Comments and suggestions on GERC Discussion Paper on Multi-Year Tariff Regulations for the Fourth Control Period (FY 2024-25 to FY 2028-29)

Gujarat Electricity Regulatory Commission (GERC) published a discussion paper on the Multi-Year Tariff Regulations for the five year tariff period from FY2024-25 to FY2028-29 and invited public consultation on the same.

Prayas (Energy Group) is making the submission toward this discussion paper in two parts. This part provides comments and suggestions on generation related aspects, the second part will deal with other aspects of the approach paper. In the interest of ensuring efficient and simplified sector operations while safeguarding consumer and sector interests and gaining clarity on the approaches proposed, we have the following inputs:

1. Consideration of delay on account of forest clearances as an uncontrollable factor

While it is important to reduce bottlenecks to timely project completion, it is also crucial to ensure accountability of the generator to adhere to timelines. If a measure as proposed in Section 1.5.2 is considered, it should be subject to strict scrutiny of the utility's role in procuring such clearances in a timely manner, and delays in obtaining Forest Clearances should be deemed as an uncontrollable factor only after the Commission is satisfied on a case-to-case basis that the delay is not attributable to the generator.

2. Passing on greater share of gains on controllable parameters to beneficiaries

In Section 1.5.3, the discussion paper seeks input on modification in the gain/loss sharing mechanism on controllable parameters. In accordance to current tariff regulations, one-third of the gain/losses on account of controllable factors is passed through as rebate/additional charge on tariff, and the balance two-thirds is retained/absorbed by the utility.

An effective gain/loss sharing mechanism should provide effective incentives to the utility to reduce losses on account of controllable parameters, while also reducing consumer tariffs and protecting consumer interests. Toward this, the Commission should consider increasing the proportion of gains shared with the consumer, and reducing the share of losses passed on. It could consider adopting CERC's gain/loss sharing mechanism, wherein 50% of the gains on account of controllable parameters are passed on to the consumer, but no losses are shared.

3. Introducing a Mid-Term Review Tariff Process

Section 1.5.4 discusses the introduction of a midterm review process as part of the utilities' parametric performance review. Regular true up process is crucial to the effective functioning of the utility but it is understood that an annual undertaking is a time intensive exercise for utilities and the Commission. In order to address this; while ensuring regulatory certainty for costs and tariffs, tracking and holding the utility accountable for its performance in the medium term, and to help with medium term planning; truing up can be carried out twice in a five year control period. The true up for the first two years (and provisional true up for the 3rd year) can be carried out during the mid term review process (carried out in the third year of the control period). The mid term review could also be used to revise the parameters for the remaining control period, if required. Final truing up for the last three years of the control period can be carried out at the end of the control period. This treatment should be applicable to all utilities in order to ensure course correction if needed and reduce risks, while providing certainty to stakeholders.

4. Need for capital investment scheme approval framework

It is good to note that the impact of capital investment schemes on costs and resources has been recognised and the need for transparency in such approval process has been stressed upon in Section 2.1.1. A framework to streamline the approval process of such schemes will aid in ensuring added clarity and scrutiny of such capital expenditure. Given the fast changing sector, bringing on additional assets must only be considered after sufficient analysis. For instance, any coal-based capacity that comes online now is likely to be capital intensive, and will only increase the cost of generation. Additionally, given the useful life of TPPs, they will remain in the sector and could potentially cause resource lock-ins till 2050 and beyond, leading to fixed cost liability for the procurers and their consumers which may not be warranted. Thus, prudence checks towards capital investment schemes should also include justification of the necessity of the project itself to prevent cost and resource lock-ins.

5. Considering RoCE for assets commissioned in the new control period

The discussion paper, in Section 2.1.2, proposes the utilisation of the RoCE method towards consideration of the debt and equity of capital assets. It discusses alternatives for its implementation and applicability to new and existing plants. The RoCE method allows for reducing equity base, along with debt, over the life of the asset by adjustment from depreciation considered from the beginning. Shifting to the RoCE method for assets commissioned in the new control period will ensure the reflection of these benefits for such capacity, however, adoption of the same for existent plants requires more consideration. In order to reflect the advantage of the RoCE method for existent capacity, the equity of such projects could be reduced to salvage value/normative levels for the new MYT period. Towards its effective implementation, it is crucial to ensure prudence while designing RoCE and include revisions each control period, to fine tune the considered assumptions towards its computation.

6. Computation and treatment of cost of equity

In Section 2.1.5, toward the computation of Rate of Return on Equity, the discussion paper discusses linking the RoR with market interest rates. Linking the RoR with G-Sec rates by adding a modest risk-premium could be considered since Section 62 projects inherently have very low risk.

Further, the methodology considered for such computation historically has been the CAPM method. The market risk premium or the expected return on market is a parameter that contributes to the computation of rate of return under CAPM. As stated earlier, investments in Section 62 projects by generators are much less risky than investing in the stock market and hence the risk premium as calculated from market returns is not appropriate for such projects, and cap must be decided by the Commission to ensure only a modest risk premium is considered.

The Commission should devise a formula to link RoR with G-Sec rates keeping these factors in mind.

Section 2.1.6 discusses the use of differential RoE toward incentivisation of performance parameters. With regard to generation, it is good to note that additional rate of RoE is considered for generation during peak demand. In addition to delays in filing of petition, penalty on ROE could also be implemented for delays in completion of projects, given the impact of such delays on the sector costs and power purchase planning, and to ensure the project proponent is held accountable.

7. Treatment of normative availability

As discussed in Section 3.1.1, an additional relaxation of 2% is allowed on NAPAF on account of coal shortage and sustained uncertainty of coal supply. However, there have been significant improvements in domestic coal supply[1]. This is seen even in GSECL plants, for instance the share of coal receipt to its allocation for Wanakbori TPP (GSECL' biggest plant at 2270 MW) increased from 46.97% in FY20 to 88.18% in FY23. Additionally, the existence of other procurement alternatives such as integrated mines, e-auctions and (soon) commercial mine also reduces the need for such concessions. The Commission should thus consider doing away with the relaxation in availability norms on account of coal shortage.

Further, as understood from the review of tariff orders from FY17 to FY22, the normative availability is approved in the truing up process, despite actuals varying from such norm. The reasoning for such treatment as per the orders is on account of availability being a controllable parameter. It is unclear why the impact on account of slippages in an controllable parameter is being passed through to the consumer. This practise sets a poor precedent as it does not hold generators accountable for not being available as projected, and in periods of peak demand, could result in insufficient capacity to meet demand. The reflection of such availability on fixed cost recovery, in accordance to tariff regulations, is also affected. In the interest of safe guarding consumer interests, setting better precedents, and ensuring proper signalling the Commission should ensure that actual availability is approved and reflected in fixed cost recovery unless such operation is on account of uncontrollable parameters—and even so should not be entertained over extended periods of time.

8. Treatment of other normative operating parameters

Section 3.1.2 considers the review of the other operating norms either on the basis of historical data or through benchmarking using CEA recommendations. While historical data is useful in bringing out trends and developing some understanding of these parameters, only considering such data will potentially result in the carry forward of past inefficiencies. Instead benchmarks and projections should be used to continuously improve performance and improve efficiency of operations in response to dynamic sector changes.

9. Scrutiny of R&M/Special allowance undertaken post extension of life

Given that it is better reflection of ground realities and actual plant operation, it is a step in the right direction to extend the useful life of these projects to 35 years from the current 25 years, as suggested in Section 3.2.

However, durations of PPAs should not be deemed to be extended along with such extension of life of the plant. Beneficiaries should continue to have a say in whether they want to procure

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[1] See https://pib.gov.in/PressReleasePage.aspx?PRID=1940460

power from the plant during the extended period, and should not by default be saddled with generation from plants on account of their extended lives.

Further, to ensure prudence, the R&M to be undertaken after 25 years, or alternatively the special allowance accepted, should be considered without escalation and subject to sufficient scrutiny. For instance, if the plant is mostly run to meet seasonal or daily peaks, and therefore is used sparingly, the justification of such expense may merit review. Similarly, if the plant avails special allowance, then it should be accountable to show corresponding performance improvement.

10. Single part tariff for generation after completion of useful life

Capacities that have completed useful are likely to play an important role in sector operations, through say grid balancing and providing peaking power, given their low fixed cost. Allowing capacity charges of such plants to also be recovered based on scheduled generation (in addition to variable costs) could be explored. But given that such costs are passed through, they should be subject to prudence checks prior to approval. A cap could be considered on this deemed fixed cost to limit the impact of this cost over and above the energy charge. Additionally, the Commission could also explore setting an upper limit for generation from such capacity to minimise excess generation from suboptimal plants beyond end of useful life.

11. Incentivisation for operation during peak periods

With regard to the incentives discussed in Section 3.4, a PLF incentive is primarily required in peak demand periods to incentivise low-cost generation from non-pithead plants by encouraging them to procure low-cost coal so that they are high on the MoD stack. The incentive is over-and-above the cost of procuring coal which is anyway pass-through (and over-and-above the RoE to the developer) – hence it can be modest. The incentives considered in the discussion paper (in line with CERC Regulations) of Rs. 0.65/kWh in peak hours and Rs. 0.5/kWh in non-peak hours are very high and should be revisited.

On the other hand, higher availability should not be additionally incentivised but AFC should be pro rata reduced for availability below the norm. There is value in encouraging plants to be available during peak hours. Going forward, the Commission should consider increasing the AFC weightage for peak hours and high demand months/seasons, as coal-based and hydro plants are likely to increasingly be required to supply electricity primarily during peak demand periods. CERC and MERC Regulations have these provisions for peak hours, though they can be strengthened further.

Further, toward the differential capacity charges discussed in Section 3.3.1, since the objective of providing greater weightage for availability during peak is to encourage availability at times that they would be most required, it is suggested that the definition of 'peak periods' 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. This should be the case since those are the periods when thermal and hydro plants would be most required. Toward this, the SLDC could submit net-load curves based on which the peak season/hours for each plant could be determined, and according to this, higher weightage for AFC recovery would be applicable.

The following parameters are likely to impact sector operations and costs in the coming control period and merit inclusion in the Tariff Regulations:

12. Include impact of Emission Control Systems (ECS) charges

Toward 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 norms. This could be done either on the basis of the generator procuring suitable certification from GPCB for adherence, or the Commission mandating generators to publish emissions data obtained from CEMS on their website and approving expenditure only after scrutiny of such data for adherence.

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), 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 and the treatment outlined in table 1 could be considered.

Table 1. 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.

13. Capping of RoM price of integrated mines

The input price of coal from integrated mines is eventually passed on to consumers. The existing formulation of computing the input price is not consistent with the objectives of offering coal mines for captive use to power plants through allotments and auctions under the Coal Mines (Special Provisions) Act, 2015 and related Rules. 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. The following official communications reinforce this point that the objective of allocating captive mines to power generators was to reduce power tariffs:

- As per 3.2(e) of the directive from the Ministry of Power to CERC, dated 16.4.2015, on supply of electricity by generating companies where the coal is being sourced from coal mines allocated under CMSP, Second Ordinance, 2014: "*The revision of tariff undertaken by the Central Electricity Regulatory Commission as above shall not lead to higher energy charges and total tariff throughout the tenure of Power Purchase Agreement than that which would have been obtained as per terms and conditions of the existing Power Purchase Agreement.*"
- The methodology for fixing floor/reserve price for auction and allotment of coal mines/blocks, prescribed by the Ministry of Coal states, in Clause (3) with regard to coal mines/blocks allotted for specific end-uses, that: "*This would ensure that there is no adverse impact on power tariff.*"
- Additionally, Clause (4) of the methodology, that deals with auctions of coal mines/blocks, also highlights the objective of reducing power tariffs, as it states: *"A ceiling price of CIL notified price for each coal block will be fixed and the bidders will be mandated to quote lower than this ceiling price"* and *"…This method will ensure that the benefit of lower bid price is passed through to the consumers."*

In view of the above, the RoM price of coal for integrated mines should be capped at the CIL notified price for the corresponding grade of coal, to be consistent with the objectives of allotting coal mines for captive consumption. Maharashtra ERC has adopted such a measure in the second amendment to its 2019 MYT Regulations.

14. Consideration of GCV as billed for ECR computation

As per the current GERC regulations, generators pay for coal based on GCV as billed, however consumer tariffs (ECR) are computed on the basis of GCV as fired. There have been considerable slippages between grades between the as billed and as received point on account of several factors including transit, and likely further loss in grade between the received and fired coal on account of stacking and other challenges. This means consumers do not get the coal they are paying for. Given that consumer tariff is computed on an as fired basis, the impact of these slippages have been passed through without sufficient scrutiny.

CEA's recommendation on operation norms for thermal power stations for tariff period 2014-19 states *"Any arbitrary practice of using as fired GCV for SHR computations without proper guidelines for determining the same would only lead to inflated claims of coal consumption"*.

Thus, consideration of GCV as fired would reflect a lower grade of coal and a higher cost burden on the consumer.

Further, Para 7 of CIL's model Fuel Supply Agreement (FSA) 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. Further, with the introduction of third party sampling through reputed agencies such as CIMFR, there is less cause for disputes regarding GCV as billed. Therefore, GCV slippage during transit should not be a factor beyond the generator's control, and hence should not be passed through to electricity consumers.

Consideration of GCV as fired allows the pass through of all grade slippages. This gives little incentive for generators to ensure quality and minimise loss. Toward this, the Commission should revise the extant norms such that ECR is calculated at GCV as billed (with some allowance for transit and stacking loss). The Maharashtra ERC, through its MYT Regulations for FY19-24, have adopted this approach to ensure more efficient operations and safeguard consumer interest.

We request the Commission to accept this submission on record and to allow us to make additional submissions in this matter. We further request the Commission to allow us to make an oral submission during a public hearing, if one is scheduled.

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