APP Comments on CERC Draft Terms & Conditions of Tariff Regulations, 2019

Clause		Comments/ Submissions for consideration
3 (2) and 3 (3)	**Definition of 'Additional Capital expenditure' and 'Additional Capitalisation'**	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 referred by Hon'ble Commission for determination of Tariff. 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, the developer itself is not allowed to recover any return on equity deployed on such projects. In view of the above, we submit to this Hon'ble Commission that such mechanism may be introduced which may give the developers an opportunity to recover reasonable rate of return (which may be kept nominal up to the cost of financing) for such equity deployed in Capital Work in Progress which may be approved only after appropriate scrutiny by this Hon'ble Commission.
3 (5)	**Definition of 'Auxiliary Energy Consumption'**	The Auxiliary Energy Consumption should also be allowed for External Coal Handling Plant (jetty and associated infrastructure) in case of imported coal based generating plant/station. Also, this definition as per draft doesn't cover the FGD system as they are not used to operate the plant. Therefore, the Definition may be modified to that extent to cover the emission control systems also that are not necessary to operate the plant but are installed as a part of Compliance of law/directions from Government.
3 (7)	**Definition of Bank Rate**	We understand that unlike existing Regulations, the definition of Bank Rate has been proposed for being linked with marginal cost of lending rate (MCLR) of the State Bank of India instead of linking it to SBI Base Rate due to waning out of use of SBI base rate. In view of this, we submit that while shifting to such new reference rate of MCLR, it needs to balance the inherent gap existing between such rates of SBI MCLR and SBI Base Rate so as to cost neutrality for the developers who already have interest costs linked to SBI Base rate. To substantiate this statement, a comparison of applicable SBI Base rates with respect to SBI MCLR over last few years (as also referred by this Hon'ble Commission in the Explanatory Memorandum) is given in the table below:

<table>
<tr><th colspan="2">Clause</th><th>Comments/ Submissions for consideration</th></tr>
<tr><td></td><td></td><td>
<table>
<tr><th>Date</th><th>SBI Base Rate (%)</th><th>SBI MCLR (1 Year) (%)</th></tr>
<tr><td>01-07-2016</td><td>9.25</td><td>9.15</td></tr>
<tr><td>01-10-2016</td><td>9.25</td><td>8.90</td></tr>
<tr><td>01-01-2017</td><td>9.25</td><td>8.00</td></tr>
<tr><td>01-04-2017</td><td>9.10</td><td>8.00</td></tr>
<tr><td>01-07-2017</td><td>9.00</td><td>8.00</td></tr>
<tr><td>01-10-2017</td><td>8.95</td><td>8.00</td></tr>
<tr><td>01-01-2018</td><td>8.65</td><td>7.95</td></tr>
<tr><td>01-04-2018</td><td>8.70</td><td>8.15</td></tr>
<tr><td>Average</td><td>9.02</td><td>8.27</td></tr>
<tr><td>Difference in SBI MCLR w.r.t SBI Base Rate</td><td></td><td>0.75</td></tr>
</table>
It is evident from the above table that SBI MCLR is on an average less than SBI Base rate by 0.75% and hence such extra margin shall be added in the Bank Rate while changing the reference. Hence, we submit that applicable Bank Rate may be made equivalent to MCLR + 350 basis points + 75 basis points i.e. MCLR + 425 basis points.
</td></tr>
<tr><td>3 (10)</td><td>Definition of Change in Law</td><td>
The Judgment of the Hon’ble Supreme Court in the Civil Appeal Nos. 5399-5400 of 2016 dated 11.04.2017 (the Energy Watchdog Case) held that even a letter issued by the Government Instrumentality has force of Law and can be considered as a Change in Law. Hence, following bullet may be added in the change in law:
Suggested Modifications:
“Any direction/ communication by Indian Governmental Instrumentality/ any Competent authority which is enforceable on the generating company/ licensee and results in financial impact”.
</td></tr>
<tr><td>3 (14)</td><td>Definition of cut off date</td><td>We submit that statutory requirements (as per Companies Act) persuade the developers/any organisation to conduct the audits on a quarterly basis and hence considering the regularity of the process, we 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.</td></tr>
<tr><td>3 (17)</td><td>Definition of ‘De-capitalisation’</td><td>
In certain cases, asset is taken out of service to be refurbished and new asset is installed in place, the refurbished asset is kept in inventory as critical spare. In such cases, if such refurbishment is admitted and allowed by the Commission, the cost of refurbishment will become part of the GFA. The refurbished asset, even if kept in inventory and not really in service, will have to be considered for tariff determination purposes and cannot be considered as de-capitalized.
This Regulation should, therefore, provide exception for such cases.
</td></tr>
<tr><td>3 (26)</td><td>Definition of ‘Force Majeure’</td><td>
While, the above definition of Force Majeure events broadly covers 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 which does not result in any offsetting compensation being payable to the project developer by or on behalf of such Contractor.
</td></tr>
</table>

Clause		Comments/ Submissions for consideration
		• Any direct or indirect cyberattack affecting the operation of the project developer. We 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.
3 (31)	**Definition of GCV as received**	The FSA with the coal companies provides a procedure for coal sampling which is in variance to the above IS Standard IS: 436 (Part I/Section I), 1964. The coal companies provide the GCV of coal on equilibrated basis both for testing done at mine end and at the un-loading (in plant end) end also. The 3rd party agency appointed by Govt. of India i.e. CSIR-CIMFR carries out the sampling as per FSA procedure and not as per IS Standard IS:436 (Part I/Section I), 1964. However, for the Power Procurers the GCV on ARB basis is required. IS 436 provides a procedure for sample collection which is more representative than the FSA procedure. As such the coal companies need to amend the FSA as per above IS Standard. Similarly, the GCV should be provided either on ARB basis or CERC should specify the standard formula for conversion of GCV equilibrated basis to ARB basis. The advance technology of collection of samples at the mine end is very much essential as billing is done by coal companies based on the GCV measured at mine end. The more representative or scientific way the sample is collected the tested GCV value would also be more representative of coal dispatched from the mines. Measuring of Gross Calorific Value by third party sampling to be defined as there is difference in methodology as per FSA and Tariff Guidelines. Third party sampling agencies to be developed for the same.
3 (34)	**Definition of Implementation Agreement**	The responsibilities and liabilities of Transmission Licensee or the generation Developers are defined in the respective TSA or PPA. Therefore, in case of any delay, the TL or the Generation Developer should be held liable as per the provisions of TSA/ PPA and accordingly, LD should be imposed as per the provisions of TSA/ PPA. The TL or the Generation Developer cannot be punished beyond what is specified in the TSA/ PPA, as otherwise their liability will become endless.
3 (35)	**Definition of Indian Government Instrumentality**	The definition should also include the Statutory agencies/bodies and Agencies under direct/indirect control of the State or Central Government. The definition may be amended accordingly.
3 (41)	**Definition of Investment Approval**	Suggested modification: *'Investment Approval' means approval by the Board of the generating company or the transmission licensee or Cabinet Committee on Economic Affairs (CCEA)* ***or date of financial closure*** *or any other competent authority conveying administrative sanction for the project including funding of the project and the timeline for the implementation of the project:*

Clause		Comments/ Submissions for consideration
		NTP (notice to proceed) is issued only after Financial Closure. Therefore, it would be prudent if any appraisal of delay is COD is considered based on Financial Closure.
3 (42) and 3 (78)	**Definition of Landed Fuel cost and Unloading point**	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. It is to be noted that while the proposed definition of "GCV as Received" in clause 3(31) covers all possible unloading and collection, preparation, testing locations of sampling like loaded wagons, trucks, ropeways, Merry-Go-Round (MGR), belt conveyor and ship, the definition of Landed Cost (clause 3(42)) read with definition of Unloading Point (clause 3(78)) tend to limit the scope as defined in the clause 3(31) and may create ambiguity. Hence, we request the Hon'ble Commission to extend/modify the proposed definition in clause 3(42) and 3(78) to cover all the possibilities of unloading points which may include loaded wagon tops, truck tops, ropeways, Merry-Go-Round (MGR), belt conveyor and ships. Also, many Generators are forced to undertake washing of coal to comply with MoEF&CC norm to achieve 34% ash content. Therefor cost of washing may be included in landed cost.
3 (45)	**Definition of Mine infrastructure**	The definition of Mine infrastructure should include the Intangible Assets like surface right/lease on mining land etc.
3 (48)	**Definition of O&M expenses**	Suggested modification: *(48) 'Operation and Maintenance Expenses' or 'O&M expenses' means the expenditure incurred for operation and maintenance of the project, or part thereof, and includes the expenditure on manpower, maintenance, repairs and maintenance spares, consumables, insurance, overheads and fuel other than used for generation of electricity, water charges,* ***environmental protection charges,*** *and security expenses* ***(including cyber security)****;*
3 (49)	**Definition of Original Project Cost**	There can be certain capital expenditure items that were not in "Original Project Cost" but became necessary, e.g. Major accident like failure of equipment requiring complete replacement of the equipment.
3 (51)	**Definition of Plant Load Factor**	PLF of the station should be calculated based on the actual generation and actual Aux. Power Consumption and not on the scheduled generation and normative APC which is the prevailing practice in the Power Sector.
3 (51)	**Definition of Plant Load Factor**	PLF formula is based on the installed capacity of the generating stations. However, there are projects where part capacity has been tied up in long term PPA under Sec. 62 and part capacity has not been tied up or partly tied up under Sec. 63. As incentive is based on PLF, it is not clear how the PLF of such power stations will be calculated.

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		Therefore, it is suggested the regulations may be suitably modified to address such generating stations. Further, PLF for such cases should be calculated only for the power contracted under Sec. 62 for which tariff is determined by the Commission under these regulations.
3 (79)	**Definition of Useful life**	Change in useful life should have an impact on loan repayment profile. Since repayment is supported by recovery of depreciation in tariff, the depreciation period may be increased to match with the actual loan repayment tenure. Also, long term funding is being advocated by various agencies at different forums including the proposed hydro policy. Further, there are certain Hydro Power plants where PPA is signed for 35 years considering its useful life. Increase in useful life to 40 years would reduce the recovery of Annual Fixed Charges for such Hydro plants. It is suggested that the change of useful life may be applied for hydro plants commissioning after 31.03.2019. Also, plants with pending loan repayment will be impacted as due to increase in project life, as per methodology, from 13th year, the remaining depreciation will be spread into 28 years instead of 23 years. Increase in the life of project has direct impact on the rate of depreciation allowed by CERC. However, there is no change in the rate of depreciation allowed by CERC in draft regulations. Even if rates are not revised, depreciation from 13th year onwards will be revised downwards. Therefore, projects with pending loan repayments will be impacted by lower recovery of depreciation. We request that considering the increase in project life depreciation period of 12 years shall be increased (say 15 years) in case of hydro in order to match the actual loan repayment to some extent. Also rate of depreciation should not be revised downwards with respect to change in the life of project. Further, there are certain Hydro Power plants where PPA is signed for 35 years considering its useful life. Increase in useful life to 40 years would reduce the recovery of Annual Fixed Charges for such Hydro plants. It is suggested that the change of useful life may be applied for hydro plants commissioning after 31.03.2019. Further to the above, existing regulations specify useful life as 35 years for AC and DC Substations and GIS for which NIT is issued after 01.04.2014, this contradicts the useful life as per Draft Regulations. This needs to be clarified.
6 (1)	**Treatment in mismatch of COD of the generating station and the transmission system**	The regulations may be modified to clearly address that for the cases where generating station has achieved COD and the complete end to end transmission system for which Open Access has been granted to such generating station has not achieved COD as on date of COD of generating station, the transmission licensee shall made the alternate arrangement for evacuation and supply of the entire Open Access quantum from the generating station, failing which, the transmission licensee shall be liable to pay the applicable transmission charges (PoC Charges) to the generating station

Clause		Comments/ Submissions for consideration
		corresponding to the quantum of Open Access granted to such generating station. 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. However, it is not very clear from the provisions that in such cases of delay, penalty would be calculated with respect to which date. Accordingly, we submit that the process may be developed that the Generating Company and the Transmission Licensee shall agree on a Scheduled Commercial Operation Date ("SCOD") of the respective projects and such date shall act as a reference for computing penalty by either of the defaulting party. Also, 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 to the defaulting party by 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. In view of this, it's not likely that the alternate arrangement which may be made available to the Generator is completely prudent to meet the requirements of the generator 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 submit that if at all the concept of such proposed alternate arrangement needs to be retained, this Hon'ble Commission should 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 COD 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 device a mechanism or procedure for compensating the Generating Company for such losses appropriately.

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		While designing an equitable compensatory mechanism to penalise for delays, and consequential suffering of other party, necessary safeguards need to built-in on either side for delays on account of factors beyond the control of Generators/ Transmission Licensees.
8	**Tariff Determination**	Suggested modification: *(4) Assets installed for implementation of the revised emission standards shall form part of the existing generation project and tariff* ***(including various components such as O&M expenses, Depreciation, Interest expenses, RoE, Interest on working capital, additional auxiliary consumption etc.)*** *thereof shall be determined separately on submission of the completion certificate by the Board of the generating company.* Further, the procedure on tariff determination for the assets installed for meeting the new environmental norms should be clearly defined as it involves capital cost expenditure which may be part of fixed cost and cost of limestone etc. would be part of variable cost. Apart from the above there has to be revision in operating norms especially for APC, additional O&M cost, etc. which need to be addressed.
8 (3)		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.
8 (6)		Clarification is required on the methodology for determination of GCV of coal rejects in order to avoid ambiguity.
9 (1)	**Application for determination of tariff**	The Hon'ble Commission has proposed that application for determination of tariff is to be filed within 60 days of anticipated COD instead of 180 days now. However, a period of 180 days has been provided in Regulation 9(2) for existing generating station or transmission system. We appreciate the concern of Hon'ble Commission regarding determination of tariff to be available as on date of COD and interim tariff to be as close to final tariff as possible. However, all the licensees should not be penalized due to non-achievement of few licensees. Therefore, we request Hon'ble Commission to propose same time period of 180 days for filing of application for determination of tariff for new and existing generating stations or transmission system.
9 (3)	**Determination of supplementary tariff in installation of emission control system**	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 submit that the AFC for such investments may be arrived it in a manner that all costs related to such investments may be recovered within the balance useful life of all generating stations.

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		Also, some components of capital expenditure are not covered, which should be considered, particularly like storage facilities required for lime or Ammonia, etc. and for by products like Gypsum, etc. Further, Capital expenditure can be certified by Auditor only after COD of such emission system. For reducing the time in tariff approval process, CERC may consider allowing provisional supplementary tariff based on cost estimates. The same may be allowed after due prudence check by CERC during the truing-up process. This will reduce the cash flow mismatch for generators. This is in line with the practice of CERC in issuing provisional tariff for generation tariff.
10 (3)	**Determination of tariff**	We request Hon’ble Commission to please specify the limit in percentage for the interim tariff as was specified in the existing regulation. The existing regulations allowed grant of tariff up to 90% of AFC.
10 (4)		We understand that the Tariff refers to per unit Fixed Cost and the Energy Charge Rate 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 Fixed Cost recoverable by the generating company is determined by this Hon'ble Commission in 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 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 31.03.2019, Normative parameters to be considered for Energy Charge Rate computation would be applicable as on 31.03.2019 or the ones applicable from 01.04.2019.
11	**In-principle Approval in Specific circumstances**	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. However, there may be situations which may not get qualified either for Change in Law or Force Majeure, but may require immediate investments during a Tariff period instead of beginning of a Tariff Period. In view of such situations, we, 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. For Change in Law approval, CERC may like to put in place a simple process which avoids differential layer of approval for the same thing. For example, for FGD, the technology has already been approved by CERC in many cases, and necessary benchmarking of prices is also available. Accordingly, Generators should be allowed to proceed for installation of Emission Control Systems, and once tendering has been done and finalised, they should be allowed to approach CERC for approval. At a later stage they can come for truing up once the task is finished.

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		Alternatively, based on approvals already granted, CERC may consider uniform tariff increases based on minimum capital costs that are in accordance with CEA guidance (Final tariff approvals can be modified to account for approved costs). The tariff increases could be staggered to make them acceptable to Discoms/ consumers.
13	**Truing up of tariff for the period 2019-24**	Mid-term truing-up should continue to be allowed as in FY 2014-19 regulations. Such truing-up helps generating companies in keeping their books updated and also helps in better cash flow management. Keeping the truing-up due for 5 years may come as onetime write-off or gain in books.
14 (2)	**Components of tariff**	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) and shall not be postponed till process of Tariff Determination of subsequent Tariff Period.
15 (e)	**Capacity charges**	Additional O&M expenses would be required to meet the expenses on account of FGD during O&M stage which also should be considered as part of the capacity charges.
16	**Variable Charges and Energy Charges have been defined as one and the same thing**	It is suggested that the term 'Variable charge' may be deleted and only 'Energy Charge' may be retained as used in Tariff Regulations, 2014. In the draft regulations, the Variable Charge or Energy Charge is proposed to be restricted to recovery of fuel cost only. The other variable costs like auxiliary energy consumption, levy of taxes and duties on generation of electricity such as electricity duty, repair and maintenance cost and cost of water charges which directly vary with the level of generation are not covered under this regulation. Hence, heading of Regulation 16 may be modified as 'Energy Charges' only.
17	**Debt-Equity ratio**	Considering the facts referred to in the preamble hereinabove, if the base for RoE is now proposed to be reduced, it will drastically alter the investment risk perception with which a project was conceptualized. This will adversely impact the cost of debt due to increased risk perception of the lenders for any future additional capitalisation which will ultimately impact the interest of the consumers whose cost of electricity will increase. Further, the Developer is not able to recover any return on the equity deployed during the construction period and hence, the provision for reduction of equity after completion of useful life would have a negative impact on the developer in terms of loss of RoE (as an offset for RoE not earned during the construction period) because the developer cannot take out the money invested as equity into the generation/transmission project. Further, as per Clause 6.4.1 (e) of the Explanatory Memorandum, it is submitted that the Appellate Tribunal for Electricity has passed a Judgment on dated 16 May, 2006 in favour of PGCIL, stating that any mechanism by which the equity is gradually reduced proportionately reducing the rate of return below the specified rate of

Clause		Comments/ Submissions for consideration
		return is not legal. The Judgment was upheld by Hon'ble Supreme Court in its Judgment dated 24 February, 2016 in Appeal No. 256 of 2007. The relevant portion of the SC Judgment is as follows: *"3. That there is no depreciation on equity, cannot be disputed. In the subsequent years, it is seen that the mistake has been corrected also."* Further, the Tariff Policy mandates regulatory certainty and any such move will de-motivate prospective investors. Moreover, this will create regulatory uncertainty and therefore, the developer will be forced to shut down the plant after the completion of useful life and this will also have a negative financial impact on Beneficiaries as they would have to procure power from alternate sources which would be costlier as compared to the developer's existing plant. Therefore, the developer should be allowed to recover RoE on the entire equity invested in the project till the project continues to generate and supply electricity to beneficiaries even beyond the useful life of the asset, in accordance with the Regulations and the provisions of this Regulation should be made applicable only to plant commissioned after 01.04.2019.
18 (2) (o) and 18 (3) (f)	**Computation of capital cost**	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 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 continue to bear the losses for not meeting the PAT targets. In view of the above, we submit to this Hon'ble Commission that any gains for sharing under Regulation 70 shall be arrived at by netting off the losses incurred by the generating company under PAT scheme. Also, existing generating stations should be allowed capital cost for any change in law or force majeure, incurred during construction.
18 (5)	**Capital cost**	It may be noted that the Transmission schemes are executed only after prior approval of CTU and/or based on the requirement of the beneficiaries. Therefore, it would be gross injustice if capitalization or O&M expenses of un-utilized bays of Transmission Licensee are denied by the Commission.

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		Further, it may be noted that the development of downstream system falls under the purview of the other Utilities in terms of load arrangement, which is not in the control of Transmission Licensee. Hence, impact of such non-readiness of other Utilities shall not be passed on the Transmission Licensees. Hence, it is requested that capital cost as well as O&M cost of such bays shall be allowed by the Commission and appropriate provision may be incorporated/amended.
19 (1)	**Prudence Check of Capital Expenditure**	Transmission systems are to be laid down in various geographical locations based on the system strengthening, access and evacuation requirements. It would therefore, be improper to generalize various factors affecting the execution and performance of transmission systems such as hilly terrain, weather conditions, wild forest zone, wind zone, RoW clearances, etc. Therefore, there cannot be any generalization of the capital cost based on the similarity of the project as each transmission project is different.
21 (b)	**Controllable and Uncontrollable factors**	We welcome the proposal of Hon'ble Commission to include land acquisitions as Uncontrollable factor. However, we suggest that time and cost over-runs on account of Right of Way (RoW) should also be included as uncontrollable in line with Land acquisitions as transmission licenses face lot of issues in RoW approval and same is also not in control of Transmission licensees. Additionally, we would like to bring to your notice that Hon'ble Commission has noted in its Explanatory Memorandum that acquisition of land and right of way have become one of the main causes of delay in commissioning of the projects and these issues are largely outside the control of the project developer. However, Hon'ble Commission has inadvertently not included Right of Way as uncontrollable parameter in Draft Regulation. Hence, we request Hon'ble Commission to include RoW as uncontrollable Parameter. Further, delay in execution of project on account of contractor, supplier may not be classified as "controllable factors". In cases where developer has made significant advance payments to the contractor/ supplier, it is very difficult to ensure timely execution in case such supplier goes into bankruptcy. Developer has no recourse but to go to NCLT for resolution and therefore such issue cannot be in control of the developer. Commission may evaluate such issues on case to case basis instead of considering such issues as "Controllable".
21 (2) (c)		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 its 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.

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		Hence, we 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. Further, there may be instances wherein reasons are beyond the control of developer, these should be considered like case to case basis. Like in hydro, any natural calamity not covered in force majeure event such as moderate flood/snowfall impacting progress, enabling infrastructure to project area which is to be provided by state authorities etc. should have impact in project schedule along with cost. These things should be considered on case to case basis.
22	**Initial spares**	The capitalized Initial Spares should be allowed even beyond the cut-off date and corresponding to any initial or additional capitalization, RoE should be allowed as is done for the main asset because any capitalization initial or otherwise is approved/ admitted by the Commission after prudence check and considering that the developer is required to maintain capitalized initial spares for smooth operation of the transmission system.
23	**Additional Capitalisation within the original scope and up to the cut-off date**	Provisions similar to Clause 14 (3) (ix) of the CERC Regulations, 2014-19 related to Transmission System should be retained in the Draft CERC Regulations, 2019-24. The said clause is reproduced below: *(3) The capital expenditure, in respect of existing generating station or the transmission system including communication system, incurred or projected to be incurred on the following counts after the cut-off date, may be admitted by the Commission, subject to prudence check:* *(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;*
24	**Additional Capitalisation within the original scope and after the cut-off date**	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*

Clause		Comments/ Submissions for consideration
		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 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.
27 (3)	**Special Allowance for Coal-based/ Lignite fired Thermal Generating station**	Special provision was introduced in the past by this Hon'ble Commission for generating stations approaching the end of their useful life. This purpose of this provision was to meet the increasing O & M expenses of the Generating expenses due to wear and tear and thus, was considered as an alternate route for the generating stations instead of taking up R & M expenditure. In the Draft Regulations, Hon'ble Commission has proposed that the expenditure incurred or utilized from special allowance shall be maintained separately by the generating station and details of same shall be made available to the Commission as and when directed to furnish details of such expenditure. It is to be noted that in certain cases, such special allowance is not sufficient to meet the additional expenses of the stations due to wear and tear and the generating stations even after availing for Special Allowance may require to incur expenses of R & M nature. In view of such situations, we submit that Hon'ble Commission shall allow the generating company to recover additional costs for such R & M expenses after offsetting the surplus available to the generating Company from such Special Allowances recovered from time to time. Also, 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.
28	**Special Provision for thermal generating station which have completed 25 years of operation from commercial operation date**	The 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. We understand that this restriction on the generator would not be an appropriate approach for the generating company as it would insert a lopsided approach towards the beneficiary whereby beneficiaries would be allowed to explore the market opportunities before tying up the extension period, but the generators would not be allowed to do so. 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. 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

Clause		Comments/ Submissions for consideration
		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 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 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.
29	**Additional Capitalization on account of Revised Emission Standards**	In case of in-principle approval it should be noted that for FGD, the technology has already been approved by CERC in many cases, and necessary benchmarking of prices is also available. Accordingly, Generators should be allowed to proceed for installation of Emission Control Systems, and once tender has been done and finalised, they should be allowed to approach CERC for approval. At a later stage they can come for truing up once the task is finished. Alternatively, based on approvals already granted, CERC may consider uniform tariff increases based on minimum capital costs that are in accordance with CEA guidance (Final tariff approvals can be modified to account for approved costs). The tariff increases could be staggered to make them acceptable to Discoms/ consumers. Also, please clarify that whether CEA specified technology is the only technology which can be used for installation of FGDs. It is understood that CEA is yet to cover all the technologies (e.g. ammonia-based technology is yet to be assessed by CEA). Therefore, it is essential that all globally established technology should be included for assessment by CEA and for prudence check by CERC. CERC may also issue benchmark cost for all the global technologies. The projects where power is being supplied to beneficiaries under Sec. 61 & 63 of the Act need not need to file a fresh petition for approval in case a petition is already filed for the same project. As it would lead to unnecessary burden of cases.
30 (2) i.	**Return on Equity (ROE) on the additional capitalization after cut-off date within or beyond the original scope of work.**	Hon'ble Commission in its explanatory memorandum have considered CAPM mechanism as an appropriate approach for arriving at the reasonable rate of return. While, agreeing to the above principle, we have attempted to work out the expected rate of return for the sector based on BSE indices for last three years which gives a more proper reflective results for the approaching Tariff Period. Such analysis suggests that the expected rate of return for the sector works out to around 14.5%. 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

Clause		Comments/ Submissions for consideration
		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. The above study suggests that considering a gestation period of minimum of 3 years, the generating company shall be allowed a minimum post tax RoE of 19-20% for achieving an IRR of 14.5% for the life of the investment. Hence, we submit to this Hon'ble Commission that post tax Return on Equity for Thermal Generating assets and Transmission assets shall be increased from 15.5% so as to ensure an IRR of around 14.5% for the useful life of the project. 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 certain investments like: • Investments which are statutory in nature and are required to comply with existing or new laws regulations, directives from any court of law. • 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. • 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. In all above situations, investments have already been made with certain expectations as per principles of earlier Tariff period or the developers would be forced to make investments for complying with any new laws. Any curtailment in returns of above investments would be unjust for such investments and hence, we submit to this Hon'ble Commission that such investments shall be taken out of the ambit of curtailed return and 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. Most of the generating companies who have already achieved COD are likely to invest such huge capex requirement and achieve COD in the Tariff Period FY 2019-24 and thus, as per proposal of this Hon'ble Commission, 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 taken out of the ambit of curtailed return

Clause		Comments/ Submissions for consideration
		and 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. Further, considering the fact that capital expenditure on account of the Revised Emission Standards, fly ash disposal etc. are inevitable/ mandatory, for the existing generating plants, any proposal to reduce the rate of RoE is regressive and such investment cannot be denied the legitimate RoE at par with the prevalent norms. There is a strong case for Return on Equity for any additional capitalization after the cut-off date within or beyond the original scope being computed at the regulated rate of 15.5% specified in the Regulations and not at the weighted average rate of interest on the actual loan portfolio because, any additional capitalization is admitted/approved only if it is reasonable and after prudence check by the Commission. In the present scenario where the stressed assets in the power sector are on the rise, the IBC Code and similar mechanisms are in place to protect the interest of the lenders. However, there is no mechanism available which protects the equity base of the project developer. This makes the risk associated with the equity capital very high. Therefore, the return available on any equity investment should also be commensurate with such risk perception and hence the rate for RoE for any additional capitalization after the cut-off date within or beyond the original scope should be retained at 15.5%. In view of the additional capitalization required to be incurred by the developer to meet the revised emission standards and equipment such as FGD etc., a reduced rate of RoE will have an adverse impact on the financial position of the developer and also have a cascading impact on the cost of debt on account of increased risk perception by lenders. This will ultimately result in the increase in tariff for the Beneficiaries. It is further submitted that additional RoE should be allowed over and above the Regulated rate of 15.5%, as an incentive to provide impetus to the sector already under stress on account of multiple factors. Generating Stations alone cannot be held responsible for data telemetry and communication set up and hence the reduction in rate of return by 1% shall not be made applicable. The penalty to the tune of 0.1% during the deficiency period only may be considered. Further, Hydro being a capital intensive project, also involves lot of construction challenges/ risk. To attract more investors in this domain, an additional RoE (say 0.5%) should be provided over and above the existing RoE. Also, the case of Transmission also needs consideration. Transmission Licensees suffer from challenges related to procuring Right of Way, Land and varying terrain spanning across the Country. The expectation of returns for a Transmission Licensee must be in line with risk perception and market expectations. Further, the returns should also ensure viability of the project.

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<tr><th colspan="2">Clause</th><th>Comments/ Submissions for consideration</th></tr>
<tr><td></td><td></td><td>Considering above aspects and the enhanced risk perception, there is a case of considering increase in the Return on Equity.

Further to the above, the purpose of additional RoE is to incentivize transmission licensees for early completion of the projects, which will have twin benefit of early power flow to beneficiary and saving in IDC. Nevertheless, completion of huge capital intensive transmission project is in overall national benefits. In view of the same, we request Hon’ble Commission to continue with progressive measure to incentivize early commissioning.</td></tr>
<tr><td>32 (5), (6), and (7)</td><td>Interest of Loan capital</td><td>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 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.</td></tr>
<tr><td>32 and 71</td><td></td><td>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</td></tr>
</table>

Clause		Comments/ Submissions for consideration
		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

Clause		Comments/ Submissions for consideration
		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.
33 (2)	**Depreciation**	While we 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 request the Hon'ble Commission to consider the approach of allowing depreciation for additional capitalisation from the date of capitalisation.
33 (3)		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. 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.
33 (5)		Further, CERC may clarify that rate of depreciation will change because of such reduction in salvage value or only the depreciation post completion of first 12 years will undergo a change. Disallowance of depreciation in case of lower availability, may be allowed to be recovered during later stage of life or life extension. Such allowance of depreciation on future date will correspond to availability of unit and is in line with the commercial principles. Also, period of 12 years needs to be reviewed in light of the actual loan tenure being provided by lenders. Generally, it is higher than this and hence there is gap between depreciation & repayment amount post 12th year.

Clause		Comments/ Submissions for consideration
		In order to streamline, this period should be 15 years which is a generally accepted loan tenure among most of the funding arrangement concluded by lenders so far.
33 (6)		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 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.
33 (8)		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 submit to the 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.
34 (1) (a)	**Interest on Working Capital: Coal based thermal generating stations**	For computation of interest on working capital, cost of Coal towards stock has been reduced from 30 days to 20 days and receivables towards Capacity and Energy charges has been reduced from 60 days to 45 days (vis-à-vis CERC Tariff regulations, 2014-19). This drastic reduction in components for computation of interest on working capital would severely hit the tariff and hence the financial viability of the generating stations, especially considering the significant delays in payments by the Utilities/ beneficiaries. Further, payments towards coal are to be made in advance to CIL and a generating station is required to keep stock of at least 30 days for seam-less and uninterrupted operations of generating stations. Hence, it would be in the overall interest of the sector, that such components for computation of interest on working capital remain unaltered as provided in CERC Tariff regulations, 2014-19 (i.e. Cost of Coal towards stock and Receivables towards Capacity and Energy

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<tr><td></td><td></td><td>charges must be restored back to 30 and 60 days respectively), else it may risk the generating stations becoming NPAs.

Further, cost of Coal Stock should not be misconstrued only for the physical coal stock lying in plant but should also consider cost of coal stock which has been paid for and is in transit. As both for imported and domestic coal, the money is paid in advance and therefore, quantity of coal paid for should be considered as “Stock in Hand”.

It is important to note that in case of imported coal based units, higher number of days of coal stock is required as the lead time of vessels is much more than 20 days.

Further, there is no change in the ground situation requiring reduction in the time period considered for cost of coal stock. In fact there are several factors affecting the generators.

In case of imported coal based units, apart from the coal stock, money is also paid in advance for the coal dispatched through ships from the port of loading and gets locked up till the time the coal reaches the power plant. Therefore, such funds which are locked up during the transit of coal from the port of loading till the power plant also should form part of the working capital requirement.

Hence, Coal stock of 30 days and receivables equivalent to 60 days should be continued in line with existing regulations and an additional component for the funds blocked during the transit of coal from the port of loading till the power plant in case of imported coal based units, also should form part of the working capital requirement.

Also, receivables equivalent to 2 months of capacity charges and energy charges for sale of electricity calculated on the normative annual plant availability factor changed to 45 days will also will reduce tariff and cause hardship to generators.

For calculation working capital receivable of at least 2 months to be considered as due to delayed payments by DISCOMs actual receivable goes to 3-4 months of sale.

This also should include working capital required for stock to be maintained for lime/ other chemicals which are to be required during operation of FGD. Further provision is to be made for maintaining spares required for the FGD plant.</td></tr>
<tr><td>34 (1) (b)</td><td>Interest on Working Capital: Open-cycle Gas Turbine/ Combined Cycle thermal generating stations</td><td>The subject provision of fuel stock for gas based power plants allows liquid fuel stock for 15 days in IOWC. In this context, we would like to submit that such liquid fuel stock is not a viable generation fuel in the current situation. Compared to such liquid fuel, LNG stock is much more viable and has advantages as mentioned below.

(a) <u>Reliable power supply at competitive rate</u>
The delivery process of LNG can be divided into two broad categories i.e. (a) contractual process and (b) operational process. The contractual process involves floating of RFP, Bid Evaluation and Contract award. It generally takes 15 days period. Operational process involves (for delivery) nomination / booking of loading port, LNG delivery ship and unloading port. As per standard practice, such nomination process is provided 45 days period. Such period is</td></tr>
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Clause		Comments/ Submissions for consideration
		required to keep margin for unforeseen or force majeure events and transportation time to ensure timely delivery. In view of the above, it is prudent to keep inventory of 60 days. Further, such two months process is also evident in prices assessment of LNG published by Platt (i.e. price assessment of 2.5 months is published). The cost of such inventory is expected to be around ~7.5 paisa per unit. However, the benefit of direct import of LNG through ICB/Spot in price discovery (vis-à-vis Govt. of India contracted Rasgas RLNG gas being supplied to Power Plant/Others) compensates more than such cost. As per the past record, the price delta of ~ 1.60 USD per MMBTU is observed which translates to a delta of ~ Rs. 1 per unit. It is also worth noting that such direct import of LNG also optimises tax cost (additional benefits). (b) Flexibility in operation due to LNG stock. In addition to the above, there is an advantage of operational flexibility in offtake. Such advantage is substantial and could be assessed in terms of (a) higher power offtake in summer and after monsoon period and (b) bare minimum offtake in winter & monsoon months. Further, it also provides flexibility to balance renewable power offtake vis-à-vis thermal power offtake which needs to be exercised on day to day basis. In view of the above, we request the Hon'ble Commission to add enabling provision in IOWC (for gas base power plants) related to 60 days of LNG stock. Such enabling provision should allow the stock of LNG in IOWC after verification of actual data at the time tariff petition (on case to case basis). Hence, it will not lead to additional normative recovery of cost of LNG stock for all generators but for generators which are maintaining such inventory on actual basis. Further to the above, invoices are normally raised to beneficiaries once the State & Regional Energy Account is published by SLDC/RLDC and receipt of invoices by fuel supplier and transporters. It may be noted that the SEA/REA contains all details required for the billing (for all transactions including revision). Hence, it requires lots of data processing, verification / confirmation and compilation. SLDC/RLDC generally takes 7-10 days to prepare & publish REA/SEA (for the previous month). Further, it takes two to three days for preparation and raising the invoices (after due verification of data). Hence, the existing actual cycle of receivable is already 70 days, i.e. 10 days for raising the invoice and 60 days of payment period. From the above it is evident that, there is already a gap of 10 days in the existing cycle which is not covered in IOWC. In view of the same, it is requested to maintain exiting provision of receivable of 60 days for IOWC.
35 (1)	**Operation and Maintenance Expenses for Thermal Generating Stations**	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.

Clause		Comments/ Submissions for consideration
		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 behaviour 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. 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.

Clause		Comments/ Submissions for consideration
		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

Clause		Comments/ Submissions for consideration
		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 notice 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 these Generating Stations which are relying on this norm for meeting expenditure of additional Capitalisation of minor nature. 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 a such 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 of minor nature capex. In view of the above, we submit that instead of discontinuing such normative allowance, alternately, it would be a better stand to

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		continue allowing such Compensation Allowance to all Generating Stations and Transmission Licensees with a condition of maintaining a consolidated fund on cumulative basis from such normative Compensation Allowance. The Generating Stations and Transmission Licensees would be required to meet the expenditure of additional Capitalisation of minor assets from this fund and any surplus may be carry forwarded in such cumulative fund. The onus to prove the reconciliation of the usage of such allowance and the fund may be put on the respective Generating Stations and Transmission Licensees. Hence, we submit to this Hon'ble Commission to continue with the practice of allowing Normative Compensation Allowance as per the current practice with certain conditions as mentioned above. Further, for 300/ 350 MW units, O&M expenses allowed for FY 20 @24.22 lakhs/MW is less than allowed for FY 19 @25.47 lakhs/MW under existing regulations. Please clarify how the O&M cost for the starting year FY 2019-20 has been determined in Draft Regulations. Also, average escalation considered in FY 14-19 was 6.30% whereas average escalation considered in FY 19-24 is considered @3.20%. Considering the WPI and CPI data published which is in line with CERC projections, no new O&M contract can be finalized at a rate lower than the existing contract value. The quotes received for newer contract are always on a higher side compared to the existing contract value. Therefore, CERC may consider the existing escalation of 6.30% for FY 19-24 period. Further to the above, the normative O&M expense in FY 2019-20 is 5.39% lower than FY 2018-19 for 600 MW and above Unit capacity. Also, the y-o-y escalation is ~3.2% in Control Period 2019-2024 as compared to ~6.3% during 2014-2019. As per the Explanatory Memorandum, it seems that these norms are proposed only on the basis of Sipat Stage 1 (3 X 660 MW) project and hence these norms are specific to only one project and does not reflect the actual O&M requirements of other stations of 600 MW & above. The reduction in O&M charges is not commensurate with the inflation. Further, the CPI & WPI for FY 2017-18 or the weighted average CPI-WPI prescribed for y-o-y escalation in the FY 2019-24 period is not negative. Therefore, there is no logic whatsoever for considering lower O&M Norms for FY 2019-20 as compared to FY 2018-19. Reduced O&M charges will result in non-availability of sufficient funds for carrying out proper maintenance and may adversely impact safe and secure operation of Power System in the long run. Specifying revision in Operating Norms for generating stations commissioned during Control Period 2004-09 and 2009-14 in present proposal is unreasonable since the machines are designed based on the norms applicable while awarding EPC Contract. Tariff Policy, 2016 provides that the operating parameters in tariffs should be at “normative levels” only and not at “lower of normative

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		and actuals". Once the norms are fixed at the time of machine design, the same need to be continued for the entire life span of the Asset and any improvement over such norms due to efficiency of the Generator needs to be incentivized. Hence, the O&M norms for the FY 2019-20 should not be lower than those for FY 2018-19 and these should be fixed by escalating the norms for FY 2018-19 by the proposed escalation index to derive norms for FY 2019-20 which should be further escalated y-o-y escalation up to FY 2023-24 based on the escalation index proposed by the Hon'ble Commission. Further, following proviso may be added *"Provided further that the Commission may allow additional O&M expenses considering specific features of the power plant in addition to applicable normative O&M expenses."* In support of O&M Expenses, the following things may be considered while deciding O&M Expense. • Minimum wages are revised twice in a year. Sometimes the increase in minimum wages goes up to 25% to 30% in some states. Besides, this will also have impact of benevolent policies/ schemes/ rules rolled out by central /state govt from time to time. (PF, Gratuity, ESI, etc). Employee cost forms the biggest component of the O&M expenses which is linked to the CPI Inflation index. Therefore, a higher weightage should be accorded to the CPI Inflation index while computing the weighted average escalation index for O&M norms for the Control Period FY 2019-24. • Impact of GST should be considered. • With the aging of the plant, the consumption of spares shall increase leading to higher maintenance cost. • In the present scenario of drastic reduction in the PLF of almost all thermal power plants in the country, higher funds are required to carry out frequent O&M of the plant to preserve its performance. • Staff, administration and general expenses increase by more than 5% Y-O-Y. • In the draft regulation, the difference between 500 MW and 600 MW is only Rs. 2.44 Cr. However, the repair and maintenance cost for a 600 MW is much higher as compared to 500 MW unit due to the following reasons: a. Higher Spares cost due to higher size of equipment of 600 MW: For example, due to higher size of Mills, component replacement cost of Mills for a 600 MW would be 25% more than that of 500 MW unit mills. b. Upgraded/ special metallurgy for higher operating parameters: For example, due to the high temperature of 600 MW Boilers, Higher Grades of Boiler tubes are being used. Replacement cost of damaged tubes during the overhauling of a 600 MW unit will be around 55 % more than that of a 500 MW Boiler. Due to high pressure and temperature ratings of the 600 MW boiler steam / water valves as compared to that of a 500 MW unit, cost of valve spares would be 15% more.

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		c. Higher chemical consumption: The chemical consumption for maintaining the water chemistry of a 600 MW requires an additional chemical treatment costing at least 17.5% as compared to a 500 MW unit chemical treatment. d. Comparing the maintenance cost of 500 MW unit with 600 MW unit, the maintenance cost is higher by at least 15%.
35 (1) (3)	**Operation and Maintenance Expenses for Open Cycle Gas Turbine/ Combined Cycle generating stations**	There are generators who have been procuring LNG (including booking of the regasification capacity) and have been directly sourcing LNG (at very competitive rate) as per the requirement of its beneficiaries. Based on the same, the operating level of gas based power plants is expected to be around normative level. Further, for operating level of 60% and above O&M expenses will remain fixed i.e. the generator will have to bear 100% O & M expense. (especially the expenses related to LTSA/LTMA for advanced F Class machine). The LTSA/ LTMA contracts are also co-terminus in nature (i.e. fixed payments are to be made). However, such contracts are sort of insurance premium to maintain high availability & reliability of the plant. Further, other major components of O&M expenses (i.e. employee expenses and administrative expenses) also remain fixed irrespective of operating level (to maintain plant availability for generation). From the above it is evident that, the pro-rata reduction in O&M expenses does not happen with reduction in PLF as considered by the Hon'ble Commission. From Tariff Regulations 2009-14, the operating life of gas based power plant has been revised from 15 years to 25 years. Hence, the support of OEM is also required to be extended. Further, such extended operating life would lead to higher risk of fast change in technology including obsolesce of parts / technology upgradation. OEM has already indicated Rs. 60 Cr for up gradation of DCS system and it has stopped support for BOP. Thus, to handle obsolescence, there should be additional provision of Rs. 2-3 Lacs per MW in O&M expenses. In view of the above, we would like to submit that the O&M expenses of Rs. 32 Lakh per MW (i.e. O&M expenses at 85% operating level plus Rs. 2-3 Lakh per MW for obsolesce of parts / technology upgradation) may be provided for the base year. Further, Hon'ble CERC has considered YoY escalation rate of 3.2% which is also very low. In this context, we would like to submit that the O&M expenses primarily consist of employee expenses, repair and maintenance expenses and admin & general expenses. It is known that the employee expenses cannot just increase by 3.2% (it increases minimum by 9-10% - please refer report of known consultancy firm on India's Annual Compensation Trends survey 2018-19), the service and supply contract (even if the ARC is placed) increase by 10% on year on year basis. The exchange rate has also increased by ~6.50% in last year. Further, the cost of Petro/Diesel (which is also major sub cost/cost driver in Admin & General expenses) has been increasing and very erratic (i.e. highest Rs. 84/litre to Rs. 70/litre) in last year. In this context, all major heads of O&M expenses are expected to increase much more than 3.2%.

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		Hence, we request the Hon'ble Commission to consider balanced escalation rate i.e. approx. 7% (if not 10%) for O&M expenses in subsequent years.
35 (1) (6)		Suggested Modification: *(6) The Water Charges, Security Expenses* ***(both physical and cyber security),*** *Capital Spares****, External Coal Handling plant etc. (for imported coal)*** *for thermal generating stations shall be allowed separately after prudence check:*
35 (2)	**Operation and Maintenance Expenses for Hydro generating stations**	Considering the WPI and CPI data published which is in line with CERC projections, no new O&M contract can be finalized at a rate lower than the existing contract value. The quotes received for newer contract are always on a higher side compared to the existing contract value. Also, a major part of the O&M cost comprises of manpower cost. Any escalation on this cost is to be derived from Inflation and it is observed that inflation (excluding food, fuel and light items) remained higher than the escalation rate being proposed. It will be difficult to retain the manpower in such a scenario. Therefore, CERC may consider the existing escalation of 6.64% for FY 2019-24 period.
35 (2) (b)		Clarification is required that whether cap of 4% of the admitted capital cost on COD of the respective year will be applicable on such project.
35 (3)	**O&M expenses - Norms for Transmission system**	CERC has applied norms of Talchar-Kolar to continue for the Mundra and Mohindergarh HVDC Transmission system. CERC may clarify that the same shall continue for FY 2019-24 as well.
35 (3)		The normative O&M expenses for sub-stations bay specified for FY 2019-20 is 56% lower than FY 2018-19. Additionally, y-o-y escalation for sub-station bay is ~3.1% in control period 2019-24 as compared to ~3.2% during 2014-19. While it is proposed to include O&M charges for Transformation capacity, it may be appreciated that the same is not sufficient to cover the reduction in O&M expenses of bays. In our case, the effect of reduced O&M expenses for bays is such that the overall O&M expenses are getting reduced by app. 20%, which is not sufficient to carry out the O&M and will hamper the O&M activities adversely. Further, we would like to bring to your notice that Hon'ble commission, while working out normative O&M expenses for Bays and Transformers in its explanatory memorandum, has allocated actual O&M expenses for substation in the ratio of 50:50 for bays and transformers. The Hon'ble Commission has also noted that in absence of the adequate data it has considered ratio of 50:50. In this regard, we would like to submit that there are very few substations with lesser number of bays and high MVA capacity compared with substations with lower MVA and higher number of bays. Therefore, the ratio considered by Hon'ble commission is not justified and adequate. Same will have adverse impact on recovery of expenses and will erode the internal accruals. Further, in case of increase in bays in any substation without increase in transformer capacity, additional adequate O&M expenses will be less.

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		We would also request the Hon'ble Commission to provide separate O&M charges for Bus Reactor, Switchable Line Reactor and FSC, as the O&M expenses on these is substantial, whereas as per current regulations, transmission licensees don't get paid for O&M of Bus Reactor, Switchable Line Reactor and FSC.
35 (3)		The Hon'ble Commission has proposed the Normative O&M Expenses for Transformers (in Rs. Lakh per MVA) & for Communication system. Without prejudice to the above point, we request Hon'ble Commission to specify the separate norms of O&M Cost for Bus Reactor, Switchable Line Reactor and FSC, as has been proposed by CERC for Transformer and Communication system.
35 (3)		The Hon'ble Commission has specified that for new HVDC bi-pole scheme, O&M expenses of similar HVDC bi-pole scheme shall be allowed on pro-rata basis. In this regard, we believe that new HVDC bi-pole scheme means new HVDC scheme achieving its commercial operation on or after 01.04.2019. HVDC Mundra-Mohindergarh system is not a new scheme and hence it is respectfully submitted to clarify that normative O&M expense of Talcher-Kolar HVDC scheme shall continue to be applicable to Mundra-Mohindergarh system to avoid confusion. Further, we would like to submit that Back-To-Back stations have been provided to transfer power from one Region to other Region when the Regions were not synchronously connected and Regions were operating at different frequencies. Now since all Regions are connected synchronously and Indian Power System is operating as one, the need for these Back-To-Back Stations no more exists and should be de-commissioned and terminals so released should be installed at new HVDC locations. Also, it may be noted that transformers at Gas Insulated Sub-stations (GIS) are similar to Air Insulated Substations and hence there should not be any discrimination in O&M norms between GIS & AIS substations.
35 (4)	**Communication system**	We request Hon'ble Commission to give clarity regarding definition of Security Expenses, Capital Spares and self-insurance along with quantum of such allowable expenses, to avoid disputes at a later date.
39	**Capital cost**	Clarification is required that whether the Capital cost incurred till the Mine Target Capacity will it be allowed to be amortized over the recoverable mine reserves.
39 (2)		Clarification is required on "achieving target capacity" - is it the Peak Rated Capacity of the Mine as per the approved Mine Plan.
42A	**Depreciation**	Clarification is required whether WDV method shall be applicable for determining depreciation.
42B	**Operation and Maintenance Expenses**	Fuel cost, Consumables cost and lubrication cost should be allowed as pass-through since it will be a function of the lead distance and

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		the mine lift, which progressively changes with the Mine Plan, which shall be subject to True up at the end of the Control Period.
45 (1)	**Determination of input price**	Clarification is required on the inclusion of capital cost as a part of the captive mine production cost.
46	**Computation of Variable cost**	Apart from cost of re-agents, it should also include cost of lime or other raw material used for FGD.
47	**Components of landed cost of primary fuel**	The regulation should include the coal washery charges also in the landed cost of primary fuel to give ample clarity, which is a legitimate cost incurred for generation of electricity and needs to be allowed as part of Landed cost of coal. Suggested Modification: *Components of Landed cost of Primary Fuel: The landed cost of primary fuel for any month shall include base price or input price of fuel corresponding to the grade and quality of fuel and inclusive of statutory charges as applicable, transportation cost by rail or road or any other means, and loading, unloading, and handling charges* ***and coal washery charges etc****.*
48	**Transit & Handling Losses**	The transit losses are higher particularly where Road-cum-Rail mode is involved which is presently forming almost 50% of the total coal supply from various coal companies due to their inability to provide coal by FSA rail mode only. In such RCR transportation the transit losses additionally include transportation losses from mine to the stacking at siding and re-loading of the coal into the rakes, As the whole operation involves multiple handling of coal the provision of additional losses during these operations is required. A provision of 2% transit losses is suggested. Further, for Imported coal based Generating Stations, the coal has to be transported over the large distance and therefore the Commission has specified applicability of transit loss of Non-pithead station for imported coal based station. However, there is some anomaly in the Explanatory Memorandum which may be clarified and corrected in line with the Draft Regulations. Further, transit loss (equal to that of Coal) may be provided to compensate the transit and handling loss during transportation of lime specifically in case of CFBC boilers and in case of Power plants with FGD using Lime as it is also required to be transported from a considerable distance.
49	**Computation of Gross Calorific Value**	The gross calorific value is computed on As Received Basis. The 3rd party sampling is done and the tested values are given on equilibrated basis. In view of the above it is preferable to specify standardized formula for conversion.
50	**Landed price of reagent**	As there is no gathered data on actual consumption of limestone/ other reagents in Indian conditions, the normative values may have to be arrived after 3-5 years of operation and during that period the actual consumption values needs to be considered during the stabilization of the systems. Similarly, the NOx control system is still

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CERC may also notify the norms of consumption norms for Ammonia based systems (Efficient Ammonia dosing system). EADS is equally efficient technology with lower operational cost and lesser issues of managing by-products. Therefore, proper assessment of such technologies may be evaluated by CERC.

Further, it is suggested that the actual expenditure towards the Reagent must be allowed instead of Normative consumption basis in line with the primary fuel cost.

Availability, Transportation & the cost of these Reagents and the Disposal of By-products may be major issue once the emission control system is installed on all the thermal power plants in the country. Therefore, determining the landed price on normative basis could adversely impact the already poor financial situation of the generators.</td></tr>
<tr><td>51</td><td>Computation of Capacity Charges</td><td>While we welcome the proposal for introducing segregation of Availability and Generation based on peak and off peak period, we 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/ complexities 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 the Discom's perspective, the chances are likely that peak period and off peak period of different beneficiaries 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 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 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.</td></tr>
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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.
In view of the above complexities, it is proposed that mechanism of computing Capacity change may be retained as the existing Regulation for FY 2014-19 which is simpler and easy to operate. The underlying assumption of gaming in capacity declaration is not correct.
It is the overwhelming view of all the Generators to continue with existing system for payment of capacity charges, till the implementation complexities are discussed threadbare.
Looking at the current situation of stress in the sector, the sector can do without such disruptive innovations. However, if a change is imperative (which we don’t think is true), then the suggested modifications may be considered.
Suggested modification:
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 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 be allowed for recovery from one quarter to the subsequent quarter.
Monthly declaration of Peak and Off-Peak is not practical for operation and may be taken on Quarterly basis.
Suggested Modification:
In addition to the capacity charge, an incentive shall be payable to a generating station or unit thereof @ 65 paise/ kWh for ex-bus scheduled energy during Peak period and @ 50 paise/ kWh for ex-bus scheduled energy during Off-Peak period corresponding to scheduled generation in excess of ex-bus energy corresponding to 70%.
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<tr><td>51 (6)</td><td>Formula for Plant Availability Factor (PAF)</td><td>We know that in current scenario, arrangement exists 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</td></tr>
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		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. Based on the above, we request the Hon'ble Commission to 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, PAF formula is based on the installed capacity of the generating stations. However, there are projects where part capacity has been tied up in long term PPA under Sec. 62 and part capacity has not been tied up or partly tied up under Sec. 63. It is suggested that a separate formula should be devised for projects whose entire capacity is not tied up in long term contracts, and where part is tied up under Sec. 62 and part is under Sec. 63. In such cases, the declared availability and tied-up contracted capacity may only be relevant.
52	**Computation and Payment of Energy Charge for Thermal Generating Stations**	The use of alternative source of coal/ alternate mode of supply is basically occurring due to poor materialisation from the original source identified during the project implementation stage. In the last few years materialisation from coal companies have been at about 50% (and in some cases as low as 40%) forcing the Utilities to go for alternate source/ alternate mode of supply and as such price of coal thereby arrived is not in the hands of the Power Utilities. Therefore, the stipulation "30% of base price of fuel computed as per clause (7) of this Regulation" needs to be deleted. Further in such cases requirement of prior permission from beneficiary should not be a pre-condition as it would affect the capability of achieving full fixed cost recovery for the Generators such mode of transportation (i.e. RCR) is not there for NTPC/ State PSUs. Further, adjustment in calorific value for 85 kCal on account of storage loss at plant should be aligned with CEA proposal vide letter dated 17.10.2017 for margin of 105-120 kCal/kg for non-pit head and 85-100 for pit head stations. Also, it should be noted that Discoms are reluctant to pay any cost more than the linkage coal cost and there are payment disputes which go beyond 3 years and payment is withheld thereby worsening financial situation of Generating companies. Therefore, it is recommended to include provision for Discom to pay up to 80% of disputed amount. Suggested Addition: *However, it is clarified that in case of any dispute the DISCOMs shall pay the 80% of the disputed amount till the matter is finally settled. If post final settlement any excess amount is paid by either party the same shall be returned back to other party at the rate of late Payment surcharge as specified in these regulations.*
53	**Declaration of Availability and**	It is practically not possible for the generating station to declare day ahead availability or any revision thereof in respect of generating

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	Dispatch in case of thermal generating station	station for each fuel source because in case of domestic coal based stations, the coal may be supplied by multiple mines. Similarly, declaration of separate availability for imported coal based stations for different coal sources.
56	**Computation and Payment of Transmission Charges for ISTS and communication system**	Since normative availability is prescribed on annual basis, there is no logic in specifying the recovery of incentive for transmission lines on monthly basis because as the lines may be taken for maintenance, only for some (one or two) times in a year and not on monthly basis. In view of this ISTS licensee is not able to claim payment of Incentives for all months of the year, despite cumulative annual availability greater than 99.75%, resulting in unavoidable distress to ISTS licensees. Therefore, transmission charges (including incentive) should be worked out based on cumulative basis. Further, same is also in contrary to provision of working out incentive, based on cumulative annual availability for generation projects. Hence, recovery formula of Monthly Transmission Charges including incentive to be modified to factor in Cumulative Annual Availability. Further, it may be noted that Hon'ble Commission allows recovery of capacity charges of generating stations based on cumulative annual availability. Thus, transmission charges inclusive of incentives should also be calculated on Annual Availability basis.
59 (A)	**Normative Quarterly Plant Availability Factor (NQPAF)**	Considering the unrequisitioned power surplus in the country, and the united capacity of more than 20 GW, there is no requirement to provide for separate availability during peak and off-peak periods. Instead of NQPAF, existing system of annual PAF may be included. NQPAF should be reduced to 75% from 83% in view of the proposal of declaration of availability in Peak and Off-Peak hours. For recovery of full capacity charges, Normative Availability shall be calculated on yearly basis because if a plant were to undergo a major maintenance there would be loss of plant availability which cannot be recovered in subsequent quarters, leading to fixed cost under-recoveries. Further, if any scheduled COH/AOH (OCC approved) is shifted due to some reason to another quarter, the same treatment should be given. There may be instances that the availability in a particular quarter falls down significantly due to various reasons beyond the control of the generating station like unforeseen/ forced outages, limited availability/ shortage of coal/ water etc. constraints in coal transportation by railways etc. Hence, to even out such aberrations, it is proposed that computation of availability may be done on annual basis instead of quarterly basis. NQPAF should be set as per the Quarterly variation in Coal Supply as per the FSA. Further for gas plants the threshold for recovery of Fixed Cost should be set taking into consideration the availability of gas for power plants.

<table>
<tr><th colspan="2">Clause</th><th>Comments/ Submissions for consideration</th></tr>
<tr><td>59 (C)</td><td>Gross Station Heat Rate</td><td>The suggested station Heat Rate is 2410 kCal/kwh for generating stations of 200/210/250 MW units will be very difficult to achieve considering part load operations due to prevailing grid conditions. Achieving a PLF of more than 60% in a year particularly for non-pit head stations is difficult. The design turbine heat rate at 60% TMCR are in the range of 2050 kCal/kwh with the design boiler efficiency of 84.6% the Unit Heat Rate with 0% operating margin works out as 2382 kCal/kwh.

The suggested Station Heat Rate would leave an operating margin of less than 2%. As such the unit Heat Rate 2450 kcal/kwh needs to be retained for this size of unit. Similarly, boiler efficiency of 86% for sub-bituminous Indian Coal as mentioned under Chapter 12 Clause 59 C (b) is difficult to achieve as design boiler efficiency itself is in the range of 84.5 to 85% only (for example for Bina 2 x 250 MW Boiler efficiency as per Design is 84.6%). The above norm needs to be re-considered.</td></tr>
<tr><td>59 (C)
(a) (i)</td><td></td><td>Heat rate is one of the most critical factor in the energy charges for thermal generating stations. However, there is lacuna in the CERC methodology for determination of heat rate norms as follows.

• There is no norm specified by CERC for 300 / 350 MW category.
• Norms specified by CERC is based on the actual data of NTPC stations with BHEL as BTG supplier. Whereas there are several imported BTG suppliers for which design parameters are defined in a different manner.

CERC may appropriately address the above two issues in the regulations by publishing specific norms for 300/350 MW size units as well.

Further CERC may exercise its own prudence check in working out the station heat rate for thermal generating stations, e.g.: CERC allows heat rate degradation of 4.5% over and above the design heat rate.

Gross design heat Rate = (Gross Turbine heat rate / Boiler efficiency)

In BHEL supplier contract, all the above parameters – turbine heat rate and boiler efficiency are defined. However, the same is not defined in Chinese / Korean machines supplier contracts. Where as in several Chinese contracts, gross design heat rate is not defined and the same has been derived as follows:

Gross design heat Rate = (Gross Turbine heat rate / Boiler efficiency) + design margin. Such design margin is ~50 kcal/kwh and varies as per the unit size.

CERC may consider such variations on case to case basis while allowing the heat rate.

Further CERC may clarify the Heat rate for “New” Generating Stations are those commissioned from 01.04.2009. it would be prudent that 5% degradation is allowed for all generating stations commissioned after 01.04.2019.</td></tr>
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Clause		Comments/ Submissions for consideration
59 (C) (a) (vi)		The Hon'ble Commission has retained the Norms for Generating Stations that achieved COD after 01.04.2009 e.g. OTPC. In this context, we submit that our Sugen plant is commissioned on 15th August, 2009 and accordingly Sugen plant is also covered by Regulation 59 (C) (c). Hence, we request the Hon'ble Commission that the heat rate of SUGEN should be 1853 kCal/kWh (i.e. based on Design Heat Rate + 5%). In addition to the above, the Hon'ble Commission has been framing regulations under the EA, 2003 duly guided by (a) principle of rewarding the efficiency, (b) multiyear tariff principles and (c) National Electricity Policy and Tariff Policy. The said guidance requires operating norms should be at normative level (not at lower of normative or actual). It should not be made more stringent on historic data and should not penalise for being efficient. We request the Hon'ble Commission to view our above-mentioned request in this aspect also.
59 (C) (b)	**New Thermal Generating Station achieving COD on or after 01.04.2009**	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 submit the Hon'ble Commission to 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.
59 (E)	**Auxiliary Energy Consumption**	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 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 be specified.

Clause		Comments/ Submissions for consideration
61	**Normative Annual Transmission System Availability Factor (NATAF)**	Hon'ble Commission has proposed to increase incentive threshold for HVDC from 96% to 97.5% (Reduction of 1.50%). It may be appreciated that HVDC system is not comparable with AC system for following reasons: • HVDC system is the state of art technology, which involves complex controls and logic function and cannot be compared with AC system. • In HVDC system, both terminal stations along with line is considered as a one element. Hence, should not be equivalent to AC system. Such reduction in incentive shall be adversely affecting the investment in the sector, as the developers invested in the project considering the benefit of this incentive and now, reducing it will adversely affect their returns and discouraging future investments in the sector. This will also be viewed negatively by lenders as at the time of financial closure, financial institutions carried out the due diligence considering this incentive as part of the revenue and non-availability will discourage them and they are bound to treat it as high risk owing to regulatory uncertainties. Therefore, the incentive should be continued as provided in the existing regulations, i.e. for availability beyond the performance norms of 96% for HVDC system.
61		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 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 up to 100%.
65 Note 3	**Billing and Payment of charges**	In the State of HP, State policy mandates a Hydro developer to give free power of 12%,18% and 30% for different periods. It has also come up with deferment of free power from initial years towards later stages. This should be allowed to pass through in the tariff at this is as per the state policy and has to be adhered.
69	**Late Payment Surcharge**	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 receivables are payable on first

Clause		Comments/ Submissions for consideration
		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 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) shall be considered for arriving the components of Working Capital. Hence, we 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, in order to bring discipline in the payment by the Discoms the LPS of 1.5% per month may be retained. Tariff Regulations does not specify the Priority of Apportionment of Payment among Late Payment Surcharge, past dues, Current dues etc. This encourages Discoms to delay the payments as the LPS remains static. Consequently, generating stations would have to incur higher working capital. This anomaly was addressed in the competitive bidding PPAs by stipulating priority of apportionment of payment. Similar provision may be included in the Regulation with payment appropriation priority as follows: (a) Amount Received is first adjusted against Outstanding Late Payment Surcharge. (b) Balance Amount if any is adjusted against Past Arrears if any.

Clause		Comments/ Submissions for consideration
		(c) Balance Amount if any is adjusted against Current Months Dues.
70 (2)	**Sharing of gains due to variation in norms**	The Sharing of gains on Heat rate and Auxiliary consumption is completely in contradiction to the provisions under Regulations 59 to 62 which clearly provide that these elements are normative parameters. The sharing of gains or losses on any parameter, defeats the very concept of fixing a normative parameter. In addition to the above, we would like to submit that the Heat Rate is dependent on (a) Site and ambient conditions (b) Scheduling and generation (c) stand-by of units (d) Deterioration due to ageing etc. and the Auxiliary Consumption is dependent on (i) operation of Plant at considerably lower load (ii) Losses of Bus Reactor, if any (iii) Losses of Inter-connecting Transformers inside Switchyard (iv) Losses of Generator Step-up Transformers, Auxiliary Transformers (v) Power Consumption for Water Intake Pump Facility, when the same is away from the Power Station etc. Hence, in the current power supply-demand situation, it would be difficult to operate with significant margin vis-à-vis normative parameters. No sharing of gains should be allowed by CERC, or the losses should also be shared equally among the stakeholders. If sharing of loss cannot be an acceptable principle, the same should also not be considered for sharing of gains made by generating stations.
71	**Sharing of benefits**	Net savings on re-financing of loan shall be shared by the beneficiaries with generating company, in the ratio of 50:50, however in existing regulation beneficiaries is entitled for 1/3rd share. Increase in share of benefit of share for beneficiary is not required as the same is done on the credibility and efforts of generator.
72	**Sharing of Non-Tariff Income**	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.

Clause		Comments/ Submissions for consideration
		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 request the Hon'ble Commission to 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. In the case of Transmission, it may be appreciated that it takes a lot of efforts to develop a new line of business and therefore, we need to incentivise the Licensees/ Generators, to optimize the resources for other businesses and therefore, the non-tariff income shall be shared in the ration of 2:1 i.e. 2 parts to licensees / generators and one part to beneficiaries, otherwise there will be no incentive for Licensees/ Generators to go for optimization of resources for other businesses. Further, we request Hon'ble Commission to include the Transmission Licensees also in the provision of Non-Tariff Income. Suggested modification: *Provided that the interest or dividend earned from investments made out of Return on Equity corresponding to the regulated business of the Generating Company* ***and Transmission Licensees*** *shall not be included in Non-Tariff Income.*
75, and 76 (1), (2), (3), (4)	**Deviation from ceiling tariff**	The clauses 76 (1), (2), (3), (4) have been substantially modified from 2014 regulations no. 48 related to deviation from ceiling tariff but explanatory memorandum does not cover any justification for the same.

Clause		Comments/ Submissions for consideration
		Further, 76 (1), (2), and (3) restrict lower than ceiling tariff for only 1 year while 2014 regulations clause 48 (1) (a) allows that the levelised tariff over the useful life of the project on the basis of the norms in deviation does not exceed the levelised tariff calculated on the basis of the norms specified in these regulations. It is suggested that the clause 48 (1) may be retained in this regulation.
-	**Additional suggestions**	These regulations are essential as there are many bilateral projects in Nepal and Bhutan with future plans to supply power to Indian States. Inclusion of tariff regulations for such cross-border projects will help in sale of power at reliable prices compared to volatility of prices discovered on power exchanges or bilateral short/medium-term agreements. Tariff Regulations should also include specific clause for determination of tariff for cross border projects which will be supplying to India.
-	**Additional suggestions**	We submit that Hon'ble Commission has specified the formula for calculation of Normative Availability of Communication System (NACF) region wise. However, Hon'ble Commission has not specified the NACF for recovery of Communication charges (including incentive). Further, Hon'ble Commission has also not defined OPGW availability calculation in complete system availability formula.
-	**Additional suggestions**	We 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*

Clause		Comments/ Submissions for consideration
		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."*