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TAMILNADU GENERATION AND DISTRIBUTION CORPORATION LIMITED

From
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To
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Lr.No. CFC/RC/SE/CERC/EE/F. TR 2019-24/D. 238/ 2018, dt. 12.07.2018

Sir,

Sub: Staff Consultation Paper for Tariff Regulation for 2014-19- Comments and suggestions of TANGEDCO – Submitted – Reg

13/07/18

Chief (Fin)

Ref:
1. Letter No. 20/2017/CERC/ Vol I/ Tariff Regu/Fin dt: 06.06.2018
2. Meeting held on 27.06.2018

E.O/Se(T)

16/7/17

With reference to the above and in continuation to the meeting held on 27.06.2018, the comments / suggestions of TANGEDCO are enclosed as Annexure.

It is requested that the views of TANGEDCO may be considered while preparing the draft Regulations please.

16/7/18

Yours faithfully,

V. Umamageswari

Chief Financial Controller/
Regulatory Cell/ TANGEDCO

VIEWS / SUGGESTIONS OF TANGEDCO ON THE APPROACH PAPER ON TARIFF REGULATIONS, 2019-24

Miscellaneous Provisions

As per Existing Tariff Regulations, 2014	Proposed by CERC in the Approach Paper for Tariff Regulations, 2019	Comments of TANGEDCO	Justification for the comments
	Para 2.2 : Evolution of Regulatory Approach Over time, the cost of service approach has been modified gradually towards normative by introducing benchmark norms for determination of one or more components of the tariff. The normative approach has been introduced for operational parameters, operation and maintenance expenses, rate of return, working capital etc. The hybrid approach, consisting of actual cost of service and pre-specified normative parameters have been followed during 2004-09, 2009-14 and 2014-19 tariff periods to induce efficiency in financial and operational performance.	Commission has to continue the practice of using the benchmark norms for certain parameters of the tariff.	In order to yield efficient and realistic results, this practise is required

	Para 2.3: The evolution of regulatory approach has been gradually shifting towards normative approach for inducing efficiency so that tariff becomes affordable and competitive. The approach for determination of tariff needs to be evolved continuously so that objectives of Section 61 of the Act are met.	In order to protect the consumers' interest as specified by the Commission, it is essential to protect the interest of the Discoms, since the consumer interest is directly linked to the financial healthiness of the Discoms	The Approach paper has not given emphasize on the financial healthiness of the Discoms, which is very vital in the Electricity Supply Value Chain
	Para 4.6: Value chain of Electricity Generation and supply: In addition, there are various taxes/duties levied by State Governments, royalty on coal and other charges (like water cess) etc. which add up to the cost of generation. For Example, Clean Energy Cess has been repealed, but has been replaced with GST Compensation Cess @ Rs 400/- per MT.	Clean energy cess for coal has been repealed and replaced with GST compensation cess. Since the Discoms face the burden of accommodating RE generation, the GST compensation cess shall be passed on to Discoms, rather than to any other agency including State governments.	The GST Compensation cess is a direct financial burden on the discoms and is in no way linked to the finance of the State. Moreover, the new environmental norms are even more stringent and involve huge additional financial stress for the Discoms buying power from the thermal generators. Therefore the cess collected from the Discoms should be passed on to the Discoms only.

	Para 4.11: Transmission Cost Inter-State transmission tariff (Rs/KWh) ("transmission rates") has gone up during last five years due to expansion in transmission infrastructure. Transmission network capacity is generally planned and needed to meet the peak demand with desired reliability	It is evident from Table 8 that All-India level peak demand has increased to 30.39% as on April 2017 compared to April 2011, whereas the aggregate Interstate transmission charges have increased to 229.66% which implies that there is a need to revisit redundant transmission schemes and plan and implement the system based on Tech no-Economical feasibility studies.	In the recent past several transmission assets are created based on the projected generation-demand scenario which leads to larger redundancy in the system and unnecessary financial burden on the discoms
	Para 5.2.2: Coal based thermal generation: National Electricity Plan (NEP) of Central Electricity Authority (CEA) estimates that the PLF of coal based stations is likely to come down to around 56.50% by 2021-22, taking into considerations likely demand growth of 6.34% (CAGR) and 175 GW capacities from renewable energy sources.	With the increase in Renewable energy, the indirect and heavy burden of compensation payment to generating stations due to backing down and increase in O & M expenses of State generating stations due to frequent backing down will be ultimately passed on to the discoms. This is also to be considered.	TANGEDCO taking a lead role in RE generation, is also paying compensation to CGS as per the notification dt: 15.05.2017, in addition to backing down our own thermal generation.
No provisions	**Para No. 5.2.4** Most of the coal is located in the .eastern parts of the country and requires transportation over long distances, which often results in supply constraints.	In order to mitigate the loss due to slippage in grade of coal, it is suggested that, a committee comprising of Ministry of Coal, Central Electricity Authority and Central Electricity Regulatory Commission may	Since the weighted average of GCV of coal is determined every 3 months, the same interval may also be followed for Joint sampling.

	The thermal plants have been facing the issue of mismatch in quality as well as quantity of coal supplied and received. There is a need for transparency in coal quality assessment of the coal supplied. The third party sampling mechanism may need strengthening along with a mechanism for quick	measurement of GCV of Coal at the Coal block and at the Generator's premises at a regular intervals of 3 months.	
No provisions	**Para Nos. 5.2.5 to 5.2.13** The Ministry of Environment and Forests and Climate Change, Government of India vide notification dt. 07.12.2015 has introduced revised standards for emission of environmental pollutants to be followed by the Thermal Power Plants.	With the penetration of more Renewable Energy of about 225 GW in the year 2022-23, the existing thermal generating stations will be forced to backdown to accommodate the Renewable Energy. The additional cost of equipments for fulfilling the environmental norms will be a pass through to the Discoms and in turn end consumers. In this regard, a prudent decision on whether the Emission control systems (ECS) are required to be established for the Installed Capacity or the Operable Capacity of the thermal stations, based on the average PLF, as it is stated that the PLF of coal based stations is likely to come down to around 56.50% by 2021-22, vide para	It is ascertained that an amount of Rs.1.12 Crore per MW/ Per year is to be incurred for compliance to the MoEFF notification dt. 7.12.2015. The anticipated additional expenditure is likely to have an impact of Rs.0.40 paise/kWh on the cost of bulk power supply. The beneficiaries like TANGEDCO which plays a major role in Wind Energy is already making payment for the capacity charges for the quantum of power allocated from the NTPC's generating stations even though there is no / lesser drawal from the

	5.2.2. Enforcement of the environmental compliance shall be taken up after finalizing the bench marks norms by CEA. The Commission shall also take into consideration the financial burden incurred by the discoms while compensating for the backing down of generation for the generating companies.	abundant Renewable Energy resources available in the State. In the event of including the expenditure towards the compliance to MoEF notification in the capital expenditure will increase the annual capacity charges determined by the Commission and in turn will affect the financial viability of the utilities. Therefore it is suggested that the expenditure towards the compliance of MoEF may be decided based on the average PLF of the stations.
I Para 5.6.2: Interstate Transmission However, issues have emerged in development of the transmission system that relate to planning and co-ordination like matching with generation project and readiness of downstream network; delay due to Forest & Wildlife clearance, right of way (RoW) issues; relinquishment of LTA by IPPs and consequent recovery of transmission charges i from abandoned/stalled generation projects.	The LTA customers should be allowed to relinquish the LTA only on payment of relinquishment charges as mandated by the Regulations and Orders issued may be in conformity with the provisions under the existing Regulations.	In the recent past, many of the LTA customers have opted to relinquish/ relinquished the LTA/ part LTA. But the relinquishment charges is yet to be recovered, dumping the charges on the discoms.

	Para 5.9 (a): Provisions of revised Tariff Policy 2016: Clause 5,2 provides exemption to the existing generating companies from competitive bidding to carry out one time expansion of 100% of the existing capacity with a view that the benefit of the infrastructure cost of existing project should be passed on to consumers through tariff. While allowing expansion as per the provision of the Tariff Policy, the Commission has to ensure that the benefit in reduction of costs due to sharing of infrastructure of existing project should be passed on to the consumers. The regulation will need to incorporate provisions of regulatory oversight:	The contention that the commission has to ensure that the benefit in reduction of costs due to sharing of infrastructure of existing project should be passed on to the consumers is a welcome move and to be incorporated in the appropriate clause of the Regulation.	Staff Paper has justified the proposed move.
	Para No. 7.2.1 & 7.2.6 Thermal Generating Stations -Tariff Structure In view of decreasing PLF of thermal generating stations, a need	Three part tariff structure consisting of Fixed Charges, Variable Charges and Energy Charges as proposed in the Approach will have a better improvement in the optimal utilisation of resources.	Discoms which are having adequate Renewable Energy resources like TANGEDCO should not be burdened to pay the Fixed charges even though there is no drawal from thermal generating

has been felt to look into two part tariff structure being followed now. As discussed in following Paras, inter alia, one option may be to introduce three part tariff structure. The two part tariff structure for generating station provides the right to use the infrastructure on payment of fixed component irrespective of quantum of electricity generated and the payment of energy cost for procuring each unit of electricity.

However, with this tariff structure, following issues emerge. The two part tariff system structure is suitable when the demand for power ensures utilization of capacity up to or around the target availability. It allows the procurer to get electricity at reasonable per unit cost through optimum utilisation of asset. Two part tariff operates well in power deficit scenario. Due to low demand, coal based power plants are running at a PLF of around 60%.

Consequently, States have not been coming forward for long term

Linking of fixed component to stations due to higher availability, variable component to penetration in the Renewable
difference between availability and Energy despatch should be deliberated and the proportion in which they are to be linked should be studied under different scenario, such as purchase of part generation from the generators, backing down of thermal stations due to RE penetration etc.

In such circumstances, the Discoms should be given the option of making the payment of fixed charges only for the drawal out of the quantum allocated from the generating station. The difference in fixed charges between the drawal and the allocation need to be proportionately shared between the Thermal Generator and the Renewable Energy developer.

power purchase to avoid fixed cost liability and rather they have been resorting to short term power purchase to meet their demand.		
Para No. 7.3.4 - Thermal Generating Stations - Older than 25 years. A clear policy/ regulatory decision are required in view of a number of thermal stations crossing the age of 25 years. Possible options could be (i) replacement of inefficient sub critical units by super critical units, (ii) phasing out of the old plants, (iii) renovation of old plants or (iv) extension of useful life etc. It is worth to note that performance of a unit does not necessarily deteriorate much with age, if proper O&M practices are followed.	Have separate norms for O&M expenses on the basis of vintage of generating station and the transmission system. Thermal generating stations are in the combination of old and newer ones. The generating stations which have been commissioned in the last 10 years will not require huge O&M expenses for running of the plant. Similarly, age old plants which have served their life may be phased out instead of incurring huge Operation and Maintenance expenses and running the plants at the low PLF level. Therefore, separate norms to be devised for determination of Operation and Maintenance expenses for vintage of Generating stations and the transmission system .	As fixing the O&M norms for old and new thermal stations are common, the beneficiaries are forced to bear the additional expenditure in the form of capacity charges, which also results into higher fixed cost.
Para 7.5.5: Interstate Transmission System- Tariff Structure: The tariff for transmission of	The two part tariff for the ISTS system proposes two alternative for recovery of fixed charges and two alternatives for recovery of variable	It is very difficult segregate the transmission system designed for immediate evacuation system, since some of the system shall

electricity on inter-State transmission system can consist of fixed components and variable components. a) The fixed components may consist of either (i) annual fixed cost of some of fixed transmission system designated for access and immediate evacuation, (ii) annual fixed cost of the evacuation transmission system or (iii) part of annual fixed cost of the entire transmission system consisting of debt service obligations, interest on loan, guaranteed return; b) The variable components may consist of either (i) common transmission system or system strengthening scheme excluding immediate evacuation transmission system, (ii) common transmission system excluding evacuation transmission system or (iii) sum of incremental return above guaranteed return, operation and maintenance expenses and interest on working capital.	charges. In case of fixed component, the proposed first option proposes sum of (i) annual fixed cost of the some of the 'fixed transmission system' designed for access and evacuation and (ii) the annual fixed cost of the evacuation transmission system. The second option proposed part of the AFC of the entire transmission system consisting of debt service obligations, interest on loan, guaranteed return. Considering the two options, option No (2) is better suited from the perspective of the discoms, as the entities for whom the Transmission project is developed are likely to be benefitted in case of part operationalization of LTA. However, norms have to be fixed for the part cost to be considering the fixed component and accordingly revisit the relinquishment charges payable by the entities.	form part of the Associated Transmission system also.	

	Para 7.5.6: The recovery of fixed component can be linked to the extent of access (Transmission Access Charge) and variable component can be linked to the extent of use, to be recovered in proportion to the' power flow (Transmission Service Charge). The fixed component may be linked to evacuation system or on normative basis based on aggregate transmission charges of the identified transmission system under the contract. The variable component may be linked with yearly transmission charges based on actual flow or actual dispatch against long term access.	The linking of the fixed component to the extent of access and the variable component with extent of use needs to be justified with case studies and the proportion of the allocation of FC and VC needs to be deliberated considering various scenarios. Further the implication of the two part tariff on the PoC mechanism needs to be studied. And it requires relevant changes in the PoC mechanism and Sharing Regulations which needs to be deliberated.	Without making necessary amendments to the Sharing Regulations, such a mechanism cannot be implemented.
	Para 7.6.1 to 7.6.4: Renewable Energy Generation-Tariff Structure: 7.6.1 The feed-in tariff structure does not offer the advantage of economic efficiency. Further, the feed-in structure has its limitations. a) In case of regulation of supply of the renewable generation, it may not be possible to	The proposed two part tariff structure for RE is a welcome move as this will resolve the balancing requirement of RE and greatly relieve the discoms. Regarding bundling of RE, a scheme is available for bundling solar with thermal generation. It has to be clarified whether the same bundling scheme is applicable for other RE sources like wind etc.	There is no necessity for bundling in the present scenario, as this will benefit thermal generators at the cost of discoms. Grid parity has been achieved by the RE generators. Hence it is prudent to recover the tariff separately.

generators with some minimum charges.

b) For merit order operation, the entire tariff of the renewable generation (which is of the nature of fixed cost) is to be compared with the marginal cost of the other generation (excluding the fixed cost component).

c) In case of bundling renewable generation with conventional power generation at the ex-bus of generating station, it may be difficult to combine the tariff as feed-in-tariff structure is a single part tariff and conventional generation has two part tariff structure

Regulatory Options: There can be Two part tariff structure for renewable generation covered under Section 62 of the Act, which comprises fixed component (debt service obligations and depreciation) and variable component (equal to marginal cost i.e O&M expenses and return on <u>equity) - fixed component as feed-</u>

The solar bundling scheme was evolved with the objective of bringing down the cost of the solar power. But in the present scenario, the cost of solar as well as wind energy has come down drastically reaching the grid parity. In many cases, the cost of the RE under TBCB route is cheaper than the cost of thermal generation (VC + FC). The objective will be defeated if the bundling is continued in the present scenario.

Among the three options for considering the integration of RE with coal/ lignite based thermal power plants, the third option of recovering tariff of RE and thermal power generation separately will be a better option, considering the present tariff of RE generators in-tariff (FIT) and variable component equal to capacity augmentation such as storage or back up supply tariff.

The tariff for supply of power from renewable generation and thermal power generation may be recovered separately. The operational norms for recovery of tariff may have to be specified separately.

Para 8: Deviation from norms:

8.2 Section 61 of the Act provides that the Commission shall be guided by the factors which would encourage competition and recovery of the cost of electricity in a reasonable manner. The present market framework involves the competition for power procurement for securing power purchase agreement. Once the power purchase agreement is secured, there is no framework for competition of dispatch. The distribution licensees follow merit order based on the tariff agreed under PPA under Section 63 of the Act or the tariff determined by the

Adopting incentive/ disincentive mechanism as stipulated in the DSM Regulations for RE generators may be considered.

In case of part capacity despatch based on non-scheduling by discoms, the generator can have an option to reduce the tariff rate based on a slab rate for different despatch levels.

In case of non compliance by the generator, a slab for disincentive may also be defined.

Commission under section 62 of the Act.

8.3 For various reasons, out of tied up capacity by the distribution licensee, some of the capacity often remains undispatched over large part of the year. Since the tariff determined by the Commission acts as ceiling, there is no embargo on the generating stations or the transmission licensee to charge lower tariff. This provides a scope for creating some competition.

Options for Regulatory Framework

Possible option could be to develop for incentive and disincentive mechanism for different levels of dispatch and specifying the target dispatch expanding the scope of Regulation 48 above.

Para No.9

Components of Tariff

The question is whether the annual fixed charges and energy charges are to be determined to the extent of the capacity tied up under

The Annual fixed charges and energy charges should be determined only to the extent of the capacity tied up. The balance capacity charges for the (untied capacity) must be collected from the STOA/ MTOA.

Section 62 of the Act or for the entire capacity. One approach could be to determine the tariff of the generating station for entire capacity and restrict the tariff for recovery to the extent of power purchase agreement on pro-rata basis and balance capacity will be merchant capacity or tied up under Section 63, as the case may be.

Para No.10
Optimum Utilisation of Capacity
<u>Coal based thermal generation:</u>
Flexibility may be provided to the generating company and the distribution licensee to redefine the Annual Contracted Capacity (ACC) on yearly basis out of total Contracted Capacity (CC), which may be based on the anticipated reduction of utilization. Annual Contracted Capacity (ACC) may be treated as guaranteed contracted capacity during the year for the generating company and the distribution licensee and the capacity beyond the ACC may be treated as Unutilized Capacity (UC). The distribution licensee will have a

The quantum of power allocated based on the Power Purchase Agreements executed between the Central Generating Stations and the Discoms should be redefined based on the Annual contracted capacity.

Due to high penetration of Renewable Energy in the States like Tamil Nadu, the scheduling of energy from the Central Generating Stations has been reduced.
The fixed charges for the difference in quantum (portion which is not drawn out of the total contracted capacity) are also being paid by the Discoms to the Central Generating Stations. Further, the Central Generating <u>Stations are being compensated</u>

On choosing the option of redefining the annual contracted capacity, the beneficiaries will have the following advantages;

1. The compensation charges for forced shutdown will be removed.
2. The payment of fixed charges for the unutilised quantum of energy will be removed.
3. The Utilities will have the option of scheduling the power from the market at the competitive rates from various alternative sources available.

right to recall Unutilized Capacity during next year and for securing such rights, some part of fixed cost, say 10-20% or to the extent of debt service obligations, may be paid; Such unutilized Capacity may be aggregated and bidded out to discover the market price of surplus capacity. The surplus capacity may be re-allocated to the distribution licensee at market discovered price.	through the Compensation Mechanism notified by CERC for forced shutdown of plants due to low demand / high penetration of renewable energy. Therefore, it is suggested that the Option 10.3(b) is beneficial as such unutilized capacity may be aggregated and bidded out to discover the market price of surplus capacity. The surplus capacity may be reallocated to the distribution licensee at market discovered price.		
Para 10.5: <u>Hydro Generation</u> Assign responsibility of operation of the hydro power stations and pumped mode operations at regional level with the primary objective for balancing. For this purpose, the scheduling of the hydro power operation (generation and pumped mode operation) may have to be delinked from the requirements of designated beneficiaries with whom agreement exists	The regional operation of the hydro and pumped hydro stations and its associated fixed charge liabilities should not be linked to the reliability charges. Since the objective of the regulatory frame work is to support the balancing system to mitigate the RE variability, the fixed charge liability may be linked to the deviation settlement charges of RE generators under DSM or as proposed in Para 7.6.3 above, the variable component of RE shall be so devised to accommodate the cost of Regional level Hydro and pumped storage generation.	The discoms will be burdened by the additional reliability charges on account of linking the fixed charges of hydro stations.	

Para 10.7: <u>Gas based thermal generation</u> Scheduling and dispatch of gas based generating station may be shifted to regional level with the primary objective of balancing	The proposed regulation framework proposes shifting of scheduling and despatch of hydro and gas. based generating stations to RLDC.s This will deprive the rights of state utilities.	The State LDC manages the grid with the scheduling and despatch of hydro and gas stations only. Hence this needs to be deliberated before finalizing.
Para <u>No.11</u> :Capital Cost One of the options is to move away from investment approval as reference cost and shift to benchmark/r eference cost for prudence check of capital cost. However, the challenge is absence of credible benchmarking of technology and capital cost.	The beneficiary Discoms will be able to calculate their power purchase cost based on the Benchmark Capital Cost determined by the Commission for various types of Units on regular basis while going in for Benchmark cost. The Benchmark costs should be compared with the Standards and steps need to be taken to curtail the expenditures to the maximum extent. A new benchmark should be introduced when there is steady decrease in the price of the major equipments. Benchmark norms for Capital cost and spares should be determined periodically for different size of Thermal Units/ Transmission elements considering the improvements / advancements in Technology to improve the efficiency to the maximum with minimum cost.	Shifting from Investment approval to Benchmark Cost based on the current market conditions will lead to a healthier market. Even the concept of Dynamic Benchmarking may be thought of for more optimisation of the cost.

Regulation 15.	**Para No.12: Renovation and Modernisation** At times the generating companies file their petitions for renovation and modernisation without giving estimated life extension period, which makes it difficult to carry out cost benefit analysis. In old plants, R&M nature of works are sometimes claimed without specific life extension. Servicing of such R&M expenditure at the end of useful life of the station without extension of useful life may be difficult to justify. The R&M of transmission system could include Residual Life Assessment of Sub-Station and Transmission Lines, Upgradation of sub-station and transmission line, System Improvement Scheme (SIS) and replacement of equipment. The Commission may allow Renovation & Modernisation (R&M) for the purpose of extension of life beyond the useful life of transmission assets. Alternatively, the Commission may allow special allowance for R&M of transmission	When the Thermal Generating station is capable of generating at PLF level as determined in the Tariff Regulations, there is no necessity for incurring the Renovation and Modernisation expenses. In the earlier Tariff Regulations, provision has been given to incur the R&M expenses when the life of the plant is completed. In the present scenario where Renewable Energy plays a major role, the Thermal Generating stations are not run at the full capacity level, therefore deterioration of plant and equipments will not be the same as was before. Therefore, the option of allowing the R&M expenses has to be considered taking into account of the NAPAF achieved by the plant in the previous years and should not be always based on the life of the generating station as default. In case of Transmission R&M, as a first option, the Commission may allow special allowance for R&M of transmission assets, instead of going in for R & M, as well maintained	R&M works are to be carried out based on in-depth study such RLA and performance of the previous years before taking up any scheme.

assets. Such provision will enable the transmission companies to meet the required expenses including R&M on completion of 25/35 years of useful life of sub-station/transmission line without any need for seeking resetting of capital base.	substations/ transmission elements do not warrant total replacement at the end of their life period.	
Para No.13.2 Financial Parameters Comments and suggestions are invited from the stakeholders for continuation of normative approach for specifying financial parameters and alternatives, if any.	The normative parameters determined by the Commission for Return on Equity, O&M Expenses and Interest on working capital are on the higher side. Therefore, the same may be redetermined considering the actual operational efficiencies, market lending rates, technological advancements in the plant and machinery and stock of fuel for both generation and stock. Further, in the earlier Tariff Regulations, the Commission Under Regulation.45- Late payment surcharge has fixed a rate of 1.50% per month, (ie) 18% p.a. This seems to be much higher. Therefore, the Commission may refix the same to the normative of 12% **P-a-** ^	The MCLR rates for the period ranging from 3 months to 6 months is in the range of 7.95 and 8.10%. Therefore calculation of surcharge for delayed payment should be reduced in line with the market conditions.

Regulation. 27(5) Depreciation shall be calculated annually based on Straight Line Method and at rates specified to these regulations for the assets of the generating station and transmission system. Provided that the remaining depreciable value as on 31st March of the year closing after a period of 12 years from the effective date of commercial operation of the station shall be spread over the balance useful life of the assets.	**Para No. 14.6: Depreciation:** a) Increase the useful life of well-maintained plants for the purpose of determination of depreciation for tariff; b) Continue the present approach of weighted average useful life in case of combination, due to gradual commissioning of units; c) Consider additional expenditure during the end of life with or without re-assessment of useful life. Admissibility of additional expenditure after renovation and modernization (or special allowance) to be restricted to limited items/equipment; d) Reassess life at the start of every tariff period or every	The Capital expenditure of the Thermal Generating Station are being serviced by the beneficiary utilities. Therefore, increasing the useful life of well maintained plants for the purpose of determination of tariff will benefit the Utilities by reduced depreciation rates for the remaining life period of the asset. Further, the Operation and Maintenance expenses allowed on normative basis are sufficient to meet out the maintenance activities and improving the efficiency. Many of the Central Generating Stations are achieving the full load capacity above NAPAF after serving the life period of 25 years. While considering this, no additional capital expenditure shall be allowed in terms of extension of the life period. Therefore, extending the useful life of the transmission assets to 50 years and thermal (coal) assets to 35 years will reduce the capacity charges at a	NTPC's Ramagundam (Stage-I & II) 2100 MW Generating Station which has been commissioned on 22.03.1985 has completed its useful life of 25 years during 31.03.2010. The Plant Availability Factor achieved during the period from January 2018 to June 2018 are given below: January 2018 - 73.76% February 2018- 95.343% March 2018 - 97.676% April 2018 - 101.204% May 2018 - 89.508 June 2018 - 90.746% Similarly, NLC's TPS-II Generating Station (1470 MW) which was commissioned during 23.04.1988 has completed its useful life of 25 years during 30.04.2013 and is achieving the Plant availability factor >85%. If the depreciation rate is higher, the present end consumers will be overburdened for the benefit of the future consumers.

and corresponding treatment of depreciation thereof; e) Extend useful life of the transmission assets and hydro station to 50 years and that of thermal (coal) assets to 35 years and bring in corresponding changes in treatment of depreciation. f) Reduce rates which will act as a ceiling. g) Continue with the existing policy of charging depreciation. However, the Tariff Policy allows developer to opt for lower depreciation rate subject to ceiling limit as set by notified Regulation which causes difficulty in setting floor rate, including zero rate as depreciation in some of the year(s).	considerable level. As suggested in the Approach paper, the depreciation rate may be reduced to avoid upfront loading of the tariff.	

<u>Para No.15.2: Gross Fixed **Asset CGFA) Approach**</u> An option could be to base the returns on the modified gross fixed assets arrived at by reducing the balance depreciation after repayment of loan in respect of original project cost.	In accordance with the provisions laid down under Section.61 (c) and (d) of the Electricity Act, it is submitted that in the GFA approach, the return on equity is determined on the normative equity of 30% till the life period of the asset. From the physical performance of the Central Generating Stations, it is understood that many of the plants have served its useful life and are running beyond the useful life period. Accordingly, the Return on Equity is also getting extended. Therefore, it is suggested that once the repayment of loan is fully made the equity component should also be reduced to the extent of the depreciation remaining after the loan is repaid.	**Gross Block Methodology:** Opening Balance Rs.150 Add: Additions : Rs.50 Less: Deletions : Rs.20 Closing Block : Rs.180 Average Block (Opening + Closing)/2 : (Rs.I50+Rs.I80)/2 : Rs.165 Equity @ 30% on Rs.165 : Rs.49.50 Return on Equity @ 15.5% : Rs.7.672 **Proposed Methodology:** Opening Balance : Rs.150 Add: Additions Rs.50 Less: Deletions : Rs.20

		Closing Block : Rs.180 Average Block (Opening + Closing)/2 : (Rs.l50+Rs.l80)/2 : Rs.165 Considering the cumulative Depreciation already recovered is : Rs.80 The balance depreciation available is Rs.70 (Rs.150-Rs.80) Therefore, calculating the normative equity of 30% on Rs.70 will be Rs.21 Accordingly, the Return on Equity @ 15.5% on Rs.21 will be Rs.3.25/- Therefore, considering the present securities market conditions, modifying the Gross fixed asset methodology duly taking into account of the remaining Depreciation value will be the optimum for the purpose of calculation of the Return on Equity.

Regulation.19 Debt-Equity Ratio For a project declared under commercial operation on or after 1.4.2014, the debt-equity ratio would be considered as 70:30 as on COD. If the equity actually deployed is more than 30% of the capital cost, equity in excess of 30% shall be treated as normative loan.	**Para No. 16.4 : Debt Equity Ratio:** For future investments, modify the normative debt-equity ratio of 80:20 in respect of new plants, where financial closure is yet to be achieved.	Allowing the Debt-Equity Ratio of 70:30 for existing thermal generating stations and 80:20 for new thermal generating stations is the optimal mix. The return on the equity are being serviced by the utilities till the life of the plant. In case of the life period extended beyond the useful life, there should be a provision to redetermine the equity percentage, so as to benefit both the generator and beneficiary utility. Normally, the LTA executed between the Generators and Beneficiary utilities are for the life period of the plant. When the life period is completed, the beneficiary may have a choice of willing to continue to procure power from the plant only in case when the rates are competitive. Therefore, redetermination of equity percentage has to be done after the life period of	Justification enclosed as Annexure
Return on Investment	**Para No. 17.1** **Return on Investment** Section 61 (d) of the Electricity Act, 2003 and Para 5.11 (a) of Tariff Policy 2016 have laid down broad guiding principles for determination of rate of return. These have	The Commission may adopt Return on Equity (RoE) approach for providing the return to the investors.	As there is no benchmark for the Rate of return from the securities market and due to revision of REPO rates by the Central Banker, it will be very complicated to calculate the cost of debt and the risk associated

	mandated to maintain a balance between the interests of consumers and need for investments while laying down the rate of return. It is stipulated that the rate of return should be determined based on the assessment of overall risk and prevalent cost of capital. Further, it should lead to generation of reasonable surplus and attract investment for the growth of the sector. As per the Tariff Policy, the Commission may adopt either Return on Equity (RoE) or Return on Capital Employed (RoCE) approach for providing the return to the investors		with the debt in respect of Electricity sector.
Regulation No. 24 **Return on Equity** Return on Equity shall be computed at the base rate of 15.50% for thermal generating stations, transmission system including communication system and run of	**Para No. 18.7** **Rate of Return on Equity** (a) Review the rate of return on equity considering the present market expectations and risk perception of power sector for new projects; (b) Have different rates of return for generation and transmission sector and within the generation and	The existing normative base rate of Return on Equity for thermal generating stations and transmission assets is on the higher side of 15.5%. It should be a fair rate of return. Therefore, the existing base rate need to be reduced to 12% considering the rates available in the securities market. The return on equity is a liability to the beneficiaries till the beneficiary purchases power from the generator	Justification for reduction in base rate of return on Equity is enclosed as Annexure.

the river hydro generating station, and at the base rate of 16.50% for the storage type hydro generating stations including pumped storage hydro generating stations and run of river generating stations with pondage.	different rates of return for existing and new projects; (c) Have different rates of return for thermal and hydro projects with additional incentives to storage based hydro generating projects; (d) In respect of Hydro sector, as it experiences geological surprises leading to delays, the rate of return can be bifurcated into two parts. The first component can be assured whereas the second component is linked to timely completion of the project; (e) Continue with pre-tax return on equity or switch to post tax Return on equity; (f) Have differential additional return on equity for different unit size for generating station, different line length in case of the transmission system and different size of substation; (g) Reduction of return on equity in <u>case of delay of the project;</u>	(or) duration of the Power Purchase Agreement whichever is earlier. Further, the beneficiaries are liable to pay the tax on the ROE by grossing up of income tax. This is also an additional financial burden upon the beneficiary utilities. The option of continuing with pre-tax ROE approach and to reconcile the difference at the time of truing up will be optimal. Due to delay in commissioning of the project, the utilities are forced to purchase the power from the alternate source in the market to meet out the demand. Therefore, it is suggested that a reduction of 1% in the Rate of Return for the period of delay may be considered, similar to Reg 24(2)(iv).

Regulation No.26 Interest on Loan ' Capital The rate of interest shall be the weighted average rate of interest calculated on the basis of the actual loan portfolio after providing appropriate accounting adjustment for interest capitalized.	**Para No.19.4** :Cost **of Debt** a) Continue with existing approach of allowing cost of debt based on actual weighted average rate of interest and normative loan, or to switch to normative cost of debt and differential cost of debt for the new transmission and generation projects; b) Review of the existing incentives for restructuring or refinancing of debt; c) Link reasonableness of cost of debt with reference to certain benchmark viz. RBI policy repo rate or 10 year Government Bond yield and have frequency of resetting normative cost of debt;	Continuing with existing approach of allowing cost of debt based on actual weighted average rate of interest will be best option for calculation of interest on loans. It is the responsibility of the Generator / transmission utility to negotiate with the banks for lower interest rates. When the market condition is good, the Generator should explore the possibility of transferring the high cost loans to other bankers and financial institutions and to pass on the benefit , to the utilities. The generators/ transmission utility should act responsibly in bringing the interest cost to the lowest level so that it can benefit the beneficiaries as well as the end consumers.	In the present market conditions, the Cost of Debt for Power Sector is very sensitive and therefore the existing option of arriving at weighted average rate of interest duly taking into account of the actual loan and repayments will be the optimal.
Regulation 28	**Para No.20 : Interest on working capital** Assuming that internal resources will not be available for meeting working capital requirement and short-term funding has to be obtained from banking institutions for working capital, whose interest	The Coal (stock) - 15 days for pithead stations and 30 days for non-pithead stations needs to be revised. The Coal (generation) - 30 days for NAPAF also need to be revised. In the present trend of growth of Renewable Energy, many thermal	In Petition No. 292/MP/2015 filed by WBSEB, the Commission vide para. 12 of its order dt. 10.11.2017 has stated as follows: "After scrutiny of the coal data for the period 2014-15, it is observed that NTPC has maintained the average coal stock for 10.35 days and the coal

liability has to be borne by the regulated entity, IWC based on the cash credit was followed during previous tariff period. Same approach can be followed or change can be made.

(b) As stock of fuel is considered for working capital, a fresh benchmark may be fixed or actual stock of fuel may be taken.

(c) While working out requirement of working capital, maintenance spares are also accounted for. Since O&M expenses also cover a part of maintenance spares expenditure, a view may be taken as regards some percentage, say,
15% maintenance spares being made part of working capital or O&M expenses.

(d) Maintenance spares in IWC which is also a part of O&M expenses results in higher IWC for new hydro plants with time and cost overrun. For old hydro stations, the higher O&M expenses due to higher number

stations are being backed down so as to accommodate the Renewable Energy to the maximum extent possible. Further, the availability of Coal is not adequate to run the thermal plants at the NAPAF.

Therefore, the Coal stock of 45 days (15+30) needs to be revised to 20 days (15 days for stock+ 5 days for generation).

Similarly, the stock of secondary fuel oil needs to be revised to 15 days in accordance with the generation activity instead of two months as provided in the earlier Regulations.

Receivables needs to be reduced to 1 month of capacity charge and energy charge instead of 2 months as provided in the earlier Regulations.

Further, due to high penetration of renewable energy and some time due to low demand the Central Generating Stations are forced to shutdown. In such circumstances, the working capital should be calculated <u>considering the actual Plant</u>

stock ranged from 1.21 days to 41.33 days during the year 2014-15."

Further, there is a huge demand for the coal in many number of thermal generating stations and the existing coal blocks are not in a position to supply on a continual basis.

Therefore, considering the above facts, the coal stock has to be reduced to the maximum extent for the purpose of calculating the working capital.

	of employees also yield higher cost for "Maintenance Spares" in IWC. Therefore, option could be to de-link "Maintenance Spares" in IWC from O&M expenses, (e) In view of increasing renewable penetration and continued low demand, the plant load factor of thermal generating stations is expected to be low. As per the present regulatory framework, the normative working capital has been provided considering target availability. In case of wide variation between the plant load factor and the plant availability factor, the normative approach of linking working capital with "target availability" can be reviewed.	availability during the period. Therefore, calculation of working capital by linking it with the actual plant availability factor will reduce the working capital component in the capacity charges. Further it is suggested that the provision of 20% of O & M charges as maintenance spares as a component of IDC may be removed as there is no provision for decapitalization of unused initial spares and the normative O&M charges will take care of the maintenance spares.	
Regulation. 29 Normative operation and maintenance expenses of thermal generating stations	**Para No.21 : O&M Expenses** Review the escalation factor for determining O&M cost based on WPI & CPI indexation as they do not capture unexpected expenditure; (b) Address the impact of installation of pollution control	Thermal generating stations are in the combination of old and newer ones. The generating stations which have been commissioned in the last 10 years will not require huge O&M expenses for running of the plant. Similarly, age old plants which have served their life may be given the option of phasing out instead of incurring huge Operation and	The O&M Expenses allowed under Regulation 29(1) of Tariff Regulations, 2014 are common for both existing and new generating stations. Example: A thermal generating station which has been commissioned in the present tariff block will not

system and mandatory use of treated sewage water by thermal plant on O&M cost.

(c) Review of O&M cost based on the percentage of Capital Expenditure (CC) for new hydro projects;

(d) Review of O&M expenses of plants being operated continuously at low level (e.g. gas, Naptha and R-LNG based plants).

(e) Rationalization of O&M expenses in case of the addition of components like the bays or transformer or transmission lines of transmission system and review of the multiplying factor in case of addition of units in existing stations;

(f) Have separate norms for O&M expenses on the basis of vintage of generating station and the transmission system.

(g) Treatment of income from other business (e.g. telecom

Maintenance expenses and running the plants at the low PLF level.

As the O&M norms for old and new thermal stations are common, the beneficiaries are forced to bear the additional expenditure in the form of capacity charges, which also results in higher fixed cost. Therefore, a separate mechanism should be devised for determination of Operation and Maintenance expenses for aged plants and new plants.

The same procedure needs to be followed for Transmission projects also. In the case of 0 & M charges for bay, the normative rates are exorbitantly high. CTU is entering into O&M agreements between the state utilities based on 1.5% of the Capital cost of the assets. Hence there is a need to revisit the normative O&M charges for the transmission assets.

Water charges

Similarly, there should be a separate mechanism for determination of water charges for aged plants and new plants depending on the type of the

require huge O&M expenses for the next two blocks.

Similarly, a generating stations which has completed 20 years will require the operation and maintenance allowed by the Commission on normative basis for efficient running of the plant.

Therefore, separate norms for O&M depending upon the life served by the plant has to be issued.

	business) while arriving at the O&M cost.	plant and the requirement of water for efficient operation of the plant. In the event of the thermal station running below the PLF level, then allowing a normative percentage of water charges will increase the fixed charges. This will only benefit the generators at the cost of the beneficiaries.	
Regulation No. 30(6)(b) Energy charge rate for coal based and lignite fired stations. ECR= GHRxLPPFxlOO/ {CVPFx(lOO-AUX)} Where, CVPF= Weighted Average Gross Calorific value of coal as received, in kCal per kg for coal based stations.	**Para No. 5.8.2 & 22.8 : Fuel-Gross Calorific Fuel** Take actual GCV and quantity at the generating station end and add normative transportation losses for GCV and quantity for each mode of transport and distance between the mine and plant for payment purpose by the generating companies. In other words, specify normative GCV loss between "As Billed" and "As Received" at the generating station end and identify losses to be booked to Coal supplier or Railways. Similarly, specify normative GCV loss between "As Received" and "As Fired" in the generating stations. Standardize GCV computation method on "As Received' and "Air-Dry basis" for procurement of	Taking actual GCV of fuel at a three months interval by a third party agency for measurement of GCV of Coal at the Coal block and at the Generator's premises on "Received Basis" with comparison to the Fuel Supply Agreement executed between the Generator and Coal block agency has to be done.	The Commission in its order dt: 25.1.2016 in 283/GT/2014 has opined as follows: "The Commission is of the view that measurement of GCV of coal on as received basis from the loaded wagons at the generating stations is the most appropriate method for computation of energy charges for the following reasons. (a) It would reflect the difference between the "GCV As billed" and "GCV as received" in a transparent manner and will enable the generating companies to take up the matter with the coal suppliers with regard to grade slippages between the loading point at the mine

Regulation 30(7) The generating company shall provide to the beneficiaries of the generating station the details of parameters of GCV and price of fuel (ie) domestic coal, imported coal, e-auction coal, lignite, natural gas, etc. ... ***Provided thai the details of blending ratio of the imported coal with domestic coal, proportion of e-auction coal and the weighted average GCV of the fuels as received shall be provided separately along***	both from and domestic international suppliers. Para No. 23.6 : Fuel - Blending of Imported coal Normative blending ratio may be specified for existing plant as well as new plants separately in consultation with the beneficiaries.	The existing Coal blocks for which the Fuel Supply Agreement has been executed between the Generator are not in a better position to meet out the growing demand of the Energy sector. Therefore, the Generator has to look out for alternate resources to cater to the rising demand. There is a huge difference of Calorific value between the Imported Coal and the Inland coal due to high volatility in the Imported Coal. While calculating the blending percentage the plant size, boilers, efficiency level etc are to be considered. As the quality of the coal plays a vital role in determination of variable charges, it is suggested that the commission may seek the details of Calorific value of imported coal from various Generating stations and to determine the blending ratio based on actuals. The policy for blending ratio may be taken in line with availability of domestic coal as per the recent coal block allocations to the CGS as well the design aspects of the plant. The	end and unloading point at the power plant. Due to high volatility content in the imported coal there will be possibilities for reduction in the Gross Calorific value of Coal. This will ultimately result into excess consumption of coal and due to which there will be increase in the variable cost. Therefore, the blending ratio should be decided in order to bring the same inline with the variable charge determined based on the inland coal.

with the bills of the respective month.		normative or agreed blending ratio shall be specified for the existing plant and new plant separately and the same can be adopted in consultation with the beneficiaries. Commission may initiate a methodology to work out the normative / agreed blending ratio for existing projects and new projects, based on the cost of the imported coal, GCV and the ratio of blending, operating hours of the unit/station. Further, it is necessary to take consensus of the beneficiaries for procurement of imported coal when there is increase of 15% more than the base fuel price.	
	Para No.5.8.8 & 24.5 : Landed Cost (a) All cost components of the landed fuel cost may be allowed as part of tariff. Or alternatively, specify the list of standard cost components may be specified; (b) The source of coal, distance (rail and road transportation) and quality of coal may be fixed	Components to be included for the purpose of arriving at fuel cost at the Generating station end is to be calculated separately for pit-head and non pit-head stations. The transport cost will be lesser in case of Pit-head stations when compared to non pit-head stations. Due to this the fuel cost in respect of non-pit head stations will be higher resulting into higher variable cost. Eventhough, the non-pit head stations are very economical and efficient in	The base price of coal to be supplied from the same Coal block for both pit-head and non-pit head stations will be equal. Only due to transportation of coal from Port to the location of the plant, the transportation cost has to be included in the base price, thus resulting into higher variable cost for non-pit head stations. A committee comprising of the Central Electricity Authority,

	running the plant at full capacity level, due to higher variable cost, they are not accommodated in Merit Order Dispatch. Therefore, a mechanism (or) formulae need to be put in place to remove the loading of transport charges from the base fuel price for the non-pit head stations. This will lead to increase in efficiency of the generating stations, create competitiveness and will ultimately benefit the end users.	CERC, Regional Power Committees and Discoms may be formed to study on the impact in variable cost in respect of non-pit head stations due to inclusion of transportation charges in the base fuel price.
Para No. 5.8.4 & 25.2 : Fuel -Alternate Source (a) Stipulate procedure for sourcing fuel from alternate source including ceiling rate; (b) Rationalize the formulation keeping in view the different level of energy charge rates, as the fuel cost has increased since 1.4.2014.	Fuel supply agreements between the Generator and the Coal supplying agency must ensure that the existing Coal block is adequate to meet out the fuel requirements of the Generator. In case of demand, it is necessary on the part of the generator to take consensus of the beneficiaries for procurement of imported coal when there is increase of 15% more than the base fuel price. Further, a ceiling percentage has to be decided for procurement of coal based on the actual plant availability factor achieved during the previous block.	

		While allowing the alternate source of coal, the Commission should ensure that the generators should not consider the imported coal as a ground and claim any change in the Gross Station Heat rates to be determined by the Commission.	
Regulation 36(C)(a) Gross Station Heat Rate Existing Coal-based Thermal Generating Stations 200/210/250 MW sets 2450 kCal/kWh 500MW (sub-critical) 2375 kCal/kWh	**Para No.26.3.6 : Station Heat Rate -Thermal** Approach for determination of station heat rate may need review including the criteria for specifying heat rate of old plants, continuation of relaxed norms for specific stations and possible changes required in the existing norms given in Tariff Regulation 2014-19.	In the Tariff Regulations, 2014 the Commission after duly considering the efficiency of the plants during the period 2009-14, has reduced the Station Heat Rate from the existing 2500 kCal/kWh to 2450 kCal/kWh for 210/210/250 MW sets and from the existing 2425 kCal/kWh to 2375 kcal/kWh. The Station Heat Rate determined in the existing Tariff Regulations, have been attained by most of generating stations. Therefore, it is suggested that the existing norms may be retained for the coal/lignite based generating stations.	In the present scenario, where there is deficiency in the coal, any relaxation in the Station heat Rate will result into excess consumption of coal and will have a deep impact on the variable cost of the generator.
Regulation 36(D) Specific Secondary Fuel Oil consumption	**Para No.26.3.7 : Specific Secondary Fuel oil Consumption** The existing norm for the Secondary Fuel Oil Consumption is 1.00 ml/KWh for lignite based	The existing level of 0.50 ml/kWh in respect of coal fired thermal power stations may be retained. For Lignite fired stations the existing SFC of 2.0 ml/kWh may be reduced to 1.5 ml/kWh in respect of	During the previous block, due to increase in efficiency of the plants, many generating stations have utilised the SFC lesser than the norms determined by the Commission and passed on the

(a) Coal based generating station- 0.50ml/kWh (b) Lignite fired generating stations except stations based on CFBC technology and TPS-I -2ml/kwh TPS-I - 1.5 ml/kWh Lignite fired generating stations based on CFBC technology - 1.0 ml/kWh	CFBC technology with some exception in case of TPS-I and 0.50 ml/KWh for Coal based project with the provision for sharing of savings with the beneficiaries. Further reduction in specific secondary fuel oil consumption norms may adversely affect the boiler operations under different operating conditions including partial loading of units due to fuel shortage conditions. With contribution from renewable generation increasing in the grid, thermal power plants are facing frequent regulations of supply and operations at lower PLF up to technical minimum. The consumption of secondary fuel oil would change on account of nature of	all lignite fired thermal power stations. Part loading of generating stations is mainly attributable to higher penetration of Renewable Energy. Further, the generators are being compensated by the Utilities through the compensation mechanism notified by CERC. Therefore, relaxation of Specific Secondary Fuel Oil consumption will further increase the variable cost and will have a direct impact on the cost of power purchase of the Utilities.	difference in SFC consumption to the beneficiaries. Therefore, the necessity of relaxation of SFC does not arise.
Regulation No.36(E) (a)-Coal based generating stations (i) 200MW sets-8.5% (ii) 300/330/350/500 MW and above	**Para No.26.3.10 : Auxiliary Energy Consumption** Generating stations which have less auxiliary consumption than the norms, are able to declare higher availability by making adjustment of difference between actual (lower) and normative auxiliary consumption. Further, colony consumption is not a	It is suggested that there should be separate norms for different size of the Units and the life served by the units. Colony consumption does not form part of the auxiliary system of the power plant. The inclusion of Colony consumption in the Auxiliary Energy Consumption will reduce the	

Steam driven -5.25% Electrically driven-7.75% (d)-Lignite fired thermal generating stations TPS-I - 12.00% TPS-II - 10.00% TPS-I Expansion-8.50%	auxiliary consumption w.e.f. 1.4.2014 and therefore, the same cannot be accounted for against auxiliary consumption while declaring availability. Methodology of declaring availability after reduction of normative auxiliary consumption and colony consumption need elaboration..	efficiency of the generator and on the other hand the beneficiaries will be forced to pay the energy charges for the quantum of energy which is not beneficially used for the purpose of generation. In case of additional auxiliary consumption is required due to complying with environmental norms, the Commission should determine the Auxiliary Energy Consumption percentage based on the life served by the units and the actuals during the previous block.	
Regulation.36(A) (a)- All thermal generating stations except those covered under clauses (b), (c), (d) &. (e) - 85%	**Para No. 26.3.15 : Normative Annual Plant Availability** The existing norms of annual plant availability may need review by considering fuel availability, procurement of coal from alternative source, other than designated fuel supply agreement, shifting of fixed cost recovery from annual cumulative availability basis to a lower periodicity, such as monthly or quarterly or half yearly.	The actual Plant Availability Factor in respect of most of the Generating Stations are lesser than the norms determined by the Commission in the earlier tariff block 2014-19. This is because of forced shutdown due to higher penetration of Renewables and low demand and partial load operations due to shortage of coal. The difference in capacity charges from the quantum allocated and quantum scheduled are being paid by the Utilities. Therefore, the option of determining the NAPAF on Quarterly/Half yearly basis may be studied.	Due to higher penetration of Renewable Energy, the fixed charges for the unscheduled portion of the allocated capacity are being paid by Utilities. Apart from this for running the plant below the NAPAF, the generators are being compensated through compensation mechanism. Therefore, when the NAPAF is determined on Quarterly/ Half year basis, the utilities will have the option of utilising the capacity at the maximum extent.

Regulation.30(8) Transit and Handling Loss: The landed cost of fuel for the month shall include price of fuel corresponding to the grade and quality xxxxxxxxxxx after considering normative transit and handling losses as percentage of quantity of coal or lignite dispatched by the coal or lignite supply company during the month as given below: Pithead generating stations: 0.2% Non-pit head generating stations - 0.8%	**Para No. 26.3.17** : **Transit and Handling Losses** There is often grade slippage of coal from the coal mines to generating stations. As per fuel supply agreement (FSA) signed by generating station with coal supplier, ownership of the coal get transferred at coal dispatch point i.e. at the mine. Therefore, it becomes the responsibility of the generating company to ensure that the grade that is billed to the generator is dispatched by the coal companies though generators have really no control over such dispatch. It is often reported that there are I substantial loss in GCV of coal due to grade slippage and loss in quantity	Existing norms of Transit and Handling losses of 0.2% for pit head generating stations and 0.8% for non-pit head stations may be continued.	Since no discrepancies have been found in the existing norms and no petition for relaxation of transit and handling norms were filed before the Commission, the necessity for revising the norms does not arise.
Regulation 38	**Para No. 26.5.5: Transmission availability**	Yes. There is a need to review the incentive formula for HVDC bi-pole	Hon'ble Commission has already approved the tariff of HVDC

factor: There is a need to validate the existing methodology of weightage factor by considering actual data/ availability. Options: a) Existing approach for computation of Transmission system availability and weightage factors to be applied for outage hours for transformer and reactors; b) Review of the incentive formula for HVDC bi-pole and HVDC back-to-back stations at par with AC system; c) Specify appropriate region (import or export) for certifying the availability of Inter-regional links (AC and HVDC line) for the purpose of incentive and recovery of annual fixed charges; and d) Review of the existing methodology or procedure for computation of availability, monthly availability and cumulative availability;	and HVDC back-to-back stations at par with AC system Agreed that an appropriate region may be specified for certifying the availability of Inter-regional links. There is a need for the review of the existing methodology or procedure for computation availability, monthly availability cumulative availability.	assets which are Regional specific on All India basis. Hence the availability and incentive for HVDC system may be on par with AC system Most of 765 kV lines have been commissioned at 400 kV level and being underutilized due to non firming up of generation projects/ end beneficiaries Lines charged at 765 kV level are kept out of service / idly charged due to over voltage problems attributed to under loading of the assets. This has to be factored into the calculation of weightage factor
Para 26.5.7 ^Transmission losses: The transmission losses considered	Norms for transmission losses shall fixed based on International bench marking and factors under control.	The Discoms are paying tariff be including transmission losses | which are based on the

	in the present scheduling framework is about 4.5-5% for inter-state transmission system and 4-4.5% for intra-state transmission system. As a result, the net power delivered to the distribution periphery is reduced by about 9-10%, which has an impact on the cost of supply. An option could be to introduce the norms for interstate transmission losses based on factors within control and international benchmarks.	Simultaneously , the provisions under Sharing Regulations for calculation of transmission losses shall also be revisited based on the proposed norms.	difference between energy injected and drawn. If there is difference between the calculated loss and norms, then provision has to be made for allocating such difference in loss in the Regulations also.
Regulation 30(4) Incentive to a generating station or unit thereof shall be payable at a flat rate of 50 paise/kWh for Ex-bus scheduled energy corresponding to scheduled generation in excess of ex-bus energy corresponding to Normative Annual Plant Load	**Para No.27.4 : Incentive** In view of the introduction of the compensation mechanism for operating plants below norms i.e.83-85%, there may be a need to review the incentive and disincentive mechanism with reference to operational norms.	When the utilities have given full schedule, and the generators could not meet out the NAPAF, there should be a mechanism to disincentivise the generators as suggested, for which a separate mechanism similar to compensation mechanism to be formalized. If the three part tariff proposed in this paper is considered, there is a need to revisit the compensation mechanism and incentive mechanism as there is provision for the generators to merchandize their unscheduled capacity .	Since the Generators are being compensated for loss in generation by way of compensation mechanism and the fixed charges for the difference between the quantum scheduled and NAPAF are borne by the Utilities. Similarly, there should be a disincentive mechanism in the event of the generator failing to achieve the operational norms.

	Para No.28 **Implementation of Operational Norms** Comments and suggestions of stakeholders are invited whether the operational norms of the new tariff period should be implemented from the effective date of control period irrespective of issuance of the tariff order for new tariff period.	The generators takes the time of 180 days for filing the petitions for determination of tariff for the tariff block and the commission determines the tariff after a period of 180 days resulting into a abnormal delay of 1 year from the date of commencement of block. Due to the delay in filing petition, the generators are following the tariff rates of previous tariff block and therefore enjoying the cushion in the merit order despatch. Therefore, it is suggested that the Operational norms should be implemented from the effective date of control period.	The state owned generating stations which are following the actual operational parameters are pushed down to lower rankings due to the above delay.
Regulation 8(6) The financial gains by a generating company or the transmission i licensee, as the case may be on account of controllable parameters shall be shared between generating company/ transmission	**Para No.29.2: Sharing of gains in case of controllable parameters:** The compensation mechanism introduced through IEGC entails the hedging of the risk of operating at low PLF. The compensation coupled with normative controllable parameters creates a buffer for generating companies. In view of this, the merit order operation can be linked with the PLF in such a way that the plants under Section 62 may be encouraged to	The existing ratio of 60:40 may be retained for the purpose of sharing of gains on controllable parameters. Eventhough, the existing regulation provides that the sharing on controllable parameters should be done on monthly basis with annual reconciliation, the generators are not passing the gains on monthly basis and the same is done only on annual basis. Therefore, procedure should be evolved to direct the generators to	The Energy bills of the Generators are being paid out of the borrowings with interest rates. Therefore, the gains if any on the controllable parameters should be passed on to the beneficiaries immediately.

licensee and the beneficiaries on monthly basis with annual reconciliation. The financial gains computed shall be shared in the ratio of 60:40 between generating station and beneficiaries.	compete for maximum PLF. Further, different generators adopt different methodology for sharing of gain, say on monthly or annual basis. Thus, procedure for the monthly reconciliation or annual reconciliation mechanism may need to be prescribed.	share the gains on monthly basis immediately in the succeeding month.	
Regulation No.45 **Late payment surcharge** In case the payment of any bill for charges payable under these regulations is delayed by a beneficiary of long term transmission customer/ DICs as the case may be, beyond a period of 60 days from the date of billing, a late payment surcharge at the	**Para No.30 : Late Payment surcharge and Rebate** The present regulatory framework provides for late payment surcharge at the rate of 1.50% per month for delay in payment beyond a period of 60 days from the date of billing. In view of the introduction of MCLR, the rate of late payment surcharge may need to be reviewed. One option is to add some premium over and above MCLR.	The bills raised by the Generators upon the Utilities is risk free and is being settled without abnormal delay. The existing surcharge rate of 1.50% per month is considered high and needs to be reduced depending on the market conditions. On the introduction of MCLR based surcharge rates, there should not be any premium over and above MCLR.	The utilities are paying the capacity charges of the generating stations even though there is no drawal from the generating station due to renewable energy and low demand. The utilities should not be further burdened with huge surcharge rates in case of delay in settling the bills raised by the generators.

rate of 1.50% per month shall be levied by the generating company or the transmission licensee, as the case may be.			
	Para No.31.1 Non-Tariff Income The income on account of sale of fly ash, disposal of old assets, interest on advances and revenue derived from telecom business may be taken into account for reducing O&M expenses. Present regulatory framework does not account for other income for reduction of operation & maintenance expenses. However, in case of transmission licensee, the income earned from telecom business are adjusted in the billing separately. The principle of treatment of other income as applicable in case of transmission can be extended for the generation business.	The Option of reducing the Operation and Maintenance expenses to the extent of Non-tariff income earned by the generator on account of sale of fly ash, disposal of old assets etc will reduce the O&M component for the purpose of tariff calculation. Therefore, this has to be taken into account and O & M expenses shall be reduced accordingly.	Since the Generators are allowed Operation and Maintenance Expenses and Compensation allowance, the Non-tariff income earned by the generators on the investments which are being serviced by the utilities must be passed on to the utilities through reduction in Operation and Maintenance expenses.
	Para No.32.1 Standardization of Billing	The Commission may publish the format to be adopted	Since Merit Order Despatch ranking is based on the variable

	Process Presently, generating companies and the transmission licensees are following different practice for raising bills on the basis of tariff order. In order to avoid possible disputes in billing, it need to be consider as to whether standardization of billing process including formats, verification and timeline etc. may be done.	generating companies for the purpose of regular monthly energy billing and arrears billings. A separate clause may be issued in this regard in the Tariff Regulations, 2019. " Further, the Commission may direct the generators to furnish the billing details in their websites. Regarding Transmission bills, no specific direction is given by the Commission with regard to sharing of the transmission charges in case of generators / TSPs not complying the provision under the Sharing Regulations. The implementing agencies are not complying the Sharing Regulations while arriving the POC slab rates. Specific clause in the Tariff Regulation with regard to implementing the same shall be introduced.	cost of the primary and secondary fuel, the components of variable costs such as basic fuel cost, royalties, taxes and duties, transportation cost or any other means shall be clearly indicated by all the generators in their Bills for the purpose of arriving the ranking
	Para No.33.2 : Tariff Mechanism for Pollution Control System Several generating companies have filed petition for approval of additional capital expenditure	From the Petitions filed by NTPC, it is ascertained that for adopting the revised environmental and Pollution control norms, the generators has to incur an additional expenditure of Rs.1.12 Crores approx.	The existing thermal stations for which the additional capital expenditure is proposed to be incurred due to revised environmental and pollution control norms are in combination

under "change in law" for complying the revised standards of emission for thermal power projects. CEA may be required to specify and benchmark appropriate technology and costing norms, apart from preparing phasing plan for shutdown during installation of emission related retrofits/ equipment. The generating companies would be required to select suitable technology at competitive rates through the process of transparent competitive bidding to minimize the impact on tariff in the power supply agreement.

Para No.34.2: Renewable Generation by existing thermal generating stations

One of the options is to install renewable project at the same location using the common facilities and land and bundle RE power with the conventional power prior to delivery point i.e. before ex-bus bar. Other option is to establish the renewable project at different location and pool the generation capacity on external basis beyond

In the event of approval of expenditure under "Change in Law," the option of determining the supplementary tariff based on the Technical Specifications on the difference in actual emission and revised emission, proposed technology, construction period, phasing plan for shutdown during the construction period will be the better option.

The Option of linking the recovery of supplementary tariff with the actual generation will lead to optimal utilisation of resources.

In the circumstances of allowing installation of renewable project at the same location using the common facilities and land, it is suggested that while determining the Capital cost for the Renewable generation, the cost which has been already served by the Utilities of thermal station has to be reduced from the Capital Cost and the tariff should be determined based on the revised Capital cost.

of old and new thermal plants.

Therefore, it is necessary to study the actual emissions and the emission allowed, technological advancements already made etc. to study the necessity of the investment in the Environmental norms. When the Thermal station is in the phasing out stage, incurring a huge expenditure on the fixation of equipments as per revised environmental norms does not benefit the end users. Therefore, such expenditures may be avoided.

If the costs which have been already served by the Utilities is included in the Capital cost of the Renewable Generation the cost per kWh will be higher and this will lead to double time servicing for the same asset.

	the delivery point. In both the cases, the annual fixed charges for thermal project and renewable project may be determined separately, based on separate set of tariff principles.	In any case, the AFC of both RE and thermal generating station shall be determined separately.	
	Para No.35 **Commercial Operation or Service Start Date** Delay can occur in the commercial operation due to factors beyond control or non-commissioning of associated transmission system. In case of the transmission system, the delay on account of non-commissioning of downstream or upstream system is more relevant. Since the declaration of commercial operation date attracts the liability of fixed charges or the transmission charges, as the case may be, the parties dispute the commercial operation date. In order to stream line the process of the declaring commercial operation date in case of the delay and to make aware the parties upfront about the consequences of delay, provisions could be made for demarcation of responsibilities	In many number of cases, there is huge delay in the Commissioning of thermal generating stations. The Commission approves the IDC/IEDC for the period of delay in commissioning citing the uncontrollable parameters and includes the same in the Capital Cost. The Commission has not considered the loss incurred to the Discoms due to delayed commissioning of the project. Therefore, a separate clause for Indemnification has to be provided in the Tariff Regulations, 2019 to compensate the loss incurred by the Discoms during the period of delay (difference between the Scheduled DOCO and Actual DOCO). For thermal generation station, the commercial operation date should be linked with the end beneficiaries tie up, as well as the commissioning	Due to the delayed commissioning of the project, the Discoms are unable to meet out the demand and therefore are forced to purchase the power from the alternative sources at higher cost.

Indemnification Agreement.	of the evacuation system requirement. Similarly, for transmission assets, the COD should be linked with the commissioning of the generating project, end beneficiary tie-up and upstream/downstream connectivity.	
Para No: 36: Energy Storage System: When the storage facility is used by generator to optimize the value of generation output and hedging purpose, it can be construed as a primary generator covered under Section 79 (a) and (b) of the Act. The regulatory options available for implementation of the energy storage system for use are to combine the tariff with transmission and generation projects. The annual fixed charges of energy storage system may be determined separately as per the pre-specified operational and financial norms by the Commission and may be recovered from the beneficiaries of the region as supplementary to the transmission charges.	The storage facility will facilitate mitigation of variability of RE generators. The cost of the storage facility should not be socialized through Transmission Tariff. Regulatory Option: The Capital cost of the storage system may be recovered through DSM pool (or) alternatively it may be provided as an ancillary support service (or) part of the fixed component of two part tariff of RE generation.	The discoms are already loaded with the compensation mechanism on account of reserved shut down and degradation of station heat rate and auxiliary consumption, mainly attributable with the higher penetration of RE. The discoms (or) entities who are availing RE power for fulfilling their RPO shall be made liable to pay the charges towards the storage system

Para No.37: Alternative approach to Tariff Design. a. Would it be advisable to undertake econometric analysis to arrive at benchmark capital cost? b. What are the variables that should be considered for the purpose of determining Capital Cost on normative basis? c. Any other methodology for benchmarking the capital cost for generation and transmission projects?	It is suggested to undertake econometric analysis to arrive at benchmark capital cost. Benchmark norms for Capital cost and spares should be determined periodically for different size of units considering the improvements / advancements in Technology to improve the efficiency to the maximum with minimum cost. Shifting from Investment approval to Benchmark Cost based on the current market conditions, will lead to a healthier market. The beneficiary Discoms will be able to calculate its power purchase cost based on the Benchmark Capital Cost determined by the Commission for various types of units on regular basis. Benchmarking of capital cost should be done regularly on annual basis taking into account of WPI and CPI indices. The Benchmark costs should be compared with the Standards and steps need to be taken to curtail the expenditures to the maximum extent A new benchmark should be introduced when there is steady decrease in the price of the major	Benchmarking of Capital Cost will bring a uniform methodology in determining the capital cost for different sizes of units. It will also reduce the time frame in determining the tariff for the generating stations as well as transmission assets.

	equipments. In the case of adoption of Benchmark Capital Cost, there should not be any option to the generator for revision of tariff with retrospective effect due to various reasons. There should be some methodology to avoid litigations on account of deviations from the Benchmark norms. In case of projects coming under TBCB route which is following different methodology the differences <u>should be removed.</u>	
Para No.38: Transparency in Billing and Accounting of Fuel The regulatory approach of pass through of coal cost to the procurer directly on the basis of certification has been well adopted. Comments and Suggestions are invited for further strengthening the existing system.	Since Merit Order Despatch ranking is based on the variable cost of the primary and secondary fuel, the components of variable costs such as basic fuel cost, royalties, taxes and duties, transportation cost or any other means shall be clearly indicated by all the generators in their Bills for the purpose of arriving the ranking. Therefore, a separate format for billing and accounting of fuel has to be put in place to bring all the generators in the same platform.	In the bills submitted by Central Generating Stations, the components like taxes and duties are not collected initially during submission of bills and they are claimed at a later state as arrears. Due to this the Generators are taking the advantage of reduction in variable cost and find a cushion in the Merit Order Rankings by pushing the other competitors to lower rankings and claiming the difference at a later date.

Regulation No.54 **Power to Relax** The Commission for reasons to be recorded in writing, may relax any of the provisions of these regulations on its own motion or on an application made before it by an interested person.	**Para No.39.1: Relaxation of Norms** The present regulatory framework provides for specifying normative operational parameters. However, there may be situations where the normative level due to the site specific features such as FGD, Desalination plant, increase in length of water conductor system etc may lead to power consumption in excess of the norms. In such situations, the present regulatory framework provides for relaxation of norms.	In the previous block 2014-19 many generators have filed various Miscellaneous Petitions before the Hon'ble Commission for relaxing the norms pertaining to Gross Station Heat Rate, Auxiliary Energy Consumption, NAPAF and Secondary Fuel oil consumption. Frequent changes in the norms determined poses problems in Billing and payment. Further, various ISGS generators are following the same methodology for getting relaxation of norms. The operational norms determined by the Commission are based on the actual data submitted by the respective generators in the previous tariff block. Therefore, it is suggested that if there is any change occuring during the course of the current tariff block, it should be addressed only at the next tariff block and not in the intervening period.	Filing of frequent petitions for relaxation of norms will result into change in operational norms with retrospective effect thus resulting into arrears claim by the Generators. Due to this the Utilities cannot assess the liabilities.
	Para No.40: Merit Order Operation The merit order operation is important for economic operation of the plants and optimum despatch of	The state owned generating stations which are following the actual costs month on month are pushed down to lower rankings vis-a-vis the VC of CGS adopted from the past data.	The generators are quoting the lesser fuel cost during the initial period of billing and claiming the difference in fuel price at a later I date with a huge claim

economic resources. The consideration of other factors such as distance of transportation, secondary fuel oil consumption may provide the option to distribution utility to optimize the despatch. Present merit order is based on the fuel cost of the past data, with time lag of up to two-three months in billing cycle	A uniform mechanism for Merit Order Despatch ranking method to be followed by all the generators (state owned generators / IPPs / ISGS generators from Case-I Bidding / CGS) by keeping them on equal footings shall be devised. Since Merit Order Despatch ranking is based on the variable cost of the primary and secondary fuel, the components of variable costs such as basic fuel cost, royalties, taxes and duties, transportation cost or any other means shall be clearly indicated by all the generators in their Bills for the purpose of arriving the ranking. It is further to be stated that the generators like NLC, has followed the lignite price for the block 2009-14 till the year 2017 and filed the Petition for revision of lignite for the period 2014-19 only during 2017. During this period, NLC has enjoyed the benefit of being accommodated in the Merit Order Rankings and pushed the other competitors to lower rankings. Further, NLC has claimed arrears for revision of lignite price after a period <u>of 2 years. This causes huge financial</u>	arrears. This results into deviation from the financial planning of the utilities as major part of the budgeted expenditures are being paid as arrears towards power purchase.

Para 41: Application of tariff determination: Review of process in case of transmission system: 41.1 Unlike the case of generating stations, the transmission system involves a large number of	burden on the beneficiaries. Therefore, it is suggested that the Generators should not claim the difference in tariff with retrospective effect, after enjoying cushion in MOD in the previous years. Similarly, the generators after enjoying a berth in MOD, shall not be allowed to claim any arrears retrospectively under Change in law at a later stage. Further, the components considered for arriving at Variable cost for state and central generator are significant since different procedure/ components (landed cost, royalty etc) are being considered to arrive at the variable cost. All components to arrive at variable cost needed to be furnished both by State/ Central generators & IPPs so as to work out variable cost at same platform. This is a welcome move proposed in the Staff Paper. The tariff of the new assets is determined now in three stages: In the first stage, provisional tariff is approved to recover 90% of the investment cost without prudence	Based on the projected paper the tariff is fixed in the existing system. By adopting the proposed method, unnecessary front loading of the tariff for assets which have not

individual transmission elements which are commissioned at different point of time over the span of 1-2 years. Sometimes, commissioning of individual elements takes more time due to ROW issues, forest clearance and matching with upstream/ downstream system. Therefore, the number of tariff petitions in transmission projects is high and spread over a period of time as they depend upon the commissioning of different elements. The finalization of tariff for an individual element also involves judicial processes which is same for the whole project. 41.2 The determination of capital cost of transmission system is distinguished on two counts -existing assets i.e. those commissioned prior to commencement of relevant tariff period and new assets commissioned during tariff period. Presently, the capital cost of the existing assets is determined on projected basis at the beginning of the tariff period and trued up on

check. Second stage is the approval of final tariff with prudence check and in the third stage, truing up is carried out. This has created a lot of disputes especially in case of assets which are not commissioned within the scheduled date of Commissioning after provisional tariff is accorded. The discoms are burdened with the front loaded tariff.

The proposed move will ensure that the tariff is approved on commissioning of the assets.

been commissioned can be avoided, ii. Number of litigations will be reduced, iii. Petition fees will be reduced, iv. Simplified tariff determination process.

completion of the tariff period i.e. twice during tariff period. One alternative to simplify the process is to determine the tariff of existing assets based on actual capital expenditure instead of projected capital expenditure, so that two applications of existing assets can be reduced to one in each tariff period. Further, the tariff of new assets can be determined during tariff period after commissioning of the new assets. 41.3 Further in case of new assets of transmission system, single petition may be admitted for all the individual elements of the project which have been commissioned within a year. Then annual fixed charges may be determined on consolidated basis and apportioned on proportion to the capital cost of individual elements. The true up maybe carried out on completion of the project based on balance sheet of individual project. **Para No.42 Goods and Service Tax** Goods and Services Tax (GST) has been introduced which has	While allowing the GST under Change in Law, it is suggested that the changes in tariff due to post-GST taxation regime has to be analysed in	As the inclusion of GST will increase the variable cost, the generators will be forced to bear

replaced various Central and State level taxes. Accordingly, prudence check of impact of pre-GST and post-GST taxation regime on the costs may be required for determination of tariff in the next control period.	depth while determining the tariff for the next control period. In the present market based scenario, the inclusion of GST will have a huge impact on the variable cost. Therefore, the question of whether to include or exclude the GST component has to be decided with detailed deliberations with the Ministry of Power and Ministry of Finance.	the additional cost towards the power purchase resulting into additional financial burden.

Annexure to Approach Paper

Justification for the following paragraphs in Approach paper.

Paragraph No.16.4- Debt Equity Ratio

Paragraph No. 18.7 - Rate of Return on Equity

Paragraph No. 20 - Working Capital

NTPC's Ramagundam Stage-I & II (2100 MW) which has been commissioned in the year 1991 has completed its useful life period of 25 years during the year 2015. The approved investment cost of this project is Rs.2059.22 Crores. The Return on Equity for the period from 2001-2019 allowed to Ramagundam Stage-I & II are shown below:

ROE allowed to Ramagundam STPS Stage-I & II from 2001-2019

	11'. ■ Allowed by CERC in Crores)	
2001-2004	788.75	Order dt. 30.6.2006 in Petition No. 148/2004
2004-2009	791.31	Order dt. 24.12.2008 in 29/2007
2009-2014	1321.25	Orderdt.27.7.16in 217/GT/2014
2014-2019	1127.86	Order dt. 24.1.17 in 292/GT/2014
Gross Total ROE so far allowed	**4029.17 Crores**	

From the above table, it is evident that the Return on Equity so far allowed to Ramagundam STPS-I & II is more than twice the original investment of Rs.2059 Crores.

- **Similarly, NLC's TPS-II Stage-I & II which has been commissioned in the year 1994 will be completing its life period of 25 years during March 2019. The approved equity infusion in respect of the project (Stage-I & II) is Rs.1076.88 Crores (as per Para.50 of the order dt. 23.3.2007 in Petition No. 5/2002). The ROE so far allowed is Rs.1041.45 Crores (Stage-I & II) as per the table given below.**

ROE allowed to NLCTPS-II Stage-I
from 2001-2019

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	ROE Allowed by CERC (Rs. in Crores)	CERC Order date and Petition No.
2001-2004	67.26	Order dt. 23.3.2007 in 5/2002
2004-2009	90.25	Order dt. 4.6.2008 in 118/2007
2009-2014	102.36	Order dt. 10.2.17 in 473/GT/2014
2014-2019	36.61	Order dt. 12.6.17 in 256/GT/2014.
Gross Total ROE so far allowed	**296.48**	

ROE allowed to NLC TPS-II Stage-II from 2001-2019

	ROE Allowed by CERC (Rs. in Crores)	CERC Order da Petition No.
2001-2004	148.15	Order dt. 23.3.2007 in 5/2002
2004-2009	192.00	Order dt. 4.6.2008 in 118/2007
2009-2014	256.28	Order dt. 10.2.17 in 473/GT/2014
2014-2019	148.54	Order dt. 12.6.17 in 256/GT/2014.
Gross Total ROE so far allowed	744.97	

- Similarly, the other generating stations of NTPC like Farakka STPS Stage-I & II (1600 MW) and Talcher Stage-I (1000 MW) are nearing the completion of life period of 25 years in the year 2020 and 2022 respectively.

- Therefore, it is humbly submitted that the Hon'ble Commission may consider for revision of ROE as given below.

> ROE to 12%

> Redetermination of Debt Equity Ratio as 80:20 for new plants

> Separate ROE% for aged plants and new plants similar to compensation allowance.

2QE

- **WBSEB in its Petition No.292/MP/2015 filed before CERC has stated that NTPC's Farakka STPS is not maintaining the adequate stock of coal for generation and is maintaining stock of less than 7 days and therefore due to shortage / lack of stock coal requested the CERC to direct NTPC for refund of the excess amount (ie) interest working capital collected from the beneficiaries based on the the normative parameters of 45 days of coal stock.**

- **NTPC themselves in their reply to the Petition 292/MP/2015 has stated that they are maintaining an average of 10.35 days stock of coal.**

- **Further, the actual coal stock maintained by the thermal generators during the previous year as published in the CEA web portal, clearly exhibits that the thermal generators are maintaining a stock level of between 5 to 10 days.**

...CATION OF REDUC[illegible]ION OF ... ECO... ARAM[illegible]ERS I... N WORKING CAPI...

- **Further to the above, considering the stable growth of Renewable Energy generation in the country, the energy available from non-conventional energy are being fully accommodated which is resulting into minimal operation of thermal plants.**

- **Therefore, when the actual stock level is very lesser than the normative determined the earlier Tariff Regulations and considering the high penetration of renewable energy, it is submitted that the coal stock for the purpose of calculation of working capital may be revised to 15 days for stock and 7 days for generation.**

- **This will reduce the inventory cost of the generator and also benefit the utilities in the form of reduction in fixed cost.**