, 2016. This process has further gained pace since the Supreme Court's judgement directing SERCs to frame regulations under Section 181 of the Act on the terms and conditions for determination of tariff for transmission projects. Below is a graph that highlights SERCs which have notified a Tariff-based competitive bidding (TBCB) threshold limit (in Rs. Crores)

It is suggested that:

- As recognised in para 16.3 of the proposed regulations, all future procurement should be undertaken only through tariff based competitive bidding, as per Section 63
- Any new capacity addition should be subject to public consultation and scrutiny
- TSERC clearly specify a TBCB limit of *100 crores* in its MYT regulations., similar to that notified in states like Gujarat, Bihar, Odisha etc.

[3] Please see Prayas 2022 paper: "Pitfalls of the massive thermal power capacity addition in Telangana"

Figure 1. TBCB thresholds across states



Source: India Transmission Portal;

Note: The thresholds (in terms of project cost) are in Rs. Crores. Each state has specified a different limit. The stipulation of the limit as well as the revisions – are available on the India Transmission Portal.

4. Operational parameters and related charges

4.1 Return on Equity (RoE) linked to performance parameters

In its explanatory note, the Commission states that it proposes to determine generation tariffs using a performance-based approach, to provide incentives based on actual performance. Given the importance of efficient and reliable operation in the fast changing power sector, this is a step in the right direction. RoE can be used as an effective lever to incentivise efficiency in actual operation and performance.

The Commission, in para 29.2 of the draft regulations has proposed reducing RoE by 0.5% per month in case of delay in submission of tariff/true-up fillings as required under the proposed regulations. In addition to this, RoE could be considered in two parts – Base RoE and Performance-based ROE. The Base RoE (of say 14% for TPPS and 14.5% for distribution licensees) should be allowed in accordance to the proposed regulation 27. The Performance-based RoE of 1.5% should be linked to actual performance. In addition to the penalisation on account of delays in submission of tariff/true-up orders, the Commission could also link RoE to improvement in reliability and technical performance, such as:

- Reduction in DT failure rates by Discoms
- Reduction in feeder level outages by Discoms
- Improvement in ramp rates by Generating company

- Achievement of longer Mean Time Between Failure by Generating company
- Optimisation toward flexible operation (operation below technical minimum as required by CEA Flexible operation of thermal power generating stations Regulations 2022)

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. Gujarat ERC has considered such an approach in its recent draft MYT Regulations.

It is suggested that:

- RoE be considered in 2 parts, base RoE and performance-based RoE, with the recovery of performance-based RoE being linked to improvement in reliability and technical performance

4.2 Ensuring targeted incentives

Para 44.2 and 44.3 of the draft regulations define availability and PLF norms for full recovery of AFC and incentives, respectively. Para 46.6 provides a flat rate incentive for generation in excess of that corresponding to the PLF norm. However, such computation of fixed costs and incentives for generation is carried out uniformly throughout the year. Given the varying demand across the day and year, this uniform application of weightage/incentive 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 a responsive/flexible system. Thus, capacity charges should be computed across 3 high demand and 9 low demand months, with 4 peak and 20 off-peak hours each day, as defined by the SLDC. Optimally, plants should be encouraged to be available and generate during periods of high demand, and incentivisation should be tapered for periods of lower demand.

Table 2 suggests an alternate structure for PLF incentives and Availability-based AFC recovery to account for different combinations of peak/off-peak hours and high/low demand seasons.

Table 2. Suggested optimisation for PLF/Availability incentivisation

	Peak hours (4 of 24 hours)	Off-peak hours (20 of 24 hours)
High Demand Season (3 of 12 months, i.e., 92 days)	Rs. 0.5/kWh PLF incentive 10% of the AFC Recovery for availability	Rs. 0.25/kWh PLF incentive 25% of the AFC Recovery for availability
Low Demand Season (9 of 12 months, i.e., 273 days)	Rs. 0.25/kWh PLF incentive 15% of the AFC Recovery for availability	No PLF incentive 50% of the AFC Recovery for availability

Source: Prayas (Energy Group)

The above proposal ensures that more AFC is recovered during high demand periods, and less during low demand periods.

- 10% of AFC recovery is linked to peak-high-demand hours (which make up just 4.2% of the 8760 hours in the year), thus giving a nearly 2.5-fold weightage to those hours compared to average.

- 50% of AFC recovery is linked to off-peak-low-demand hours (which account for 62.3% of the year), thus giving a weightage of only 0.7 to each such hour, compared to the average.
- Similarly, 40% of AFC is recovered in the 33.5% of the year that forms the "intermediate demand periods" corresponding to off-peak-high-demand or peak-low-demand – thus giving them a slightly higher than average weightage.

In the above proposal the weightage associated with peak hour availability is 25% of fixed cost recovery allocated to peak hours (which form only 16.66% of the year).

Incentives for generation above the normative PLF could be considered, similar to that offered in CERC 2019 MYT Regulations, which provides incentives for generation above the norm at a different rate for peak and off-peak hours . The Commission could further improve PLF based incentivisation, as illustrated in the proposal outlined in Table 2— such that the highest incentivisation (say Rs. 0.50/kWh) could be provided to plants that have generated in excess of the normative PLF during peak hours in the high demand season, and no incentive need be provided for such generation during off peak hours in the low demand season. A lesser incentive (say Rs. 0.25/kWh) could be provided for operation in excess of the normative PLF during both peak hours in low demand season and off peak hours during high demand season. Since the PLF incentive is over and above the cost recovery through ECR and RoE for the generator, the values should be relatively modest.

Toward ensuring availability and generation of thermal power plants when the system most requires it, peak hours and high-demand seasons should be defined based on net load (i.e., after accounting for the must-run capacity such as solar and wind) instead of overall load.

It is suggested that:

- Availability weighted AFC recovery and PLF incentives should be provided based on the suggested matrix, such that incentivisation is targeted to periods of high demand and reflects system needs

4.3 GCV consideration in ECR calculation:

Para 46.4 of the draft regulations proposes that energy charges should be computed on GCV As Received. Due to this, the grade loss or slippage between GCV As Billed and GCV As Received can be passed through as actuals, burdening the end consumer and minimising accountability on other actors in general, and generators in particular.

This is of particular interest when viewed in line with Para 7 of CIL's model Fuel Supply Agreement (FSA) which governs coal purchase by the generators. It states,

"7. Transfer of Title to Goods

Once delivery of coal have been effected at the Delivery Point by the Seller, the property/title and risk of Coal so delivered shall stand transferred to the Purchaser in terms of this Agreement. Thereafter the Seller shall in no way be responsible or liable for the security or safeguard of the Coal so transferred. The Seller shall have no liability, including towards increased freight or *transportation costs, as regards missing/diversion of wagons/rakes or road transport en-route, for whatever causes, by Railways, or road transporter or any other agency." [Emphasis added]*

Given this, the coal becomes the generators property at the loading/delivery point and all the risks thereafter are transferred to it. Allowing the pass through of all grade slippage between loading and unloading gives little incentive for generators to ensure quality and minimise loss, though the coal is in their custody from the delivery point.

The total heat content (kcal) of coal at the loading point cannot reduce during transit, except corresponding to some loss of coal quantity during transit— that is already allowed (0.2-0.8%) as per Para 44.11 of the draft MYT regulations. Thus, GCV variation during transit should not be considered beyond the generator's control, and hence should not be passed through to electricity consumers.

Maharashtra ERC has recognised this responsibility of the generator and the undue burden on the consumer, and MERC's 2019 MYT regulations, computes ECR on GCV As Billed (less a maximum of 300 kcal/kg for differences between As Billed and As received, and 85 or 120 kcal/kg for stacking loss)

Towards safeguarding consumer interests and ensuring efficiency in operations, the Commission should revise its tariff regulations on similar lines such that energy charge rate is calculated at GCV as billed (with some allowance for transit and stacking loss).

A further measure toward balancing concerns on account of GCV measurement methodology is discussed in Annexure 1.

It is suggested that:

- The Commission should revise its tariff regulations such that energy charge rate is calculated at GCV as billed (with some allowance for transit and stacking loss).

4.4 Tracking and reporting of collection efficiency

Toward better tracking and reporting of collection efficiency the DISCOMs should be mandated to report the extent of dues pending from the previous year which were collected in that year. This will enable a better understanding of performance of the DISCOMs, especially as collection efficiency can exceed 100% (without caps) if such collection was significant. The distribution licensee should also report category-wise pending dues and age-wise analysis of receivables of the DISCOMs.

It is suggested that:

- The distribution utility submit data regarding collection of prior period dues, category wise pending dues and age-wise receivables to ensure better tracking of collection efficiency.

5. Encoding 'Demand Side Management' in the regulations

Demand Side Management (DSM) will play an important role in supplementing the state's electricity transition goals, with higher integration of renewable energy (RE) going forward. Utility-scale DSM will have a significant potential to manage and shift consumer demand to periods where RE is available. TSERC notified its DSM Regulations in 2020. Within the said regulations, the distribution licensee is required to submit a perspective DSM plan covering the period of the MYT Control Period. This plan should constitute DSM plan goals, description of DSM programmes, implementation process and schedule, plan for monitoring and reporting as well as indicative cost effectiveness assessment of programmes.

For harmonising provisions across regulations, it is suggested that the Commission encode the following regulation within the current MYT Regulations -

'The distribution licensee shall submit the DSM plan at the start of the MYT Control Period, in accordance with the TSERC DSM Regulations, 2020'.

To ensure that distribution licensees take proactive steps towards implementing DSM post a DSM plan has been approved; the Commission should consider levying a *penalty* for the DISCOM – in case DISCOMs are unable to incur 90% of actual DSM expenditure of the total approved DSM expenditure for the year, a penalty is levied by way of reduction in the rate of return on equity by 0.25%.

It is suggested that:

- The distribution utilities should be mandated to submit a DSM plan as part of their MYT submissions.
- The Commission should consider penalising lapses in implementation of the submitted DSM plan, as proposed.

6. BEE Energy Audit Regulations

Bureau of Energy Efficiency (BEE) had notified its Energy Audit Regulations for DISCOMs in 2021. The MYT Regulations can specify the distribution licensees to submit these audit reports as part of the tariff petition. The annual energy audit report for the preceding financial year and the preceding quarterly reports can be submitted along with the petition for true-up or the mid-term review. The Commission can take cognisance of data submitted in the energy audit reports to remain informed about various performance measures.

It is suggested that:

- The distribution utilities should submit annual energy audit report for the preceding financial year and the preceding quarterly reports along with the petition for true-up or the mid-term review.

7. Impact of environmental norms

Towards adherence to the revised emission standards and deadlines notified by the Ministry of Environment, Forests and Climate Change, thermal power plants are required to install emission control systems (ECS). The draft MYT regulations have considered this impact, and have included consideration of additional capitalisation on this account, which is a step in the right direction.

However, in addition to the impact on fixed cost, operation of ECS will also impact the variable cost/energy charge of the generating station. While all of TSGENCO's TPPs are in category C (according to CEA's categorisation as per MoEFCC's revised emission norms 2022) and are held to the laxest timelines of adherence, the final deadline falls within this control period. Thus, in order to minimise litigation and ensure regulatory clarity, the commission should also discuss cost compensation mechanisms on account of implementation and operation of ECS.

It is important to note that to ensure 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 norms. This could be done either on the basis of the generator procuring suitable certification from the state PCB for adherence, or the Commission mandating generators to publish emissions data obtained from CEMS (Continuous Emissions Monitoring System) on their website and approving expenditure only after scrutiny of such data for adherence.

Further, the implementation of such ECS will impact the cost of plants and, in turn, affect their position on the MoD stack. Given the varying deadlines for compliance applicable to different plants, the Commission could exclude ECS expenses from consideration for MoD till the final deadline (31st December 2027) applicable to all plants, which falls within the upcoming control period. Toward ensuring timely compliance and in the interest of preventing regulatory bottlenecks, clarifications on the applicability of the supplementary FC and VC subject to adherence to the norms should be provided well in advance. Supplementary charges can be included to decide MoD for all plants after the final deadline and the treatment outlined in table 3 could be considered.

Table 3. Proposed treatment for noncompliant generation post deadlines

	If PCE CapEx is incurred	If PCE CapEx is not incurred
If the TPP is compliant	PCE related costs to be passed through; supplementary VC not to be part of MoD until final deadline	N.A.
If the TPP is not compliant	Disallow PCE related FC, and apply notional additional penalty to affect their MoD position after plant deadline	Apply notional additional penalty to affect their MoD position after plant deadline

Source: Prayas (Energy Group)

Thus, generation from plants that have not installed ECS by their applicable 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. In addition, PLF incentive should also not be applicable for such plants until they are able to comply with the norms.

It is suggested that:

- Framework for cost recovery through FC and VC should be stipulated in the regulations to avoid litigation and regulatory ambiguity
- Allowance of ECS cost is based on utilisation as opposed to only installation
- ECS expenses should be excluded from consideration for MoD till the final deadline (31st December 2027) applicable to all plants, which falls within the upcoming control period. After the deadline, the suggested matrix could be considered for ensuring compliance.

8. Decommissioning of assets

Given the transition that the sector is undergoing, closure of coal-based assets is going to be increasingly common. Thus, ensuring there is due process in place for such closures, taking into account the socio-economic and environmental impacts of the same, beforehand is crucial toward preventing regulatory ambiguity and bottlenecks. The Central Pollution Control Board has already come up with draft guidelines for decommissioning of TPPs in 2021. To ensure that no counterproductive guidelines are provided and toward ensuring coordinated action, the Commission may consult the state PCB towards accounting for TPP closures, including the case of plant decommissioning before the completion of its useful life, and account for costs of such decommissioning.

It is suggested that:

- There should be due process set up in advance for the closure of assets to ensure such asset closure happens comprehensively and without regulatory ambiguity and litigious bottlenecks.

9. Capping of input price of integrated mines

Section 50 of the proposed regulations rightly uses the CIL notified price for the corresponding coal grade as the ceiling for input price for supply of coal from the generating company's integrated mines. However, in section 61 of the document, it allows an increase of up to 20% from CIL's notified price, as reflected in the ECR on account of input price of coal. 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 consider capping 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.

It is suggested that:

- The Commission should cap the RoM price of coal for integrated mines to the CIL notified price for the corresponding grade of coal.

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Annexure 1: GCV consideration in ECR calculations-Balancing issues on accounting methodology

Losses between GCV As Billed and GCV As Received can be split into losses on account of methodology (i.e., difference in coal GCV between what is priced and what is purchased by the generator) and losses on account of transit. Losses on account of transit have already been accounted for in Para 44.11 of the suggested regulations, and should not be allowed beyond the permitted losses.

On the other hand, generators should be compensated for losses on account of methodology. The coal supplier determines the price of fuel on GCV As Billed, which is calculated on Equilibrated Moisture Basis (EMB). But actual coal purchase does not occur under standardised conditions, and the coal purchased by the generator is not necessarily of the grade determined under EMB even at the loading point. The actual quality of coal purchased by the generator will be contingent on field conditions at the loading point, .i.e., coal quality assessed at the loading point on Total Moisture Basis (TMB).

Since GCV As Billed on EMB is recorded at the loading end, equilibrated moisture (moisture in the coal sample at standardised conditions) is also captured. If total moisture content in the coal is additionally measured at the loading end, GCV As Purchased on TMB can be calculated as:

GCV (TMB) = GCV (EMB) x [1-Total Moisture]/[1-Equiliberated Moisture] (kcal/kg)

Both GCV As Billed and GCV As Purchased are assessed at the loading point. The only difference between both the parameters is that GCV As Billed is computed as per EMB, whereas GCV As Purchased is determined as per TMB.

With this understanding, the Commission could consider a reasonable allowance in GCV on account of the difference in GCV As Billed (EMB) and GCV As Purchased (TMB), in the computation of the energy charge rate on the following lines. This is exactly the same as proposed in the draft regulations with the exception of the definition of CVPF which is highlighted.

ECR = (GSHR – SFC X CVSF) X LPPF / CVPF+SFC X LPSFi} X 100 /(100-AUX)

Where, AUX = Normative Auxiliary Energy Consumption in percentage;

CVPF = *a) Weighted average gross calorific value of primary fuel as billed in kcal/kg for coal-based stations, which is arrived at based on CVB – CVLa – CVLb – CVLc where*

i. *CVB is the weighted average gross calorific value of coal/lignite as billed by supplier in kCal/kg*
ii. *CVLa is the loss in calorific value of coal/lignite between "as billed by supplier" and "as purchased by generating station" to account for the difference between EMB and TMB, subject to the maximum loss in calorific value of 10% over the GCV as billed*
iii. *CVLb is the equivalent loss in calorific value corresponding to the quantity of coal lost in transit as per Regulation 44.11 and*

iv. *CVLc is the loss in calorific value due to stacking subject to the maximum loss of 1% over the GCV as purchased*

b) In case of blending of fuel from different sources, the weighted average Gross Calorific Value of primary fuel shall be arrived in proportion of blending ratio;

CVSF = Calorific value of secondary fuel, in kcal/ml;

GSHR = Normative Gross Station Heat Rate, in kcal/kWh;

LPPF = Weighted average landed price of primary fuel, in Rs./kg, as applicable, during the month; in case of blending of fuel from different sources, the weighted average landed price of primary fuel shall be arrived in proportion of blending ratio;

SFC = Normative Secondary Fuel Oil Consumption, in ml/kWh;

LPSFi = Weighted average landed price of secondary fuel in Rs./ml during the month.

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