Centre for Energy Regulation

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28th Jan. 2019

Mr. Sanoj Kumar Jha
Secretary
Central Electricity Regulatory Commission
3 rd & 4 th Floor, Chanderlok Building,
36, Janpath, New Delhi- 110001

Subject: Comments on "Draft Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2019 for the tariff period from 1.4.2019 to 31.3.2024"

Dear Mr. Naik,

This is with reference to the "Draft Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2019 for the tariff period from 1.4.2019 to 31.3.2024" issued by CERC. I have gone through the draft regulations and record some of my comments on the same. Some additional issues are also highlighted in the comments attached.

I would like to highlight that some of the proposed changes and some of the existing aspects may lead to increase in tariff burden on the ultimate consumers. Some methodological improvements have also been highlighted for consideration.

I would like to request propose a presentation through skype.

I would be pleased to address any clarification, if required.

Thanking you,

Yours sincerely,

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Comments on "Draft Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2019"

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1. **Separate Fixed Charge for Peak and Off-peak period:** Proposal for time of day based fixed charges needs a reconsideration.

   - Justification for time-of-day based fixed charges would be greater if the cost associated with the peak and off-peak hours are different (this is not the case).

   - The argument that this may incentivise higher availability during peak hours can be of value only if there is evidence of poor availability during peak hours.

   - Implementation framework for the proposed ToD based fixed charges, *ceteris paribus*, would enhance overall recovery of fixed charges, thus increasing the ultimate burden on the consumers. [51]

   - The proposed formulation may also require modification of the power purchase agreements, specifically those of independent power producers. [51]

   - The load profile, and thus the duration and time of occurrence of peak, varies within the same region across seasons. Thus, declaration of peak and off-peak periods in a region by the concerned RLDC on a monthly basis may not be in congruence of actual 'peak' demand the states in a region. [51. (3)]

   - The relative difference in weights for peak and off-peak periods will not incentivise maintenance of availability during peak hours unless it is augmented with a relative difference in the normative availability requirement between the two periods (51(2)).

   - The basis for selecting the multiplying factor as 1.25 should to be supported with some justification so that it delivers the impact it is intended to. [51. (2)]

   - The terms NPAFp and NPAFop are not defined. It is desirable to define NPAFp > NPAFop.

2. **Computation of Annual Fixed Cost (Chapter 8)**:

3. The clause may be modified as: "Provided that if there is no actual loan for a particular year but normative loan is still outstanding, the last available weighted average rate of interest, **adjusted for the change in bank rate since the last weightage average rate of interest** shall be considered." [32. (5)]

4. The clause may be modified as: "[…] In case of multiple units of a generating station or multiple elements of transmission system, weighted average life for the generating station **or** the transmission system shall be applied […]" [33. (2)]

5. **Salvage value for hydro and for thermal plants should be retained at existing levels** and may be differentiated across thermal and hydro plants. We suggest that it should be retained at 10% for thermal, and lower (say 5%) for hydro – due to the composition of assets of these plants. [33. (3)]

6. Further, income accruing out of the sale of assets above salvage value (book value) after adjusting for any capital gains tax should be shared with the beneficiary of the plant.

7. Although 33. (3) allows for 100% depreciation of IT equipment and software, the header for the same (p) in Appendix-I allows for 85% depreciation of the same. [33. (3)]

8. **Interest on working capital – Captive Mine:** Since coal stock requirement for the generating plants with integrated coal mine would be minimal, allowance for working capital and interest thereof should not be same as that for other plants (i.e. 15/20 days) but much less. [34. (a) (i)]

9. **Interest on working capital** – **Moreover, it has often been noted that thermal generating stations report critical coal stock of less than a week, sometimes of a few days**. Working capital and interest thereof should reflect the actual situation on the ground. Alternatively, risks arising out of coal stock below the normative inventory level should be completely borne by the generating plant, who can in turn pass on the same to the coal supplier. Provision for 15-20 days of coal stock while still facing the risk of plant unavailability due to coal shortage. Consumer is the loser in either case and bears the risk on both sides, a rather unfair situation for the consumers.

10. Period of scheduled maintenance should be excluded for estimating working capital requirement for the relevant quarter. The period of scheduled maintenance is excluding while estimating availability. Hence, analogous principle should apply in this case as well. [34. (a)]

11. Further, to provide for lower of the actual and the normative availability, 34. (a) (i) may be modified as: "[…] for generation corresponding to the **actual plant availability factor** or maximum coal/lignite stock storage capacity whichever is lower […]"
12. **Return of equity -** Return of equity should be determined based on appropriate models for cost of capital [30]. A study by IIT Kanpur earlier had found that regulated returns were higher than the one the market provides for.

13. **Incentive for excess generation would work against desirable target frequency at 50 Hz:** Incentive in energy charges for scheduled generation beyond the normative quarterly plant load factor (NQPLF) is undesirable as it **would encourage over injection** that may cause frequency deviation. A reminder of the good old days before implementation of the ABT regime.

14. **Formula Corrections:** The formula of energy charge rate for coal based and lignite fired stations has a misplaced bracket. [52. (2) (a)]. The formula may be re-written as:

    ECR = {(SHR – SFC x CVSF) x LPPF /CVPF + **(**SFC x LPSFi + LC x LPL**)**} x 100 /(100 – AUX)

15. The term (100-FEHS)/100 gets cancelled out in the formula for energy charges (hydro). It should be included once –in either the formula for energy charges or the energy charge rate. [54. (4)]

16. The formulas for computation and payment of transmission charge for Inter-State Transmission system and communication system should be modified as under [56. (2)]:

    For AC system:

    (b) For TAFM 98.00% < TAFM ≤ 98.50%.....

    (d) For TAFM > 99.75%.....

    For HVDC bi-pole links and HVDC back-to-back Stations:

    (b) For TAFM 95.00% < TAFM ≤ 97.50%.....

    (d) For TAFM > 99.75%.....

17. **Equity Reduction Post Loan Repayment - Capital Structure (Chapter 5 – 17(6))**:

    Accumulated depreciation less loan repaid should be used for reduction in equity base for provision of RoE and should be implemented immediately on loan repayment.

    During any year prior to end of useful life, if permissible depreciation amount is more than the actual loan repaid, the excess depreciation amount should be used to reduce equity base for RoE. This is important as the excess depreciation is held back by the investors and its equity exposure to the project is reduced.

    Further, the concept of normative/admissible equity vs actual equity should be followed (in this case) as in the case of 70:30 debt-equity ratio used to compensate for RoE. [17.]

18. **Computation of Capital Cost (Chapter 6)**:
    i. If hedging cost is already passed through (Sections 78, 79), then it is not justifiable to have associated profit/loss passed through (Section 18 (2) (c)). Hence, the following modification may be made: ‘Any gain or loss on account of foreign

exchange risk variation pertaining to the loan amount availed during the construction period, **to the extent that is not hedged**' [18. (2) (c)]

ii. Prudence check of capital expenditure based on **National and International benchmarks** should be retained (as in previous T & C). Reliance on historical data would keep the inefficiency alive and would have adverse incentive not to reduce cost as it would have implication on all future capital cost. [19. (1)]

iii. Carefulness in judgements and execution related decisions is subjective in nature. [19. (1)] The clause may be modified as under:

"Provided that, while carrying out the prudence check, the Commission shall also examine whether the generating company or transmission licensee, as the case may be, has been careful in its **judgments and decisions in design and execution of the project, including procurement process and other relevant aspects**."

iv. CERC should have a say in the appointment of an independent agency or an expert body for the purpose of vetting of capital cost of the hydro-electric projects, in line with prevailing or fresh guidelines for the same. [19. (2)]

v. Time and cost over-runs on account of land acquisition **attributable to the generating company or the transmission licensee** should be retained in list of controllable factors while those not attributable to them should be in the list of uncontrollable factors. [21]

vi. Cost of hedging – Actual amount of loan or normative loan amount up to 70% of the cost of debt whichever is higher is considered for the purpose of allowing cost of debt (and hence equivalent RoE). However, **hedging cost on actual amount of foreign loan rather than normative amount, be permitted.** Since this cost is only due to the extent of foreign loan and actual hedging undertaken, consideration of normative loan for considering hedging would result in additional undue cost burden for the buyers and the ultimate consumers.

19. Computation of Additional Capital Expenditure (Chapter 7):

i. Clause 23. (2) may be modified as: "The generating company or the transmission licensee, as the case maybe shall submit, **along with the application for determination of tariff**, the details of works […] for execution"

ii. Scope of additional capitalisation items should be generic rather than on account of any specific requirement (for example, 'ash dyke'). [24 (g)]

iii. Cost-benefit analysis should go beyond expected regulatory changes in other fields as well. For example, change in environmental laws, regulations and standards. [26 (2)]

iv. Additional capitalisation on account of **capital expenditure to enhance flexible/variable operation of the plant** to address variability of renewable energy sources) should also be allowed under the head of renovation and modernisation. [26]

v. Any capitalisation/capital expenditure borne by Power System Development Fund (PSDF) or any other such domestic/international concessional funding, if any, should be appropriately accounted for. Normative loan must exclude the additional capitalisation/capital expenditure on account of capital expenditure, including concession/funding, if any, corresponding to such funding.

vi. Operational norms post R & M should not more remain relaxed as capex would have been justified on account of improvement in operational parameters.

vii. To address situations wherein all beneficiaries do not consent to a generating station intending to undertake renovation and modernisation, a proviso should provide for conflict resolution. [26. (1)]

20. Special Provision for Plants after their useful life:

i. It is important to clarify whether Special Provision and Special Allowance are mutually exclusive or linked. Can thermal generating stations already having availed Special Allowance also reap the benefits of Special Provision or be allowed to exit the contract for a plant for which buyers would have recently footed the R & M bill? [27/28]

ii. Thermal generating stations availing Special Provision after the completion of 25 years of operation from the commercial operation date would have higher even higher 'total per unit cost' (fixed + variable), reducing their dispatch except in the case of peak/shortage. [28]

iii. It is not clear if the 'fixed' cost of plants availing special provision are distributed over the period of 'scheduled' generation or across the whole period (month/quarter/year) for which such provision is applicable. In the case of the former, the 'per unit' fixed cost component would be significantly higher, making such plants less probable to be included through an MoD (except in peak periods, depending on cost structure). More clarity with some of the pertinent examples and discussion would be useful.

21. Norms of Operation (Chapter 12):

The following points may be considered in **Norms of Operation (Chapter 12)**:

i. Normative Quarterly Plant Availability Factor (NQPAF) should not be reduced to from 85% to 83%. Otherwise, this would give a signal for laxity on part of the generating plants and would also enhance overall tariff burden for the utilities and the ultimate consumers. Further, with improvement in technology and operational practices there does not seem to be a justification for lowering PAF. [59]

ii. The normative gross station heat rate for generating stations having a combination of 200/210/250 MW sets and 500 MW and above sets should be the **weighted average gross station heat rate based on actual energy generated by the combination of units**. Weighted average of station heat rate based on declared capacity gives undue benefits on account of generating units having lesser declared capacity. [59. (C) Note 2]

iii. The station heat rate should have tighter range under a regulatory jurisprudence providing incentive for efficiency improvement. Otherwise, the long-term signal to the sector would encourage inefficiency. Any economically justifiable R & M to improve efficiency could always be presented before the commission. [59. (C)]

iv. The clause may be modified as [59. (C) (b) (i)]:

"For coal-based and lignite-fired thermal generating stations:

(1.05 or deviation as agreed in the equipment purchase contract, whichever is lower) x Design Heat Rate (kCal/ kWh)."

The reason for 5% relaxation in heat rate to new thermal generation stations needs to be justified. Given that the EPC contract already provides for a 'guaranteed' heat rate, any relaxation would only encourage laxity on the part of the generating company to ensure that EPC conditions are met. Consumers should not be made to bear for this lapse. Further, the presence of heat rate 'guarantee' (with a deviation range) also means that while the generating station is compensated by the EPC contractor, it also gains additional economic gains due to 5% relaxation in the heat rate used for tariff. This reminds one of the first IPP in the country that had similar contractual arrangements and were scoffed at.

v. The heading should be modified as [59. (C) (b) (i)]: "New Thermal Generating Stations achieving COD on or after **01/04/2019**:"

vi. The maximum design heat rate of generating stations having electrically-driven boiler feed pumps should not be greater than those having turbine-driven boiler feed pumps as it contradicts the clause in (59. (C) Note 2). [59. (C) (b) (i)]

22. The following points may be considered in **Scheduling, Accounting and Billing (Chapter 13)**:

i. Late payment surcharge should be applicable at the (marginal) bank rate instead of a fixed rate of 1.25%. [69]

ii. Static synchronous compensation (STATCOM) has been included in the text but not in the formula for calculation of transmission system availability factor for a calendar month. [Appendix II, 2]

iii. The following should be retained as in the existing T&C for tariff regulations because the weightage factor of a line should be a function of power transfer capability of the line (Appendix - III) to capture the relative importance of lines having capability to transfer more power. [Appendix II, 3 (a)]

"For each circuit of AC line – **Surge Impedance Loading (SIL) for uncompensated line multiplied by ckt-km**"