TATA

28th January 2019

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

Sub: Comments/ Suggestions 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 Sir,

This is with reference to the public notice issued by CERC pertaining to 'Draft Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2019 for the tariff period from 1.4.2019 to 31.3.2024' having reference no: No. L-1/236/2018/CERC dated 14th December 2018, inviting comments/ suggestions on the same.

Tata Power's comments to the said publication are elaborated under **Annexure,** enclosed herewith. We request the Hon'ble Commission to allow us to submit additional comments, if any, by 31st Jan 2019. We further request the Hon'ble Commission to grant an opportunity to all stakeholders to share their views by conducting a public hearing on the above matter.

Yours sincerely,

Pankaj

Mr. Pankaj Prakash
(Head - Regulatory (ER))

TATA POWER
The Tata Power Company Limited
"Shatabdi Bhawan", B-12&13, Sector-4 Noida 201 301 (U.P.)
Tel.: 91 120 610 2000
Registered Office Bombay House 24 Homi Mody Street Mumbai 400 001
Website : www.tatapower.com Email : tatapower@tatapower.com
CIN : L28920MH1919PLC000567

<u>ANNEXURE: TATA POWER'S VIEWS ON DRAFT CENTRAL ELECTRICITY REGULATORY COMMISSION (TERMS AND CONDITIONS OF TARIFF) REGULATIONS, 2019</u>

1. Clause 3(2) and 3(3)

   *3(2) **'Additional Capital expenditure**' means the capital expenditure incurred, or projected to be incurred after the date of commercial operation of the project by the generating company or the transmission licensee, as the case may be, in accordance with the provisions of these regulations;*

   *3(3) **'Additional Capitalisation'** means the additional capital expenditure admitted by the Commission after prudence check, in accordance with these regulations;*

   <u>Our Views and observations</u>
   We understand that Hon'ble Commission has mentioned the above two definitions separately to differentiate between the GFA block which may be appearing in the books of accounts as per Company Act and the GFA block which may be admitted by Hon'ble Commission for determination of Tariff. Accordingly, we propose the following changes in the proposed regulations 3(3) for ensuring clarity in the matter.

   *3(3) **'Additional Capitalisation'** means the additional capital expenditure admitted <u>to be capitalised for tariff determination</u> by the Commission after prudence check, in accordance with these regulations;*

   We submit that there during the development stage of the project and even during Work In progress stage for Additional Capitalisation Projects, while the developer is given an opportunity to recover the Interest expenses (i.e IDC) associated with such projects upon scrutiny, he is not allowed to recover any return on equity deployed on such projects for the construction period thereby denying him an opportunity to claim a return against the risk he undertakes during the construction period. Further, though the CEA report cited in Explanatory Memorandum (EM) states that no new capacity addition is required till 2027, the planning for such capacity shall have to start in this tariff period. We humbly submit that Hon'ble Commission may consider to introduce a reasonable rate of return for such equity deployed in Capital Work in Progress which may be approved only after prudence check.

2. Clause 3(14)

   *3(14) **'Cut-off Date**' means the last day of the calendar month after three years from the date of commercial operation of the project;*

   <u>Our Views and observations</u>

   We submit that statutory requirements (as per Companies Act) mandates companies to conduct the audits on a quarterly basis. Hence, to synchronize with the existing statutory process and to avoid any additional administrative burden, we humbly submit that Cut Off date may be linked to the last day of the quarter after three years from the date of commercial operation of the project instead of linking it to last day of the calendar month after three years from the date of commercial operation of the project.

3. Clause 3(26)

   (26) 'Force Majeure' for the purpose of these regulations means the event or circumstance or combination of events or circumstances including those stated below which partly or fully prevents

the generating company or transmission licensee to complete the project within the time specified in the Investment Approval, and only if such events or circumstances are not within the control the generating company or transmission licensee and could not have been avoided, had the generating company or transmission licensee taken reasonable care or complied with prudent utility practices:
(a) Act of God including lightning, drought, fire and explosion, earthquake, volcanic eruption, landslide, flood, cyclone, typhoon, tornado, geological surprises, or exceptionally adverse weather conditions which are in excess of the statistical measures for the last hundred years; or
(b) Any act of war, invasion, armed conflict or act of foreign enemy, blockade, embargo, revolution, riot, insurrection, terrorist or military action; or
(c) Industry wide strikes and labour disturbances having a nationwide impact in India;
(d) Delay in obtaining statutory approval for the project except where the delay is attributable to project developer;

<u>Our Views and observations</u>
While, the above definition of Force Majeure events broadly cover all possible events of Force Majeure, we understand that based on the past experiences of the sector and the trend of events being observed in current scenario around us, two more eventualities may be considered for inclusion in the above definition:

- Any failure or delay by the Contractor of the project developer due to some Force Majeure events to the extent it is compensated by any offsetting compensation being payable to the project developer by or on behalf of such Contractor
- Any direct or indirect cyberattack affecting the operation of the project developer

We humbly submit to this Hon'ble Commission that the above two mentioned eventualities are completely beyond the project developer's control and hence, may be considered by Hon'ble Commission for inclusion in the definition of Force Majeure.

In addition to the above, we propose certain minor changes in the above Regulations so as to impart clarity to the relevant sections as below:

(26) 'Force Majeure' for the purpose of these regulations means the event or circumstance or combination of events or circumstances including those stated below which partly or fully prevents the generating company or transmission licensee to complete the project <u>or any Additional Capitalisation</u> within the time specified in the Investment Approval <u>or hampers or adversely affects its operational performance after its Commercial Operation Date</u>, and only if such events or circumstances are not within the control the generating company or transmission licensee and could not have been avoided, had the generating company or transmission licensee taken reasonable care or complied with prudent utility practices:
(a) Act of God including lightning, drought, fire and explosion, earthquake, volcanic eruption, landslide, flood, cyclone, typhoon, tornado, geological surprises, or exceptionally adverse weather conditions which are in excess of the statistical measures for the last hundred years; or
(b) Any act of war, invasion, armed conflict or act of foreign enemy, blockade, embargo, revolution, riot, insurrection, terrorist or military action; or
(c) Industry wide strikes and labour disturbances having a nationwide impact in India;
(d) Delay in obtaining statutory approval for the project <u>or additional capitalisation or operation</u> except where the delay is attributable to project developer;

4. Clause 3(42) and 3 (78)

*3(42) **'Landed Fuel Cost'** means the total cost of coal (including biomass in case of co-firing), lignite or the gas delivered at the unloading point of the generating station and shall include* *the base price or input price, transportation cost (overseas or inland or both) and handling cost and applicable statutory charges;*

Read with

3(78) ***'Unloading point'*** *means the point within the premises of the coal or lignite based thermal generating station where the coal or lignite is unloaded from the rake or truck or any other mode of transport;*

Our Views and observations

We appreciate the proposal of this Hon'ble Commission to introduce the definition of Landed Fuel Cost in its Tariff Regulations. This inclusion will bring clarity on the parameters which shall be billed by the Generating Companies to their respective beneficiaries and would diminish the disputes which are raised by beneficiaries. However, we request this Hon'ble Commission to kindly clarify further in the matter and stipulate that cost of sampling, preparation and testing shall be allowed for built in Landed Fuel Cost by the generating companies.

5. Regulation 6(1)(b)

6. Treatment of mismatch in date of commercial operation*: (1) …*

(b) Where the associated transmission system has not achieved the commercial operation as on the date of commercial operation of the concerned generating station or unit thereof, the transmission licensee shall make alternate arrangement for the evacuation from the generating station at its own cost, failing which, the transmission licensee shall be liable to pay the transmission charges to the generating company at the rate of the applicable transmission charges of the region as determined in accordance with the Sharing Regulations till the transmission system achieves the commercial operation.

Provided that despite making alternative arrangement of evacuation, if the associated transmission system does not achieve the date of commercial operation within the six months of date of commercial operation of the generating station, the transmission licensee shall be liable to pay to the generating company the applicable transmission charges of the region as determined in accordance with the Sharing Regulations in addition to the above.

Our Views and observations

Regulation 6(1)(a) and Regulation 6(1)(b) stipulates for compensation amount payable by Generating company and the Transmission Licensee respectively for the delay in commissioning of the respective projects leading to mismatch of date of commercial operation with the non-defaulting counter party. We submit that while calculating the delay period for the purpose of the computing the penal amount, due consideration should be given to delays caused by the defaulting party due to various recognised uncontrollable factors.

In the matter of alternate arrangement, we are aware that most of the thermal projects are usually of considerable capacity and thus, in most cases, it is always a requirement by the CTU to build additional transmission capacity for dispatch of power from such upcoming project. At the same time, it is always needed that associated Transmission assets of the Transmission Licensee should always get commissioned much earlier than commissioning of the generation project as there are various Pre - COD activities of the generation project dependent on the availability of the Transmission Licensee starting from availability of Start Up Power to commencing of injection of infirm power. Therefore, the Scheduled COD of the Generating Company/Transmission Licensee should be defined in advance by the parties beforehand and the penalties should be linked with respective SCODs. In view of this, it's probable that the alternate arrangement which may be made available to the Generator is capable of evacuating the power generated (without abnormal congestion) and hence, the practice of making the generator dependent on a temporary alternate arrangement for six months may not be an appropriate step. Hence, we humbly submit that if at all the concept of such proposed alternate arrangement needs to be retained, this Hon'ble Commission shall decide the basic requirements to be fulfilled by the Transmission Licensee for making its proposed arrangement qualify under such alternate arrangement as envisaged by Hon'ble Commission. We also request this Hon'ble Commission to reduce this dependency time on alternate arrangement to maximum of 2 months and thus, counter for payment of penalty amount payable by the Transmission Licensee should commence immediately after that if the Licensee fails to achieve SCOD of its project by then.

Also, it is to be noted that while the penal amount as per Regulation 6(1)(a) appropriately addresses the Transmission Licensee's concern for its opportunity cost which is being compensated by the Generating Company, the penal amount proposed for payment by the Licensee to the Generating company due to delay at Licensee's end as per Regulation 6 (1) (b) may not be sufficient to compensate for the losses of the Generating Company in events of delay by Transmission Licensee . Hence, we request this Hon'ble Commission to devise a mechanism or procedure for compensating the Generating Company for such losses appropriately.

6. Regulation 8(3)

In case of expansion of existing generating station, the tariff shall be determined for the expanded capacity in accordance with these regulations:

Provided that the common infrastructure of existing generating station, shall be utilized for the expanded capacity and <u>the benefit of new technology</u> in the expanded capacity shall be <u>extended to the existing capacity</u>.

<u>Our Views and observations</u>

Hon'ble Commission would appreciate that the existing unit may not be compatible to adopt the new technology. Also, efficiency gains [better heat rate] through new technology in the new units being applied to the existing unit would lead to unrecovered variable charge for the existing unit. Hence, the Hon'ble Commission is requested to allocate the benefit of new technology in the expanded capacity to the existing capacity only if feasible based on prudence check.

7. Regulation 9, Clause 3

9(3) In case of emission control system required to be installed in existing generating station as per revised emission standards, the application shall be made for determination of supplementary tariff (fixed charges or variable charge or both) based on the actual capital expenditure duly certified by the Auditor;

<u>Our Views and observations</u>

Hon'ble Commission would appreciate the concern that such projects to be taken up by the Generating Companies for emission control systems would involve huge investments. Generating companies are finding it difficult to attain financial closure for such projects due to uncertainty associated with such investments. In view of this, we humbly submit that the entire depreciable value (i.e 95% the project cost) of such projects shall be allowed to be recovered by the generation projects within the balance useful life of the generating stations. Further, it is desirable that tariff is determined in advance and hence, generator should be allowed to approach this Hon'ble Commission any time prior to its commissioning with actual expenditure incurred till that date for provisional tariff.

8. Regulation 10(4)

   10 (4) In case of the existing projects, the generating company or the transmission licensee, as the case may be, shall continue to bill the beneficiaries or the long term customers at the tariff approved by the Commission and applicable as on 31.3.2019 for the period starting from 1.4.2019 till approval of final tariff by the Commission in accordance with these regulations:

   Our Views and observations

   We understand that the Tariff refers to Annual Fixed Cost and the Energy Charge Rate along with other charges specified in the Regulations to be recovered by the Generating Companies from respective beneficiaries for the power supplied by the Generating Companies to respective beneficiaries. Further, we are aware that Annual Fixed Cost recoverable by the generating company is determined by this Hon'ble Commission through subsequent Tariff Orders, whereas the normative parameters for arriving at Energy Charge Rate are referred from Tariff Regulations unless specifically mentioned in respective Tariff Orders. Hence, we request the Hon'ble Commission to kindly clarify in this section that for the purpose of monthly Invoicing and till the issuance of final Tariff Order for the period beyond 31st March 2019, while the Generating Companies would rely on AFC applicable as on 31.3.2019, Normative and other parameters to be considered for Energy Charge Rate and other related charges would be applicable as per the extant Regulations applicable on 31.3.2019 or the ones applicable from 01.04.2019.

9. Regulation 11

   *11. **In-principle Approval in Specific circumstances:** The generating company or the transmission licensee undertaking any additional capitalization on account of change in law events or force majeure conditions may file petition for in-principle approval for incurring such expenditure after prior notice to the beneficiaries or the long term customers, as the case may be, along with underlying assumptions, estimates and justification for such expenditure if the estimated expenditure exceeds 10% of the admitted capital cost of the project or Rs.100 Crore, whichever is lower.*

   Our Views and observations

   We welcome this proposal of Hon'ble Commission to introduce provisions pertaining to process of In-principle approval for events of change in law or force majeure conditions. In addition, there may be situations which may not get qualified either under Change in Law or under Force Majeure, but may require immediate investments during a Tariff period instead of beginning of a Tariff Period which are necessary for efficient, safe and successful running including R & M and could not be foreseen in the beginning of control period. In view of such situations, we, humbly submit that the provision may be extended for such *unforeseen events* so as to provide an avenue to the developers to approach the Hon'ble Commission.

10. Clause 14(2)

    14(2) The supplementary fixed cost for additional capitalization on account of implementation of revised emission standards in the existing generating station or new generating station, as the case may be, shall be determined by the Commission separately;

    Our Views and observations

We wish to submit that while the Draft Tariff Regulations envisage for determination of supplementary fixed cost for additional capitalization on account of implementation of revised emission standards, provision for determination and allowance of supplementary fixed cost shall be extended also for petitions received by this Hon'ble Commission for In-Principle approval (as mentioned in above section for Change in law and Force Majeure events and other unforeseen events as requested) and shall not be postponed till process of Tariff Determination of subsequent Tariff Period.

11. Regulation 18(2) (b) and 18(3)

18 (2) (b) Interest during construction and financing charges, on the loans (i) being equal to 70% of the funds deployed, in the event of the actual equity in excess of 30% of the funds deployed, by treating the excess equity as normative loan, or (ii) being equal to the actual amount of loan in the event of the actual equity less than 30% of the funds deployed;

<u>Our Views and observations</u>

As may be referred above, clause 18 (2) (b) of the Draft Regulation specifies for inclusion of Interest during construction ("IDC") and financing charges in Project Cost for New Projects, on the loans being equal to 70% of the funds deployed, in the event of the actual equity in excess of 30% of the funds deployed. This implies that Hon'ble Commission recognises the fact that there is certain cost of financing associated with the project cost from the day of investment and thus, allows the generator to build IDC in the project cost even on normative debt (equity in excess of 30%) which is towards the cost of financing of the debt component of the project cost. Similarly, such cost of financing should also be allowed on normative debt (including equity in excess of 30%) for all additional capital projects approved by Hon'ble Commission from time to time and such cost of financing should be computed in the same lines as specified above for Project cost of new projects. Hence, we submit that such clause of 18 (2) (b) shall also be extended for additional capitalisation in existing projects and thus, be included under Regulation 18 (3) which provides for components of capital cost for an existing project.

12. Regulation 18(2) (o) and 18(3)(f)

18 (2) (o) Capital cost incurred or projected to be incurred by a thermal generating station, on account of implementation of the norms under Perform, Achieve and Trade (PAT) scheme of Government of India shall be considered by the Commission subject to sharing of benefits accrued under the PAT scheme with the beneficiaries.

…

18 (3) (f) Capital cost incurred or projected to be incurred by a thermal generating station, on account of implementation of the norms under Perform, Achieve and Trade (PAT) scheme of Government of India shall be considered by the Commission subject to sharing of benefits accrued under the PAT scheme with the beneficiaries.

<u>Our Views and observations</u>

PAT scheme implementation has set stringent operational performance targets on the utilities of various sector including power sector utilities. For certain parameters, such targets could be even more stringent than the norms approved by this Hon'ble Commission. In such cases, there is a possibility that a generation utility operating at performance levels (as approved by this Hon'ble Commission), takes up Improvement projects (of Capital nature) to meet such PAT targets and after implementation of such Capital projects may improve its operational norms as compared to earlier operating/normative levels, but fails to achieve the stringent targets set under PAT scheme by BEE due to uncontrollable factors beyond generating station's control. In short, after implementation of such Improvement Capital Projects, the actual operating levels of the generating station may end up somewhere between the earlier normative/operating levels and the stringent PAT scheme targets. As a result, the generating company will continue to share the gains (in approved ratio of 50:50) with the consumers as per the Regulation 70 due to improvement in actual operating levels as compared to earlier operating/normative levels, whereas on the other hand would have to bear the penalties by BEE for not meeting the PAT targets.

In view of the above, we humbly submit to this Hon'ble Commission that any gains for sharing under Regulation 70 shall be arrived at by netting off the losses (including penalties) incurred by the generating company under PAT scheme.

13. Regulation 21

> ***Controllable and Uncontrollable factors****: The following shall be considered as controllable and uncontrollable factors leading to cost escalation, IDC and IEDC of the project:*
> ------------------------------
>
> *(2) The "uncontrollable factors" shall include but shall not be limited to the following:*
> --
> *c. Time and cost over-runs on account of land acquisition except where the delay is attributable to the generating company or the transmission licensee;*

Our Views and observations

It is a welcome step to consider time and cost over-runs on account of land acquisition as un-controllable factor while computing the capital cost of the generating station or the transmission asset. In addition to above, we would also like to bring it to Hon'ble Commission's notice that all generation projects have certain requirement of raw water for operating their projects and water, being a natural resource is dependent on various factors including rainfall and it's supply is directly or indirectly regulated by the government bodies. In view of this, there could be situations where the generation project may get deprived of adequate supply of water impacting its operations. Hence, we humbly submit to this Hon'ble Commission to consider such instances of shortage of water for inclusion as an Uncontrollable event whether it be due to limited supply from Civic bodies or may be due to low rainfall or may be due to embargo/limitation on drawl of water from rivers.

14. Regulation 24

Our Views and observations

In the matter of Additional Capitalisation within the original scope and after the cut-off date, we wish to submit that in tariff regulation 2014-2019, the Hon'ble Commission had allowed additional capitalization under Regulation 14 (3) (ix)

> *"In case of transmission system, any additional expenditure on items such as relays, control and instrumentation, computer system, power line carrier communication, DC batteries, replacement due to obsolesce of technology, replacement of switchyard equipment due to increase of fault level, tower strengthening, communication equipment, emergency restoration system, insulators cleaning infrastructure, replacement of porcelain insulator with polymer insulators, replacement of damaged equipment not covered by insurance and any other expenditure which has become necessary for successful and efficient operation of transmission system."*

We may humbly submit that the same provision as stated above from existing Tariff Regulation 2014-19 may be retained to cover the additional expenditure on items such as polymer insulators, insulators cleaning infrastructure etc. so as to avoid any ambiguity.

15.Regulation 26 (4)

26 (4) After completion of the R&M, the generating company or the transmission licensee, as the case may be, shall file a petition for determination of tariff. Expenditure incurred or projected to be incurred and admitted by the Commission after prudence check, and after deducting the accumulated depreciation already recovered from the original project cost, shall form the basis for determination of tariff.

Our Views and observations

In reference to this matter, we wish to submit that out of the total depreciated value, while 70% of the recovered value is considered for offsetting the long term loan amount, the balance recovered value lies in the books of accounts of the generating company and is not available for the project developer for taking out of the business. In such a scenario, on any day equity invested by the developer would always continue to be 30% of the original project cost along with equity invested for subsequent additional capitalisation. In view of this, it's completely inappropriate that during any phase of the project, tariff is determined for the project based on the project cost after deducting the accumulated depreciation. Hence, we submit to this Hon'ble Commission that the particular proposed clause may be reworked so as to consider complete project cost for determination of tariff at least for the purpose of computation of Return on Equity for the Project Developer.

16.Regulation 27(3)

27 (3) The special allowance admissible to the generating station shall be @ Rs 9.5 lakh per MW per year for the tariff period 2019-24.

Our Views and observations

We submit that such norm of Special Allowance shall be allowed along with a nominal year on year escalation rate as is also provided in the existing regulations. Such nominal escalation rate may be kept equivalent to escalation rate allowed for normative O & M expenses. This nominal escalation rate is required to catch up with year on year inflation factor. Further, since no escalation has been provided for the year 2019-20, the base figure of Rs 9.5 lakhs per MW shall be allowed at least one escalation to arrive at 2019-20 norm.

17.Regulation 28

*28. **Special Provision for thermal generating station which have completed 25 years of operation from commercial operation date:***

(1) In respect of a thermal generating station that has completed 25 years of operation from the date of commercial operation, the generating company and the beneficiary may agree on an arrangement where the total cost inclusive of the fixed cost and the variable cost for the generating station as determined under these regulations, shall be payable on scheduled generation instead of the pre-existing arrangement of separate payment of fixed cost based on availability and energy charge based on schedule.

(2) The beneficiary will have the first right of refusal and upon its refusal to enter into an arrangement as above the generating company shall be free to sell the electricity generated from such station in a manner as it deems fit.

Our Views and observations

The above proposed provision provides for extension of the existing power sale arrangement from the generating company to the respective beneficiaries. The above provision suggests an arrangement providing an exclusive first right of refusal to the beneficiaries for extension of the term. So while the beneficiary is allowed to explore the market opportunities before tying up the extension period, the generators are not allowed to do so making it an unequitable proposition. Hence, we suggest that while the clause may be retained in the final set of Regulations, it shall be introduced in a non - obligatory manner for each of the party giving right to either party to decide for the extension for subsequent period on mutual agreement basis. Further, the option of continuing with existing two part tariff framework may also be provided/included.

Also, the clause has been proposed for generating stations which have already completed 25 years of operation. We wish to bring it to your notice that there are existing PPAs which have been signed for a period of more than 25 years and also there could be a situation where the PPA has been signed for certain Long Term period after a considerable operation run period of 10/12 years. For such situations, PPAs would remain operative for the generating companies even after completion of 25 years of operating period. Hence, we humbly submit to this Hon'ble Commission that such clause may be retained with a slight modification of not linking it to 25 years of operation and instead may be linked to the respective PPA term of the generating companies with respective beneficiaries.

While, the provision in the Draft does not differentiate for generating stations which have availed or not availed R&M or Special Allowance, the explanatory memorandum suggests that such clause would be only applicable for those thermal generating stations, which have neither undertaken R&M nor availed Special Allowance. We wish to draw the attention of the Hon'ble CERC to the case where a power station has multiple beneficiaries. As per the draft regulations, for submission of R&M proposal, consent of beneficiaries needs to be taken. In a scenario when the consent of only some beneficiaries and not all is available, will the developer be allowed to tie up the balance power on composite tariff basis in the market? We wish to submit that clarity may be provided that such clause with above suggested changes shall be applicable for all generating stations irrespective of them availing benefit under R & M expenses or Special Allowances.

18. Regulation 30

30. Return on Equity: (1) Return on equity shall be computed in rupee terms, on the equity base determined in accordance with Regulation 17 of these regulations.

(2) Return on equity shall be computed at the base rate of 15.50% for thermal generating station, transmission system including communication system and run of the river hydro generating station, and at the base rate of 16.50% for the storage type hydro generating stations including pumped storage hydro generating stations and run of river generating station with pondage:

Provided that:

- *i. Return on equity in respect of additional capitalization after cut off date within or beyond the original scope shall be computed at the weighted average rate of interest on actual loan portfolio of the generating station or the transmission system;*
- *ii. in case of a new project, the rate of return shall be reduced by 1.00% for such period as may be decided by the Commission, if the generating station or transmission system is found to be declared under commercial operation without commissioning of any of the Restricted Governor Mode Operation (RGMO) or Free Governor Mode Operation (FGMO), data telemetry, communication system up to load dispatch centre or protection system based on the report submitted by the respective RLDC;*

iii. *in case of existing generating station, as and when any of the requirements under proviso ii of this Regulation are found lacking based on the report submitted by the respective RLDC, rate of return shall be reduced by 1.00% for the period for which the deficiency continues.*

Our Views and observations

Hon'ble Commission in its explanatory memorandum have considered CAPM mechanism as an appropriate approach for arriving at the reasonable rate of return. We have attempted to work out the expected rate of return for the sector based on BSE indices for last five years which gives a more proper reflective results for the approaching Tariff Period as such term of five years have also been held adequate by this Hon'ble Commission for arriving the base norms for WPI/CPI and the applicable Bank rates for computing Interest on Working Capital. Such analysis suggests that the expected rate of return for the sector works out to around 14.32%. It is to be noted that CAPM suggests a rate of return which shall be applicable for any investment right from the time of investment and in other words suggests an IRR for any investment. Also, we know that Tariff Regulations issued by this Hon'ble Commission for the period of FY 2009-14 and FY 2014-19 considered a timeline of 36/42/44 months for construction of thermal generating stations depending on the specifications of the project. Accordingly, though this Hon'ble Commission itself has acknowledged a gestation period of 4-7 years in section 11.5.8 of the Explanatory Memorandum, we have for the purpose of arriving at bare minimum levels of Return, have considered a gestation period of minimum of 4 years and arrived at the bare minimum levels of post-tax return of around 19% - 20% that the generating company shall be allowed during the life of the operating project.

Hence, we humbly submit to this Hon'ble Commission that post tax Return on Equity for Thermal Generating assets and Transmission assets should be increased from 15.5% to 19% so as to ensure an IRR of around 14.3% for the useful life of the project. Brief Workings of the above exercise have been annexed as **Annexure 2** for ready reference.

As far as the Additional Capitalisation is concerned, Hon'ble Commission has proposed to reduce the applicable post tax RoE for equity associated with Additional Capitalisation (after Cut-off date) to weighted average rate of interest on actual loan portfolio instead of 15.5%. We wish to submit that sudden curtailment of RoE on equity associated with Additional Capitalisation (after Cut-off date) would be inappropriate for reasons below:

- Certain investments are statutory in nature and are required to be complied with existing or new laws regulations, directives from any court of law.
- Certain investments which were already a part of original scope of work of the projects, but would get capitalised after cut off date due to reasons beyond the developer's control.
- Other Investments which already have been made under Tariff Regulations 2009-14 and 2014-19, but have spilled over the Tariff Period FY 2014-19 and are expected to get capitalised in Tariff Period FY 2019-24.
- The proposed clause of considering only weighted average rate of long term loan as Rate of Return on Equity assumes that entire funding of such investments is made through long term loan which is completely an unrealistic proposition
- In fact, considering the huge investment requirement for capex required to meet the revised emission norms, developers are facing difficulties/reluctance from Bankers to finance such projects.
- The risk associated with equity investment of the project developer has remained the same if not increased w.r.t the risk associated with equity invested in original project cost.
- It is not appropriate to reduce the return on additional capitalisation after cut-off date already approved in previous control periods.

Considering the above situations, any curtailment in returns of above investments would be unjust for such investments and hence, we humbly submit to this Hon'ble Commission that all equity (upto normative level of 30%) infused in all approved Capital Investments shall be allowed to recover post tax RoE in tune of 15.5% or the rate (post tax RoE) which Hon'ble Commission may decide for the Original Project Cost, whichever is higher.

Also, we would like to bring to your notice a distinctive situation of investments to be made in the sector by all generating companies for complying with revised emission norms. In the present scenario, Most of the generating companies who have already achieved COD are likely to invest such huge capex requirement and achieve commissioning of emission control system in the Tariff Period FY 2019-24 and thus, as per proposal of this Hon'ble Commission, the investment for such huge additional capex would face challenges from both end i.e while, on one hand, it's going to be a challenge for the developers to secure loan for such huge additional capex requirements, on the other hand, equity for such Capex Schemes would be entitled for post-tax RoE at weighted average rate of Long term loans.

Whereas, on the other hand, Generation Projects which would get commissioned in Tariff Period FY 2019-24 are likely to include such investments in the original scope of work and thus, would recover RoE at 15.5%. This would lead to disparity among new projects and the existing projects. Hence, in view of this situation, it further becomes more relevant that such investments shall be allowed to recover post tax RoE in tune of 15.5% or the rate (post tax RoE) which Hon'ble Commission may decide for the Original Project Cost, whichever is higher

19. Regulation 32 (5),(6),(7)

32…
(5) The rate of interest shall be the weighted average rate of interest calculated on the basis of the actual loan portfolio after providing appropriate accounting adjustment for interest capitalized:
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 shall be considered:
Provided further that if the generating station or the transmission system, as the case may be, does not have actual loan, then the weighted average rate of interest of the generating company or the transmission licensee as a whole shall be considered.
(6) The interest on loan shall be calculated on the normative average loan of the year by applying the weighted average rate of interest.
(7) The changes to the terms and conditions of the loans shall be reflected from the date of such re-financing.

<u>Our Views and observations</u>

In the matter of applicable Interest Rate, the proposal is kept more or less similar to existing provision of extant Tariff Regulations, which stipulate for applicable Interest Rate as per the following conditions:

- Scenario 1: If there exists an actual loan portfolio, then weighted average rate of interest of such loan portfolio would be applicable, or
- Scenario 2: If there is no actual loan for a particular year but normative loan is still outstanding, the last available weighted average rate of interest shall be considered, or
- Scenario 3: If the generating station or the transmission system, as the case may be, does not have actual loan, then the weighted average rate of interest of the generating company or the transmission licensee as a whole shall be considered.

In view of the above provision pertaining to Scenario 2, we find it pertinent to mention that there could be a situation that a developer decides to put an ad cap with normative debt and its last actual debt got repaid 5 years back as per the books of accounts. In such a situation, allowing the last available weighted average rate of interest may not be appropriate as the lending rates undergo a considerable change even over a span of few months and instead, the normative rates should be considered as per the current trends and should be linked to a little lower rate than Bank Rate but should be linked to current trend of lending rates.

Similarly, for situations under Scenario 3, there are events that a particular station could be the only asset of the generating company and thus such separate reference may not be available for considering Interest rates of the Company as a whole. In such situations as well, it would be appropriate that the normative rates shall be considered as per the current trends and shall be linked to a little lower rate than Bank Rate but shall be linked to current trend of lending rates.

In view of the above, we humbly submit to this Hon'ble Commission that for situations under Scenario 2 and 3, rate of such normative debts may be considered as MCLR + 300 basis points (as on 1st April of respective financial year) instead of linking it to last available weighted average rate of interest of last available loan or the one applicable for the generating company as a whole.

20. Regulation 32 (5),(6),(7) read with Regulation 71

32…
(5) The rate of interest shall be the weighted average rate of interest calculated on the basis of the actual loan portfolio after providing appropriate accounting adjustment for interest capitalized:
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 shall be considered:
Provided further that if the generating station or the transmission system, as the case may be, does not have actual loan, then the weighted average rate of interest of the generating company or the transmission licensee as a whole shall be considered.
(6) The interest on loan shall be calculated on the normative average loan of the year by applying the weighted average rate of interest.
(7) The changes to the terms and conditions of the loans shall be reflected from the date of such re-financing.

Read With

71. Sharing of saving in interest due to re-financing: If re-financing of loan by the generating company or the transmission licensee, as the case may be, results in net savings on interest and in that event the costs associated with such re-financing shall be borne by the beneficiaries and the net savings shall be shared between the beneficiaries and the generating company or the transmission licensee, as the case may be, in the ratio of 50:50.

Our Views and observations

For this particular parameter, instead of immediately reaching the conclusion, we have attempted to reach to the discrepancy starting from initial stages. We know that once the project gets commissioned in any tariff period, this Hon'ble Commission based on actual commissioning details issues the final Tariff order for the project applicable for the corresponding Tariff Period. This approved AFC also includes a component of Interest on Loan which is determined as per the applicable Interest Rate and as per the norms prescribed in the relevant Tariff Regulations. In such a scenario, there are events whereby the project developer gets its loan refinanced in middle of the Tariff Period and accordingly shares the portion of the benefit with the beneficiaries at the stipulated ratio in the corresponding Tariff Regulations.

Subsequently, once the Tariff period completes, the project developer is required to file a true up petition to the project developers based on the actual operating data and details for the past Tariff Period. Let's assume that for the purpose of True -Up, there had not been any considerable change in any fact, detail and operating parameter except for the applicable Interest Rate (which got lowered due to refinancing). In such a scenario, there would be a situation that the Project Developer would have to refund the extra amount recovered (due to reduction in AFC due to actual lowered interest rates post re-financing) along with carrying cost. This would result to a situation that not only the entire benefit of refinancing gets passed onto the beneficiaries during true up, the project developer also ends up paying an additional amount to the beneficiaries in the form of the amount shared from time to time the benefits as per the relevant provisions of Sharing of Gains due to such refinancing.

In view of this discrepancy, we find it pertinent to mention that instead of considering actual applicable rates of Interest during True - up process, it would be appropriate to consider the initial rate of Interest applicable as at the beginning of the tariff period along with the effects of market forces on such interest rates. Any gain of refinancing shall not be considered at the time of true up as the gain out of refinancing shall continue to be shared with the beneficiaries as per the approved ratio from time to time. Such gain of refinancing shall be computed from the date of refinancing and by comparing it with the rate applicable on the day just prior to the date of refinancing. We have attempted to strengthen our view with the help of a demonstrative example.

Parameters	FY 11	FY 12	FY 13	FY 14	FY 15	FY 16	FY 17	FY 18	FY 19	FY 20
(A) Actual Interest Rate Principle as per the Loan Agreement	SBI PLR - 1%	SBI PLR - 1%	SBI PLR - 1%	SBI PLR - 2%	SBI PLR - 2%	Base Rate + 2%	Base Rate + 2%	Base Rate + 1%	Base Rate + 1%	Base Rate + 1%
(B) Applicable SBI PLR	12.25%	12.00%	13.00%	13.00%	12.00%					
(C)Applicable SBI Base Rate						8%	9.15%	9.15%	9%	9.05%
(D) Actual Interest Rate	11.25%	11.00%	12.00%	11.00%	10.00%	10.00%	11.15%	10.15%	10.00%	10.05%
(E)Effect of Refinancing (+ refers to increase and -ve refers to drop)				-1.00%				-1.00%		
(F) Effect of Market		-0.25%	1.00%		-1.00%	0.00%	1.15%		-0.15%	0.05%
(G) Interest Rate to be considered for Tariff True up considering only the effect of market	11.25%	11.00%	12.00%	12.00%	11.00%	11.00%	12.15%	12.15%	12.00%	12.05%
(I) Gain to be shared with the Benefciaries considering 60:40 ratio	0.00%	0.00%	0.00%	0.40%	0.40%	0.40%	0.40%	0.80%	0.80%	0.80%
(J) Realised Interest Rate in Tariff	11.25%	11.00%	12.00%	11.60%	10.60%	10.60%	11.75%	11.35%	11.20%	11.25%
(K) Gain to be retained by the Generator	0.00%	0.00%	0.00%	0.60%	0.60%	0.60%	0.60%	1.20%	1.20%	1.20%

Hence, we submit to this Hon'ble Commission to consider our proposal that the applicable Interest rate shall never be reset during the term of any tariff period after COD except for changes pertaining to market effect and any benefit of refinancing shall be worked out based on actual Interest Rates realised by the Project Developer viz-a-viz the long term interest rates applicable on the day just prior to the day of refinancing, as this comparison would not only protect the Project Developer from any extra pay out to the respective beneficiaries, but will also reflect the correct picture of the benefits passed on by the Generating Company for its respective beneficiaries since the time of COD over the life of the project.

21. Regulation 33(2)

33 (2) The value base for the purpose of depreciation shall be the capital cost of the asset admitted by the Commission. In case of multiple units of a generating station or multiple elements of transmission system, weighted average life for the generating station of the transmission system shall be applied. Depreciation shall be chargeable from the first year of commercial operation. In case of commercial operation of the asset for part of the year, depreciation shall be charged on pro rata basis.

Our Views and observations

While we completely agree with the principle of allowing the depreciation from the date of commercial operation for the project, it has been observed that for additional capex projects depreciation is allowed considering that the assets have been capitalised in the mid of the year. It is to be noted that it might not be an appropriate approach as the assets get capitalised at various dates in books and thus, the depreciation for such assets get computed for respective operation days as per the books of accounts. Whereas, the assumption as per Tariff Regulations that all such additional capex gets capitalised at middle of the year causes a difference with respect to books of accounts and hence, we humbly request the Hon'ble Commission to kindly consider the approach of allowing depreciation for additional capitalisation from the date of capitalisation.

22. Regulation 33(3)

33 (3) The salvage value of the asset shall be considered as 5% and depreciation shall be allowed up to maximum of 95% of the capital cost of the asset:

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Our Views and observations

As per the current practice, Hon'ble CERC after taking into consideration of the assets of the generating company, arrives at a weighted average rate of depreciation and thus, works out the depreciation amount which is to be recovered through Tariff. In Tariff Regulations 2009-14 and Tariff Regulations 2014-19, assets were allowed to be depreciated to a maximum of 90% with salvage value being 10%. So, there would be assets which would have achieved 90% depreciation in earlier Tariff periods. With this current proposal of Hon'ble Commission of reducing the salvage value to 5%, while, all such assets which have already achieved 90% depreciation in earlier Tariff Periods shall be allowed to depreciate further to 95%, there is a possibility that such assets being already depreciated may not have find any rate available in the books for depreciation and hence, we request the Hon'ble Commission to define clear guidelines to ensure recovery of such due depreciable amount of older assets, which else would lead to differential treatment of different assets.

23. Regulation 33(5) and 33 (6)

33 (5) Depreciation shall be calculated annually based on Straight Line Method and at rates specified in Appendix-I to these regulations for the assets of the generating station and transmission system:

Provided that the remaining depreciable value as on 31st March of the year closing after a period of 12 years from the effective date of commercial operation of the station shall be spread over the balance useful life of the assets.

33 (6) In case of the existing projects, the balance depreciable value as on 1.4.2019 shall be worked out by deducting the cumulative depreciation as admitted by the Commission upto 31.3.2019 from the gross depreciable value of the assets.

Our Views and observations

There are occasions which necessitate the implementation of certain capex schemes which may be for the purpose of efficient operation, to meet the statutory requirements, to meet the requirements under change in law or any such reason. In such situations, where this Hon'ble Commission approves the implementation of such capex scheme and approves the capital cost after prudence check, the developer should be allowed to recover the complete depreciable value of the asset over the balance useful life of the project irrespective of the tenure left. Hence, we humbly submit to this Hon'ble Commission to introduce appropriate clauses to ensure complete recovery of complete depreciable value by the generator through tariff during the useful life of the project.

24. Regulation 33(8)

33 (8) In case of de-capitalization of assets in respect of generating station or unit thereof or transmission system or element thereof, the cumulative depreciation shall be adjusted by taking into account the depreciation recovered in tariff by the decapitalized asset during its useful services.

<u>Our Views and observations</u>

We would like to bring to the notice of this Hon'ble Commission, certain situations when generating companies undergo sudden failure of vital equipment due to reasons beyond Developer's control. In such scenarios, developers are required to immediately replace the damaged assets with new good quality assets and the accounting principles allow the write off of such damaged/out-lived assets from the books of the generating companies. On the other hand, Tariff Regulations do not provide for any treatment of such damaged assets and simply allow decapitalisation of such assets. Doing this, it causes the Generating Companies absorbing the entire loss due to such failure which is not only limited to under recovery of principal value/cost of the asset but is also impacted due to non-recovery of the cost of financing of such assets as the loans/equity still remains outstanding. Hence, we humbly submit to this Hon'ble Commission that appropriate provisions may be introduced to allow the generating companies to recover at least the depreciated cost adjusted for any income from scrap sale i.e the complete depreciable value of such damaged asset which would at least support the generator to meet the loss corresponding to such replaced asset. However, the final recoverable value may be decided by Hon'ble Commission on case to case basis upon scrutiny of the matter.

25. Regulation 34

34. Interest on Working Capital: (1) The working capital shall cover:

(a) Coal-based/lignite-fired thermal generating stations

- *(i) Cost of coal or lignite and limestone towards stock, if applicable, for 15 days for pit-head generating stations and 20 days for non-pit-head generating stations for generation corresponding to the normative annual plant availability factor or the maximum coal/lignite stock storage capacity whichever is lower;*
- *(ii) Advance payment for 30 days towards Cost of coal or lignite and limestone for generation corresponding to the normative annual plant availability factor;*
- *(iii) Cost of secondary fuel oil for two months for generation corresponding to the normative annual plant availability factor, and in case of use of more than one secondary fuel oil, cost of fuel oil stock for the main secondary fuel oil;*
- *(iv) Maintenance spares @ 20% of operation and maintenance expenses specified in Regulation 35 of these regulations;*
- *(v) Receivables equivalent to 45 days of capacity charges and energy charges for sale of electricity calculated on the normative annual plant availability factor; and*
- *(vi) Operation and maintenance expenses for one month.*

<u>Read with</u>

69. Late payment surcharge: In case the payment of any bill for charges payable under these regulations is delayed by a beneficiary or long term transmission customers as the case may be, beyond a period of 45 days from the date of billing, a late payment surcharge at the rate of 1.25% per month shall be levied by the generating company or the transmission licensee, as the case may be.

<u>Our Views and observations</u>

For the purpose of arriving at optimum levels of Receivables for the component of Working Capital, we would like to discuss here the manner receivables are built at developer's end over the billing cycle. During a billing cycle i.e a month in this context, it would be inappropriate to assume that entire receivable are payable on first day of the month and neither it would be appropriate to assume that entire receivable are built on last day of the month. The receivables for any developer get built over the month and thus, it is safe to assume that any developer gets entitled for receivables for an average period of 15 days only on the last day of the billing cycle i.e the month. Subsequently, upon REA issuance by respective RPCs, developer raise the invoice for the past month and once such invoice is raised by the developer, respective beneficiaries get an interest free period to pay before any LPSC is made applicable. Such interest free period is usually referred as Due Date. Now, this free period plays a role in deciding the no of days of receivables that should form a part of Working Capital. So, whatever be the No of interest free days i.e days from invoicing day till Due Date, such period along with a sum of 15 days (receivables for an average period of 15 days built for the developer on the last day of the billing cycle) shall form the no of days for the purpose of working out Receivables as a Working Capital component.

We wish to further bring it to your knowledge the fact that it has been noticed that respective RPCs usually cause a delay of average no of 5 days from the last day of the billing cycle till the REA release date. This is evident from the details annexed as <u>**Annexure 3**</u>. This causes the developers to raise the bill at an average delay of 5 days. In view of the above, it would be further appropriate to provide an additional margin of 5 days while arriving at the No of Receivables days as a part of Working Capital.

In short, since the proposal of this Hon'ble Commission stipulates for a Due Date of 45 days which is evident from Regulation 69, Receivable equivalent to 65 days (which includes 45 days for interest free period being provided to the beneficiaries from date of invoicing, 15 days on account of average receivables built for the developer on the last day of the billing cycle & 5 days for the delay caused by RPCs in issuing the REA) should be considered for arriving the components of Working Capital.

Hence, we humbly submit to this Hon'ble Commission that the components of Normative Working Capital in the Tariff Regulations may be revisited based on above factors.

Further, the stock of non-pit head stations has been sought to be reduced from 30 days to 20 days. It is submitted that burgeoning coal shortage scenario, the stock requirement should be increased to 40 days from 30 days to cover these risks with long distance transportation.

26. Regulation 35

(1) Thermal Generating Station: Normative Operation and Maintenance expenses of thermal generating stations shall be as follows:

(1) Coal based and lignite fired (including those based on Circulating Fluidised Bed Combustion (CFBC) technology) generating stations, other than the generating stations or units referred to in clauses (b) and (d):

(in Rs Lakh/MW)

Year	200/210/ 250 MW Series	300/330/ 350 MW Series	500 MW Series	600 MW Series	800 MW Series and above
FY 2019-20	30.59	24.22	20.38	17.39	15.65
FY 2020-21	31.57	24.99	21.03	17.94	16.15
FY 2021-22	32.58	25.79	21.71	18.52	16.66
FY 2022-23	33.62	26.62	22.40	19.11	17.20
FY 2023-24	34.69	27.47	23.12	19.72	17.75

Provided that where the date of commercial operation of any additional unit(s) of a generating station after first four units occurs on or after 1.4.2019, the O&M expenses of such additional unit(s) shall be admissible at 90% of the operation and maintenance expenses as specified above;

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(6) The Water Charges, Security Expenses and Capital Spares for thermal generating stations shall be allowed separately prudence check:

Provided that water charges shall be allowed based on water consumption depending upon type of plant, type of cooling water system etc., subject to prudence check. The details regarding the same shall be furnished along with the petition:

Provided further that the generating station shall submit the assessment of the security requirement and estimated expenses;

Provided also that the generating station shall submit the details of year wise actual capital spares consumed at the time of truing up with appropriate justification for incurring the same and substantiating that the same is not funded through compensatory allowance or special allowance or claimed as a part of additional capitalisation or consumption of stores and spares and renovation and modernization.

Our Views and observations

With respect to the norms proposed by Hon'ble Commission for the purpose of normative O & M expenses, it has been observed that only few selected stations of NTPC have been considered and has left aside the disproportionate O&M Expenses for many other stations of similar size. In our opinion, by doing so some of the reasonable/justified higher expenses, which may be genuine and plant specific, get excluded from the base normative O&M Expenses for industry.

Selecting only efficient plants would artificially tighten the O&M norm. In this context, reliance is being placed upon Judgment of Appellate Tribunal dated 04.04.2007 in Appeal No 251 of 2006. The Hon'ble Tribunal while considering the deviation from norms of a utility by the Commission instead of being rewarded for better performance, held as under:-

"55. Norms for operation for power stations are determined for the industry based on the technology, industry performance and in order to ensure optimum utilization of machines with efficient and economic operation. Black's Law Dictionary defines norms as: "An actual or set standard determined by the typical or most frequent behavior of a group". We are quite intrigued: once the Commission has specified "norms" how the same can be changed for a particular generator merely because it has consistently performed better. One can understand if the entire industry performs at better operational levels, then observing the consistent industry average improve, norms for all can be upgraded. It is against natural justice that an individual station, instead of being rewarded for better performance, is made to meet higher targets of performance and exposed to the risk of not achieving it. Achieving exceptionally high levels of efficiencies requires great deal of effort and expertise and must be incentivized. If Commission wishes to revise norms

upward, it may also do so but such a revision has to be applied to all players after watching the industry performance over a period of time."

CSR expense is a legitimate expense incurred in compliance to Companies act. Exclusion of such cost from O&M costs eventually reduces the total RoE which results into a return lower the assured return of 15.5% on ROE by about 0.3%. As such the RoE needs to be higher by 0.3% so that real return available is the regulated return since the generator cannot make higher profits to make up for such expenses.

It may also be noted that for plants having limited/ low capacity of Ash pond, Ash handling and disposal charges should be given over and above O&M expenses, similar to water charges, security charges as these are incurred on account of MoEF Notification or in other words in compliance to the mandate of law. Further, these expenses are dependent upon various factors – availability of land for ash dyke, quality of coal burnt, distance to be travelled for disposal, covering it with top soil etc. Also, the income, if any, from ash disposal has to be utilized for environment protection and hence, cannot be deducted from the cost of handling/ disposal. Present norms of O&M expenses based on NTPC's plants do not cover such expenses for most of its plants as they have ash dykes for which capitalization is allowed separately. The Ash disposal Expenses in Rs. Lakh/Mw for last five year for MPL are presented below to understand the Ash Disposal Cost incurred by MPL

FY	**FY 2014-15**	**FY 2015-16**	**FY 2016-17**	**FY 2017-18**
Ash Disposal Expenses	4.12	5.81	3.61	3.47

Also, in case of Transmission Assets, way leave charges are required to be paid to railways and other statutory bodies like Highway, PWD, MMRDA etc. Such charges cannot be contained within normative O&M expenses, and hence, should be given over and above Normative expenses.

These expenses are directly related to the inflation rate and are also specific to the State where the Generating Station is located since it decides the availability of labour, spares and other administrative expenses. Hence, O&M Expenses for any year cannot be specified at a fixed inflation rate. It would be prudent to link the annual escalation of the Normative O&M Expenses with the actual inflation rate at the time of true-up. The annual Inflation Rate for each year may be derived separately by the following formula as used by Hon'ble Commission:

Inflation Rate = I = 60% x WPI + 40% x CPI,

Where,

WPI = Increase in Wholesale Price Index for All Commodities, a number published by the Central Statistical Organization, Ministry of Statistics and Programme Implementation, Government of India.

CPI = Increase in Consumer Price Index for Industrial Workers, a number published by the Central Statistical Organization, Ministry of Statistics and Programme Implementation, Government of India.

For a Transmission company having only few projects, the Normative O & M Cost allowed by CERC does not cover the actual expenses incurred by the Company. The transmission system of Power Grid

Corporation involves various facilities including transmission lines, sub stations, tie lines and operated in the entire region with **greater economies of scale** in comparison to the transmission system of a Private Company having one or a few projects. Hence O&M norms need to be revised upwards for private players in transmission having limited number of projects.

For Operation and Maintenance of transmission line, the Transmission licensee has different site offices and Corporate office in different states. Since the Transmission licensee was registered under VAT in these states on the date of GST coming into force, it was automatically considered as a taxable person under GST and had to get itself registered under GST in each state separately. Transmission Licensee gets revenue from Powergrid Corporation of Indian (PGCIL) as Transmission service charges (TSC) which is as per tariff orders passed by CERC for the transmission of electricity. As transmission service charges are exempted under GST, Transmission Licensee is not in a position of availing any input tax credit.

Usually, the Transmission licensee has several stores in the states wherein various transmission line inventory, tools and plants and capital inventory/equipment are kept which is required for O&M of Transmission line. Movement of materials (line inventory, T&P and capital inventory/equipment) can happen within the state or inter-state as per requirement.

As per Schedule 1 (Section 7) of CGST movement of goods or services within the same company with different GSTNs would be considered as supply even if without consideration. Hence, movement of assets/material from one state to another state within the same Company, would attract GST. Earlier VAT/Service tax was not applicable on such transactions. This is the over and above the cost that Company has to bear after implementation of GST ACT applicable in INDIA. Whereas under earlier state VAT/Service Tax no tax was applicable of within the Company transfer of material and services from one state to another state. Accordingly, the norms proposed by Hon'ble Commission for transmission licensees do not cover such expenses.

Therefore, the Hon'ble Commission includes GST expenses so incurred for use of material and services from one state to another state of same Company as passthrough expense in addition to the normative O&M expenses for transmission licensee under the draft regulation.

We would also like to draw your attention to the parameter of Compensation Allowance. As we are aware, that this Hon'ble Commission had introduced the concept of Compensation Allowance to meet the expenses of additional capital expenditure on new asset not within the original scope of work including assets in the nature of minor assets to avoid tedious and time consuming exercise of prudence check of several minor items of capital nature. The practice continued for two Tariff Periods including FY 2009-14 and FY 2014-19. However, Hon'ble Commission in its draft proposal have proposed for discontinuation of such allowance on the ground that during the past two tariff periods, the generating stations have still approached the Commission for additional capital expenditure for works of minor nature, which was expected to be met out of the Compensation Allowance and it has become difficult to establish whether the Compensation Allowance is serving the desired purpose.

While, we understand the difficulty being faced by this Hon'ble Commission and we also agree with the fact of certain generating companies approaching this Hon'ble Commission for additional capital expenditure for works of minor nature, it is also a fact and it cannot be denied that this normative expense provides a great comfort and is strongly needed by all generating stations which have crossed an operation period of 10 years. For most of the Generating Companies (except a few) depend on this normative allowance for meeting the additional expenditure of minor assets instead of approaching the Hon'ble Commission for capitalisation of such minor assets complying to actual purpose of this Allowance. So, sudden removal of such allowance would cause difficulty for all rest of the Generating Stations which are relying on this norm for meeting genuine expenditure of additional Capitalisation not only of minor nature but also those assets for which depreciation, RoE and Interest on Loan cannot be recovered in balance useful life of the plant. This would lead to all such Generating Stations which have crossed an operating period of 10 years (and the ones approaching operating period of 10 years) to start approaching this Hon'ble Commission with a combined petition for allowance of such assets including minor assets and follow the long drawn procedure for approval of this Hon'ble Commission which is also likely to increase the burden of this Hon'ble Commission of handling all such petitions.

Apart from this, a project which has undertaken major investment assuming that it shall be able to recover its cost through allowance in balance useful life, would be adversely hit and this would attract promissory estoppel.

In view of the above, we submit that instead of discontinuing such normative allowance, alternately, it would be a better stand to continue allowing such Compensation Allowance to all Generating Stations and Transmission Licensees. Also, it shall be discriminatory between projects that have already enjoyed the benefit of such allowance and projects that would now become eligible to use this allowance.

Hence, we humbly submit to this Hon'ble Commission to continue with the practice of allowing Normative Compensation Allowance as per the current practice with certain escalation in the Allowance for each year of the Control Period.

27. Regulation 50

50. Landed Price of Reagent (Limestone, Sodium Bi-Carbonate, Urea and Anhydrous Ammonia etc.):

(1) Where the specific reagent such as limestone, Sodium Bi-Carbonate, Urea and Anhydrous Ammonia are used during operation of emission control system, the landed price of such reagents shall be determined based on normative consumption specified in clause (2) of this Regulation and purchase price of the reagent through competitive bidding, applicable statutory charges and transportation cost;

(2) The normative consumption of specific reagent for the various technologies installed for Emission Control System shall be considered as under:

Particulars		Specific Reagent Consumption (gms / kWh)
SOX Control System	Wet Limestone Type	15.00 (Limestone)
	Dry sorbent injection	12.00 (Sodium Bi-Carbonate)
Standard Particulate Matter		-
NOX Control System	Combustion Modification	-
	Selective Non-Catalytic Reduction	1.85 (Urea)
	Selective Catalytic Reduction (SCR)	1.60 (Anhydrous Ammonia)

Provided that the specific reagent consumption specified as above is allowed on provisional basis, and shall be applicable only where emission control system is installed. The above norms shall be reviewed based on the actual of performance during the 2021-22.

<u>Our Views and observations</u>

With regard to normative reagent consumption, it is submitted that to start with, the above norms may be considered in the current control period along with normative additional auxiliary consumption of 1.5% for wet limestone/ se-water based SOx system and 0.5% for NOx system. It is also submitted that such plants need to be given priority in merit order and for such purposes MoP had sought comments from stakeholders. MoP paper and our comments thereon are enclosed for your kind consideration as **Annexure 4**. We request that the proposed methodology/ formula for computation of energy charges for billing and for merit order purposes may kindly be considered.

28. Regulation 51

51 (3)

Normative Plant Availability Factor for "Peak" and "Off-Peak" periods shall be equivalent to the NQPAF specified in Regulation 59 (A) of these regulations. The number of hours of "Peak" and "Off-Peak" periods in a region shall be declared on monthly basis in advance, by the concerned RLDC and the Peak period in a day shall not be less than 4 hours.

…

51 (5)

..

Provided that if the cumulative peak period PAF achieved during a quarter is more than the specified NQPAF for peak period and the cumulative Off-Peak period PAF achieved during the quarter is less than the specified NQPAF for Off-Peak period, the loss in recovery of Capacity Charge for Off-Peak period shall be off-set against the notional gain on account of over-achievement in Peak period, subject to the ceiling of full recovery of Capacity Charge for Off-Peak period;

Provided further that if the cumulative peak period PAF achieved during the quarter is less than the specified NQPAF for peak period and the cumulative Off-Peak period PAF achieved during the quarter is more than the specified NQPAF for Off-Peak period, the loss in recovery of Capacity Charge for Peak period shall not be off-set against the notional gain on account of over-achievement in Off-Peak period;

Provided also that carry forward of under-recovery of Capacity Charge shall not be allowed for recovery from one quarter to the subsequent quarter.

<u>Our Views and observations</u>

While, we welcome this methodology of segregating Availability and Generation based on peak and off peak period, we humbly submit that it is equally important to deliberate on the mechanism so as to avoid any implementation issues. In view of this, we have attempted to bring out a few issues/queries which may need to be addressed before the implementation of this mechanism:

- As we are aware, that Peak and Off Peak periods are always relevant from Discom's perspective, the chances are likely that peak period and off peak period of different beneficiaries which may be in different states or even regions, would be different depending on season, geography and several other factors. On the other hand, from the sections mentioned above, it seems that it would be the concerned RLDC of the Generating Station which would be responsible for deciding the Peak and Off Peak period for that region. In such a situation, it would be a difficult proposition for the RLDC to take into consideration peak and off peak of all beneficiaries of the generating stations of that region and arrive at a common peak and off peak for the region. Accordingly, we request the Hon'ble Commission to decide a consultation process among the RLDCs and beneficiaries/SERCs for arriving at the peak and off peak period for the month.

- It would be very relevant that a detailed step wise consultation process is developed for planning the Annual Scheduled Plant Maintenance for the Generating Stations of any region. Since as per the proposal, the timespan for such Annual Scheduled Plant Maintenance would not be considered for computing Plant Availability of the Generating Station for the relevant quarter, the procedure for planning Annual Scheduled Plant Maintenance shall include treatment for events when actual shutdown period exceed or falls short of the planned maintenance. Also, the procedure should include steps for requesting for change in Annual Plant Maintenance Schedule due to reasons beyond Generating Station's control. There should not be any adverse impact in such situations on Generating Companies.
- In current scenario, the Generating Company had an opportunity of making up for shortfall on account of forced outages in availability by increasing availability for the beneficiary in balance months of the year. In the proposed scenario, since availability of one quarter would not be carried forward to subsequent quarter and also excess availability of off peak period would not be allowed to compensate for availability of Peak Period, it would be impossible for the generating company to protect the recovery of Annual Fixed Charges in situations where forced outages occur, particularly in the middle of a quarter and immediately before or after planned outage. Hence, we request Hon'ble Commission to kindly consider the option of relaxing the norms for the generating stations for such exceptional events.

29. Regulation 51 (6)

(6) The Plant Availability Factor achieved for a Day (PAFD), Plant Availability Factor achieved for a Month (PAFM) and Plant Availability Factor achieved for a Quarter (PAFQ) shall be computed in accordance with the following formula:

$$\text{PAFD or PAFM or PAFQ} = 10000 \times \sum_{i=1}^{N} DC_i \,/\, \{ N \times IC \times (100 - AUX) \} \,\%$$

Where,
AUX = Normative auxiliary energy consumption in percentage.
DCi = Average declared capacity (in ex-bus MW), for the ith day of the period i.e. the month or the year as the case may be, as certified by the concerned load dispatch centre after the day is over.
IC = Installed Capacity (in MW) of the generating station
N = Number of days during the period or number of hours during the peak or off-peak periods of the day, as the case may be.

Our Views and observations

In regards to above definition of Plant Availability as per Regulation 51(6), we propose the following change in definition of *"DCi"* and *"IC".*

DCi = Average declared capacity (in ex-bus MW) for the beneficiary, for the ith day of the period i.e. the month or the year as the case may be, as certified by the concerned load dispatch centre after the day is over.
IC = Installed Capacity (in MW) of the generating station or contracted Capacity for the beneficiary

The proposed changes have been requested considering the current arrangement whereby generating companies have tied up Long Term Bilateral Contracts with more than one beneficiary states and thus declare availability to respective beneficiaries in reference to their respective contract capacities instead of declaring it in reference to Installed Capacity of the Generating Station. This methodology has also been accredited by this Hon'ble Commission in its order in the matter 28/MP/2016 dated 31st August 2017 and 192/MP/2016 dated 20.03.2018. Further, since availabilities are declared and computed separately, the generator should be allowed to declare different available capacities for different beneficiaries which may not be in proportion of their contracted capacity in tied up capacity provided that Declared Capacity for a beneficiary out of Total Available Capacity should not be more than the proportion of Contracted Capacity in Tied up Capacity.

Based on the above, we request the Hon'ble Commission to kindly reconsider the methodology of working out the Availability in its Tariff Regulations and allow the developers to declare availability to its beneficiaries with reference to respective contract capacities instead of Installed Capacities.

Further, it would be appropriate that the generating companies may be allowed to recover generation linked incentive against their respective supplies to their respective Beneficiaries as the current mechanism does not incentivise generator to achieve higher availability. The linkage of incentive with PLF is dependent on the beneficiaries' requirements and does not truly represent generator's efficiency. Therefore, it is proposed that instead of PLF linked incentive, Availability linked incentive may be provided as was there in Tariff Regulations 2009.

In addition to above, if still PLF based incentive is considered, we request the Hon'ble Commission to reconsider the earlier methodology whereby receivable incentive by any generating station is decided depending on the total PLF of the Station. Instead, we humbly request this Hon'ble Commission to kindly allow the generating companies to recover generation linked incentive against their respective supplies to their respective Beneficiaries.

30. Regulation 52 (3) Proviso 1 and Proviso 2

Provided further that the weighted average price of use of alternative source of fuel shall not exceed 30% of base price of fuel computed as per clause (7) of this Regulation.

Provided also that where the energy charge rate based on weighted average price of use of fuel including alternative source of fuel exceeds 30% of base energy charge rate as approved by the Commission for that year or energy charge rate based on weighted average price of use of fuel including alternative sources of fuel exceeds 20% of energy charge rate based on based on weighted average fuel price for the previous month, whichever is lower shall be considered and in that event, prior consultation with beneficiary shall be made not later than three days in advance.

<u>Our Views and observations</u>

We are aware of the Coal Supply Scenarios under Fuel Supply Agreements signed by the Generating Companies with the Coal India Limited and its subsidiaries. Such situation has also been acknowledged by this Hon'ble Commission in its Approach Paper. The shortage of domestic coal has become a completely uncontrollable factor for the Generating Company. In view of such constrained supply of coal, the Generating Companies are required to invest a lot of manpower, skills and time in exploring the options of alternate sources like E-auction coal (depending on opportunity), Special E-forward auction (depending on opportunity), coal washeries and even on imported coal in certain instances to meet the requirements of its beneficiaries. In certain options like E-auction coal and Special E-forward auction, Generators are not even in a position to predict the final landed price of coal till completion of the Auction process and also the timelines for delivery also cannot be correctly predicted. In view of such circumstances, it would not be fair to expect the generators to initiate a price consultation process with the beneficiaries in given time span when there are uncertainties in coal supplies.

Further, it is to be noted that options like E-auction coal and Special E-forward auction are opportunity based options and it is not certain whether the generators would get supply of coal and hence, the only other options left with the generator are Washery Coal and Imported Coal. In such situations, there is a possibility that the weighted average price of use of fuel including such alternative source of fuel exceeds 30% of base energy charge rate or exceeds 20% of energy charge rate based on weighted average fuel price for the previous month. During such possibilities, in case beneficiary do not provide their consent to the generators for procuring coal from such alternative sources, the Generators shall be considered deemed available for such period and shall be allowed to recover annual fixed charges for such effected period.

Hence, we humbly submit to this Hon'ble Commission to kindly consider restructuring of these relevant Regulation 52 (3) Proviso 1 and Proviso 2 in view of the above mentioned scenarios and recommendations.

31. Regulation 59 (C) (b)

(C) Gross Station Heat Rate

(b) ***New Thermal Generating Station achieving COD on or after 1.4.2009:***
(i) For Coal-based and lignite-fired Thermal Generating Stations:
1.05 X Design Heat Rate (kCal/kWh)
Where the Design Heat Rate of a generating unit means the unit heat rate guaranteed by the supplier at conditions of 100% MCR, zero percent make up, design coal and design cooling water temperature/back pressure.
…
Provided further that in case pressure and temperature parameters of a unit are different from above ratings, the maximum design unit heat rate of the nearest class shall be taken:
Provided also that where unit heat rate has not been guaranteed but turbine cycle heat rate and boiler efficiency are guaranteed separately by the same supplier or different suppliers, the unit design heat rate shall be arrived at by using guaranteed turbine cycle heat rate and boiler efficiency:
Provided also that where the boiler efficiency is below 86% for Sub-bituminous Indian coal and 89% for bituminous imported coal, the same shall be considered as 86% and 89% respectively for Sub-bituminous Indian coal and bituminous imported coal for computation of station heat rate:

Our Views and observations

The sector has witnessed and is continuously witnessing various challenges impacting the operations of the sector. Such factors are completely out of control of the project developer who had set the projects considering the resource availability at the time of project development. One such factor is the falling levels of coal supply which is causing the generators/developers to procure coal from alternate sources to meet the demand of its beneficiaries. Even if it is assumed that coal is supplied by the Coal Companies to complete quantum as per the FSA, it would not be appropriate to assume that the generator is able to secure and procure the coal as per the design specifications and is a factor completely beyond the control of the generator.

Further, there may be deterioration in SHR due to installation of emission control systems. Additional, 1% margin in SHR may be provided for projects installing such as SOx and NOx systems by considering a factor of 1.06 instead of 1.05 in the above stated formula.

Hence, in view of such circumstances, we humbly submit the Hon'ble Commission to kindly include a proviso by way of which this Hon'ble Commission may allow relaxed operating norms to the generating companies on account of factors beyond the control of generating companies and effecting the operations of the generating company.

32. Regulation 59 (E)

(E) Auxiliary Energy Consumption:

(a) For Coal-based generating stations except at (b) below:

S. No.	Generating Station	With Natural Draft cooling tower or without cooling tower
(i)	200 MW series	8.50%
(ii)	300/330/350/500 MW series	
	Steam driven boiler feed pumps	5.75%
	Electrically driven boiler feed pumps	8.00%
(iii)	600 MW and above	
	Steam driven boiler feed pumps	5.75%
	Electrically driven boiler feed pumps	8.00%

Provided that for thermal generating stations with induced draft cooling towers and where tube type coal mill is used, the norms shall be further increased by 0.5% and 0.8% respectively:

<u>Our Views and observations</u>

Current proposal of norms for Auxiliary Power Consumption stipulates for Generating Companies prior to installation of equipment for meeting the revised emission norms. We request the Hon'ble Commission to kindly include indicative norms which may be reviewed based on the actual performance (in the manner envisaged/stipulated in proposed Regulation 50 (1) and 50 (2)) for additional Aux Power consumption taking into consideration the operation of such additional equipment to be installed by the generating companies for meeting the revised emission norms after the control period to be used for True -up. It is requested that Additional Aux of 1.5% for SOx and 0.5% for NOx may kindly be specified.

33. Regulation 61

<u>Our Views and observations</u>

In the current draft it's given that no incentive shall be payable for availability beyond 99.75%. It's hereby requested that the Hon'ble Commission may kindly allow incentive on actual TAFM, if TAFM >99.75%. Transmission licensee with one or a few projects/ lines are able to maintain the line availability of 100% in most number of months in a year. This is due the fact that the O&M teams are regularly and efficiently doing the line patrolling with the help of every possible resource. The teams are also regularly coordinating with Powergrid for any opportunity of shutdown which they are availing for their sub-station or transmission lines, so that any fault identified for maintenance work of licensee's lines during line patrolling can also be attended during the outage duration of opportunity shut down. The teams have also replaced the Porcelain insulators in these polluted areas where after taking shutdown, maintenance has reduced drastically. The maintenance measures to keep availability high are, therefore, causing the O&M Cost to be more than the norms. Therefore it is proposed that incentive for availability may not be limited to 99.75% and should be allowed upto 100%.

34. Regulation 70(2)

70. (2) The financial gains by the generating company or the transmission licensee, as the case may be, on account of controllable parameters shall be shared between generating company or transmission licensee and the beneficiaries or long term transmission customers, as the case may *be, on monthly basis with annual reconciliation. The financial gains computed as per the following formulae in case of generating station other than hydro generating stations on account of operational parameters as shown in Clause 1 of this Regulation shall be shared in the ratio of 50:50 between the generating stations and beneficiaries.*

<u>Our Views and observations</u>

Hon'ble Commission would appreciate that it takes a lot of efforts, manpower engagement and sometimes even considerable investments to attain even slightest level of operational gains. It is a rational expectation of the developer to meet at least its expenses involved in the process of achieving such operational benefits from such operational gains. Thus, any further sharing beyond the existing limits of 60:40 would be inappropriate and discouraging for the developers to put further efforts to improve operational performance. Hence, we humbly to this Hon'ble Commission to kindly retain the existing profit sharing ratio of 60:40 in favour of developers and the beneficiaries respectively.

35. Regulation 72

72. Sharing of Non-Tariff Income: The non-tariff income in case of generating station and transmission system on account of following shall be shared in the ratio of 50:50 with the beneficiaries and the long term customer on annual basis:

- *a) Income from rent of land or buildings;*
- *b) Income from sale of scrap;*
- *c) Income from statutory investments;*
- *d) Interest on advances to suppliers or contractors;*
- *e) Rental from staff quarters;*
- *f) Rental from contractors;*
- *g) Income from advertisements;*
- *h) Interest on investments and bank balances;*

Provided that the interest or dividend earned from investments made out of Return on Equity corresponding to the regulated business of the Generating Company shall not be included in Non-Tariff Income.

<u>Our Views and observations</u>

The second proviso to section 41 of the Electricity Act 2003 envisages sharing of income of other business using assets of transmission licensees such that licensed business does not subsidise other businesses i.e part cost of the licensed business assets used for other business to be borne by such other business. In other words, the licensed business should not subsidise other businesses. On this issue, Hon'ble APTEL has decided that licensed and other businesses have to be kept in water tight compartments. Licensed business should neither subsidise, nor should not get subsidised by other businesses. There is no such provision in the act for generation business which is not licensed as per Hon'ble Supreme court's various judgements. Therefore, neither the act envisages nor evokes any consideration of any income for determination of generation tariff. Even the income generated from use of generation assets which are owned by and maintained by developer at its own risk, there cannot be any sharing as such income although being from generation business in incidental and not a part of cost for cost plus tariff determination. Moreover, such incomes are uncertain and not mandated to be earned from assets otherwise required for generation. Therefore, no other income should be adjusted.

Without prejudice to the above, if Hon'ble Commission still wishes to consider other income, the following may be considered.

We are aware that any asset capitalised by the generating company is allowed to depreciate up to 90% (now it would be 95% as per the current proposal). This implies that after repayment of long term loan of around 70% of the project cost, generating company is allowed to recover only 20% (now it would be 25% as per the current proposal) of the Project Cost against its 30% equity investment and thus, the generating company is never able to recover the equity invested completely.

Also, there are situations when certain equipment undergo failure and are replaced by a healthy equipment at its own cost during the useful life of the project. In such situations, generating company writes off the asset from the books of the company absorbing the entire loss due to such equipment failure.

In such above scenarios, when the generating company decides to sell the fully depreciated assets or damaged assets at some scrap value, the proceeds shall be utilised to make up for the loss and only the balance left over after meeting the above two obligations may be shared with the beneficiaries of the station.

Based on the above rational, we humbly request the Hon'ble Commission to kindly exclude the proceeds under "Income from sale of scrap" from the list of sources of Non- Tariff Income for sharing with beneficiaries as envisaged in Regulation 72.

Further, it is noted that the Proviso to Regulation 72 stipulates for excluding the Income by way of interest or dividend earned from investments made out of ROE corresponding to regulated business of the Generating Company from the list of sources of Non-tariff income. We would further request the Hon'ble Commission that such exclusion shall be made applicable to Transmission Licensees as well.

36. Other Proposal

Our Views and observations

We humbly submit to this Hon'ble Commission that for the purpose of existing generating stations, Change in Law may be allowed as pass through and recoverable directly from beneficiaries during operation period as well as for any additional capitalisation below the limit set by Hon'ble Commission for in-principle approval of additional Capitalisation as has been held regarding applicability of GST, as a Change in Law event. This is in line with this Hon'ble Commission's order in the matter No. 13/SM/2017 dated 14th March 2018, whereby it has held that:

"It has been observed that some of the generators and discoms have submitted the calculations of impact of change in law. These calculations show varying impact of such changes on different generators and discoms on various dates. The impact worked out by the discoms was different from that submitted by the generators. Further, the generators have also not submitted a clear declaration as called for that there are no other taxes, duties, cess etc., which have been reduced or abolished or subsumed. From the forgoing, the Commission feels that due to varied nature of such taxes, duties and cess etc. that have been subsumed/ reduced, it is not possible to quantify in a generic manner, the impact of change in law for all the generators.

Hence, we are of the opinion that introduction of GST and subsuming/ abolition of such taxes, duties and levies has resulted in some savings for the generators having generation based on domestic coal and the same needs to be passed to the discoms/ beneficiary States. Since, these are change in law events beneficial to the procurers, the same needs to be passed on to the procurers by the generators.

Accordingly, we direct the beneficiaries/ procurers to pay the GST compensation cess @ Rs 400/ MT to the generating companies w.e.f 01.07.2017 on the basis of the auditors certificate regarding the actual coal consumed for supply of Order in Petition No. 13/SM/2017 Page 19 of 19 power to the beneficiaries on basis of Para 28 and 31. In order to balance the interests of the generators as well as discoms/beneficiary States, the introduction of GST and subsuming/abolition of specific taxes, duties, cess etc. in the GST is in the nature of change in law events. We direct that the details thereof *should be worked out between generators and discoms/beneficiary States. The generators should furnish the requisite details backed by auditor certificate and relevant documents to the discoms/ beneficiary States in this regard and refund the amount which is payable to the Discoms/ Beneficiaries as a result of subsuming of various indirect taxes in the Central and State GST. In case of any dispute on any of the taxes, duties and cess, the respondents have liberty to approach this Commission."*

ANNEXURE 2: WORKING FOR IRR FOR GENERATION PROJECTS

Parameters	UoM	Value
Normative Levered Beta for Power Sector	No.	1.05
Market Value as on 01-04-2014	No.	22446.44
Market Value as on 02-04-2018	No.	33255.36
Average yearly market return	%	14.00%
Assumed Risk Free Return	%	8%
Expected Return for Power Sector - Thermal Gen	%	14.32%

RoE	19.00%

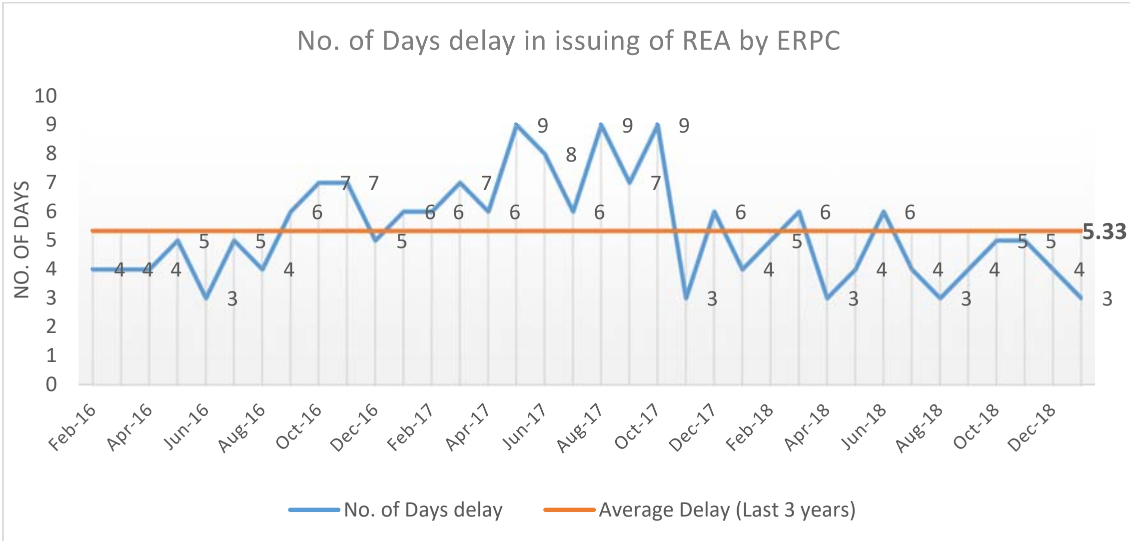
Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15
-20	-10	-45	-25	19	19	19	19	19	19	19	19	19	19	19

Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28	Year 29
19	19	19	19	19	19	19	19	19	19	19	19	19	19

IRR	14.37%

Note: The detailed excel data file have been provided separately along with the submission to ensure brevity

ANNEXURE 3: AVERAGE DELAY IN NO. OF DAYS IN ISSUANCE OF REA



ANNEXURE 4: LETTER FROM MINISTRY OF POWER AND CEA

No. 23/22/2018-R&R
Government of India
Ministry of Power
***

Shram Shakti Bhawan, Rafi Marg,
New Delhi, 18th October, 2018

To

1. Chairman/CMDs for all PSUs under administrative control of Ministry of Power.
2. CMDs/MDs of DISCOMs/GENCOs/TRANSCOs of all State Governments.
3. DG, Association of Power Producers, New Delhi.

Subject: Regarding New Environmental Norms for coal based Thermal Power Plants (TPPs).

Sir/Madam,

I am directed to forward herewith a copy of CEA's letter no. 7/X/VIP/GM/2018/1517-20 dated 26.09.2018 on the aforementioned subject.

2. It is requested to provide your comments, if any, to this Ministry urgently latest by 26.10.2018. The comments may also be emailed at sandeep.naik68@gov.in and debranjan.chattopadhyay@nic.in.

Yours faithfully,

Encl: As above

Sandeep 18|10|18
(Sandeep Naik)
Director
Tel: 2371 5250

Copy to: PPS to Secretary (Power), PPS to AS(R&R), PS to Chief Engineer(R&R), PS to Director (R&R)

भारत सरकार
Government of India
विद्युत मंत्रालय
Ministry of Power
केन्द्रीय विद्युत प्राधिकरण
Central Electricity Authority
ग्रिड प्रबंधन प्रभाग
Grid Management Division

विषय: प्रदूषण नियंत्रण उपकरण की शुरुआती स्थापना के लिए थर्मल पावर प्लांट्स को प्रोत्साहन।

उपरोक्त विषय से सम्बन्धित दस्तावेज आपकी जानकारी एवं आवश्यक कार्यवाही हेतु संलग्न है।

संलग्न: (यथोपरि)

(विक्रम सिंह)

निदेशक

सयुंक्त सचिव (तापीय), विद्युत मंत्रालय

संख्या: 7 /एक्स/बी.आई.पी./जी.एम./2018/ 1517-20 **दिनांक: 26/09/2018**

प्रतिलिपि :-

1. सदस्य (तापीय), केन्द्रीय विद्युत प्राधिकरण
2. ~~मुख्य~~ अभियंता (आर एंड आर व ओ. एम.), विद्युत मंत्रालय
3. मुख्य अभियंता (विधि), केन्द्रीय विद्युत प्राधिकरण

US (R/R)

11/10/18

12/10

ASO (RK)

भारत सरकार

Government of India
विद्युत मंत्रालय
Ministry of Power
केन्द्रीय विद्युत प्राधिकरण
Central Electricity Authority
ग्रिड प्रबंधन प्रभाग
Grid Management Division

Subject: Recommendations regarding Incentives to thermal power plants for early installation of pollution control equipment.

As per phasing plan submitted by CEA, installation of pollution control equipment in the thermal power plants has been planned from 2018 to 2022. It is felt that incentivizing installation of pollution control equipment will motivate the power generators to complete the installation on time or even earlier and will help in reduction in environment pollution. However, power generators had raised their concern that early installation of pollution control equipment is disadvantageous to them as it leads to increase in variable cost which results in their lower ranking in merit order dispatch (MOD). A meeting was held on 23.01.2018 & 11.07.2018 under the chairmanship of Member (Thermal), CEA with the RPCs and concerned divisions of CEA to discuss incentives which may be given to thermal power plants (TPPs) for early installation of pollution control equipment in existing as well as under construction TPPs. Based on the decision taken at this meeting, issue of incentivizing thermal power plants for early installation of pollution control equipment was also discussed within RPCs as well.

Keeping in view the discussions held at the above meetings, the following measures are recommended to incentivize early installation of pollution control equipment by the TPPs:

a. The variable cost of TPPs installing FGD and other pollution control equipment as per the timelines in the notice of CPCB would continue to remain same as that before installation of pollution control equipment for the purpose of Merit Order Dispatch (MOD), i.e. the increased Variable Cost because of installation of pollution control equipment would not be considered, in preparation of stack for merit order dispatch. However, payment to the TPP for the energy scheduled would be based on actual variable cost.
b. For already compliant plant, incremental O&M charges due to pollution control equipment would be deducted from the variable charges of such plant for the purpose of deciding its location in the merit order. The normative impact of FGD on variable charges of electricity

tariff (ex-bus) in a broad manner at current price level has been worked out and the same is indicated below:

Wet lime stone based FGD	**Pit head station**	**Load centre station**
Sub critical power plant units (with motor driven boiler feed pumps)	Paise 4.31 /kWh	Paise 6.68 /kWh
Super critical power plant units (with turbine driven boiler feed pumps)	Paise 3.74 /kWh	Paise 5.77 /kWh

Sea water based FGD (costal plants)

Sub critical power plant units (with motor driven boiler feed pumps)	Paise 3.17 /kWh
Super critical power plant units (with turbine driven boiler feed pumps)	Paise 2.71 /kWh

(Assumptions considered in the evaluation of normative impact of FGD implementation in variable charges are enclosed at Annexure – 1)

The above mentioned incremental O&M charges would also be worked out by each compliant TPP and submitted to the appropriate Electricity Regulatory Commission (ERC) & RPC within a period of one month. The incremental O&M charges arrived at by the plant or the normative incremental charges worked out above, whichever is less, would be deducted from the notified/adopted variable charges for the purpose of deciding the location of TPP in the merit order list. The TPP would not be eligible for the above benefit of reduced variable charges if it fails to submit the aforesaid calculations within the prescribed period.

After determination of incremental O&M charges by the ERC, such charges would be used for the above purpose.

c. The TPP, which does not complete installation of Pollution Control Equipment as per the schedule given in the notice of CPCB, may be taken to the bottom of MOD until it installs FGD and other pollution control equipment and becomes compliant to new environmental norms.

d. Meeting NOx norms of 300 mg/Nm^3 (before 01.01.2017) and 100 mg/Nm^3 (w.e.f. 01.01.2017) requires installation of Selective Non-Catalytic Reduction /Selective Catalytic Reduction systems, for which pilot studies have been undertaken for their suitability to local conditions. Till issues related to NOx norms get settled, uniform value of NOx of 450 mg/Nm^3 may be considered for assessing compliance by the TPPs.

e. The priority to the environmental norms compliant TPPs may be continued until December 2022 and beyond until all the TPPs are compliant to new environmental norms.

f. Soft loans may be provided to Central/ State Generating Stations from NCEF for installation of pollution control equipment. This is going to help State utilities in particular.

g. Excise duty/ GST may be waived/reduced for pollution control equipment like FGD etc.

Ministry of Power may like to consider the above recommendations for implementation through Forum of Regulators/Ministry of Finance with a view to incentivizing early installation of FGD/ other pollution control equipment by the thermal power stations.

In this connection, it may be worth mentioning that a case regarding implementation of new environmental norms is pending before the Hon'ble Supreme Court in the form of Appeal No. WP (C) No. 13029/1985 (M C Mehta v. Union of India).

This issue with the approval of the Member (GO&D), CEA.

(Vikram Singh)

Director

Joint Secretary (Thermal), Ministry of Power

No. 7/X/VIP/GM/2018 **Date: 26.09.2018**

Annexure- 1

Normative impact of FGD installation & operation (pollution control measure) on variable charges of electricity tariff of Thermal Power Plants

Normative impact of FGD installation & operation on variable charges of electricity tariff has been estimated considering wet limestone FGD and sea water FGD which are two most commonly used type of FGDs for control of SOx emission from thermal power plants.

The inputs/ assumptions considered in the evaluation of normative impact of FGD implementation in variable charges are as below:

Sl. No.	Description		Normative value
i)	Normative gross unit heat rate:	:	2450 kcal/kWh for sub-critical units (with motor driven BFPs- MDBFPs)
		:	2250 kcal/kWh for super-critical units (with turbine driven BFPs- TDBFPs)
ii)	Normative auxiliary power consumption	:	9% for sub-critical units
		:	5.75% for super-critical units
iii)	Normative specific oil consumption	:	0.5 ml/kWh
iv)	GCV of coal	:	3800 kcal/kg
v)	Suplhur content of coal	:	0.4%
vi)	Landed cost of coal	:	Rs. 2000 per ton or pit head station
		:	Rs. 4000 per ton for load centre station and coastal location
vii)	GCV of oil	:	10000 kcal/l
viii)	Landed cost of oil	:	Rs. 40000 per kl
ix)	SO_2 removal efficiency of FGD system	:	90%
x)	Normative auxiliary power consumption of FGD	:	1.5% for wet limestone FGD
		:	1% for sea water FGD
xi)	Sulphur to SO_2 conversion factor	:	0.95
xii)	Stiocheiometric ratio for limestone consumption	:	1.05
xiii)	Purity of limestone	:	85%
xiv)	Landed cost of limestone	:	Rs. 2000 per ton

For the inputs/ assumptions as above, the normative impact of FGD implementation on variable charges of electricity tariff at Ex Bus of the power plant at current level works out as below:

A. <u>Wet limestone FGD:</u>

	Pit head station	Load centre station
Sub- critical power plant units (with MDBFPs) :	Paise 4.31/kWh	Paise 6.68/kWh
Super- critical power plant units (with TDBFPs):	Paise 3.74/kWh	Paise 5.77/kWh

Notes:

i) Impact of limestone cost: The above impact has been evaluated considering landed cost of limestone as Rs. 2000 per ton. The impact of energy charge shall increase (or decrease) by about paise 0.45/kWh for every Rs. 500 per ton increase (or decrease) in landed cost of limestone cost w.r.t. Rs. 2000 per ton.

ii) Impact of sulphur content in coal: The above impact has been evaluated considering supphur content of coal as 0.4%. The impact of energy charge shall increase (or decrease) by about paise 0.45/kWh for every 0.1% point increase (or decrease) in sulphur content of coal w.r.t. 0.4%.

iii) Impact of TDBFPs/ MDBFPs: The above impact has been evaluated considering sub- critical units with MDBFPs and super- critical units with TDBFPs.

iv) In case of load centre location, if a sub- critical unit is provided with TDBFPs (or a super- crirtical unit is provided with MDBFPs), the impact of energy charge shall reduce (or increase) by about paise 0.16/kWh from that indicated above.

v) In case of pit head location, if a sub- critical unit is provided with TDBFPs (or a super- crirtical unit is provided with MDBFPs), the impact of energy charge shall reduce (or increase) by about paise 0.09/kWh from that indicated above.

B. <u>Sea water FGD:</u>

In this case, the normative impact of FGD implementation on variable charges of electricity tariff at Ex Bus of the power plant at current level works out as below:

Sub- critical power plant units (with MDBFPs)	:	Paise 3.17/kWh
Super- critical power plant units (with TDBFPs)	:	Paise 2.71/kWh

Note:

i) Impact of TDBFPs/ MDBFPs: The above impact has been evaluated considering sub- critical units with MDBFPs and super- critical units with TDBFPs.

(ii) In case of coastal location, if a sub- critical unit is provided with TDBFPs (or a super- crirtical unit is provided with MDBFPs), the impact of energy charge shall reduce (or increase) by about paise 0.10/kWh from that indicated above.

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Comments on Letter issued by CEA on the subject *'Recommendations regarding Incentives to thermal plants for early installation of pollution control equipment'*

We really appreciate the efforts of CEA and Govt of India in foreseeing the impact on **merit order despatch (MOD)** of thermal generators on account of difference in implementation time of capex projects by various Generators to comply with revised environmental norms. The generators which comply with FGD implementation timelines earlier than other generators would have a higher Energy Charge rate (ECR) as compared to others (whose timelines for compliance are at a later date) putting them at a disadvantage in merit order ranking. However, while we address the issue of MOD, we need to deliberate on the issue of **recovery of incremental costs (both fixed and variable)** on account of implementation of revised emission norms. So our comments will be segregated into two sections - the first to deal with the MOD aspect and the second to deal with the recovery aspect.

A. Impact on Merit Order Despatch (MOD)

The letter mentions that *"The variable cost of TPPs installing FGD and other pollution control equipment as per the timelines in the notice of CPCB would continue to remain same as that before installation of pollution control equipment for the purpose of Merit Order Dispatch (MOD)* However, payment to the TPP for the energy scheduled would be based on actual variable cost".

We fully endorse the view that the increased Variable Cost because of installation of pollution control equipment would not be considered, in preparation of stack for merit order dispatch.

Accordingly, we understand that the Variable cost being considered before installation of FGD equipment shall be considered for MOD even after its installation without any reference to increase in variable cost or **actual variable cost due to FGD installation, which shall be used only for recovery purposes**.

Accordingly, for projects u/s 62, the Hon'ble CERC/SERCs have already stipulated the formulae for calculation of Variable charges (ECR) as,

"ECR = {(GHR – SFC x CVSF) x LPPF / CVPF + SFC x LPSFi + LC x LPL} x 100 / (100 – AUX)".

Where,

AUX =Normative auxiliary energy consumption in percentage.

CVPF= (a) Weighted Average Gross calorific value of coal as received, in kCal per kg for coal based stations

(b) Weighted Average Gross calorific value of primary fuel as received, in kCal per kg, per litre or per standard cubic meter, as applicable for lignite, gas and liquid fuel based stations.

(c) In case of blending of fuel from different sources, the weighted average Gross calorific value of primary fuel shall be arrived in proportion to blending ratio.

CVSF =Calorific value of secondary fuel, in kCal per ml.

ECR = Energy charge rate, in Rupees per kWh sent out.

GHR =Gross station heat rate, in kCal per kWh.

LC = Normative limestone consumption in kg per kWh.

LPL = Weighted average landed price of limestone in Rupees per kg.

LPPF =Weighted average landed price of primary fuel, in Rupees per kg, per litre or per standard cubic metre, 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 to blending ratio)

SFC = Normative Specific fuel oil consumption, in ml per kWh.

LPSFi=Weighted Average Landed Price of Secondary Fuel in Rs./ml during the month".

Although the above formula takes into account the impact of Limestone cost, for plants which are not having FGD do not take Limestone Consumption and Landed price of Limestone for computations of Energy Charges and Auxiliary Consumption is taken as per CERC/ SERC approved norms. It's therefore proposed that for section 62 projects, **even after installation of FGD**, the above formula may be used taking both Limestone Consumption and Landed price of Limestone as zero and Auxiliary Consumption **as per approved norms without installation of FGD**. For this purpose, MOP may recommend to CERC/SERCs to approve normative Aux separately for plant **without FGD and additional Aux norms for FGD** for the current tariff period and for the upcoming tariff period 2019-24.

Similarly, for section 63 projects, their bid variable rate (prior to FGD implementation) may be considered for MOD purposes as is being done currently.

This would be an uncomplicated way and a fair way to decide on the MOD ranking rather than that proposed in CEA paper which states that "for already compliant plants, incremental O&M charges due to pollution control equipment would be deducted from the variable charge of such plant for the purpose of deciding its location in the merit order". This would also render it futile to formulate **normative incremental O&M charges** based on some assumptions which are not going to hold true for plants across the country.

Further, till all FGDs are installed/the deadline for a plant the merit order may be run without any reference to additional variable charge. We understand that these additional O&M charges cover only the Limestone cost and other O&M charges (of fixed nature) shall be allowed separately.

B. Impact on Energy Charge Rate for recovery from Beneficiaries

For recovery, both fixed and variable costs post implementation have to be considered. Accordingly, we have in the sections below, have attempted to present our category wise views in the matter.

1) *For **variable costs recovery** of Sec-62 projects the following points need to be considered:*

i. The afore-mentioned CERC formula needs to be used for calculation and recovery of variable charges corrected as per the following observations:

ii. We are aware that the FGD equipment would consume additional power thereby increasing the Auxiliary Power Consumption which in turn would Increase in Energy Charge (Rs/Kwh). Such increase in APC results in increase in cost of fuel for each unit of energy sold. In the CEA paper, for evaluation of *normative* impact of FGD installation on Variable charges of electricity tariff, several parameters have been assumed at normative levels, for eg, Normative Auxiliary Power consumption has been considered as 9% for sub-critical units and 5.75% for super-critical units. For recovery purposes, we submit that considerable variations exist in the normative parameters as approved by CERC/ SERCs for thermal stations across the country viz-a-viz the norms considered in the extant workings (even though it was meant to work out a normative incremental charge for the sake of MOD only). **Hence, it is proposed that the values of such**

norms be kept same as approved by Central/ State Regulatory Commissions for the respective plants/ units.

iii. Further, it was noted that the assumptions considered for evaluation of normative impact of FGD implementation, several parameters such as (a) GCV of Coal, (b) GCV of Oil, (c) Landed Cost of Coal, (d) Landed cost of Oil, (e) Sulphur content of Coal (f) Purity of Limestone (g) Landed Cost of Limestone have been assigned normative values. Whereas, Hon'ble CERC and SERCs have allowed these parameters on actuals in their respective tariff orders after due scrutiny. In fact, GCV and Landed Cost is allowed to be billed on actual basis using the formula for ECR specified in respective regulations. **Hence it is proposed that these parameters may be considered at actuals rather than assigning them predefined values** which seems inappropriate. However, for new generating stations for which tariff is yet to be determined by SERC/CERC, the normative parameters as assumed may be taken as reference till the issuance of final tariff order or till true up is done subsequently.

iv. For normative limestone consumption in kg/kwh used in the above formula, the following may be considered:

$LC = \{ [(GHR – SFC \times CVSF)/ CVPF] \times Sul_{\%} \times (SO_{2Mol}/S_{Mol}) \times SO_{2\ Fac} \times SO_{2\ RemEff} \times (CaCO_{3\ Mol}/SO_{2Mol}) \times (StoRat / LSPur) \}$

where,

GHR =Gross station heat rate, in kCal per kWh (normative CERC/SERC figure)

SFC = Normative Specific fuel oil consumption, in ml per kWh (normative CERC/SERC figure)

CVPF= (a) Weighted Average Gross calorific value of coal as received, in kCal per kg for coal based stations (as per actuals)

(b) Weighted Average Gross calorific value of primary fuel as received, in kCal per kg, per litre or per standard cubic meter, as applicable for lignite, gas and liquid fuel based stations (as per actuals)

(c) In case of blending of fuel from different sources, the weighted average Gross calorific value of primary fuel shall be arrived in proportion to blending ratio.

CVSF =Calorific value of secondary fuel, in kCal per ml (normative CERC/SERC figure).

$Sul_{\%}$ = Percentage of Sulphur produced in % in coal. (as per actuals)

S_{Mol} = Molecular weight of Sulphur; 32.065 g/mol

SO_{2Mol} = Molecular weight of Sulphur Dioxide; 64.066 g/mol

$CaCO_{3\ Mol}$ = Molecular weight of $CaCO_3$; 100.0869 g/mol

$SO_{2\ Fac}$ = Sulphur to Sulphur Dioxide Conversion factor (assumed as 0.95 in CEA letter)

$SO_{2\ RemEff}$ = SO_2 removal efficiency, in % (assumed as 90% in CEA letter)

StoRat = Stoichiometric ratio (assumed as 1.05 in CEA letter)

LSPur = Purity of Limestone, in % (as per actuals).

2) <u>*For variable costs **recovery of Sec-63 projects** the following points need to be considered:*</u>

Impact on ECR for Section 63 power plants - The ECR computation for section 62 is given by formula *ECR = {(GHR – SFC x CVSF) x LPPF / CVPF+SFC x LPSFi + LC x LPL} x 100 /(100 – AUX).*

Let *{(GHR – SFC x CVSF) x LPPF / CVPF+SFC x LPSFi } be equal to 'A', and*

LC x LPL be equal to 'B'

Hence the ECR formula can be re-written as,

$ECR = \{[A/(1 - AUX)] + [B/(1 - AUX)]\}$,

For plants set up under Competitive bidding scenario, such as CGPL, the Energy charges (Escalable as well as Non Escalable) are fixed and can be written as

$A/(1 - AUX)$, referred as Bid Energy Charge because B is zero before installation of FGD.

To capture the impact of increased Auxiliary consumption because of FGD implementation, the ECR formula can be written as

$New\ ECR = \{[A/(1 - AUX - AUX_{FGD})] + [B/(1 - AUX - AUX_{FGD})]\}$, OR

$New\ ECR = \{[A/(1 - AUX - AUX_{FGD})] + [B/(1 - AUX - AUX_{FGD})]\} \times [(1 - AUX) / (1-AUX)]$, OR

$New\ ECR = \{[A/(1 - AUX)] + [B/(1 - AUX)]\} \times [(1 - AUX) / (1-AUX- AUX_{FGD})]$, OR

$New\ ECR = [A/(1 - AUX)] \times [(1 - AUX)/(1-AUX- AUX_{FGD})] + [B/(1 - AUX)] \times [(1 - AUX)/(1-AUX- AUX_{FGD})]$,OR

$New\ ECR = Bid\ Energy\ Charge \times [(1 - AUX)/(1-AUX- AUX_{FGD})] + [B/(1-AUX- AUX_{FGD})]$

The energy charge would thus be required to increase in the following manner

$$\text{New Energy Charge= Bid Energy Charge}^{1} \times \frac{(1-Normative\ Auxiliary\ Consumption\%)}{(1-Normative\ Auxiliary\ Consumption\%-AUXFGD)} + \frac{(LC\ x\ LPL)}{(1-Normative\ Auxiliary\ Consumption\%-AUXFGD)}$$

The additional segment mentioned above for recovery of Limestone Cost is in view of coal cost pass through mechanisms already envisaged in the recent versions of Standard Bidding Documents for Section 63 Projects.

3) *<u>Additional factors to be considered for variable costs</u>* ***<u>recovery for both Section 62 and Section 63 projects</u>****:*

i. It is to be further noted that for TPPs at Coastal locations, same norms have been considered as that for other TPPs, which we consider as inappropriate as most of the TPPs at coastal locations are using imported coal or blended coal (imported coal mixed with domestic coal). Hence, we humbly submit that such coastal TPPs operating with coal having higher Sulphur content, GCV and price, are not appropriately represented with such illustration workings.

ii. Norms of SHR and AUX may be given for TDBFP and MDBFP for both kinds of plants or may be adopted as given by regulator.

iii. Impact on Auxiliary Consumption on Sea Water FGD: CEA has assumed a normative APC due to FGD using Sea water as 1.0%. In our view, the APC arising out of FGD will depend on various factors like layout constraints, length of the pipeline to bring the sea water and size of scrubber pumps. While the APC considered by CEA at 1.5% for Limestone based FGD seems to be in order, the normative APC for sea water FGD should also be atleast 1.5%. This is based on the independent assessment of the APC using the designed equipments by us for our CGPL which is coastal plant and would use sea water.

In addition, there are very few power plants that use Sea Water FGD in India. In fact, to our knowledge only 500 MW Thermal Plant at Dahanu of Reliance (now Adani) uses the Sea Water FGD. Based on their MERC filings the Auxiliary Consumption of the plant is worked out to as follows:

[1] Along with Compensatory Tariff if any as well as Change in Law

Table 1: APC due to FGD Equipment at Dahanu

		FY 2015-16	FY 2016-17	FY 2017-18
Consumption by FGD	Mus	45.12	45.89	51.05
Total Generation	MUs	3824.54	3742.53	3189.8
APC of FGD	%	1.18%	1.23%	1.60%

Clearly the consumption as demonstrated by Dahanu Power Plant suggested that APC due to FGD equipment is above 1% as assumed by CEA.

- **Coastal Gujarat Power Ltd (CGPL) using Sea Water FGD**

In case of CGPL, the estimated APC for FGD is about 1.53%. This is due to layout requirements which requires bringing sea water from about 1.5 km distance, higher Sulphur content in coal as compared to 0.5% assumed by CEA. Based on the computations carried out for the power required for Auxiliary Equipment, the Auxiliary Consumption works out to 1.53% as given in the table below:

Table 2: APC due to FGD Equipment at Mundra

Description		UOM	Auxiliary Power Consumption (APC)				
			Total equipments (nos.)	Working (Nos.)	Standby (Nos.)	APC per equipment (MW)	Total APC (MW)
Auxiliary power requirement of FGD system	Booster fan	MW	10	10	0	3.5	35
	Scrubber pump	MW	15	10	5	1.8	18
	Aeration fan	MW	7	5	2	1.5	7.5
	Misc. LT load	MW				3	3
Total Auxiliary power consumption		MW					63.5
Auxiliary power consumption per unit		MW					12.7
Percentage APC		%					1.53%

Accordingly, the increase of 1% for APC on account of FGD may not be adequate and it is suggested the same be increased to 1.5 %

Further it is suggested that under CERC Tariff Regulations for the period 2019-24, a provision should be introduced to mandate the computation of both (a) Auxiliary Consumption without FGD, and (b) Auxiliary Consumption with FGD.

4) For Fixed costs recovery, the following may be considered:

i. Apart from the variable costs aspects covered in the above section, it is pertinent to mention that there is additional cost of capital nature which is required to be incurred by each generating station to comply with the revised norms. While, the recovery of such costs shall also be discussed in detail, for the purpose of this exercise of presenting our views regarding the proposed workings, we have attempted to capture the critical points briefly in the section below.

ii. In the matter of Capital Cost, we find it appropriate to draw your notice to recommendations of CEA phasing plan Committee dated 22.12.2016 wherein estimated capital costs figures have been indicated as Rs. 50 lakhs and Rs. 10-15 lakhs for FGD and NOX control systems respectively. This may be taken as a norm for all thermal generating stations which in turn shall be trued up during tariff determination exercise or at the time of adjudicating Change in Law petitions, as the case may be.

iii. Increase in terms of O&M Expenditure – The O&M Costs primarily consists of Employees, Repairs and Maintenance i.e R&M, Admin and General Expenses and Raw Water Expenses. While, Raw Material Costs which are Variable in nature have been covered in sections above, for O & M costs which are Fixed in Nature and does not depend on the Generation, we would again draw your notice to Hon'ble CERC's order dated 28th March 2018 in Petition No: 104/MP/2017, approving the provisional O & M cost of running the FGD at 2% per annum of the Capital Cost of FGD. We propose that the same provisional O & M cost may be considered as a norm for all thermal generating stations which in turn shall be trued up during tariff determination exercise or at the time of adjudicating Change in Law petitions, as the case may be.

iv. Grossing up Fixed Charges - This is applicable for power plants such as CGPL where the entire capacity has been tied down with Discoms and the Fixed Charges are recovered in terms of Capacity Charges (Rs/Kwh) instead of FC recovery on Annual Fixed Charge (Rs Cr) basis. Due to increase in APC, lesser capacity would be available for sale, leading to lower recovery of fixed charges and hence the Fixed Charges are required to be grossed up.

v. Increase in Fixed Charges- Obviously, due to Capital Cost of FGD, there will be a requirement of Additional Capacity Charge or Additional Annual Fixed Charge. Since the CEA paper has dealt with only the variable charge, we have not provided any comments on the same in this submission of ours.

5) Some additional Points which needs to be considered for recovery aspects:

i. CEA has considered 85% limestone purity with INR 2000/T of cost. Further it is indicated that for every INR 500/T increase in cost of limestone, the additional variable cost will be Paise 0.45/KWH. For Sulphur, CEA basis is 0.4% and for every 0.1% increase in Sulphur, additional variable cost will be Paise 0.45/KWH.

The actual cost of the FGD system at the plant may be more than the normative limit and as per the proposal, lower of actual or the above norm shall be considered as additional O&M expenses. This is not fair and actual cost as per above formula with norms for operational parameters. It is, therefore, proposed that this provision may be replaced with actual cost.

ii. Gypsum is a by-product in the process of de-sulphursiation. CEA has neither considered any revenue from Gypsum nor has considered any costs towards disposing of the same. In our view, revenue from sale of gypsum should not be considered, as the saleability of gypsum is heavily dependent on quality of limestone and demand for gypsum. Hence revenue from sale of Gypsum is a suspect. On the contrary, costs need to be budgeted for disposal of Gypsum.

iii. The letter/note of CEA indicates that soft loans may be provided to central/state generating stations from NCEF for installation of pollution control equipment. We request you kindly extend this facility to private generators also.

iv. Although not directly related to Variable Charge, it is important to submit that in the case of Case 2 projects like CGPL, there is no spare capacity that is available to accommodate the FGD consumption and also maintain Contracted Capacity at Ex Bus Level. The Contracted Capacity of CGPL is 3800 MW and the Gross Capacity is 4150 MW. The Capacity Charges of CGPL is recoverable at 80% Availability. Since there is no extra capacity that is available to accommodate the Auxiliary Consumption of FGD, it is necessary that the Contracted Capacity is reduced to the extent of Auxiliary Consumption. Hence if the Auxiliary Consumption of FGD is say 1.5%, the Contracted Capacity is required to be reduced to 3800 x .985 = 3743 MW. Alternatively, the Normative Availability may be reduced to 78.8% (80 x .985 %).

v. Additional Capacity Charge - FGD installation would entail capital expenditure. In addition, there would be shutdown of units thereby reducing the availability of the existing plant. Such reduction of Availability will deprive the existing plant of its Capacity Charge, which needs to be recovered separately.