Prayas (Energy Group) submission on draft Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2024

The Central Electricity Regulatory Commission (henceforth the Commission or the CERC), had published the draft notification on the Multi Year Tariff (MYT) Regulations for the control period FY25-FY29 on 4th January 2024, and invited public comments on the same.

The draft regulations, and related processes have taken several positive actions and steps in the right direction. However, it is crucial to further strengthen flexibility measures, target incentives, safeguard consumer interests and ensure clarity in the MYT regulations – given the fast paced changes in the sector and the impact of these regulations on multiple stakeholders across the country for the next five years and beyond. Prayas (Energy Group) has the following suggestions towards strengthening the proposed tariff regulations:

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1. Scrutiny and treatment of new capacity

The generic MoU based PPA structure of central generators with beneficiaries effectively means that central capacity additions with tariff determined under Section 62 are fait accompli on its beneficiaries. Given the ongoing energy transition and the long-term nature of such PPAs, new coal-based capacity additions with 25-year fixed cost commitments on beneficiaries pose a serious risk of long-term lock-ins. Therefore, such capacity addition should be subject greater scrutiny from the beneficiaries and regulators.

Instead of Section 62, the competitively bid Section 63 route, with due approval from appropriate regulatory commissions, 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 state regulators.

If at all any new projects are to be considered under Section 62, their capital cost approval by the CERC should be contingent on approval from state ERCs (corresponding to their beneficiaries) for procurement of at least, say, 70% of the proposed capacity at indicative costs. This will ensure that beneficiaries pro-actively seek the required capacity after due regulatory process, rather than it being fait accompli. Therefore, we suggest that the Commission add a proviso to draft Reg 2 (1), which states that stations that do not have explicit agreements for that capacity with beneficiaries must obtain consent from beneficiaries, duly approved by their respective ERCs in order to be considered for tariff determination.

The first proviso of draft Reg 2 (1), states that,

"Provided that any generating station for which agreement(s) have been executed for the supply of electricity to the beneficiaries on or before 5.1.2011 and the financial closure for the said generating station has not been achieved by 31.3.2024, such projects shall not be eligible for determination of tariff under these regulations unless fresh consent of the beneficiaries is obtained and furnished."

An identical clause, with a cut-off date of 31.3.2019, was present in the 2019 MYT regulations. Hence, this proviso is effectively relevant only for the generating stations that had executed agreements on or before 5.1.2011 and achieved financial closure between 1.4.2019 and 31.3.2024. Since more than eight years had elapsed by 31.3.2019 for such stations, there is no need to provide a further extension for such stations. We suggest that this proviso be amended to state that only stations which have executed agreements on or before 5.1.2011 and have obtained fresh consent from beneficiaries can approach the Commission for tariff determination.

Further, to ensure prudent investments in Section 62 capacity, central generators should come up with a business/resource plan for every control period, outlining the details of projected capital investments under Section 62 in that time period and providing justification for the same. New thermal and hydro capacity have long gestation periods and lifetimes, which could become unviable in a rapidly changing electricity sector and impose an unnecessary financial burden on procurers over long periods of time. A business plan, subject to approval after public process, would provide clarity to multiple sector actors, including consumers, about cost and expenses over the coming control period (and beyond), and about capacities and projects in the pipeline. This practice is already followed by many state level utilities.

We request the Commission to:

- Encourage capacity addition through Section 63, and minimise the Section 62 route, for any capacity without explicit agreements.
- Add a proviso to Reg 2(1) to ensure that if any Section 62 capacity without explicit agreements is considered for capital cost approval, it should be subject to approval from state ERCs.
- Amend the first proviso of draft Reg 2(1) to state that only stations which have executed agreements on or before 5.1.2011 and have obtained fresh consent from beneficiaries can approach the Commission for tariff determination.
- Require central generators to submit a year-on-year business plan with justification for every control period, and the Commission should approve the same after due scrutiny of prudence through a public process.

2. Improvements in process

Central generators have significant regulated capacity that impacts power procurement planning across multiple states. Given the scale of stakeholders impacted, the tariff approval of such capacity should be subject to a public hearing process to ensure that all stakeholders have an opportunity to participate. Draft Reg 10 (6) already has a provision enabling public hearing for the granting of interim or final tariff, which should be operationalised by the Commission.

Further, draft Reg 10 (2) has a provision for addressing data gaps in the petition from the generator/transmission licensee, as may be pointed out by the staff of the Commission. In addition to this, the Commission should carry out a technical validation session (TVS) in consultation with CERC's consumer representatives (CRs). Such a practise would strengthen the identification of data gaps and errors in the petition, and ensure a more meaningful and smooth public engagement.

Delays and ambiguities in the cost approval of central projects have impacts across the sector. Currently, tariff approvals of centrally regulated capacity are undertaken separately for each asset (stage/unit of generating station) under CERC's jurisdiction. As on July 2023, under this case by case treatment, only around 40% of NTPC capacity had tariff orders for the last control period (2019-2024), even as it comes to an end. This is despite Regulation 9(2) of the 2019 CERC MYT regulations requiring all existing stations/units to make an application for capital cost approval by 31st October 2019. Towards ensuring timely tariff approvals and simplification of process, tariff/cost approvals for generators under CERC's jurisdiction should be carried out for the generating company as a whole, wherein the generator submits a single petition with details of all the plants whose tariff needs to be determined, according to the required formats by a stipulated date. No applications for capital cost approval should be entertained post that date for existing capitalisation.

All the above suggestions are already implemented by several state ERCs.

We request the Commission to:

- Ensure that tariff approval for central generators happens through a public process.
- Implement TVS, with CR consultation, before tariff setting/approval for central generators.

- Carry out cost/tariff approval of central generators at the company level in a timely manner.
- Disallow applications for capital cost approval submitted after the stipulated time period

3. Inclusion of high/low demand seasons

Reg 42 of the 2019 MYT Regulations provided for capacity charge recovery separately across high and low demand periods, in addition to peak and off-peak hours. This has been removed in the current draft, citing operational difficulties.

However, in the context of the energy transition and an increasingly dynamic power sector, flexible and responsive operations, especially from coal-based thermal power plants is crucial. This has been recognised in many provisions/schemes in the sector, such as the lower technical minimum required from TPPs (40%, from the earlier 55%). It is critical for regulations to also factor in such variability of the need of coal-based generation across seasons and over the time of day, to encourage coal-based capacity to be available when most needed. Towards this, a seasonal weight (similar to that allowed for fixed cost recovery during peak/off-peak hours) for AFC recovery during high/low demand months should also be considered.

The difficulty of setting high/low demand seasons at the RLDC level has been cited as an operational hurdle while doing away with them. However, with an integrated national grid, the coincident national peak and load is of importance. This has been highlighted in the MoP Resource Adequacy guidelines as well. Thus, high/low demand seasons, and even peak/off-peak hours should be set at the national level overcoming the cited operational difficulty. The high/low demand seasons and peak/off-peak hours at the national level could be defined by GRID-India, in consultation with the RLDCs.

Further, 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.

Table 1 elaborates these ideas further with indicative weightages for AFC recovery.

Table 1. Proposed consideration of availability-linked FC recovery and application of PLF incentive

	Peak hours	Off-peak hours
High-Demand Season	~2.5X weightage per hour for AFC recovery* → Rs. 0.5/kWh PLF incentive	~1.2X weightage per hour for AFC recovery* → Rs. 0.25/kWh PLF incentive
Low-Demand Season	~1.2X weightage per hour for AFC recovery* → Rs. 0.25/kWh PLF incentive	~0.8X weightage per hour for AFC recovery* → No PLF incentive

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

Source: Prayas (Energy Group)

*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 10%, 25%, 15% and 50% respectively.

We request the Commission to:

- Reintroduce availability linked fixed cost recovery across high/low demand seasons (in addition to peak/off-peak hours), with appropriate weights on the lines suggested in Table 1.
- Mandate GRID-India, in consultation with RLDCs, to define, high/low demand seasons and peak/off-peak hours based on national net load.

4. Application of PLF incentive

As per draft Reg 62 (6), the incentive for scheduled generation in excess of ex-bus energy corresponding to the normative PLF during peak hours has been increased to Rs. 0.75/kWh. The incentive for such generation during off-peak hours has been retained at Rs. 0.50/kWh.

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 NAPAF (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 1.

We request the Commission to:

- Consider varying PLF incentives across high/low demand seasons and peak/off-peak hours, as suggested in Table 1.
- Revise the PLF incentives on the lines suggested in Table 1.

5. Consideration of GCV 'As Billed' for ECR Calculations

As per draft Reg 60, the ECR of thermal generation is calculated based on GCV 'As Received' provided the generators carry out sampling at the billing and receiving end, and ensure recovery of compensation based on Fuel Supply Agreements and pass on the benefits to the beneficiaries. GCV 'As Billed' is to be considered in the absence of third party sampling. While such a mandate is a step it the right direction, 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 59 and 64.

Thus, towards ensuring regulatory accountability, operational efficiency, and safeguarding consumer interests, GCV 'As Billed' (with allowance for transit and stacking loss, as already capped in draft Reg 59 and 64) is the appropriate measure for ECR calculation. The Maharashtra ERC has adopted a similar approach.

If GCV 'As Received' is considered as in draft Reg 60, the Commission must ensure accountability and follow through towards effective adherence of seeking compensation for any slippages and passing on the benefits to beneficiaries. Towards this, generators must be mandated to publish on their website details such as sampling results at loading and unloading ends, compensation sought, received and shared on their website at regular (say, quarterly) intervals. Adherence to this regulation must be strictly reviewed as part of the next tariff process, and lack of due effort on the part of generators to obtain compensation must be duly penalised, given the impact of fuel costs on the ECR of all consumers.

It should also be made clear that GCV 'As Billed' will be considered for ECR calculation in the absence of third party sampling at either billing or receiving end. Further, in the event GCV ' As Billed' is considered, the draft Regs propose an allowance of slippage of 300 and 600 kcal/kg for pithead and non-pithead plants, respectively. The reasons for this have not been provided in the Explanatory Memorandum. As stated earlier, Draft Regs 59 and 64 already account for losses during transit and storage. Moreover, no such slippages in GCV should be allowed for generating stations that use coal from an integrated mines as indicated towards the end of Draft Reg 60(1).

It must be noted that there is an existent mandate for the regular publication of details pertaining to GCV, price, and source of fuel procurement (as per draft Reg 60 (2)/Reg 40 (2) in MYT Regulations 2019). However, generators have not been adhering to this stipulation and such information is not available on their website, though it is extremely critical for ECR determination. Given the context of likely shortages of coal and the need for accountability and transparency in fuel procurement, adherence to this mandate must be imposed and continued non-compliance must be penalised. Similarly, not publishing information regarding third-party sampling results, compensation sought, obtained and shared in a timely manner should also be duly penalised.

We request the Commission to:

- Use GCV 'As Billed' as the basis for calculation of ECR.
- Disallow 300/600 kcal/kg for GCV slippage between 'as billed' and 'as received' for pithead/non-pithead plants since this is already provided for in other regulations.
- Disallow any GCV slippages for plants procuring coal from integrated mines.
- Ensure draft Reg 60 (2) and other regulations for timely publication of data is adhered to by generators and penalise continued non-compliance.

- Mandate periodic publication of third party sampling results and details of compensation shared with beneficiaries by generators on their website on a quarterly basis, especially if GCV 'As Received' is considered for ECR calculation.
- Require GCV 'As Billed' to be used for ECR calculation if third party sampling is not carried out at either, the billing or receiving points.

6. Capping fuel blending based on ECR impact

Draft Reg 64 (4) revises the provision for fuel blending without beneficiary consultation, and allows up to 6% blending by weight. However, 6% by weight can have a wide range of impact on consumer ECRs based on the alternative fuel source used. Blending with imports, for instance, will have a significantly higher impact on ECR as compared to blending from other procurement alternatives such as e-auctions. Thus, prudence should be ensured in the selection of the source of blending. In addition, it should be noted that there is legal uncertainty about whether a letter from the central government asking for a certain percentage of imported coal to be blended is necessarily binding on the generators.

Since the impact of such procurement will affect what consumers ultimately pay for electricity, and given the legal uncertainty about the binding nature of any such letters, a threshold impact on ECR should be the basis of seeking such consent from beneficiaries instead of the blending % by weight.

We request the Commission to:

- Cap blending of fuel without beneficiary consultation based on impact on ECR (say up to 10% of ECR).
- Ensure prudence in the selection of alternate fuel procurement sources.

7. Capping input price of coal from integrated mines

The input price of coal from integrated mines is eventually passed on to consumers. The input price, as computed the draft Reg 38, 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 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."* ***[Emphasis added]***

In view of the above, the input 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. The Maharashtra ERC has adopted such a measure in the second amendment to its 2019 MYT Regulations.

We request the Commission to:

- Cap the input price of coal from integrated mines at the CIL notified price for the corresponding grade of coal.

8. Provision of PLF incentives for older plants

Draft Reg 70 A (b) and B (b) introduce relaxations in availability and PLF operational norms for coal/lignite based generating stations completing 30 years from COD as on 31st March 2024. Proposed Reg 62 (6) incentivises generation above the normative PLF during peak and off-peak hours.

However, several generating stations older than 30 years have been near-consistently operating at PLFs higher than the proposed laxer normative PLF. This is especially true of older pit-head central generating stations which have recovered all their costs and still are eligible for RoE basis their gross fixed assets though they are fully depreciated. Of the total pithead central capacity older than 30 years, around 65% generated at PLFs greater than the proposed 80% in FY23. Similarly, in April-December 2023, around 53% of the total pithead central capacity older than 30 years generated at PLFs greater than 80%. Therefore, these plants are getting scheduled very regularly and do not need any additional incentives for generation.

As discussed in Section 4 of this submission, PLF incentives are over-and-above all cost recovery and the RoE to the generator. Thus, the Commission should ensure that the NAPLF defined in Draft Reg 70(B) remains at 85% for pithead plants older than 30 years. The Commission can consider reducing it to 80% for non-pithead plants older than 30 years. NAPAF can also be adjusted accordingly.

We request the Commission to:

- Ensure that the NAPLF for pithead plants older than 30 years remains at 85%, with corresponding NAPAF
- Consider NAPLF of 80% for non-pithead plants older than 30 years as proposed in the Draft Regs

9. Application of primary frequency response incentive

Draft Reg 62 (5) and 65 (4) introduce incentives of up to 1% and 4% of the annual capacity charge on average monthly frequency response performance, for thermal and hydro generating stations, respectively. The basis for considering 1% and 4% of the annual capacity charge for thermal and hydro stations has not been clarified in the Explanatory Memorandum.

However, as per the Indian Electricity Grid Code, thermal and hydro stations are mandated to provide a stipulated primary response. The Grid Code also outlines the assessment of frequency response performance. Thus, such operation is mandated from the generator, and hence there is no need for provision of an incentive to meet a stipulated norm.

We request the Commission to:

- Withdraw incentivisation on average monthly frequency response performance.

10. Allowance of costs related to ECS

Draft Reg 63 links the Emission Control System (ECS) related fixed cost recovery with the availability of the plant itself, and as per draft Reg 64 (2), the ECR impact of ECS is computed based on scheduled energy of the plant.

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 either on the basis of the generator procuring suitable certification from CPCB or respective SPCB for adherence.

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 charges for such units/stations from consideration for MoD till the final deadline (31st December 2027). After that, supplementary charges 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 2.

Table 2. Proposed treatment with regard to adherence to revised emission norms post final deadline

	If ECS CapEx is not incurred	If ECS CapEx is incurred
If 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 PCE related FC and VC; Apply notional additional penalty to compute MoD so as not to give unfair advantage

Source: Prayas (Energy Group)

We request the Commission to:

- Allow ECS cost recovery (FC and VC) based on compliance to the norms, which can be linked to certification from the respective PCB 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 2, so as to avoid unfair advantage to non-compliers.

11. Inputs on financial aspects

11.1. RoE consideration

The second proviso of draft Reg 30 (3) offers RoE based penalties/incentives for certain technical and operational parameters.

Since RoE can be an effective lever in influencing optimal operation, the Commission could consider the RoE in two parts – Base RoE and Performance-based RoE. Given the nature of the power sector in India, there is almost guaranteed off-takers for any central capacity addition, making them fairly low-risk investments. It should be noted that the annual return of the stock market (Nifty50) – considered fairly risky investments – has averaged 13.12% over the past 10 years. Therefore, the Base RoE should be below this value – say 12.5% or 13%.

An additional performance-based RoE of, say, 1.5% should be linked to actual performance by the generator. Performance-based RoE could be linked to parameters such as better than expected SHR, in addition to existent parameters.

Reg 30 (3) also offers a higher RoE (of 17%) for new hydro (storage type hydro generating stations, pumped storage hydro generating stations and run-of-river generating station with pondage) projects. As recognised in Para 4.16 of the CERC's approach paper "***Hydro generating stations except ROR based are already allowed 1% higher RoE, however, not much capacity addition has been witnessed in recent times*** *due to delays so additional RoE in the form of timely completion of projects may also be an option to attract investors.*" ***[Emphasis added]***

Given that hydro projects already receive a higher RoE, despite which not much capacity addition has been seen, there is no justification for further upward revision of RoE for new hydro projects.

We request the Commission to:

- Consider a two-part RoE, with a base RoE that is allowed in accordance with provisions in the regulations but reflective of the low-risk nature of these investments, and a performance-based RoE that is contingent on improvement in actual performance and operation.
- Consider performance-based RoE for parameters such as improved SHR, in addition to the existent parameters.
- Withdraw the higher RoE provided for new hydro projects

11.2. Rate of interest on long term loans

As per draft Reg 32, the WARoI on the actual loan portfolio is considered for long term loans. However, unlike the cap on interest on working capital loans, there is no cap on interest on long term loans. Towards ensuring cost prudence and optimal selection of financing options, the Commission should introduce a cap on the RoI allowed, which can be linked to the prevalent MCLR.

The Commission has revised the reference rate of interest used for working capital borrowings downward, to MCLR+325 basis points (draft Reg 3 (66)). While this is appropriate, there is precedence of state ERCs considering even lower reference bank rates. For example, Maharashtra ERC's tariff regulations 2019 and Gujarat ERC draft Tariff regulations 2024, both consider MCLR+150 basis points. Given that central projects are likely to get lower cost finance than state generators, the CERC should also revise their reference rate of interest to MCLR + 150 basis points.

We request the Commission to:

- Cap the interest on long term loans by linking them to MCLR.
- Reduce the reference bank rate to MCLR+ 150 basis points.

11.3. Gain and loss sharing

The gain and loss sharing mechanism outlined in draft Reg 81, stipulates sharing of impact on account of performance with regard to the operational norms in a 1:1 ratio. Towards reducing the burden on the consumer, the Commission should consider passing on 2/3rd of the gains as rebate, and 1/3rd of the loss as an additional charge in tariff, to the consumer. This practise is seen in several states.

We request the Commission to:

- Implement gain and loss sharing on account of performance on operational norms, such that 2/3rd of the gains and 1/3rd of the losses is shared with the beneficiary.

11.4. NFA consideration for NCLT projects

As per draft Reg 19 (5) the lower of the GFA or acquisitional value is considered for capital cost approval of NCLT projects. However, GFA considers an inflated asset base and does not account for depreciation over time, especially for plants under operation. NFA on the other hand, accounts for depreciation over time, and is the appropriate measure to use at least in case of capital cost of NCLT projects. Thus, the Commission should consider the lower of the NFA or acquisitional value for capital cost approval of NCLT projects.

We request the Commission to:

- Consider the lower of the NFA or acquisitional value for capital cost approval of NCLT projects.

12. Definition of operational life

Draft Reg 3 (88) introduces operational life for thermal and hydro plants (35 and 50 years, respectively) as part of the definition of Useful Life, which is defined as 25 and 40 years for thermal and hydro projects, respectively.

The reasoning for the consideration of 35 years as the operational life for thermal projects is unclear. For instance, the Companies Act states that the useful life of TPPs is 40 years.

Towards clarity, the Commission should provide a clear and separate definition for operational life and clearly indicate in the regulations where operational life should be considered, and where useful life should be considered.

We request the Commission to:

- Provide a clear and separate definition of operational life and where it is to be used.
- Justify the choice of operational life of thermal/hydro projects.

13. Clarifications regarding hydro, PSP and transmission projects

Draft Reg 65 includes the computation and recovery of AFC for hydro generating stations, and draft Reg 66 includes AFC computation and recovery for pumped hydro projects. However, the AFC breakdown in the case of combined hydro projects, with both hydro generation and pumped storage operations is not clear.

Draft Reg 65(10 proposes an incentive for generation over scheduled energy during peak hours to ROR hydro stations. However, it is not stated if this is only applicable to ROR hydro stations with pondage since it is unclear how ROR hydro stations without pondage can schedule their generation to match peak load.

Draft Reg 36 (3) talks about additional O&M expenses for transmission assets in north-east and hilly regions. No basis for consideration of "1.5" factor is provided either in draft regulation or EM shared with the draft. Also, the additional O&M expense is applicable only to transmission licensees with assets only the said regions, and are thus not available for all transmission assets in said regions. In this regard, we suggest that the additional expenses should be applicable on each transmission asset in the said regions. In case a line is partly on hilly/ NE region and partly on plain terrain, the O&M expenses of hilly/ NE region should be considered proportionally.

We request the Commission to:

- Provide clarity on the treatment of AFC in the case of projects with both hydro generation and pumped storage operations.
- Clarify the operationalisation of the generation incentive applicable to ROR hydro stations.
- Ensure that the additional O&M expenses are applicable on each transmission asset in hilly/NE regions, with it being considered proportionally for lines that are partly in said regions.

14. Sale of un-requisitioned surplus power

The sale of un-requisitioned surplus (URS) power on market platforms enables better utilisation of the capacity in the system. This has also been recognised in the draft Electricity (Late Payment Surcharge and Related Matters) Amendment Rules, 2023 – which requires generating companies to offer its URS power in the power exchange.

Tracking of URS power becomes crucial towards understanding its effective utilisation and its impact on beneficiaries. The Commission should mandate generating companies to report details regarding URS capacity, including URS capacity sold and platform of such sale and benefits shared with beneficiaries. Such reporting should be made available on the generator's website periodically, say every month.

We request the Commission to:

- Mandate the publication of details regarding URS capacity of generators (including URS capacity, URS capacity sold and platform of such sale, and benefits shared with beneficiaries) on the generator's website periodically, say every month.

15. Decommissioning of assets

Draft Reg 35 discusses the decommissioning of assets before the completion of their useful life on account of factors not attributable to the project proponent.

In addition to this, the cost impact of decommissioning TPPs in general must be accounted for. Given the transition that the sector is undergoing, closure of coal-based assets is going to be increasingly common in future. Closure of coal-based assets is likely to involve costs for physical asset closure and disposal, and aspects such as addressing social and environmental impacts. Providing regulatory clarity regarding this aspect in advance of expected closure of assets is crucial.

Accounting for decommissioning costs is going to have different impact on capacity with different vintages. Accounting for these costs in the case of assets which are near or past the end of their useful life, for instance, will require different considerations than those for plants which have significant balance operational life or are new/yet to be commissioned. The Commission should put out a staff paper discussing approaches to deal with the impact of decommissioning costs of thermal capacity with differing vintages under its jurisdiction. The staff paper should be open to deliberation from stakeholders through a public process, given that decommissioning costs are likely to impact consumer tariffs. Regulations for cost recovery related to decommissioning can be based on the results of the public deliberations.

We request the Commission to:

- Publish a staff paper discussing approaches to deal with the impact of decommissioning costs on thermal capacity with differing vintages under its jurisdiction, subject to public process.

16. Database of benchmark capital costs

The Commission, as per draft Reg 20 (4) has required generating companies and transmission licensees to furnish capital cost for new and existing projects, towards the preparation of a database of benchmark capital cost of various components.

This is a good step towards ensuring transparency and prudence of costs, and simplification of cost approvals going forward. The Commission should prepare this database at the earliest (say, by 31st December 2024), and make it accessible to the public on its website. The timely submission of petitions (by 31st October 2024, per draft Reg 9(2)) becomes even more pertinent, and generators and transmission licensees should be strictly penalised for delays in submission of the petition and such data.

We request the Commission to:

- Prepare and publish the database of benchmark capital cost on its website at the earliest (say, by 31st December 2024)
- Penalise generators and transmission licensees that do not submit such data by 31st October 2024.

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