एनटीपीसी
NTPC

एनटीपीसी लिमिटेड
(भारत सरकार का उद्यम)

NTPC Limited
(A Govt. of India Enterprise)

केन्द्रीय कार्यालय/ Corporate Centre

Ref No. 01.CD.737-D
Date: 31.07.2018

To,

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

Subject: Comments of NTPC on CERC Consultation Paper on the Terms and Conditions of Tariff for the tariff period 2019-24.

Sir,

Hon'ble Commission vide its notification dated 24.05.2018 has published the Consultation Paper on Terms and Conditions of Tariff for the period 2019-24. Hon'ble Commission has invited suggestions/ comments from various players in the electricity industry and other stakeholders on the said consultation paper.

In this regard, please find enclosed comments/ suggestion of NTPC on the Consultation Paper.

Thanking you,

Yours faithfully,

(Pramod Kumar)
Executive Director (Commercial)

Gaurav

पंजीकृत कार्यालय : एनटीपीसी भवन, स्कोप काम्पलेक्स, 7, इन्स्टीट्यूशनल एरिया, लोधी रोड़ नई दिल्ली–110003
कार्पोरेट पहचान नम्बर : L40101DL1975GOI007966, **टेलीफोन नं.:** 011-24387333, **फैक्स नं.:** 011-24361018, **ईमेल:** ntpccc@ntpc.co.in, **वेबसाइट:** www.ntpc.co.in

Registered Office : NTPC Bhawan, SCOPE Complex, 7 Institutional Area, Lodi Road, New Delhi-110003
Corporate Identification Number : L40101DL1975GOI007966, **Telephone No.:** 011-24387333, **Fax No.:** 011-24361018, **E-mail :** ntpccc@ntpc.co.in
Website : www.ntpc.co.in

NTPC COMMENTS ON

CERC Consultation Paper on

Terms & Conditions of Tariff for the Period 01.04.2019 to 31.03.2024

PRELIMINARY SUBMISSIONS:

1. INDIAN POWER SECTOR: REGULATION SCENARIO

Hon'ble CERC has played a significant role in development of the electricity sector. During last 20 years or so significant capacity has been added in the sector and the reliability and availability of electricity has increased exponentially. Regulatory system has also brought in consistency, stability and transparency in the process of determination of tariff and has balanced the interest of the investors and consumers. CERC has established exemplary regulatory practices in the country, which have on one hand acted as a guide for the State Regulatory Commissions in furthering the regulatory systems in the States and on the other hand have ensured grid security in the country, and have facilitated development of power markets in the country. The successive regulations of CERC have been quite stable in their approach and have facilitated massive capacity addition by generating companies including NTPC and at the same time consumers have been getting the benefits of increased availability of power at the prudent cost subjected to the regulatory oversights.

The Consultation Paper has discussed all relevant issues pertaining to tariff formulation including anticipated challenges due to renewable integration, cyclic operation, flexibility requirement, ramp up/ ramp down requirements. The Hon'ble Commission has recognized that fixed cost of generation has reduced over a period of time whereas other elements of electricity cost to end consumer have increased significantly.

While formulating the regulatory framework for the next tariff period, it is submitted that the following aspects may also be kindly considered:

1.1. DEMAND GROWTH

CEA, in the recently issued the National Electricity Plan 2018, has stated that there would not be any need of capacity addition and the existing and upcoming capacity would be sufficient to meet the growing electricity needs. However, the following need to be considered while arriving at the above conclusion:

- The draft Tariff Policy issued by GoI mandates all distribution utilities to provide 24X7 electricity w.e.f. 01.04.2019 and non-supply is envisaged to be penalized. It would be necessary for distribution utilities to tie up the power requirement for their area on long terms basis. To comply with the Tariff Policy provisions substantial additional capacity tie-up would be required.
- The per capita consumption of India is less than a third of the World average. India is poised for high economic / industrial growth due to various initiatives of GOI such as “Make in India”. More and more of population is getting access to electricity. During first six months of this calendar year, a demand growth of 6 to 7 % has been witnessed. Through Government initiatives under SAUBHAGYA and UDAY the per capita consumption is expected to rise exponentially.
- With enforcement of the new emission norms, it would not be viable for some of the old capacities to comply with the new norms and may have to be closed down. While Badarpur station of NTPC is being closed, NTPC has also plan to decommission Talcher TPS by 2021-22. There would be need to replace such capacities.
- Amendments have been proposed in the National Electricity Policy which would ease open access. Industry will move towards closing down its highly inefficient captive generating plants and seek supply from large generating stations.
- It would be inappropriate to believe that there is surplus power scenario and the available capacity is much in excess of the requirement. It was seen that during many months such as Sep-17, Oct-17, Mar-18, June-18 etc. the Discoms had to purchase power from the PX at rates in excess of Rs. 11 per unit. While comparing the installed capacity with the

requirement, only the capacity that is operational needs to be considered. Any increase in demand is expected to revive the shortage conditions encountered in many months during last one year. The power surplus scenario prevailing for some periods is only short-lived. RE capacity being intermittent will be of little help in meeting peak demand in the evenings. As setting up of thermal generating station takes 7-8 years, steps need to be taken now itself to add thermal capacity.

- When finalizing Tariff Regulations, overall interest of the consumers which includes assured and reliable supply at all times needs to be ensured. Therefore, promoting investment in thermal sector for providing adequate and reliable power serves the overall interest of the consumer.

It may therefore be concluded that additional thermal capacity needs to be considered besides thrust on renewables, which would require substantial investment in generation sector.

1.2. **REGULATORY CERTAINITY**

- Any major departure in established regulatory approaches create considerable risk for regulated entities. This is particularly so for existing assets which have been set up based on the prevailing regulations and tariff principles applicable at the time of the assets being planned. Discoms have also agreed to buy power from these existing stations based on extant tariff recovery principles. Any change in basic regulatory approach will adversely impact revenues and cash flow projections and thus jeopardize the availability of the projects.
- Any major departure in the fundamental approach from established principles may deter funding by lenders. It is therefore important to maintain regulatory stability, consistency in approach and minimize recovery risk which are also identified as the objectives of the Tariff Policy issued by GoI. The National Electricity Policy also stresses the need to have regulatory certainty in order to promote investors' confidence.
- Regulatory uncertainty will result in higher interest rates that will increase cost of power and, in case investors lose confidence, new capacity will not be set up leading to power outages.

- Therefore any change in basic approach to tariff determination methodology may not be made applicable to the existing stations. For the new projects, where investment approval has not been made, requisite changes in the Regulations may be explored only after careful consideration and after creating positive investment scenario leading to investment.

1.3. PROFITABILITY OF GENERATION SEGMENT

- The profitability in the generation segment is decreasing rapidly. The Return on Net-Worth of NTPC is continuously decreasing and has reduced to around 8% in 2017-18 from 13.6% in 2012-13.
- The yearly profit of NTPC is stagnant at around Rs. 10,000 cr for last 6 years even though NTPC's installed capacity has increased by about 33% from 34GW to 45 GW. There is no cash surplus available with NTPC.

Year	Year-end Comml Capacity (MW)	NTPC PAT (Rs Cr)	Net worth (Year End)	ROE allowed in tariff	Return on Net Worth
2012-13	34882	10935	80387	15.50%	13.60%
2013-14	36447	10975	85815	15.50%	12.80%
2014-15	37142	10291	83830	15.50%	12.27%
2015-16	39102	10243	91294	15.50%	11.20%
2016-17	40522	9385	96231	15.50%	9.75%
2017-18	44500	8503*	101777	15.50%	8.4%

* Excluding effect of the Hon'ble Supreme Court order dated 10.4.18 and CERC Koldam Order

- From the comparative analysis given at Para 4.7 of the Consultation paper, it is seen that while the total cost of power has increased by 31% between 2009-10 and 2016-17, the fixed cost of generation has reduced by 21%. Other elements like coal cost, transmission cost and distribution cost have increased from 69% to 189%. The average tariff of NTPC coal stations has been almost constant. While the fixed charges (FC) have marginally increased (in spite of new capacity addition of about 10, 000 MW in the period) the variable charges (VC) have decreased in spite of increase in coal and freight charges.

YEAR	FC (Rs/kwh)	VC (Rs/kwh)	Total (Rs/ kwh)

2013-14	1.14	1.95	3.09
2014-15	1.10	2.03	3.13
2015-16	1.18	1.91	3.09
2016-17	1.21	1.98	3.19
2017-18	1.22	1.91	3.13

➢ Thus, the generation segment is already stressed and relief needs to be extended to this vital part of the power sector. There is requirement of investment in the generation sector. Other than by PSUs, no major investment has been announced in this segment in last 3-4 years. Therefore, a favourable climate needs to be provided so the generation segment becomes attractive for investment.

1.4. **GENERATOR RISKS AND RoNW**

As can be seen from the table above, the return on net worth of NTPC has been continuously declining and has reached around 8% in 2017-18. This is mainly on account of the risks that have been apportioned to the generators. Thermal generators have the following risks:

- Project delay risk
- Coal availability risk
- Machine availability risk
- Water availability risk
- O&M under recovery risk
- Risk of not achieving normative operating parameters.

While the above risks are assigned to generating companies, they are not fully equipped to mitigate some of these risks as they are beyond their control, including risks on account of fuel supply and water supply, project delay risks such as land acquisition, financial performance of agencies, climatic conditions etc., and salary and wages of staff. These risks have increased multifold over the years. It is therefore necessary that either these risks are not assigned to the generator or there should be higher returns on equity than that are presently available. Operating norms need to be fixed duly considering the design / vintage of plants. Further, both gains and losses on account of deviation from normative operating parameters should be shared and not the gains alone.

The tariff structure is such that the upside to a generator is capped whereas there is no limit to the down side. There is a need to redefine risk allocation between the generators and distribution utilities. Such high-risk allocation to generators is also not in the consumer interest as reduced profitability and cash flows lead to increase in interest rates and reduced investments in the sector leading to non-availability of assured and reliable 24X7 supply.

In order to encourage better performing generators, Regulations should incentivize and promote performance in the light of emerging requirements of the grid such as flexible operation, increased ramp up / ramp down rates, AGC, technical minimum (55%), new environmental norms, etc, rather than the approach of compensating losses.

2. Detailed Para-wise submissions on the issues discussed in the consultation paper have been made in the subsequent pages. However, a brief summary of the submissions on key issues is given below:

2.1. THREE PART TARIFF

Three part tariff is not in the overall interest of the sector and may not be resorted to. Since beginning linking of recovery of fixed charges with availability has been on the premise that generator can control only the plant availability while PLF is an uncontrollable factor for the generators. Denying recovery of fixed cost and return on investment due to under scheduling by procurers would be penalizing the generator for none of its faults. Moreover, investment decision to set up the plant is based on recovery of cost based on declared availability. Beneficiaries have also signed PPAs considering the same. All elements of AFC are costs that are required to be the incurred for declaring availability. In order to ensure reliability and certainty of supply in the long run, the trend world over is to move towards capacity contracts.

Moreover, three part tariff would be discriminatory for central generating stations vis-a-vis IPPs and State Gencos because Discoms, while preparing the merit order, would include variable component of AFC along with ECR. This will vitiate the entire merit order scheduling process. This is also not in line with the Tariff Policy, which mandates two part tariff in order to facilitate merit order scheduling. Three part tariff structure is not in the consumers interest in the long run due to the following:

- Increase in financing cost due to increase in risk.
- Distortion of merit order
- Adverse impact on capacity addition

2.2. <u>RETURN ON EQUITY</u>

The return on equity has to commensurate with the risks. Thermal power stations face significant construction & operational risks, which are unique and are not faced by other segments in power sector. The risks include the long gestation period of 7 to 8 years during which no return is available. Thermal stations face risks on account of project delay, coal availability, water availability, machine availability, O&M expenditure under recovery, non-achievement of normative operational parameters, etc. The increased risk in generation sector is also validated by increased level of NPAs and stressed assets in generator sector. Any reduction in the ROE will bleed the bottom line and the revenues may not be sufficient to service debt. There would be rating down grade and increased cost of debt. It would be pertinent to mention that 100 bps increase in interest cost results in tariff increase by 7p/kWh. Investment decisions are taken after assessing the viability based on extant provisions. Subsequent to making the investment the parameters should not be changed.

It would be inappropriate to equate return of all infrastructure projects since they have different gestation periods and risks (14% ROE for solar equates to 19% for thermal generation sector). Accordingly, there is a case for increase in ROE. In the alternative, ROE may be allowed during construction.

2.3. GROSS FIXED ASSETS

It is respectfully submitted that GFA approach may be continued. Hon'ble Commission while formulating 2014-19 regulations have discussed the issue in detail and concluded that since investments have been made based on GFA approach, any change in the methodology for existing projects would have detrimental effect on the returns. As stated by Hon'ble Commission, GFA approach incentivizes generator to efficiently operate and maintain infrastructure even when the plant is depreciated and internal resources accrued are utilized for further investments in the sector. In the absence of GFA, old stations may go into loss due to lower ROE and higher risk of under recovery in O&M / Operating parameters. Any change in approach would shake the investors as well as lenders confidence and would lead to increase in interest rate and is therefore not in the overall interest of the consumer and may not be resorted to.

2.4. DEBT/EQUITY RATIO

In regard to debt equity ratio it is submitted that the Tariff Policy envisages financing in the debt equity ratio of 70:30. Moreover, in the current scenario of high NPA levels in power sector bankers are reluctant to provide loan to power sector. Therefore, getting loan at higher leverage than existing level would not be feasible for developers. In regard to debt equity ratio of old projects, it is submitted that the investment decision has been taken considering viability of project based on extant regulations. Any change would adversely impact the cash flow. Old stations may go into loss due to lower ROE and high under recovery in O&M / Operating parameters. This would be a loss to beneficiaries as they may lose power from cheaper stations.

2.5. O&M EXPENSES

Hon'ble Commission fixes O&M expenses norms based on past actual expenses. Therefore, ideally, there should not be any under recovery on account of O&M Expenses. However, NTPC has under-recovery in O&M expenses to the tune of Rs. 1000-1200 cr per annum in the last tariff period.

Hence, there is a need to review the methodology of fixation of norms. Moreover, all prudent expenditure incurred needs to be considered while fixing the norms. Further, new impositions during the tariff period like GST and pay revision need to be factored in the actual data separately. Increase in O&M expenses due to ageing, cycling, start/stops and partial loading may be considered while fixing O&M norms.

2.6. **GCV**

In India presently, the supply and transportation of coal is through entities which are essentially monopolistic. Since fuel cost consists of 60-70% of input cost, generator is not in a position to absorb risks associated with quality & quantity. Loss of quantity and quality between mine end and station end has been rightly recognized in the Consultation Paper to be beyond the control of the generator by Hon'ble Commission, which is a welcome step. The Consultation paper proposes to allocate the above losses amongst the Coal Company and Railways. To make this effective, it is submitted that the Coal Company may transfer title of coal to the generator at the plant end. This would require intervention by the Ministry of Coal and the Ministry of Railways. Facilitation and support of Hon'ble Commission in this regard is sought so that interest of consumer and generator is protected.

2.7. **OPERATING NORMS**

Operating norms have been fixed by the Hon'ble Commission based on the past actual data. The actual loading factor of thermal plants is expected to reduce further due to the increase in RE penetration. Coal quality is also deteriorating. Presently, many NTPC stations are not able to meet the existing heat rate, APC and specific oil norms. Norms need to be relatable and achievable. In view of the above, operating norms need to be fixed with operating margin based on the anticipated operating conditions and loading factor in the next tariff period instead of past actual. A margin of 7.5-8.0% for units older than 10 years and 6.0-6.5% for new units less than 10 years on design heat rate may be provided. Similarly, APC norms for 500 MW units needs to be relaxed by 0.75%. Data in justification of the above is give in the Submission.

2.8. ENVIRONMENTAL NORMS

Substantial capital investment would be required to comply with the environmental and pollution control norms in coal based plants. The Consultation Paper has proposed that the entire capex may be treated as debt. In a cost plus regulatory framework, generator would have no incentive for making the investment if the cost of equity is denied. Lenders would also not be inclined to finance the same without equity participation. Moreover, capex to meet environmental compliance needs to be incentivized by the Hon'ble Commission so as to facilitate timely compliance. It is therefore submitted that such capex may not be differentiated from any other add-cap and be treated as additional capitalization with D/E ratio of 70:30. Plants which have implemented pollution norms would be in disadvantage with regard to merit order scheduling as compared to plants where pollution norms are yet to be complied. Therefore, incremental increase in tariff on this account may be loaded in the Fixed Charges in order to have no effect on their merit order scheduling.

2.9. NATIONAL MERIT ORDER OPERATION

NTPC has been making continuous efforts to reduce the tariff of NTPC stations in order to supply affordable and reliable power to its customers. It is observed that while a costly station in one region is scheduled at the same time another cheaper station in a different region remains unscheduled. It is therefore proposed to optimize the operation of NTPC plants, by National Merit Order Operation of all NTPC Plants. All Generating stations of NTPC should operate in the order of Least Energy Charge to Higher Energy Charge basis till the entire energy requirement of all the States is met. Thus, the average cost of power would reduce. Allocation from individual stations and billing mechanism would remain largely unchanged. Original beneficiaries of any "station" shall retain the first right to schedule as per their allocation. The gains arising out of the mechanism may be shared with the beneficiaries in 50:50.

2.10. COMPANY SPECIFIC TARIFF

Section 79 (1) (a) of the Electricity Act 2003 provides that Central Commission shall regulate the tariff of generating companies owned or controlled by the Central Government. For the sake of simplicity, the Hon'ble Commission may consider determination of company specific tariff applicable jointly to all NTPC stations instead of determining station-wise individual tariff.

2.11. MARKET DEVELOPMENT

The Consultation Paper has proposed that a part of capacity allocation from the generating company may be relinquished by beneficiaries for a period of 1 year subject to mutual agreement with the generator on payment of 10-20% annual fixed charges. This capacity is to be reallocated to other beneficiaries at market price. Mutual agreement may not be practically feasible. Further, sanctity of long-term PPAs is required to be maintained as relinquishment on annual basis shall tantamount to reopening of long term contracts. The Tariff Policy provides that 15% capacity of power plants may be earmarked for sale outside long-term PPA in order to promote market development. Therefore, it is submitted that a part of capacity, say 10%, from NTPC stations may be allowed to be sold outside long-term PPA in the market in order to promote market development.

PARA-WISE COMMENTS

Tariff Design: Generation

1) The tariff design has evolved in order to harness available resources in an optimal manner to meet the growing demand. For this, performance-based cost of service was evolved and implemented during the previous control periods. Further, in order to induce efficiency, some of the components of tariff were pre-specified on normative basis. Following tariff design has been adopted for generation (thermal, hydro and renewable) and transmission.

2) The existing tariff structure are as under:

i. Two part tariff structure for generation: -

a. Fixed charges representing fixed cost components and energy charges representing variable component with incentive and disincentive mechanism; and

b. For hydro power plants, the recovery of fixed charges is through two components i.e. "capacity charges" & "energy charges", each component representing 50% of Annual Fixed Charges (AFC). Recovery of "capacity charges" is linked to availability of plant and recovery of "energy charges" is linked to actual energy generated;

ii. Single part tariff structure for inter-state Transmission system: -

a. Annual fixed charges with incentive and disincentive linked to availability of the transmission system.

iii. Feed-in Tariff structure for Renewable Generation: -

a. Feed-in Tariff structure comprising fixed charges of the renewable generation project.

Thermal Generating Stations –Tariff Structure (Three part tariff structure)

3) Possible three part tariff structure for thermal generating stations is discussed in subsequent paragraphs.

4) In view of decreasing PLF of thermal generating stations, a need has been felt to look into two part tariff structure being followed now. As discussed in following paragraphs, 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 power purchase to avoid fixed cost liability and rather they have been resorting to short term power purchase to meet their demand.*

5) *As stated above, the two-part tariff structure works well when the gap between available capacity and dispatch is low. It is because all the procurers are placed in a similar position and it can be said that there is a homogeneous demand. When procurers have homogeneous demand, there is no difference in pricing mechanism whether one procurer purchases electricity from one generating company or many. This situation has undergone change. As the gap between plant availability factor and plant load factor has widened due to low PLF, the procurers are no longer placed in similar position. AFC per unit would be on higher side for the procurers having low demand. When two procurers are not placed on similar positions, the present two-part tariff structure does not provide for charging differential fixed charges from different procurer. Though the tariff determined by the Commission acts as ceiling, there is no mechanism specified to charge the tariff lower than ceiling.*

Options for Regulatory Framework

6) *The possible options for tariff structure could be to offer to the procurers having low demand a menu of options for ensuring dispatch by linking a portion of fixed charges with the actual dispatch and balance of AFC to availability. This will ensure optimum utilization of the infrastructure, as procurers will continue to procure power from the generating stations and the generator will get reasonable return without losing the demand.*

7) *The tariff for supply of electricity from a thermal generating station could comprise of three parts, namely, fixed charge (for recovery of fixed cost consisting of the components of debt service obligations allowing depreciation for repayment, interest*

on loan and guaranteed return to the extent of risk free return and part of operation and maintenance expenses), variable charge (incremental return above guaranteed return and balance operation and maintenance expenses) and energy charges (fuel cost, transportation cost and taxes, duties of fuel).

8) The recovery of fixed component could be linked to target availability, whereas variable component could be linked to the difference between availability and dispatch. Fuel charges could be linked with dispatch.

3. COMMENTS:

3.1. Linking of recovery of fixed charges with PAF so far has been based on the premise that generator can have control only on the Plant Availability, whereas the actual generation of power / dispatch of power (PLF) is fully dependent on the procurer / Discoms and is un-controllable for a generator.

3.2. In a cost-plus regulatory framework, the investment decision is taken after entering into PPA with the beneficiaries for offtake of power. Moreover, the financial viability of the project rests on the recovery of Annual Fixed Charges (AFC). The generator is responsible for operational risks, arranging fuel, water and other inputs, undertake periodic maintenance and overhauling in order to ensure availability of the unit for generation. In view of the above, the recovery of fixed charges is linked with achieving target Plant Availability Factor (PAF) as per the established industry practice. The Annual Fixed Charges comprises of the following elements:

a. Return on Equity
b. Depreciation
c. Interest on Loan
d. O&M expenses
e. Interest on working capital.

3.3. All the above elements except return on equity are costs that are required to be incurred to declare availability. Return on equity is the return on the investment. Denying recovery of cost and return on investment due to non-scheduling by procurer is penalizing the generator for none of its fault.

3.4. Once the unit is made available, its Plant Load Factor (PLF) depends on schedule given by the procurers which is beyond the control of the generator. As the generating units are dispatched by the procurer based on merit order scheduling it may happen that certain plants may not be scheduled in low demand scenario certain time of the day / season, more so in view of renewable integration. However, the procurer has entered into long-term contract (PPA) after considering the demand situation based on which the plant has been set up. Thus, in a regulatory cost plus framework, where servicing of costs subject to prudence has to be ensured, AFC has to be necessarily linked with PAF.

3.5. PPA of tariff based bidding projects is also based on two-part tariff where capacity charges is linked with availability.

3.6. Further, central generating stations with three part tariff will be at a disadvantage in the merit order ranking as compared to generating stations of IPPs & States having two part tariff as the States would include the component of AFC, which is directly dependent on the schedule given, while preparing the merit order. This will vitiate the entire merit order scheduling system since, for some generating stations whose tariff is decided by CERC, a component of AFC would be included in merit order rankings. This is also in line with the Tariff Policy which mandates two part tariff in order to facilitate merit order scheduling.

3.7. If the case would have been that there is no difference between PAF and PLF then it does not matter whether the recovery of fixed cost is linked to PAF or to PLF, but as pointed out in the discussion paper that there is considerable variance between PLF and PAF, the linking of recovery of fixed cost components with PLF/dispatch will only lead to under-recovery of the prudent and admitted costs incurred by the generator.

3.8. Projects under long term PPA are planned & developed to cater the base demand of the procurers and the entire investment on such plants are made on consent of Discoms and their assessment for future demand forecast. Overall demand in the country has been continuously increasing. The fact is that country in the last few years has witnessed higher supply addition, considerable quantum of which is uncontracted, which has resulted in distressed sale of power in the short-term market / exchange which is the major reason for current drop in exchange / short–term prices. Many of Discoms taking economic advantage of such peculiar situation have been resorting to purchase power from short-term sources. This is also one of the reasons that the average PLF for contracted plants under cost plus regime has reduced.

3.9. Lower PLF therefore has been resulted majorly because of changing market dynamics and inadequate planning of Discoms which in order to minimize the future risk entered into long term contracts. Introduction of three part tariff may not able to result in increasing the PLF, but instead it will be detrimental for generators who might lose part of fixed charges which otherwise they are legitimately entitled to. This will also be contradictory to the basic principle of cost-plus approach which allows the investor to recover all the cost incurred in the prudent manner. Linking the recovery of fixed component of tariff with the PLF would result in undue under-recovery for the generator for no fault of his.

3.10. Presently, there is a lot of latent demand in the system which is required to be met. Moreover, the Discoms try to limit their losses by restricting supply. The per capita consumption of the country needs to be improved. The demand needs to be boosted by providing access to electricity for all on 24×7 basis in order to facilitate growth of the economy. Then automatically the PLF of plants shall increase. Further, the Draft Tariff Policy requires Discoms to tie up long-term power so that reliability of supply in its area of supply is ensured at all times. Therefore, rather than implementing 3 part tariff it is suggested that Discoms may be encouraged to increase supply of electricity in their areas.

3.11. According to established economic principles, the main economic criteria in the power system operation is minimizing the cost of generating power in real time. This cost has two components (1.) The fixed cost which is determined by the capital investment, interest on loan, loan repayment, labour charge, salary given to staff and other expenses that need to be met irrespective of the plant load factor. 2. The variable cost consists of the fuel cost which is a function of the plant load factor. The economic operation of a power plant can be achieved by minimizing the variable factor only while the fixed charges are to be necessarily incurred in order to make the plant available for generation. Therefore, the separation of tariff into two parts where variable cost exclusively is a function of fuel consumption, heat rate, loading factor, and units being generated allows easy implementation of principles of economic operation by implementing economic dispatch and unit commitment by using merit order. Incorporating fixed cost components in variable part linked to plant load factor is against any established economic principles and would distort the merit order and would ultimately result in uneconomical system operation incurring higher expenses for generating per unit of power.

3.12. Two-part tariff structure is also in-line with the Tariff Policy, which act as guiding principles for designing tariff regulations due to the above reason.

3.13. Para 6.2 (1) of the Tariff Policy provides as under:

"A two-part tariff structure should be adopted for all long-term and medium-term contracts to facilitate Merit Order dispatch. According to National Electricity Policy, the Availability Based Tariff (ABT) is also to be introduced at State level. ……………Power stations are required to be available and ready to dispatch at all times."

3.14. The Tariff Policy also recognizes that the two-part tariff framework is essential and should be adopted to facilitate merit order. Further, Tariff Policy also provides for a mechanism to utilize unrequisitioned surplus of power stations. Therefore, the contention of the consultation paper that two part tariff is not suitable for low demand scenario is not correct. The tariff structure is not based on the demand scenario. The state utilities need to manage their power purchase portfolio through a basket of long-term, medium term and short term purchases. While all long term and medium term contracts need to be two part based as also provided in the tariff policy short term contracts are generally based on single part. Long-term contracts are essentially based on two part tariff. The un-requisitioned surplus sold in the market thus gives rise to the short term transactions.

3.15. The current two-part tariff system has been in operation for nearly 3 decades and has been well accepted by the beneficiaries, utilities and the investors. Regulatory certainty is key to promote future investments into the sector. Dividing the ROE component into two parts viz. risk free rate and premium over risk free rate and linking the two to PAF and PLF respectively, is a radical change which proposes to change ex post investment, the rules of the game in a fundamental manner. Such a move would erode shareholder value and shake the investor confidence in the regulatory regime.

3.16. 3-part tariff structure is not in the consumer interests due to the following:

a. Increase in financing cost due to increase in risk

b. Distortion of merit order

c. Adverse impact on capacity addition

NEW PROJECTS

3.17. The proposed three part tariff increases the complexity of the tariff structure and significantly alters the risk reward sharing between the generators and the customers. Over the life of power plant, the demand and supply dynamics would vary from time to time.

3.18. It is not suitable for even new projects since the risks of recovery of full fixed charges would be enhanced. The investors would need to be provided much higher return to match the risk. The debt rate for such projects would be significantly higher. Thus the intention of reducing the cost to consumer shall not be achieved.

3.19. As the risk of recovery of AFC increases significantly with the 3 part tariff, it is likely to have an adverse impact on capacity addition in the country.

In view of the above, two-part tariff comprising capacity charges linked to PAF and energy charges based on fuel cost as per the existing tariff framework needs to be continued for both existing and new projects.

Thermal Generating Stations – Older than 25 years

1. *As on 31st March 2016, as per CEA total thermal installed capacity in the country was 2,10,675 MW. Out of this 1, 85,173 MW was from coal based (including lignite) thermal power plants. The supercritical thermal power plants contribute 34,950 MW, which is about 19% of total coal based generation capacity. The coal based thermal power plants more than 25 years old are about 37,453 MW, out of which around 35,506 MW capacity pertain to State / Central sector.*
2. *Present basket of thermal generating stations comprises of several old thermal generating stations which have completed 25 years. These generating stations have completed useful life, whereas some others have completed 10-12 years of life. Such generating stations are placed differently as they were conceived based on the policy/regulatory environment and technology available at that time.*

They are not comparable with the new generating stations in terms of operational norms and capital cost.

3. *As most of these have already recovered depreciation and completed loan repayments, they may have advantage from financial consideration. But their operational cost could be higher due to less efficiency, such as high consumption of coal due to higher station heat rate (SHR). Further, their O&M cost could be high.*

Options for Regulatory Framework

4. *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.*

4. COMMENTS:

4.1. Currently the incremental financial impact of running the old plants efficiently through utilization of provision of special allowance for R&M (Rs 7.5 Lakh per MW) is as low as 10 to 14 paisa per unit (in PLF range of 85% to 60%). For the plants which are operating at efficient levels should be allowed to continue with the existing provision of special allowance as allowed in the current Regulations.

4.2. However, in order to facilitate the optimal utilization of natural resources i.e. land, water and coal, it is suggested that in line with CEA Report (September, 2015) on "Replacement of old and inefficient sub critical units by super critical units/ retirement /renovation" the old & inefficient units with high station heat rate (SHR) above 2500 Kcal/kWh may be replaced with super critical units resulting in more generation of electricity per ton of coal. It will also reduce emissions (CO_2, SO_2, Mercury and NO_x) per unit of generation and save environment.

4.3. With proper and routine O&M and Renovation & Modernization after completion of useful life of 25 years, the performance of thermal units can be sustained without much deterioration for another 10 - 15 years. This has been demonstrated by many NTPC units that have already completed 25 years. Further, it is economical to run such units due to the lower capacity charges. The beneficiaries also benefit from the cheap power from such stations. The Tariff Policy also mandates that the benefit of depreciation should remain with the beneficiaries.

4.4. However, smaller sized units (having heat rate greater than 2500 kcal/kwh) which have outlived their useful life and are still operational due to certain considerations may be replaced with larger sized supercritical units based on cost benefit analysis on a case to case basis. Capacity addition is being done through supercritical technology and the older fleet of units would be retired. Continuing operation of units more than 25 years old and which are operating efficiently is in the interest of beneficiaries. Biomass co-firing may be employed in these plants to reduce their net carbon emission and increase renewable generation targets.

4.5. Further, as compared to super critical units which are very inefficient while flexing due to movement from wet mode to dry mode, the sub-critical are best suited to meet flexible demand which is increasing day by day due to increasing renewable integration.

In view of the above, the dispensation of Special Allowance for units after 25 years needs to be continued.

Hydro Generating Stations – Tariff Structure

1. *The two part tariff structure of hydro generating stations seems adequate in present scenario. However, in view of large capital cost, hydro generating stations often find it difficult to get dispatched due to resultant higher energy charges. In order to address this issue, for the hydro generating stations, the fixed charges and variable charges may need to be reformulated.*

Options for Regulatory Framework

2. *The fixed component may include debt service obligations, interest on loan and risk free return while the variable component may include incremental return above guaranteed return, operation and maintenance expenses and interest on working capital. The annual fixed cost can consist of the components of return on*

equity, interest on loan capital, depreciation, interest on working capital; and operation and maintenance expenses.

5. COMMENTS:

In case of hydro generating stations, two part tariff structure is already in place. Presently, AFC of hydro stations is notionally split into fixed and variable charges in the ratio of 50:50. The recovery of fixed charge is linked with availability and variable charge is linked to schedule. The proposed fixed component may cover return on equity, debt service obligations and interest on loan while variable charges may comprise of O&M expenses and IWC. Alternatively, the ratio of fixed to variable charges may be changed to 70:30 instead of 50:50. The formulation would lower variable charges thus facilitating dispatch of costly hydro stations.

Renewable Energy Generation - Tariff Structure

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 compensate 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.*
2. *The tariff structure of the renewable generation may be rationalized.*

Options for Regulatory Framework

3. *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 equity) - fixed component as feed-in-tariff (FIT) and variable component equal to capacity augmentation such as storage or back up supply tariff.

4. *In case of integration of the renewable generation with the coal/ lignite based thermal power plant, the following may the alternatives.*
   i. *The renewable generation may be supplied through the existing tariff for the contracted capacity of thermal power plant under PPA. In this alternative, the tariff of renewable generation may replace the energy charges;*
   ii. *Tariff of renewable generation may be combined with the fixed and variable components of the thermal generation to the extent of contracted capacity under PPA. The operational norms of conventional plants may require revision such as higher target availability for recovery of fixed charges, higher plant load factor for recovery of incentive;*

6. COMMENTS:

Generation from renewable energy sources is essentially of “MUST RUN” nature. As the variable cost of generation is zero, it needs to be either consumed as and when it is generated or stored for future consumption. All forms of renewable sources of energy, i.e., solar, wind, etc. are infirm and intermittent. Therefore, integration of RE sources requires conventional generation to modulate in order to absorb the variations of RE generation. Even renewable sources like run of river hydro generation have limited flexibility. As large scale storage system for energy is not economically feasible presently, renewable energy falls outside the ambit of merit order scheduling and are as must run facilities. In view of the above, single part tariff for renewable energy is appropriate and is working well in the present context.

Alternatively, all the energy charge of renewables shall be treated as fixed charge, with very little or zero variable charge. Once the energy charges as fixed charges are already committed by the beneficiaries for renewable generation based on its availability (or PLF), the economic operation of the grid is ensured because the renewables have zero or very little variable cost pushing its merit order rating to the top.

Deviation from Norms

1. *The Commission, during the 2014-19 tariff period, has specified in the Regulation 48 for deviations of norms as below.*

   "48. Deviation from norms: (1) Tariff for sale of electricity by the generating company or for transmission charges of the transmission licensee, as the case may be, may also be determined in deviation of the norms specified in these regulations subject to the conditions that:

   (a) The levelised tariff over the useful life of the project on the basis of the norms in deviation does not exceed the levelised tariff calculated on the basis of the norms specified in these regulations and upon submission of complete workings with assumptions to be provided by the generator or the transmission licensee at the time of filing of the application; and

   (b) Any deviation shall come into effect only after approval by the Commission, for which an application shall be made by the generating company or the transmission licensee, as the case maybe..."

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 Commission under section 62 of the Act.*

3. *For various reasons, out of tied up capacity by the distribution licensee, some of the capacity often remains un-dispatched 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.*

<u>Options for Regulatory Framework</u>

4. *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.*

7. Comments / Suggestions –Deviation from Norms

7.1. In the existing regime, the generator under the day-ahead scheduling already declare its available capacity and the tariff which is subject to the normative parameters approved by the commission. Such tariff is ceiling and developers are already free to offer discount on such ceiling tariff, so therefore there is no need for revision in regulations to that extent.

7.2. Furthermore, as the Commission approves the normative parameters and tariff based on the historic performance of the plants, allows only the prudent costs incurred by the developer, there is usually no margin of discount that can be offered by a generator. If there is any margin in efficiency parameters i.e. Station Heat Rate, Secondary Fuel Oil Consumption and Auxiliary Power Consumption, existing CERC regulations already provide for sharing of efficiency gains due to improvement in efficiency parameters with the beneficiaries which is therefore passed on to the beneficiary. Moreover, the Commission's approach is to reset the normative parameters in every control period based on the actual parameters.

7.3. Further, the dispatch of power from a particular plant depends largely on its energy charges rate and the merit order principals. It is often debated that merit order principles are not followed in true-spirit by the States. The major reason is that the merit order dispatch data is not made available transparently in public domain, which make it difficult to check whether the Discoms truly follow the dispatch principles or not. Discoms purchases power from multiple sources therefore on yearly average data it may seem that merit order is being followed, however at 15 min time block level, priority might be given to state generating plants over other plants having higher cost efficiency.

7.4. This would not result only in higher average cost of power for Discoms but would also result in lower PLF for efficient plants.

7.5. It is suggested that there should be a mechanism which enables the merit order data at 15 minute time blocks be made available in public domain to enable more transparency in market.

7.6. In addition, CERC determines tariff only on normative basis, whereas in many instances the actual operating parameters are more than normative parameters. And generator already bears loss pertaining to such variation in operating norms. Thus in such cases generator recovers less than its actual cost subject to ceiling tariff approved by the Commission, therefore there is usually no scope of discount or negotiation that can be offered to the beneficiaries.

Components of Tariff – Multiple mode for selling; Cost plus, competitive bidding or merchant

1) *Unlike the Central Generating Stations, for privately owned generating stations, not all the generating capacity may have tied up power purchase agreements. In such case, part capacity may have been tied up under Section 63 and/or Section 62 of the Act and balance may have remained as merchant capacity.*
2) *Section 62 of the Act provides that the Appropriate Commission shall determine the tariff for (a) supply of electricity by a generating company to a distribution Licensee, (b) transmission of electricity, (c) wheeling of electricity and (d) retail sale of electricity. Section 61(b) of the Act provides that the Appropriate Commission shall specify the terms and conditions of tariff for generation, transmission, distribution and supply of electricity are conducted on commercial principles. The commercial principles inter-alia emphasize the risk allocation through contractual arrangement such as power purchase agreement in case of generation and transmission service agreement or long term access agreement in case of transmission service.*

Options for Regulatory Framework

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

8. Comments / Suggestions –Components of Tariff – Multiple mode for selling; Cost plus, competitive bidding or merchant

Separate determination of the tariff for the capacity tied up under cost plus mechanism may not be practically possible. The current methodology to determine the tariff of the generating station for entire capacity and then subsequently restricting the tariff for recovery to the extent of power purchase agreement on pro-rata basis may be continued.

Optimum utilization of Capacity

Coal based Thermal Generation

1) *The unutilized capacity due to partial or less demand has impact on the recovery of the cost by the generating plant. At the same time, the distribution licensee may be impacted by way of liability of fixed charges without availing dispatch from the generating station.*
2) *If the unutilized capacity of the generating station is allowed to be utilized by other distribution companies or through open market, the obligations of the distribution companies may reduce to the extent of utilization.*

Options for Regulatory framework

3) *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 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;*
4) *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.*

Gas based Thermal Generations

5) *The use of gas based generating station is important because of possibility of immediate ramp up and ramp down for balancing the variations of renewable generation.*

Options for Regulatory framework

6) *Scheduling and dispatch of gas based generating station may be shifted to regional level with the primary objective of balancing. After meeting the requirement of designated beneficiaries, the regional level system operator can use it for balancing power at the rate specified by the generating companies. Alternatively, all the gas based generating station capacities may be pooled at regional level. After meeting the requirement of designated beneficiaries, the balance generation may be offered for balancing purpose as and when required.*

9. Comments / Suggestions – Optimum utilization of capacity

9.1. Country today is facing situation of supply overhang in certain times of the day / season which is majorly due to considerable quantum of uncontracted / merchant capacity addition in past few years. Such situation has lead the overflow of power in exchange under distress sale thus leading to fall in exchange prices and therefore somewhat lower despatch from the contracted capacities and higher quantum of purchase from short-term market / exchange. The current tariff at the power exchange is not the true reflection of the long term economic tariffs and most of the plants pumping power in exchange are recovering only a small part of fixed cost besides the variable cost of generation. This is also one of the reasons for the current state of financial stress in the power sector leading to stranded assets. Prices in the short term market cannot be the basis to determine the prices under long term power purchase agreements since the obligations of the parties under the two are entirely different.

9.2. The developers of merchant capacities after due consideration of the associated risks (under surplus situation) as well as higher expected returns (under deficit situation) have developed these plants. The objective of contracted capacities which have been operated under regulated market is to ensure certainty of tariff as well availability to the procurers. For so many years these plants have supplied power only making regulated profits even under severe shortage conditions. However, linking the same with the exchange market rates would create higher uncertainties leading to increased risk of operation for the generators.

9.3. The surplus un-requisitioned power is already being sold in the Power Exchange by NTPC with the consent of the procurer along with passing the additional profit to the beneficiaries which reduces the net fixed cost burden for Discoms.

9.4. If some of the state Discoms are facing surplus situation and on the other hand there are states which are still deficit, mechanism needs to be devised to make available surplus capacity with a utility to other utilities needing such capacity. Further, due to the allocation of power, some cheaper station in one region may be having un-requisitioned surplus whereas at the same time, costlier station in another region may be scheduled. Such situation leading to increase in overall cost can be addressed by the National Merit Order operation of NTPC stations wherein cheaper stations would be despatched fully before operating costlier stations resulting in overall savings by reduction in average cost of power from NTPC stations. Any gain from such operation would be shared with the beneficiaries.

9.5. The above measures / options shall ensure that the un-requisitioned power is optimally utilized. This will lead to higher PLF of cheaper plants and thus resulting in cost savings as well as conserving the fuel resources of the country.

9.6. Discoms are better equipped to supply electricity to various categories of customers located in their area when compared to the generator supplying through open access.

9.7. The Tariff Policy already provides framework for utilization of Un-requisitioned surplus (URS) capacity of generating stations by other needy beneficiaries within the region based on consent of the original beneficiary. This provision allows the beneficiaries to reduce the burden of capacity charges in case of surplus capacity and also provides flexibility in recalling its power. Further there is provision of relinquishment of allocated capacity permanently by approaching Ministry of Power if the capacity can be reallocated to some other beneficiary. Conditional relinquishment for one year as proposed by Consultation Paper provides easy route for opening long-term PPA and should not have regulatory sanction. Contractual issues in PPA may be left to the seller and procurer. Sanctity of Contracts need to be maintained.

9.8. The Tariff Policy provides that 15% capacity of power plants may be earmarked for sale outside long-term PPA in order to promote market development. Therefore, it is submitted that a part of capacity, say 10%, from NTPC stations may be allowed to be sold outside long-term PPA in the PX in order to promote market development.

Gas Based Thermal Generation

9.9. Gas-based stations on the other hand have technological advantage of immediate ramp-up and ramp-down, they may be optimally utilised for balancing the various renewable capacities. However, this requires provision of ramping up or ramping down of the gas supply quantities built into the gas supply contracts. Non availability of such provision right now is a big hurdle in utilizing gas stations for ramp up and ramp down duties. Scheduling and dispatch of gas based generating station may be shifted to regional level with pooling at regional level.

9.10. Presently, gas plants are eligible to provide ancillary services wherein the system operator can use the unutilized power remaining after meeting the requirement of the designated beneficiaries. The energy charges are provided to the regional system operator in order to schedule the gas plants under RRAS. Therefore the proposal suggested by consultation paper is already implemented.

9.11. The proposal of pooling all gas based capacities under regional system operator and running them as per the balancing requirements by the system operator may be done by scheduling all gas stations by RLDC /

NLDC in merit order at NTPC level similar to the proposed national merit order dispatch of NTPC coal based stations.

9.12. In order to encourage better performing generators, Regulations should incentivize and promote performance in the light of emerging requirements of the grid such as flexible operation, increased ramp up / ramp down rates, AGC, technical minimum (55%), new environmental norms, etc.

Hydro Generation

7) *The present commercial framework under PPA allows the use of hydro power to meet the demand of the designated beneficiaries under PPA. There is a need to extend the use of hydro power for balancing the variability of renewable generation. In other words, there is a need for a framework for flexible operation of the hydroelectric project. Further, as the scheduling of cascade hydro power station i.e. reservoir operations at a hydro plant affect the cascade downstream and upstream reservoirs, there is a need for a coordinated approach for scheduling of such hydro projects;*

Options for Regulatory framework

8) *Extend the useful life of the project up to 50 years from existing 35 years and the loan repayment period up to 18-20 years from existing 10-12 years for moderating upfront loading of the tariff.*

9) *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 power scheduled to the hydro generation can be dispatched to designate beneficiaries through banking facility so that flexibility in scheduling can be achieved for balancing purpose and to address the difficulties of cascade hydro power station. Some part of fixed charge liability to the extent of 10-20% against the use of flexible operation and pumped operations may be apportioned to the regional beneficiaries as reliability charges.*

10. Comments / Suggestions – Optimum Utilization of Capacity for Hydro Stations

10.1. Increasing useful life from 35 years to 50 years and loan repayment period from 12 years to 18-20 years for lowering front loading of tariff needs to be re-considered from the point of total debt servicing over life of the asset.. Increased repayment term would increase the total repayment and this may effectively increase the tariff and so may be counterproductive. Further, debt for 25 year maturity (7 year construction period plus 18 year repayment period post commissioning) is scarce in the country as neither banks lend for such long tenure nor the bond market and would expose the utilities to refinance risk besides increasing the borrowing costs.

10.2. In case hydro power is used for balancing by the System operator, the existing PPAs with beneficiaries need to be modified. It has to be ensured the entire cost servicing of the investment made by the hydro generator is recovered. The consultation paper proposes to charge only a part of fixed charge liability to the extent of 10-20% against the use of flexible operation and pumped operations which may be apportioned to the regional beneficiaries as reliability charges. It does not specify how the balance fixed charges would be required. It is submitted that the balance 80-90% fixed charges are required to be recovered from the beneficiaries for providing energy during peak hours.

Capital Cost

1) *The approval of Capital Cost is the most critical aspect of tariff determination. Capital cost is considered as the base for determination of return on investment. The existing regulations allow capital cost for the new projects (to be commissioned in the control period) based on the expenditure incurred as on date of commercial operation (COD), duly certified by the Auditors after prudence check. For the existing projects, the capital cost admitted by the Commission during the preceding tariff periods is considered along with additional capitalization during the control period after due diligence.*
2) *During the control period 2004-09, the capital cost was determined based on the actual cost as per the balance sheet of the regulated entities. From the control period*

2009-14, the Commission switched over to the methodology of determination of capital cost based on the projected capital expenditure. This enabled the generating companies or transmission licensees to file their tariff application prior to commissioning of the project. The undischarged liabilities were not included in the projected/actual capital expenditure for the purpose of capitalization.

3) *Capital cost includes interest during construction, financing charges and foreign exchange rate variation up to the date of commercial operation of the project. Any revenue generated on account of injection of infirm power through unscheduled interchange in excess of fuel cost is used to reduce capital cost.*
4) *The principles of tariff determination as per the Act mandate balancing of consumer's interest while allowing reasonable cost to the generator. The capital cost has a direct correlation with the cost of value chain of fixed charges and therefore the Commission always endeavors to allow capital cost after prudence check. The Tariff Policy, 2016 stipulates that the Appropriate Commission would evolve benchmark of capital cost as reference to allow reasonable capital cost to the generators or transmission licensees.*
5) *There are several issues and challenges with respect to the capital cost for the transmission system, thermal generating stations and hydro generating stations*
   i. *Variation between actual project cost vis-a-vis projected capital cost.*
   ii. *Additional capital expenditure estimated up to cut-off date on account of reasons like deferment in commissioning of projects, non-placement of orders due to limited vendor responses etc.*
   iii. *Delay in project execution is due to various reasons such as delay in land acquisition, delay in getting statutory approvals/clearances, delay due to geographical location of the site, delay on the part of contractor /supplier of material, execution philosophy etc, leading to increase in IDC, overhead expenses etc.*
   iv. *Absence of benchmark capital cost, leading to use of the estimated capital cost as per investment approval for reference purpose. Estimated capital cost as per investment approval may not truly reflect the efficiency in procurement and execution of the project when compared to market rates.*
   v. *Use of the audited annual accounts to ascertain the claim of the capital expenses. The tariff filing forms have been prescribed for filing regulatory information to facilitate reconciliation with financial statements prepared as per*

accounting standards. The financial statements of power companies have been changed w.e.f.1st April, 2016 due to introduction of the Indian Accounting Standards Rules, 2015. The formats for filing regulatory information may need to be reviewed in this context.

vi. *On the basis of indicative location, fuel and estimated cost of the generating station (investment approval), the beneficiaries enter into power purchase agreement and undertake the obligations to off-take the power on commercial operation of the project. Often, on declaring commercial operation, the generating companies revise the investment based on revised cost and beneficiaries may not be aware of the revised estimated cost. Similarly, the transmission licensees also revise the costs, which the customers may not be aware of.*

6) *There are specific issues and challenges in respect of thermal generating stations.*

i. *The claims of deferred works were allowed to be capitalised up to the cut-off date under the head "works deferred for execution/deferred works" but there is no provision for allowing such expenses after cut-off date. In some of the cases, expenditure was allowed even after cut-off date;*

ii. *The Tariff Regulations, 2014 provides for specific treatment of expenses of capital nature at the fag-end of project life and allows allowances which had consequential impact on tariff as entire depreciation would have to be charged within balance useful life. This provision may need review in view of the policy of phasing out of old plants and expected benefit for getting dispatch after completion of useful life;*

iii. *Additional capitalization by thermal generators to meet the efficiency improvement targets under the Perform, Achieve & Trade (PAT) scheme, water from Sewage Thermal Plant (STP), Pollution Control System to meet revised standards of emission norms, adoption of storage facility and combining renewable generation with thermal power project.*

iv. *The efficacy of normative compensation allowance and special allowance may need to be reviewed vis-à-vis actual expenditure. The regulatory oversight may be required to address overlapping of expenditure under compensation allowance and O&M allowance.*

v. *Provisions to handle capital expenditure to comply with new environmental norms, expenditure due to change in law (whether it is possible to specify* *events),servicing of expenditure relating to rail infrastructure, availability of wagons etc. to tackle major breakdowns and expenditure relating to grid security.*

Options for Regulatory Framework

7) *One of the options is to move away from investment approval as reference cost and shift to benchmark/reference cost for prudence check of capital cost. However, the challenge is absence of credible benchmarking of technology and capital cost.*
8) *Higher capital cost allows the developer return on higher base of equity deployed. In the cost plus pricing regime, the developer envisages return on equity as per the original project cost estimation. The regulations allow compensation towards increase in cost due to uncontrollable factor so as to place the developer to the same economic position had this uncontrollable event not occurred. Therefore, in new projects, the fixed rate of return may be restricted to the base corresponding to the normative equity as envisaged in the investment approval or on benchmark cost. The return on additional equity may be restricted to the extent of weighted average of interest rate of loan portfolio or rate of risk free return. Further, incentive for early completion and disincentive for slippage from scheduled commissioning can also be introduced.*

11. Comments / Suggestions – Capital Cost

11.1. The present methodology of according approval to a project based on the investment approval as reference cost is appropriate as it rightly takes into account multiple factors such as land acquisition, right-of-way, construction cost etc. specific to the project while arriving at the investment approval cost. Arriving at the benchmark reference cost is difficult as project-specific costs will not be factored into it. Further, the presence of multiple factors makes it difficult to arrive at the benchmark capital cost.

11.2. The Commission as per the existing Regulations allows the final capital cost of the project based on final audited costs, the Commission also undertakes the detailed prudence check to identify if there is any imprudent cost or additional expense incurred which may not be required for the project. All such costs are not allowed for process of determination of tariff of a power project. To assess the reasonability of the costs, the actual capital cost of the project is also compared with the benchmark cost determined earlier by the Hon'ble Commission. Thus the present approach being followed by the Commission already takes into account benchmark capital costs and also variations due to project specific factors.It is therefore requested to continue the exiting approach for finalization of capital cost of a project.

11.3. The present practice of allowing return on equity on the admitted capital cost after prudence check is appropriate and should continue. Return on Equity needs to be provided on the entire admitted capital cost in a uniform approach. The Commission after prudence check anyway disallows imprudent cost in case delay is attributable to the generator, where hit is already taken by the generator on its invested equity, in addition the generator also has to service the loan pertaining to disallowed cost from its own resources.

11.4. Incentive for timely completion of the projects is already there in the form of additional RoE of 0.5% and generator loses out on this additional return in case of delay of the project. Further, even in cases where delays in construction are condoned by the Hon'ble Commission, only IDC/EDC is allowed in the capital cost for the delayed period. Since no ROE is allowed in the tariff during the construction period, the effective ROE reduces due to the delays putting the generator at a disadvantage. The proposal to reduce the ROE in case of delays would effectively amount to twice penalizing the generator for the same cause and should be avoided.

11.5. The proposal to restrict the return on additional equity deployed above the normative equity as envisaged in the investment approval to the cost of debt or risk free rate of return is inequitable to the generators since the admitted capital cost is arrived by the Hon'ble Commission after prudence check and comparison with benchmark costs. Once having approved the capital cost after satisfying itself on the incurred costs, return on the entire equity should be allowed at the same rate since allowing return at the risk-free rate to the equity holders who bear the entire construction and operation risk does not appear to be equitable/logical.

11.6. It is submitted that the following issues may be considered while admitting capital cost of projects and specific provisions may be made in the Regulation in regard to the following:

11.6.1. Regulations may have specific provision to admit the capex to comply with New Environment Norms, STP etc. Further, there could be other similar requirements for capital addition arising during the tariff period which cannot be envisaged upfront. Provisions of “In principle approval” of capital cost may be therefore provided in the Regulations to address such circumstances.

11.6.2. Provision of Special Allowance is towards meeting the capex of renovation and modernization exclusively. The norm of Rs. 7.5 lakhs per MW per year works out to 1.2 to 1.5 crores / MW over a period of 15 years. Such amount is barely sufficient to meet capex requirement of R&M. Therefore other necessary expenditure related to Ash Dyke and Change in Law for units of more than 25 years may be allowed separately as the same is not covered in Special Allowance which is towards meeting the R&M expenses. Specific provision in this regard may be provided.

11.6.3. In order to reduce the expenses many services are being taken up commonly for the stations from the RHQs/ Corporate Office. The benefit of lowering of costs by providing common services is passed onto the beneficiaries and therefore needs to be promoted. Accordingly servicing of Capex at Corporate Centre / RHQs may be allowed in tariff as being done in case of DVC.

11.6.4. De-cap of assets is given effect whereas corresponding Add-cap is being disallowed. In such case alternatively De-cap may not be done and assets serviced at historical cost.

11.6.5. Wagons/ locos are prone to accidents/ damage. Presently in case they become unserviceable, the asset is decapitalised and the capital cost reduced. However capitalisation of the replacement is not permitted. The assets continues to provide service without being serviced by beneficiaries. Capitalisation in such case may be allowed as replacements are necessary to operate plants at normative levels. In the alternative, at least the asset may be allowed to be serviced at its historical cost instead of replacement cost.

11.6.6. In order to ensure smooth transportation of coal matching the commissioning of the power plant, it has become necessary to fund rail infrastructure projects outside the power plant as infrastructure strengthening in some areas is not on the priority of the Indian Railways. Servicing of such capex towards developing rail infrastructure for smooth transportation of coal to station needs to be serviced as part of capital cost in tariff. Any benefit in the form of lower freight costs shall be passed on in tariff.

11.6.7. Expenditure towards major break down due to generator failures/ rotor breakdown etc. may also be allowed as it involves huge cost for repair/ replacement.

11.6.8. Expenditure towards systems/ equipment's installed at Switchyard incurred by the generator which are of nature of grid security or for grid monitoring purpose may be allowed.

11.7. **Initial spares:** may be allowed 2.5% of the capital cost to make the computation simple

11.8. **Condonation of Delay in New Projects:**

- Land acquisition, law and order problem, and change of course of river and ROW / ROU issues may also be considered as uncontrollable factor.
- Delay in appointment of new contractor in case of non-performance of original contractor may be condoned as NTPC being a PSU has to follow prescribed guidelines as the same is monitored by CAG, CVC etc.
- Delay due to failure on part of the contractor may be condoned as contract is awarded after prudent financial and technical evaluation.

11.9. **Treatment of IDC**: In case of delay, the methodology of computation of IDC which is disallowed corresponds to the IDC accrued during the period of delay beyond the SCOD. As an example, if there is a delay in six months on account of controllable factors, IDC accrued during last 06 months of construction period is deducted. This methodology is not fair towards the generator as IDC accrual in the last months is corresponding to the full capital cost whereas the delay may have occurred at the beginning of the construction period or in between. Therefore it is suggested that either IDC for the disallowed period may be deducted from capital cost on pro-rata basis (IDC disallowed = Total IDC x 6 / construction period in months) or alternatively, IDC disallowed may be equal to IDC accrued during the respective months when there was delay for the actual period of delay not condoned.

11.10. **Cut-off Date:** Works under original scope may be allowed after cut-off date. In case of delay beyond cut-off date the increase in cost due to delay may be disallowed. However, the original cost as per investment approval by the Board may be allowed as is being done by the Hon'ble Commission in case of delay of project from the SCOD.

11.11. **FERV/ Hedging Cost:** The treatment of extra rupee liability due to FERV may be continued and hedging cost if any may continue to be passed on.

11.12. **Special Allowance:** Special Allowance needs to be continued as it is the most cost effective option for continued efficient generation. Further, there shall be no increase and decrease in Capital Cost in case of add cap or de-cap in case of R&M except arising out of change in law. Special allowance should be delinked with DC as declaration of DC and utilization of Special allowance for Renovation and Modernization are inter linked. Also special allowance being part of fixed charges when billed on DISCOMs is eligible for rebate of 2% whereas special allowance is not considered for arriving at the 2 months receivables in the calculation of Interest on working capital. Since special allowance is a part of Annual Fixed charges, the same should also be considered for calculation of IWC

11.13. **Compensation Allowance:** The Compensation Allowance provided in the Regulations pertaining to coal based units from 10 to 25 years is for capital expenses of minor nature and is different from the purpose of providing O&M expenses which are of revenue nature. As such there is no overlap between the two as stated by the Consultation Paper. Moreover, Compensation Allowance is required to be provided in case of gas based plants (on similar lines as in case of coal based units) where the useful life has been extended from 15 to 25 years The compensation allowance provided by the Commission is inadequate and may be enhanced based on actual past data.

11.14. **Project timeline for different unit sizes, Greenfield / Brownfield projects:** The targets and timeline may be based on the past actuals as in most of the projects the time line are not being achieved by all generators.

11.15. Compensation allowed in case schedule generation is less than 85% is not adequate. The same may be enhanced based on actual; commensurate to deterioration in efficiency parameters.

11.16. **Roof Top Solar:** In certain stations, Environment Clearance for MOEF mandates installation of roof top solar. In such cases, the cost of installation of roof top solar and associated expenditure may be allowed as add-cap. Power produced from such roof top solar installations shall be supplied to beneficiaries free of cost.

11.17. **Flexible Operation:** In view of large-scale integration of renewables, certain thermal stations may be identified for flexing operations. Allow additional capitalization on such stations as part of the capital cost

Renovation &Modernization

1) *The generating companies and the transmission licensees are allowed to undertake renovation & modernisation for the purpose of extension of life beyond the useful life of the generating station or a unit thereof or a transmission system. The admissibility of the renovation & modernisation claim are required to be supported by Project Report containing information about reference date, financial package, phasing of expenditure, schedule of completion, useful life, reference price level, estimated completion cost, record of consultation with beneficiaries etc.*
2) *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.

3) *An alternative provision was made in the Tariff Regulations, 2009 in the form of special allowance to be allowed in lieu of R&M for coal/lignite based thermal power stations. This provision enabled generating companies to meet the requirement of expenses including R&M on completion of 25 years of useful life to a unit /station without any need for seeking resetting of capital base.*
4) *The old transmission lines and substations are sometimes inadequate to cater to the new demand due to capacity degradation and obsolesce of technology. However, construction of new transmission lines and sub-stations require high initial capital investment and substantial time towards seeking approvals, tackling right of way (ROW) issues and environmental clearances. R&M with and without up-gradation of existing projects is one of the cost effective alternatives to increase the power transmission capabilities. The upgradation of transmission line and substation to higher voltages has emerged as a viable alternative to cater to the load growth or transmission requirements. It also offers commercial advantages as some of the original foundations, structure, or equipment can be re-used with minimal modifications.*
5) *In coastal areas, line structures/ towers, hardware, conductors etc. get rusted due to saline atmosphere. Lines passing through chemical zones also require to be strengthened by stub strengthening, replacement of conductors, hardware, insulators, earth wire etc. The transmission lines which are in service for more than 25 years are affected due to atmospheric conditions and aging.*

Options for Regulatory Framework

6) *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 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.*

12. Comments / Suggestions - Renovation & Modernisation

12.1. Currently the incremental financial impact of running the old plants efficiently through utilization of provision of special allowance for R&M (Rs 7.5 Lakh per MW) is as low as 10 to 14 paisa per unit (in PLF range of 85% to 60%). For the plants which are operating at efficient levels should be allowed to continue with the existing provision of special allowance as allowed in the current Regulations.

12.2. However, in order to facilitate the optimal utilization of natural resources i.e. land, water and coal, it is suggested that in line with CEA Report (September, 2015) on "Replacement of old and inefficient sub critical units by super critical units/ retirement /renovation "the old & inefficient units with high station heat rate (SHR) above 2500 Kcal/kWh may be replaced with super critical units resulting in more generation of electricity per ton of coal. It will also reduce emissions (CO_2, SO_2, Mercury and NO_x) per unit of generation and save environment.

12.3. With proper and routine O&M and Renovation& Modernization after completion of useful life of 25 years, the performance of thermal units can be sustained without much deterioration for another 10 - 15 years. This has been demonstrated by many NTPC units that have already completed 25 years. Further, it is economical to run such units due to the lower capacity charges. The beneficiaries also benefit from the cheap power from such stations. The Tariff Policy also mandates that the benefit of depreciation should remain with the beneficiaries. However, smaller sized units (having heat rate greater than 2500 kcal/kwh) which have outlived their useful life and are still operational due to certain considerations may be replaced with larger sized supercritical units. Capacity addition is being done through supercritical technology and the older fleet of units would be retired based on case to case analysis. Continuing operation of units more than 25 years old and which are operating efficiently is in the interest of beneficiaries. Further, units older than 25 years may be renovated to meet environmental norms and to operate smoothly, and can be utilized for flexible generation. This will allow more efficient super critical units to be operated at full load at supercritical parameters at higher efficiency therefore resulting in more economical operation of the power system.

12.4. In view of the above, the dispensation of Special Allowance for units after 25 years needs to be continued.

12.5. In case of carrying out R&M on units older than 25 years, longer shut-down is required to be taken which is presently not provided for units availing Special Allowance. It is therefore submitted that recovery of Special Allowance may not be linked to target availability and may not made part of AFC.

Financial Parameters

1) The performance based cost of service approach, a combination of actual cost and normative parameters has been evolved for the Tariff regulations. Components like return on equity, operation & maintenance expenses and interest on working capital have been specified on normative basis whereas cost of debt has been allowed based on actual rate of interest on normative debt. The normative parameters are expected to induce operational and financial efficiency. While continuing with the hybrid approach, more weightage may be provided for normative parameters to induce greater efficiency during operation as well as in development phase.

Comments/Suggestions

Comments and suggestions are invited from the stakeholders for continuation of normative approach for specifying financial parameters and alternatives, if any.

13. Comments / Suggestions –Financial Parameters

13.1. Normative approach in case of cost of debt may also be introduced as the same would incentivize fiscal efficiency. Hon'ble Commission has fixed norms for almost all operational and financial parameters. In case of debt, it can be easily earmarked with benchmark lending rates. If a utility has tied up loans at higher rates in the past, it will force it to switch and shall lead to reduction in tariff for the distribution utilities. However while fixing the benchmark rates, cost of raising debt such as syndication cost, upfront charges, and commitment fees, guarantee fees, etc., should also be considered. The benchmark shall be uniform for all entities based on average credit rating of all the entities in the sector, provide for adequate margin to take care of fluctuations in the market interest rates and could be linked to publicly available benchmarks such as 10year Gsec bond yields or SBI 1 year MCLR rate.

Depreciation

1) *Depreciation is a major component of the annual fixed cost. Para 5.8.2 of the National Electricity Policy, 2006 provided that "depreciation reserve is created so as to fully meet the debt service obligation." The regulatory principle evolved over time stipulates that there should be enough cash flow available to meet the repayment obligations of the generating company or transmission licensee during first 12 years of operation. The depreciation rate has been considered based on the above principle. The Tariff Policy, 2016 stipulates that the Central Commission may notify the rates of depreciation in respect of generation and transmission assets and the rates so notified would be applicable for the purpose of tariffs as well as accounting.*
2) *The depreciation depends on three factors viz. rate base which includes subsequent additions also, method of depreciation and useful life. The following factors are relevant for determination of depreciation:*
    i. *The tariff setting approach, ROE based or ROCE based, has a bearing on depreciation. Presently Historical cost (HC) based approach for determining the rate base is in place*
    ii. *Straight Line method of depreciation has been used in all the four tariff periods. In the context of tariff setting, useful lives for all the technologies except gas based stations, have remained the same in all the tariff periods. For gas based stations, life of 15 years was used in tariff period 2001-04 & 2004-09. It was enhanced to 25 years in tariff period 2009-14 and continued in 2014-19 period;*
    iii. *With passage of time, the regulatory definition of depreciation, as pronounced in2009-14 tariff regulations viz. enough cash flow to meet the repayment obligations of the generator during first 12 years of operation, has gained precedence in tariff setting. Accordingly, depreciation rate is arrived at by considering normative repayment period of 12 years to repay the loan (70% of the capital cost).*

iv. In line with the tariff policy notified in 2006, to dispense with the provision of AAD (which was adopted during tariff period 2001-04 & 2004-09) and to have uniformity in depreciation rates for accounting as well as tariff setting, the aspect of fair life got delinked in 2009-14 and 2014-19 at least for first 12 years of operation, while setting the depreciation rates.

v. There are two sets of assets viz. those coming under cost plus (section 62) and others through competitive bidding (section 63). Further, within the subset of cost plus assets, many of existing units/stations have already outlived or will outlive their originally envisaged useful life of 25 years in the tariff setting period of 2019-24. Renovation and Modernization is allowed based on two approaches i.e. actual expenditure incurred and normative special allowance for coal based/lignite fired thermal generating station. In case of former approach, proposal includes estimated life extension wherein the calculation of allowable depreciation is feasible. However, in case where special allowance is allowed, itis not feasible to workout depreciation in absence of life extension.

3) The depreciation depends on three factors viz. rate base which includes subsequent additions also, method of depreciation and useful life. The following factors are relevant for determination of depreciation:

i. Additional capital expenditure at the end of life or special allowance approved in lieu of renovation and modernisation have consequential impact on the tariff duet recovery of depreciation over balance useful life

ii. Additional capital expenditure after allowing the special allowance has an impact on recovery of depreciation

iii. The useful life of Hydro Stations, as specified in Tariff Regulation, 2009, is 35years. However, the actual life of these Hydro stations may be much more than35 years. For hydro stations allowing higher depreciation rates during first 12years results in front loaded tariff. To keep the tariff on lower side, the depreciation rate for hydro stations could be spread over the entire useful life i.e.35 years. Similarly for thermal stations, the life may be more than 25 years and the International experience in this regard needs to be looked into to bring further improvements.

4) Section 123 of the Companies Act 2013, under Schedule II- provides life of Special Plant and Machinery, as 40 years for generation, transmission and distribution of *power whereas Part B of the same has linked useful life to be as specified by regulatory authority. The relevant portion of Part B is extracted under:*

"The useful life or residual value of any specific asset, as notified for accounting purposes by a Regulatory Authority constituted under an Act of Parliament or by the Central Government shall be applied in calculating the depreciation to be provided for such asset irrespective of the requirements of this Schedule".

5) *Books of Accounts are required to be prepared as per Ind AS (Ind Accounting Standard) for generators whose tariff is determined based on regulations notified by Commission. RBI's notification dated July 15, 2014 regarding flexible structuring of long term project loans to infrastructure and core industries covers power industry. Stipulations relating to depreciation have been laid down in Tariff policy notified on 28January 2016.*

<u>Options for Regulatory framework</u>

1) *Increase the useful life of well-maintained plants for the purpose of determination of depreciation for tariff*
2) *Continue the present approach of weighted average useful life in case of combination, due to gradual commissioning of units;*
3) *Consider additional expenditure during the end of life with or without reassessment of useful life. Admissibility of additional expenditure after renovation and modernization (or special allowance) to be restricted to limited items/equipment;*
4) *Reassess life at the start of every tariff period or every additional capital expenditure through a provision in the same way as is prescribed in Ind AS and corresponding treatment of depreciation thereof*
5) *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.*
6) *Reduce rates which will act as a ceiling*
7) *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).*

14. Comments / Suggestions –Depreciation

14.1. The existing provision of considering the weighted average useful life in case of combinations of units should be continued. In such an event, the depreciation shall be computed from the effective date of commercial operation. In case of combination of units of generating station or combination of transmission elements of transmission system, the effective date of commercial operation shall be worked out by considering the date of commercial operation and installed capacity of all the units of generating station or capital cost of all elements of transmission system, for which single tariff needs to be determined.

14.2. Restriction of Additional Expenditure after Renovation & Modernization (or Special Allowance) –

- It may not be practically feasible to cover all capex items under R&M or Special Allowance. Capital expenditure towards development of ash dyke, ash handling system including cost of land that may be required after 25 years and any expenditure required for additional BOP equipment/facilities would need to be considered separately as the same cannot be factored into Special Allowance. Further it would not be possible to estimate requirement of expenditure that may become inevitable on account of change in law in regard to environmental and pollution control necessitating up gradation of ESPs or other facilities.
- Besides, provision of compensatory allowance available to coal based stations from 11-25 years needs to be extended beyond 25 years as expenses for which compensation allowance is given would also continue to be required after R&M. For the extended life minor assets in nature of MBOA, Vehicles, Fire Fighting equipment and systems, medical equipment, safety equipment etc. also need to be considered along with the compensatory allowance.

14.3. For the assets that get added during the fag end of the life of the project, i.e., after 20 years of operation for thermal power stations and 30 years of operation for hydro generating stations and transmission projects, the generating company or transmission licensee, as the case may be, submits the details of proposed capital expenditure during the fag end of the project as per the existing provisions of the regulations. The Commission based on prudence check of such submissions approves the depreciation on capital expenditure during the fag end of the project. This be continued in accordance with the existing provisions of the regulations

14.4. Further, reassessing life at the start of every tariff period/every additional capital expenditure would lead to inconsistency and add to regulatory uncertainty.

- Reassessment of useful life can be made through RLA studies for various major equipment. However, RLA studies are very time consuming process and it may not practically possible to reassess remaining useful life at the start of the every tariff period. These studies are only done by few agencies only, other than the OEM apart from the time required for analysis of results and subsequent planning for modifications / replacement
- Again it may not be a practical way of reassessing useful life of the station on the basis of amount of additional capital expenditure alone and would be anomalous. For example, In a power plant having an capital cost of Rs.1000 crores, if additional capital expenditure amounting to Rs. 200 crores is necessitated for up-gradation of ESP for meeting a new pollution control norm, say at the 20th year, its life will not increase by 20% to 30 years (from 25 years). For enhancing the life, capital expenditure in R&M of BTG would be essential. Further, reassessing life at the start of every tariff period / every additional capital expenditure would lead to inconsistency and add to regulatory uncertainty.
- Since banks rarely extend loans beyond 10 years after moratorium, the increase in Plant life will lead to more cash out flow in the form of loan repayments and interest than the revenue received in tariff in the initial years.

14.5. Presently, tariff regulations have considered 12 years as repayment period and the rate of depreciation for plant and equipment has been set at 5.28%

for the initial 12 years. The weighted average rate of depreciation of the stations works out to around 5%. Depreciation is considered as deemed repayment for tariff purposes. However, in this approach, the total depreciation amount available with the developer in the initial 12 years is around 60%, which is less than the total debt of 70%. In essence, the depreciation provided in tariff to the developer is not sufficient for repayment of loans since the loan tenure now available is around 15years only including the construction period – leaving 10to 11years for repayment after COD. In view of the above, depreciation should be enhanced to cover the repayment of loan within 12 years. Therefore, depreciation rate of 5.83% (= 70% / 12) may be considered flat for 1st twelve years in order to make the computation simple and ease of computation. This would be especially useful in case of decapitalization of assets.

14.6. In Cost plus regime all prudent and legitimate costs have to be reimbursed especially when under recovery of fixed cost due to lower availability cannot be made up with increased availability. Therefore, unrecovered depreciation of the past period may be allowed for recovery if the unit is providing service beyond useful-life. During 2017-18 alone, the unrecovered depreciation for NTPC Stations total to about Rs. 360 Crs. Payment of unrecovered depreciation , if any, after the end of the useful life is considered reasonable and justified if beneficiaries utilizes the asset after the end of useful life.

14.7. Depreciation recovery of add cap necessitated at the fag end of the plant life may be allowed. Period of such recovery may be specified.

14.8. **Flexible Operation:** In view of large-scale integration of renewables, certain thermal stations may be identified for flexing operations. Higher depreciation in tariff may be charged from such stations (life as 75% of life of other stations)

Gross Fixed Asset (GFA) Approach

1) The Commission in the previous Tariff Regulations has adopted GFA approaches it incentivizes the equity investors to efficiently operate and maintain the infrastructure, even after the plant has been fully depreciated. The *internal resources generated by way of depreciation are reutilized for further capacity addition. CEA has estimated that in view of present demand growth rate and availability of commissioned and under construction capacity, no new coal based capacity may be required till 2027.*

Options for Regulatory Framework

2) 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.

15. Comments / Suggestions –GFA Approach

15.1. In the GFA approach, returns are provided on the normative equity base i.e.30% of cost of asset till it is retired. The interest on loan is being computed duly taking into account the loan repayment equivalent to the depreciation and considering weighted average rate of interest calculated on the basis of the actual loan portfolio at the beginning of each year applicable to the project.

15.2. The Commission in the Statement of Reason for Tariff Regulations, 2014 has discussed the issue of GFA vs Modified GFA in detail and has continued with GFA approach on the after giving due consideration to the fact that investors have made investments on a project based on GFA approach and changing the methodology of the existing projects will have detrimental effect on the returns on the investments. Also GFA approach provides reasonable quantum of internal accruals which the promoters utilizes for putting more capacity. A considerable quantum of equity would be required to put up solar or other RE based projects as well as for additional thermal capacities required for balancing. Such equity from internal accrual will be then utilized for RE investment.

15.3. The consultation paper has stated that GFA approach has been adopted in previous regulations as it incentivizes the equity investors to efficiently operate and maintain the infrastructure even if the plant is depreciated and internal resources generated are reutilized for further capacity addition.

With implementation of Saubhagya the demand is likely to increase and thus capacity addition would be required. If modified GFA is implemented there would be no incentive to maintain and run asset after recovery of depreciation. Stations may go into loss due to lower ROE and high under recovery in O&M / operating parameters. There exist greater risk of loss in such old plants in case target availability is not achieved due to certain reasons. If such old stations are closed , it would result in loss to beneficiaries as they may lose supply from cheaper stations. Besides this would affect the internal revenue generation and affect the capacity addition program of under construction projects. The tariff structure should be such that the promoter has to remain invested for entire life of the project to recover the initial investments. The regulatory uncertainties further increase the risk perception.

15.4. The present tariff structure puts the break-even point at around 68 % of DC under GFA approach, meaning that ROE is zero at this level of operation and only on achieving 85 % of DC; prescribed ROE of 15.5 % can be earned. If the Net Fixed Asset approach is followed, the owner's equity in the old power plant will get reduced to 10 % of the historical cost and it may be noted that the ROE is completely wiped off at a DC of around 78 % (i.e. drop in DC by 7 % from the current NAPAF of 85 % will make the ROE zero), Thus, any decrease in availability (DC) due to factors beyond the control of the generators, such as, fuel availability, logistics of fuel transportation, etc., or increase in O&M expenses over the normative O&M allowed in tariff, will not only result in complete erosion of return on equity but also will result in losses and negative cash flow due to which the business growth and survival can be dramatically affected.

15.5. The risks of operating the fossil fuel based power projects are much higher as compared to hydro, nuclear, renewable power projects and will continue to increase as the plants gets older and the NFA approach will totally dis-incentivize the promoters to continue and more and more generating assets may get stranded.

15.6. To further substantiate the above point, it is noted that under the Net Fixed Asset approach, the return on equity will be a much small percentage of annual fixed charges. The return on equity starts moving down as a percentage of the total cost of power from the 13th year through 25th year (end of the useful life) from 6.15% to 1.2%, whereas under GFA approach it slopes from 6.15 % to 3.47% in the same period.

15.7. Under NFA approach, developers will have no incentive for operating the plant at the optimum level. Stake of the project developer will reduce to just residual value of the plant and as a result developer may consider not adopting best O&M practice or incurring Renovation and Maintenance expenditure for life extension of the project. Rather, the promoters will prefer to close down the project. This may result in wastage of scarce national resources and hamper the economic growth in the country.

15.8. Generation are not permitted any return on the equity invested during the long gestation period when the project is under construction. The existing GFA approach to some extent mitigates the generating company for the returns the lost revenue which it was deprived upfront.

15.9. Sudden shift from existing GFA approach will also lead to :

15.9.1. Lack of confidence of the lenders (Domestic as well as Foreign) in power sector which would result in higher interest rates as compared to other sectors.

15.9.2. Financial covenants / projections at which the lenders have already invested will be impacted and this may not be acceptable to the existing lenders. It may impact the lender covenants of the company for future loans, wherein lenders may enforce strict covenants, charge higher rate of interest, seek security cover, etc. It will also reduce the amount of debt available in the market for the power sector.

15.9.3. Lower return on investment will shake the investor perception and result in lower market capitalization and affect the ability of company to raise funds from the capital market. NFA will lead to the equity erosion and reduce ROE to salvage value of the plant and will make even well managed generators unviable which as listed Companies will be very detrimental to investors.The infusion of further capital into the sector will also stop.

15.9.4. The existing lenders may even call back the loans owing to deterioration in Interest Service Coverage Ratio (ISCR) and Debt Service Coverage Ratio (DSCR) resulting from reduction in income.

15.9.5. The rating agencies will also view the reduction in income as a stress on profitability and this will impact the rating adversely triggering a cascading effect on the company's ability to mobilize debt resources. Thus, the entire investment in power sector by generating companies regulated by CERC, including NTPC, will be in jeopardy.

15.9.6. It may not be out of place to mention here that any reduction in the returns/ resources will be counter to the mandate of CERC to attract investment and generate sufficient resources for further growth in the sector as the Modified GFA or Net Fixed approach will drastically reduce the resources available for investment in power sector.

15.10. The other advantage of GFA approach is that it ensures the predictability of returns and thus provides the consistency under uncertain market scenario on long term basis.

15.11. Any change in the approach at this stage on such fundamental principle would severely affect the cash flow of power generators and would jeopardize their own existence and the power supply scenario in the country.

15.12. Therefore, in short, in the interest of the entire sector and to prevent the generation sector from becoming sick, it is submitted that the Hon'ble Commission needs to consider continuation of GFA principles in the Regulations for the 2019-24 period

Debt:Equity Ratio

1) *The capital cost for generation and transmission projects commissioned after 1.4.2019 is considered to be financed through a debt equity ratio of 70:30. Further, it is provided that if the actual equity deployed is more than 30% of the capital cost, the equity in excess of 30% shall be treated as normative loan whereas if the equity deployed is less than 30% of the capital cost, the actual equity shall be considered for determination of tariff. The above provision in Tariff Regulations is consistent with the principles laid down in the Revised Tariff Policy 2016.*
2) *Some of the utilities in private sector operate with a very high financial leverage. Also, it is observed that financial institutions are willing to extend finance up to debt equity ratio of 80:20 depending on the credit appraisal of the utilities. When demand for capacity addition is low, maintaining debt:equity of 70:30 may need review.*
3) *Further, for some of the old plants, the equity base has been maintained beyond 30% (up to 50%) for the purpose of fixed return to enable the developer to generate internal resource for further capacity addition. In view of availability of sufficient capacity in the market, there is a need for review of the same.*

Options for Regulatory framework

4) *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.*

16. Comments / Suggestions –Debt-Equity Ratio

16.1. Any change in the debt-equity ratio would also severely affect the internal resource generation for the power project developers and will affect the cash flows of the generators and this will jeopardize the lenders' covenants. This in turn will impact the borrowing program and thereby the growth plans of the sector. As the repayment capacity reduces, high leverage makes it riskier for the lenders. Lenders are not willing to provide the debt at higher leverage or they may insist for more stringent security, covenants and impose conditions curtailing the freedom of the company to carry out its business such as seeking prior permission of the lenders for different matters.

16.2. The Tariff Policy stipulation regarding D/E ratio as under:

"For financing of future capital cost of projects, a Debt: Equity ratio of 70:30 should be adopted." Thus, proposed D/E ratio of 80:20 is not in line with the Tariff Policy, which has stipulated D/E ratio of 70:30 for new projects.

16.3. Apart from above, following also needs to be kept in view:

16.3.1. Higher debt will increase IDC and consequentially the cost of project resulting in higher cost of power. Further, the rate of depreciation would have to be enhanced to avoid imbalance between the depreciation recovered and debt repayment obligation. The current depreciation rate of 5.28% for first 12 years will not be sufficient if debt component is increased to say 80 %. This may lead to front loading of tariff. Even in the present Tariff Regulations, only around 64 % of debt repayment is covered in the first 12 years and considering the average maturity of 10-12 years including construction period the depreciation alone is insufficient to repay the loans.

16.3.2. Further, increase in capital cost coupled with higher depreciation rate would unnecessarily put burden on consumers. Given the fact that operational risk are already very high in power sector due to fuel risk, land acquisition and other clearances and collection / recovery of dues from the beneficiaries; making debt equity ratio higher than 70:30 will add to further financial risk, leading to higher overall risk of the power sector. It would be difficult to raise the required debt for the planned capacity additions. With higher overall risk, debts may not be available to the power sector to the extent required and also the cost of debt will increase substantially to cover the additional risks of the lenders.

16.3.3. It is not out of place to mention that the health of the Discoms has put a lot of strain on the cash flows of the power sector and the collection period / liquidation of dues is on rise. The low turnover of receivables impacts the ability of debt servicing as well as increases the requirement of working capital for the sector. Already many banks & financial institutions are constrained to further lend to power sector due to NPAs and stranded / sub-optimal assets. With high leverage at 80:20, any small deterioration in the receivable position could trigger defaults in debt servicing by the generating/transmission utilities.

16.3.4. With high debt equity ratio, promoter(s) would have lower equity participation which would reduce the commitment of the developers and the developer may quit the project, in case project faces troubles. Considering the project life of ~25 years involving high investments, it may not be in the interest of power sector to further reduce the promoter's stake.

16.3.5. Also, increase in D:E from 70:30 to 80:20 will lead to more interest burden on DISCOMs and at the same time for gencos, there will be risk of breach of covenants tied up under existing loan agreements such as leverage ratio (Total Outstanding Loan/Tangible Net-Worth) not exceeding 2 or the Interest Cover Ratio not below 1.75 etc. Any such breach of covenants would give rise to the danger of lenders calling back the loan or the lenders stipulating more stringent covenants or seeking greater operational control over the generator.

16.3.6. Existing lenders who have agreed to lend at the debt-equity ratio of 70:30 may not give consent / agree for reduction in the equity portion of the promoters.

16.4. It is agreed that some of the plants in private sector used higher leverage for financing of the power projects. However considering the higher financial leverage from the existing level of 70:30, may only be reasonable if majority of developers/promoters can avail such financial leverage. The same would have been possible if the power generation sector would have been matured with lower level of associated risks. Also as on date considering the NPA levels, banks are also reluctant to provide loan to the infrastructure projects with increased risk profile. Considering the same getting loan at higher leverage than the existing level would not be feasible for the developers. Notwithstanding the above, the Regulations also does not restrict using the higher leverage and provides return on equity component lower of the actual or the normative equity of 30%. Therefore if a particular promotor is able to get higher leverage the benefit of the same would be passed on to the consumers.

16.5. In the Indian context, it is still difficult to get loans for infrastructure projects on long-term basis. As the maturity period of loans is generally not commensurate with the life of the plant short-term basis, the loan repayment may not be adequately covered through the ROE provided on the smaller rate base.

16.6. It may also substantially reduce the quantum of debt for the power sector, since the lenders while deciding on the quantum of debt give more weight-age to project with stable cash flows, to ensure timely debt servicing. The cash flows are to be generated by the project matching with debt servicing schedule. When elements of the capacity charges, such as, depreciation, interest on debt capital, O&M expenses, etc. are fixed on normative basis, the variability / mismatch in project cash flows would increase as opposed to tariffs based on actual costs. In such a scenario, increasing the debt-equity ratio would not be viewed favorably by the lenders as the risk of variability in cash flows increases the probability of credit default.

16.7. Further, domestic banks are constrained by and have already exhausted the individual company limits and sector limits under their prudential norms. Therefore higher debt cannot be sanctioned by the banks. Any increase in debt from the existing level will impact the entire financial sector in the country. The financial sector in the country is already facing a lot of pressure due to the poor financial conditions of the State Discoms. The scheme for Financial Restructuring of State owned Discoms also highlights the fact that existing condition of the power sector may have severe impact on the entire financial sector in the country. Therefore, the existing debt-equity level may be maintained.

16.8. As regard the issue raised on existing projects using higher equity over 30% for getting fixed rate of return, it is submitted that all such projects are very old and are facing considerable operational issues. Actual operational parameters (SHR, O&M, Auxiliary consumption etc.) of such projects are also higher than the allowed normative parameters. Also most of these projects are under Renovation and Modernization and subsequently, a considerable quantum of assets have been decapitalized, and the equity associated with such decapitalized assets have been removed. No returns are being allowed on the equity associated with such retired assets. Revising the debt: equity ratio for the old units will also not be in line with regulatory certainty and jeopardize the operations of these projects.

16.9. The consultation paper has stated that D/E ratio of old projects having D/E ratio above 30% up to 50% needs to be reviewed as there is no need for further capacity addition. Further, investment decision has been taken considering viability of project based on extant regulations. Therefore, D/E ratio of existing and under construction projects should not be altered as this would adversely impact the cash flow and stress under construction projects. Such old Stations may go into loss due to lower ROE and high under recovery in O&M / operating parameters. This would be a loss to beneficiaries as they may lose cheaper stations.

16.10. In order to provide regulatory certainty, it is proposed to continue with the existing Debt: Equity ratio provisions

Return on Investment

1) *In a cost plus tariff setting approach, the utilities are allowed to earn a reasonable return on their investments besides recovering all other costs incurred through tariff. The return on investment is allowed as a compensation to the investors for assuming the investment related risks. It is based on opportunity cost principle and risk premium. Under the concept of cost of capital approach, the rate of return is allowed on the basis of different components viz. return on equity, cost of debt etc. catering to the different types of investors.*
2) *Section 61 (d) of the Electricity Act, 2003 and Para 5.11 (a) of Tariff Policy2016 have laid down broad guiding principles for determination of rate of return. These have 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.*
3) *Over a period of time, allowing fixed rate of return on equity has evolved as an acceptable approach and the same has been followed by most of the State Electricity Regulatory Commissions. The RoE approach has been widely accepted by investors in the sector. The large scale investment in the power sector is*

attributable to the approach of fixed rate of return. The Commission had compared both the approaches, viz. RoE and RoCE while framing the Tariff Regulations for 2014-19 and decided to continue with RoE approach with the following observations in the Explanatory Memorandum;

> *"As the tariff is determined on multiyear principles, it is important to maintain certainty in approach over each control period to maintain the confidence of investors and regulated entities. In view of the fluctuating interest rate, shallow debt market and considering the financial health of Utilities and the other serious issues faced by Developers in sector such as fuel shortages etc., it appears that it is not the desirable to switch to ROCE approach and thus the Commission proposes to continue with the ROE approach for next Tariff Period. Further most of the stakeholders have suggested for continuing the existing ROE approach."*

Comments/Suggestions

4) *Comment and suggestions are invited from the stakeholders on the continuation of fixed rate of return approach or alternatives, if any.*

17. Comments / Suggestions – Return on Investment

17.1. The Commission in the existing provisions has considered Return on Equity approach in which the returns are provided upto the normative equity base i.e.30%. The interest on loan is provided separately on actual basis duly taking into account the loan repayment equivalent to the depreciation and considering weighted average rate of interest calculated on the basis of the actual loan portfolio at the beginning of each year applicable to the project.

17.2. The issue of ROCE Vs ROE has been raised and debated by the Commission during the framing of earlier Regulations. However, due to practical difficulties in implementing the ROCE approach, the Commission has continued with ROE approach so far.

17.3. Existing ROE model is fair and equitable. The actual cost of financing is charged from the beneficiaries and any savings resulting on account of refinancing / loan substitution, etc. during the currency of any loan is shared with the beneficiaries. ROCE model involves working out of the rate base and estimating WACC. Tariff calculations may become very complex in case ROCE approach is adopted. As per the current Tariff Regulations, the rate base changes on a year on year basis on account of liability discharge, addition of permitted capital assets, de-capitalization of assets, etc. Further, the debt equity ratio will also change every year due to repayments and consequently the WACC.

17.4. Further, the ROCE approach requires estimation of appropriate debt-equity ratio, cost of debt and Debt Beta corresponding to the debt-equity ratio, expected post-tax return on equity and equity beta corresponding to the debt-equity ratio.

17.5. Determination of Debt-Equity Ratio

The first challenge in estimation of appropriate ROCE is estimation of optimal debt-equity ratio for the regulated assets. In case the ROCE is computed on lower debt-equity ratio, the appropriate ROCE would be higher due to loss of tax-advantage of debt. On the other hand, higher debt-equity ratio would lower ROCE on assumption of larger tax advantage whereas the level of assumed debt may not be actually feasible or too costly. The calculation of post-tax interest rates are also subject to change, due to applicability / revision of the corporate tax rate from year to year.

17.6. Determination of Cost of Debt (for benchmarking)

In ROCE approach, the regulator has to estimate an appropriate cost of debt besides cost of equity to determine the allowed ROCE over the tariff period. CERC Regulations so far have allowed actual cost of servicing debt, which is most appropriate for Indian economy, where the interest rates have been fluctuating significantly. Further, the cost of debt varies amongst borrowers and it is influenced by large number of factors, such as, the credit rating, type of borrowing (i.e. project financing / borrowing on balance sheet strength), tenure of loan, floating / fixed rate, secured / unsecured loan etc. Further, the debt requirement of power sector is huge and the same cannot be catered by domestic banks and domestic capital market. The developers have to seek foreign currency loans from international markets, which carry currency fluctuation risk and sovereign rating risks. All these factors are beyond the control of the Utilities.

17.7. Under ROCE approach, return once fixed may result in under recovery to the project developers due to elements like floating rate of interest on loans, foreign exchange rate variation, etc. These elements are additionally recoverable from the beneficiaries under the current Tariff regulations. Under ROCE approach these elements have to be considered on a notional basis, otherwise it may result in under / over recovery from the beneficiaries.

17.8. In case of stringent benchmarking of cost of debt, financial planning for small companies or new entrants shall be difficult as the cost of debt will be higher as compared to large size companies. This shall be detrimental for new entrants creating an entry barrier for new companies and also will be in line with the Tariff Policy which encourages competition in the sector.

17.9. Merits of RoE Approach

In contrast, the Return on Equity approach has certain inherent advantages, as follows:

- RoE approach is transparent and fair for both developers and beneficiaries and it is very simple to adopt and can be aligned with the state of economy of the country in different tariff periods.
- In RoE approach, the Commission approves the normative debt-equity mix for the capital cost of project. Promoters would be free to have higher quantum of equity investments. The equity in excess of this norm should be treated as loans advanced at the weighted average rate of interest and for a weighted average tenor of the long term debt component of the project after ascertaining the reasonableness of the interest rates and taking into account the effect of debt restructuring done, if any. In case of equity below the normative level, the actual equity would be used for determination of return on equity in tariff computations.
- In RoE approach, it is simple to compute the rate base by applying the debt equity mix to approved capital cost of project
- In RoE approach the investor can be assured returns on equity investment if other things remain favorable.

17.10. Hence, considering the complexities involved in implementation of the ROCE approach and in view of the immature bond market and turbulent and volatile financial markets in India, it is suggested that RoE approach may be continued in the 2019-24 tariff period which would also provide regulatory continuity to the developers.

17.11. As the tariff is determined on multiyear principles, it is important to maintain certainty in approach over each control period to maintain the confidence of investors and regulated entities. In view of the fluctuating interest rate, shallow debt market and considering the financial health of Utilities and the other issues faced by Developers in sector such as fuel shortages etc., it is not desirable to switch to RoCE approach

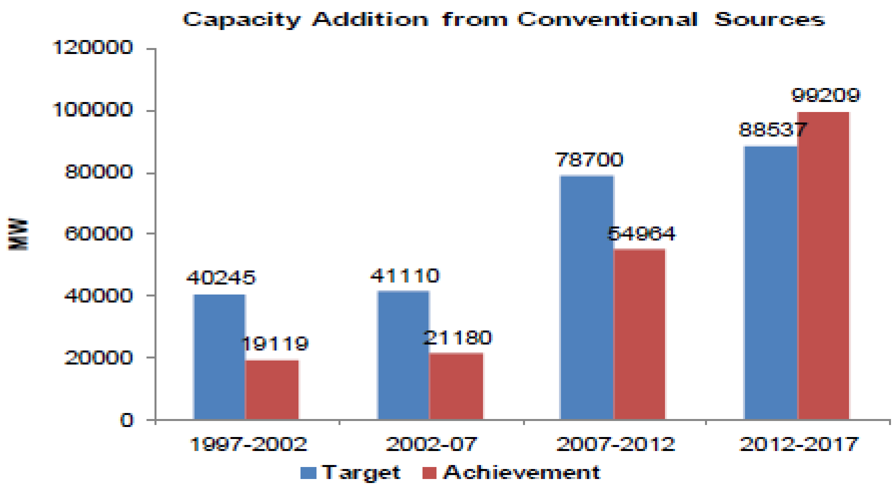
Therefore, the present approach of RoE may be continued.

Rate of Return on Equity

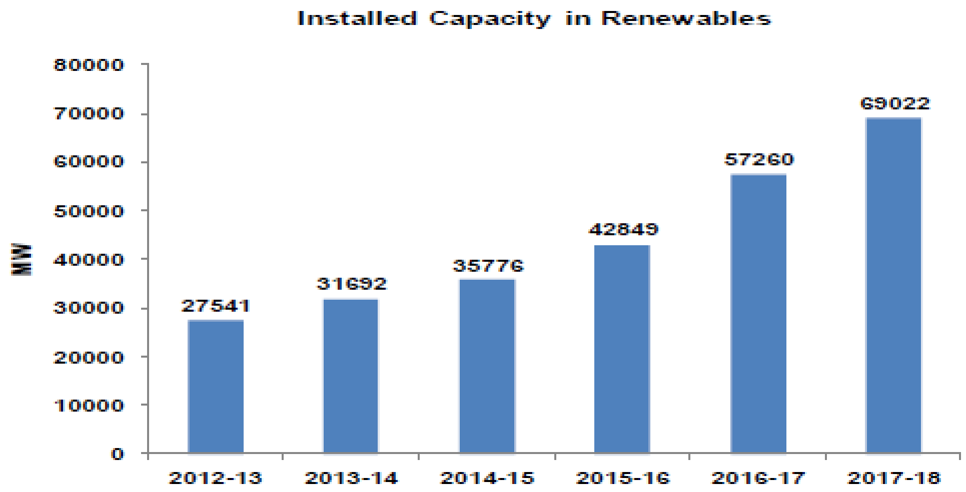
1) Return on equity is the return allowed to the ordinary shareholders on their equity investment in generation/transmission projects. To ensure that it is fair to both the investors and the consumers, the return allowed should be commensurate with the returns available from alternate investment opportunities having comparable risk. Different models viz. Discounted Cash Flows (DCF), Risk Premium Model (RPM), Capital Asset Pricing Model (CAPM) etc. are available for estimation of cost of equity/RoE. However, the Commission has been largely depending on the CAPM model for arriving at RoE during previous tariff periods.
2) The Commission had specified a post-tax RoE of 16% and 14% respectively for the tariff periods 2001-04 and 2004-09 respectively. For the tariff period 2009-14, the Commission had specified a post-tax base rate of 15.5% and allowed it to be grossed up by the applicable tax rate. An incentive of 0.5% was also allowed for the generation/transmission projects completed within the prescribed timeline. For the tariff period 2014-19, the Commission continued with the post tax base rate of 15.5% as allowed for 2009-14 tariff period with an additional 1% RoE i.e. 16.5% allowed for storage type hydro generating stations.
3) As per the present regulatory framework, the additional return on equity is allowed for all the units or the transmission elements irrespective of their size or length of line if such assets have been commissioned as per the timeline specified by the

Commission. The timeline applied is same irrespective of size of the project-length of line in transmission project or capacity of the unit in generation projects.

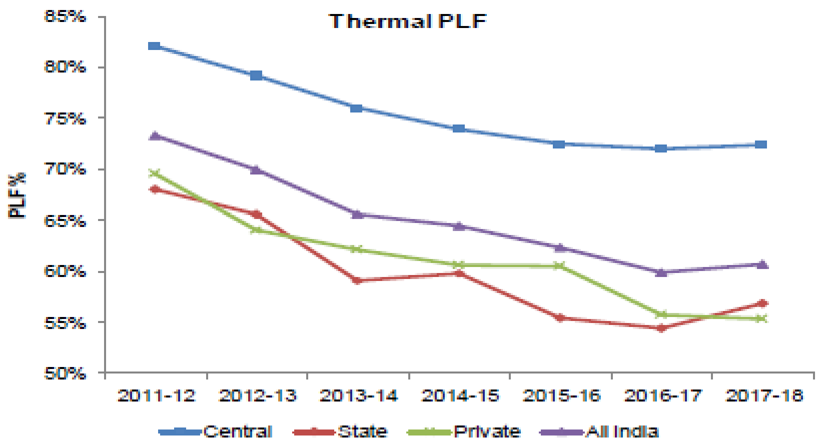
4) Further, the additional return of 0.5% is given to incentivize the project developer for timely completion. However, there is no disincentive for delay in completion of the project.
5) Following key trends have been observed during recent times: -
   i. The capacity addition (asper CEA report) achieved from conventional sources during the plan period 2012-2017 exceeded the target with more than 50% of the capacity addition coming from the private sector. Besides, there has been a rapid increase in renewable energy capacity addition.



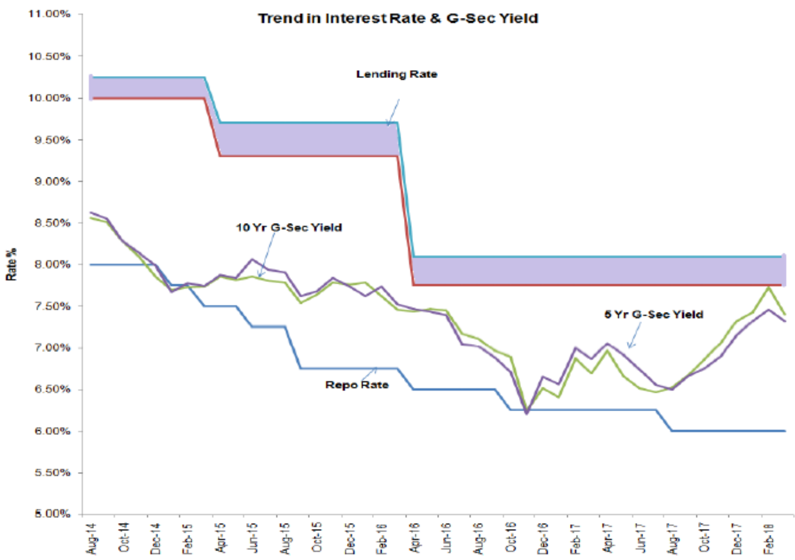
   ii. The draft National Electricity Plan 2016 of CEA has indicated that there will be no need for additional non-renewable power plants till 2027 with the commissioning of 50,025 MW of under construction coal based power plants and additional 1,00,000 MW renewable power capacity.



iii. The PLF of thermal power plant has come down steadily during last 4-5 years (as per CEA report), mainly due to higher capacity additions, low demand growth and increase availability of renewable energy.



iv. As per RBI database, notwithstanding the recent increase in the yield for 10 year benchmark government securities, the overall interest rate has shown a declining trend during the period 2014-19. The yield on 10 year benchmark Government Bond has come down to 7-7.5% during 2018 as compared to 8-8.5% during 2014. The RBI repo rate, interbank rate and SBI base rate have also come down during this period. With better control over inflation, the interest rates are expected to remain low and stable over short & medium term.



v. The Tariff Policy has mandated the distribution licensees to procure their future requirement of power through Tariff Based Competitive Bidding. The market forces are likely to exert downward pressure on the IRR of the new projects.

<u>Options for Regulatory Framework</u>

6) According to CEA, the capacity addition is no more a major challenge and adequate installed capacity (along with currently under installation) exists to meet the demand for the next 8-10 years. Further, the rate of interest has also come down in recent times. Therefore, there is market dynamics which favors reduction of rate of return. However, any such reduction will have negative impact on the equity already invested in the existing and under construction projects, creating further financial stress on such projects. Different rate of return for new projects (where financial closure is yet to be achieved), may be thought of, with different rates for generation and transmission projects.

i. Review the rate of return on equity considering the present market expectations and risk perception of power sector for new projects;

ii. Have different rates of return for generation and transmission sector and within the generation and transmission segment, have different rates of return for existing and new projects;

iii. Have different rates of return for thermal and hydro projects with additional incentives to storage based hydro generating projects;

iv. *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;*

v. *Continue with pre-tax return on equity or switch to post tax Return on equity;*

vi. *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;*

vii. *Reduction of return on equity in case of delay of the project;*

18. <u>Comments – Return on Equity</u>

18.1. Thermal power stations encounter certain operational risk which are unique and not faced by other segments of power sector. The sector is currently fraught with several risks such as non-availability of fuel, chances of default of the customers, delay in project clearances, dispatch of power, environment risks, etc. Apart from all existing risks, as compared to last control period, the uncertainties in the existing scenario has increased owing to the following factors:

18.1.1. Large scale penetration of renewable power – Existing + Planned

18.1.2. Flexible and cyclic operation by thermal plants

18.1.3. Uncertainties over adequate fuel availability and transportation

18.1.4. Various mechanisms being explored by the Commission which have lower certainty of fixed cost recovery for the projects.

18.1.5. Stringent environmental norms requiring retrofits at existing units

18.1.6. Deteriorated financial health of Discoms.

18.1.7. Supply overhang situation

18.2. Such changed dynamics in the sector impacting the existing as well as the upcoming capacities has actually increased the risk in the sector, this is also validated by increased level of NPAs and stressed asset in the power sector. Increased risk in the sector can also be validated by higher tariffs quoted under latest long-term Case-1 bids invited by Discoms**.**

18.3. Hence, there is a case for thermal power generators to be compensated for the higher operational risks by increasing the ROE by at least 6% (15.5%+6%)

18.4. Thermal generation projects are capital intensive and have long gestation period. Power plant development takes at least 8 years from conception to commercial operation. Actual expenditure starts much before the actual investment approval. In all cases equity deployment starts with land purchase and other development activities and debt is deployed only after investment approval.

18.5. Current CERC Regulations prescribe a Return on Equity (ROE) of 15.5% for thermal projects and timeline of 52 months from investment approval to commercial operation for a 660 / 800MW unit. As no return is allowed on equity during the construction period, the effective return on equitated Annualised ROE available to generator is only 10.39%. Further RE projects have 1/5th of gestation period as compared to Thermal stations. The risk weighted return in Power Generation should in no case be equated to return on financial instruments having no operational risk.

18.6. The risks in case of thermal projects are the highest in the entire power sector. Execution of power projects is fraught with various risks during construction period starting from land acquisition, environment forest and other clearances, contractor defaults, equipment delays, etc. Delay in COD leads to cost and time overrun resulting in effective return much below 11%.

S. No.	Delay in COD	Equated Annualized Return (%)
1.	No delay	10.39 %
2.	1 year	9.42%
3.	1 year (Cost overrun disallowed in tariff)	7.91%

18.7. Moreover, thermal plants are also faced with host of risks during the operational phase including issues of fuel and water availability, etc. leading to under recovery of annual fixed charges. NTPC Stations with FSA signed post 2009 have domestic coal linkage of 68% only. There has been a fixed charge under recovery of around 1444 crores in FY 2017-18. With tightening of operational norms, many stations failing to achieve these norms adversely impact the returns.

18.8. Effective ROE is less than 10% per annum and even after adding 8 GW capacity over last 4 years, PAT of the company has declined. Any further reduction in normative ROE will bleed the bottom line and Gross internal revenue may not be sufficient to service debt. Coupled with requirement of internal revenue of Rs 9000 crore per annum to support 13.9GW of capacity under construction, there could be threat of imminent rating downgrade. This will create challenges for raising financial resources and keep the Company afloat.

18.9. In a recent RE Regulation issued in March 2017, CERC allowed ROE of 14% considering Risk free rate of 6.85% and spread of 7.15%. In the rising interest scenario, the G-esc yield have widened to 7.80%. Considering the same spread, the ROE comes to 14.95%, say 15%. However, for longer gestation period of thermal projects, the existing ROE of 15.5% yields effective ROE of 10.39% only. In case the same is to be extrapolated to ROE of 14% for thermal stations, the effective RoE will be only 9.38%. **Thus, a further premium of 5% needs to be added to make the returns comparable.**

18.10. In view of the above, any lowering of prescribed ROE would lead to rating downgrade of the company and increase in interest costs. 100 bps increase in interest costs results in tariff increase by ~7 p/kwh. This would be an additional burden to the customer.

18.11. Investment decisions are taken after assessing the viability based on the extant regulatory provisions. Subsequently, after the investment is made, the parameters should not be changed. ROE and other parameters should be maintained for old projects.

18.12. Being a regulated entity operating in cost-plus performance based regulatory framework, NTPC plough backs the surplus it generates in capacity addition in the power sector and towards dividend payment to GOI. Already the country is facing shortages in many months of the year. Due to SAUBHAGYA and other initiatives of GOI, the demand for power is likely to go further up. There is requirement of investment in the generation sector. Other than from PSUs, no major investment has been announced in this segment in last 3-4 years. Therefore a favorable climate needs to be provided so the generation segment becomes attractive for investment.

18.13. It would be inappropriate to equate all infra projects for the purpose of ROE, since they have different gestation periods and risks (e.g. 14% ROE for solar equates to ~19% ROE for thermal projects)

18.14. Any reduction in ROE will also lead to :

18.14.1. Lack of confidence of the lenders (Domestic as well as Foreign) in power sector which would result in higher interest rates as compared to other sectors.

18.14.2. Financial covenants / projections at which the lenders have already invested will be impacted and this may not be acceptable to the existing lenders. It may impact the lender covenants of the company for future loans, wherein lenders may enforce strict covenants, charge higher rate of interest, seek security cover, etc. It will also reduce the amount of debt available in the market for the power sector.

18.14.3. Lower return on investment will shake the investor perception and result in lower market capitalization and affect the ability of company to raise funds from the capital market.

18.14.4. The existing lenders may even call back the loans owing to deterioration in Interest Service Coverage Ratio (ISCR) and Debt Service Coverage Ratio (DSCR) resulting from reduction in income.

18.14.5. The rating agencies will also view the reduction in income as a stress on profitability and this will impact the rating adversely triggering a cascading effect on the company's ability to mobilize debt resources. Thus, the entire investment in power sector by generating companies regulated by CERC, including NTPC, will be in jeopardy.

18.15. It may not be out of place to mention here that any reduction in the returns/ resources will be counter to the mandate of CERC to attract investment and generate sufficient resources for further growth in the sector .

18.16. **RoE should be allowed during construction. Alternatively RoE may be increased**

18.17. Around Rs. 3.20 Lakhs Crores is outstanding loan as on March-18 in Power CPSE which are under the ambit of regulatory framework. Any reduction in

ROE will lead to difficulty in servicing the debt and an imminent credit default risk. In addition, there are NPAs of over Rs.1.80 Lakhs Crores in power sector due to stressed assets making the sector unattractive from investment point of view.

18.18. **Grossing up of ROE**

At present RoE of 15.5% (post tax) is being allowed with a grossing up by Effective Tax Rate. Also at present, income tax benefit of Sec 80 (IA) is no more applicable. Accordingly, the approach of RoE (post tax) may be continued with grossing up of corporate tax rate.

Cost of Debt

1) *Cost of debt is the cost incurred by the utility in the form of interest payments and upfront fee for raising finances through debt. As per the prevailing Tariff Regulations, the weighted average interest rate calculated on the basis of actual loan portfolio of the utility is considered as the cost of debt. The cost of debt thus arrived at is applied on the normative outstanding loan to compute the annual interest expenses of the utility which is given a pass through in the tariff. This approach does not provide incentive to the utility to lower the cost of borrowings, as even higher rates are given as pass through in tariff.*
2) *Clause (d) of para 5.11 of Tariff Policy, 2016 has stipulated that the utilities should be encouraged and suitably incentivized to restructure their debt for bringing down the tariff. The Tariff Regulations for 2014-19 has provided that the regulated entities shall make every effort to refinance the loan to lower the interest costs. And for this purpose, while the costs associated with refinancing shall be borne by the beneficiaries, the savings on interest shall be shared between the beneficiaries and the utilities in the ratio of 2:1.*
3) *Following key trends have been observed during recent times.*
   i. *Regulated entities are availing long term loan from different sources viz. banks, financial institutions, debt markets both in India and abroad. The terms & conditions of debt including the interest rate varies across sources depending upon several factors viz. quantum, tenor, type, timing, etc. As of now utilities are predominantly borrowing from banks and other financial institutions for*

capital expenditure through non-standardized and negotiated bank loans in the form of corporate loan, project loans, syndicated loans etc. Long term credit rating of utilities varies across utilities. The interest rates at which funds are borrowed from banks/financial institutions/debt market depend upon the credit rating of the utilities.

ii. *As per RBI database, the size of the Indian corporate bond market vis-a-vis GDP is still low in comparison to developed and even several developing countries. However, corporate bonds outstanding as a % of GDP have grown from around 5% in 2012 to 23% during 2017-18. Further, amount of corporate loan raised through issuing bonds in primary market during last 7 years has grown at a CAGR of around 15%. Historically, the corporate bond market has been dominated by PSU's AAA and AA rated bonds. However, the trend seems to be changing with a number of mutual funds investing in debt portfolio with low rated bonds.*

iii. *As of now except the better rated utilities like NTPC Ltd. and PGCIL, others utilities are primarily dependent upon banks & financial institutions for meeting their loan requirement. However, with the strengthening of corporate bond market, it will provide an alternative for the companies to raise their finances.*

iv. *RBI has gradually revised its repo rate downward from 8% during 2014 to 6% in August, 2017. Since August 2017 RBI has maintained status quo in the policy rates based on the recommendations given by the Monetary Policy Committee (MPC) during its bi-monthly meetings. Further, RBI has introduced the Marginal Cost of Fund Based Lending Rate (MCLR) system during 2016 as an alternative to the base rate system for efficient transmission of policy rates into the money market. As a result, the bank lending rates have also reduced during this period.*

Options for Regulatory Framework

4) *While allowing the cost of debt as pass through, options available for regulatory framework are either to consider normative cost of debt based on market parameters or actual cost of debt based on loan portfolio. As the tariff is determined for multi-year period and cost of debt varies based on changing market conditions, linking cost of debt to market parameters such as MCLR & G-sec will bring a degree of*

unpredictability. The regulatory approach evolved so far has been to allow the cost of debt based on actual loan portfolio. This does not incentivize the developers to restructure the loan portfolio to reduce the cost of debt. The current incentive structure may need review to encourage developers to go for reduction of cost of debt.

i. *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;*

ii. *Review of the existing incentives for restructuring or refinancing of debt;*

iii. *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;*

19. Comments / Suggestions –Cost of Debt

19.1. Allowing normative rate of interest may be considered, as the same will incentivize fiscal efficiency. The existing Regulations has fixed norms for almost all operational and financial parameters. As rate of interest is a market driven parameter the same may also be easily earmarked with the market lending rates on appropriate basis. It is good time to shift from regime of passing the actual interest rates to the normative interest rate which will encourage the generators to better negotiate with the lenders to achieve lowest interest rates.

19.2. If a utility has tied up loans at higher rates in the past, through this approach it will force it to switch and shall lead to reduction in tariff for the distribution utilities. However while fixing the benchmark rates, additional cost of raising debt such as syndication cost, upfront charges, commitment fees, guarantee fees, etc., may be allowed separately on actual basis.

19.3. Further, with introduction of Marginal Cost of Fund Based Lending Rate (MCLR) system during 2016 as an alternative to the base rate system for efficient transmission of policy rates into the money market, the debt market has been matured for adopting normative benchmarking of interest rates.

19.4. Currently the incentive to lower the cost of debt is very nominal. It is suggested that investor may be provided greater incentives to secure lower cost of debt. Therefore, it would be beneficial to switch to normative cost of debt.

19.5. The benchmark shall be uniform for all entities based on average credit rating of all the entities in the sector, provide for adequate margin to take care of fluctuations in the market interest rates and could be linked to publicly available benchmarks such as 10year G-sec bond yields or SBI 1 year MCLR rate.As loans from banks are linked to MCLR, it is suggested to link the normative cost of debt to SBI one year MCLR + 400 bps. This would also take care of movements from time to time in the interest rate conditions.

19.6. Adjustment in cumulative repayment in case of de-cap may be continued. Specific provision is required in Regulations as regards to this.

Interest on Working Capital (IOWC)

1) *The working capital is separately specified by the Commission for coal-based or lignite-fired thermal generating station, open-cycle gas turbine/combined Cycle thermal generating stations and hydro generating station & transmission system. The working capital is determined based on fuel stock, inventory of maintenance spares, one month operation and maintenance cost and two months receivables depending on the type of thermal generating station, hydro and transmission projects.*

2) *The existing Tariff Regulations provides the definition of bank rate as the Base Rate of interest specified by the State Bank of India (SBI) from time to time or any replacement thereof for the time being in effect, plus 350 basis points. The Reserve Bank of India (RBI), vide ref. RBI/2015-16/273 DBR.No.Dir.BC.67/13.03.00/2015-16 dated 17.12.2015, introduced Marginal Cost of funds-based Lending Rate (MCLR). The new methodology for computing benchmark lending rates came into effect from April 1, 2016. The objective of MCLR is to get response of bank faster to policy rate revisions. As per the reference of RBI, MCLR will automatically apply to new loans. However, the existing borrowings linked to the Base Rate may continue till*

repayment or renewal, as the case may. Alignment of Regulations to above development may therefore, be required.

3) *Options for Regulatory Framework*

   i. *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 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.*

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

   iii. *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.*

   iv. *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 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.*

   v. *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.*

20. Comments / Suggestions – Interest on Working Capital

20.1. Maintenance spares are one of the major component of inventory to be maintained by a generating station to ensure reliable operation of the plant. Having adequate spares is therefore almost a compulsion, and cost of maintaining the inventory in terms of interest on working capital should be reasonably allowed. The same approach has been followed by the Commission till now.

20.2. Maintenance spares in working capital is the carrying cost of maintaining spares (of revenue nature) which would be required in case of breakdowns and preventive maintenance whereas maintenance spares in O&M expenses is revenue expenditure incurred during the year on account of consumption of revenue spares. Both are different and have no duplication whatsoever. So the separate provisions regarding maintenance spares in IWC and O&M expenses needs to be retained.

20.3. On the issue of review of linking of PAF with IWC, it is humbly submitted that it may be the case that PLF for many plants have reduced in future also the PLF of many high cost plants would remain low, however in view of not having certainty that at which point of time/month the PLF would be less (as the same is dependent on demand of the procurer, and therefore the generator has to maintain fuel stock for running the plant at least at 85% PLF and not on the lower availability/PLF.

20.4. Presently Regulations has fixed the cost of fuel to be considered for working capital requirements based on fuel price at the beginning of the tariff period. Even though the cost incurred towards fuel in all working capital components is based on current fuel prices whereas it is serviced in tariff at historical prices. Thus the variations in fuel cost is not factored in the IWC. Therefore it is suggested that fuel prices in IWC should be linked to actual fuel prices annually at the beginning of the year instead of fuel price in the beginning of tariff period. In the alternative, on a normative basis escalation factor of the past period may be used for escalation of fuel prices during the tariff period.

20.5. Generally, REA is issued by the 5th of every month and billing is done on 6th. Two days are allowed to the beneficiaries to make payment with a rebate of 2%. Therefore, receivables for 68 days are required to be provided instead of 60 days. In case more than 02 days are allowed in Regulations to avail full rebate by beneficiaries after the date of presentation of bills, the extra cost may be passed on in IWC.

20.6. Cost of coal allowed towards stock (15/30 day) needs to be considered as the same is technical requirement to take care of exigencies. Presently, if the generator is not able to maintain stock, the resultant risk of losing the availability is taken by generator. NTPC (including JVs) lost more than Rs. 1250 Crs in 2017-18 due to coal shortage. In case less stock is permitted resulting into less tariff for beneficiaries the resultant risk would also need to be taken by beneficiaries.

20.7. Cost of fuel considered in IWC for gas station is based on fuel type used. In such case, the cost of liquid fuel maintained at the station remains un-serviced. The same need to be considered based on stock actually maintained.

20.8. In order to align the Regulations, current normative rate of interest considered for IWC may be appropriately linked with MCLR. At present 350 basis points are allowed over the SBI base rate which is works out to 12.2% rate of interest for IOWC. Although market risk for power generating companies has increased, still keeping the same interest rate, mark up of 425 over the prevailing MCLR for 3 month tenure may be considered.

20.9. While computation of Working Capital is done, it is submitted that Special Allowance and taxes, duties and cess should be included in the receivables as Payment Rebate is allowed on the Billing which includes Special Allowance also.

Operation & Maintenance (O&M) Expenses

1) The Commission has notified normative O&M expenses for thermal generating stations and transmission system in the existing tariff regulations based on the data of 2009-10 to 2013-14. Presently O&M expenses have been specified on per MW basis for generation and per bay basis for the transmission system.

2) Some of the issues and challenges in fixation of O&M expenses norms are:

i. The fixed escalation rate used for arriving year on year O&M cost, takes into account WPI and CPI indexation. However, variations in WPI & CPI index pose challenge in specifying the fixed escalation rate for the entire tariff period. Further, the fixed escalation rate does not capture the variation due to unexpected expenses such as wage revision etc.

ii. *For new hydro stations whose COD was declared during the tariff period2014-19, the first year normative O&M has been specified as 4% and 2.5% of original project cost (excluding cost of R&R works) for stations less than 200MW projects and for stations more than 200 MW respectively. But O&M expenses could vary depending on the type of plant and number of units*

iii. *O&M expense of hydro stations is given as a percentage of capital cost, which is inclusive of IDC & IEDC. Thus, projects with substantial time & cost overrun get higher O&M*

iv. *There could be overlapping of the O&M expenses and the compensation allowance, due to overlapping of items covered under these two*

3) *O&M expenses vary if the dispatch of the generating station is continuously low, as in the case of gas/ naphtha based generating stations. In such cases, specifying recovery of O&M expenses based on installed capacity may need review*

4) *The O&M expenses of transmission substation comprises O&M expenses for transformer, reactors, bays, compensation devices, transmission lines, control room switchgears, DC system, switchyard etc. When the number of bays increases, there will be a corresponding increase in switchgear panel in the control room. However, there may not be increase in the capacity of transformer and other components of the substations. As an alternative, the O&M expenses may need to be worked out on the basis of MVA capacity instead of individual components else some weightage may be accorded to different components.*

5) *In case of expansion of capacity in existing generating station or existing transmission substation, the O&M expenses may vary on account of economies of scale. The O&M expenses have been rationalized by multiplying factor of 0.90, 0.85 and 0.80 to O&M expenses per MW depending on the size of the units. Rationalization similar to generating stations could be considered for the transmission system where the generating stations receive lower amount towards O&M expenses in case of addition of units in same generating stations as stated above. At the same time, different multiplying factor can be prescribed for different unit sizes even in case of the generating stations.*

6) *The O&M expenses of a generating station generally increase with increase in the life completed by it. That is to say, the new plants requires less O&M*

expenses whereas old plants requires higher O&M expenses. Specifying generic norms for O&M expenses for all plants irrespective of its life may need a relook.

Options for Regulatory Framework

1) *Review the escalation factor for determining O&M cost based on WPI & CPI indexation as they do not capture unexpected expenditure;*
2) *Address the impact of installation of pollution control system and mandatory use of treated sewage water by thermal plant on O&M cost*
3) *Review of O&M cost based on the percentage of Capital Expenditure (CC) for new hydro projects*
4) *Review of O&M expenses of plants being operated continuously at low level(e.g. gas, Naphtha and R-LNG based plants)*
5) *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;*
6) *Have separate norms for O&M expenses on the basis of vintage of generating station and the transmission system*
7) *Treatment of income from other business (e.g. telecom business) while arriving at the O&M cost*

21. Comments / Suggestions – O&M Expenses

21.1. Operation and Maintenance expenses are the expenses, which have to be incurred by a generator to maintain the health of the plant and sustain the level of operation. NTPC respectfully submits that the existing O&M norms and the resultant cash flow are grossly inadequate and do not cover all the costs that are required to be incurred. NTPC has suffered significant under recoveries of O&M expenses through tariff as given below:

Total NTPC Stations - O&M Expenditure Rs. Cr.

	Particulars	2014-15	2015-16	2016-17
A	Net O&M Expenses	8171.39	9206.83	9672.05
B	Total Normative O&M allowed	6451.84	7128.44	7773.54
C	Heads Passed on in Tariff	738.31	801.26	832.96
D=A-B-C	**Under-Recovery**	**981.24**	**1277.13**	**1065.55**

21.2. Inadequate provision of O&M expenses in the long-run severely affects the maintenance and life of the equipment necessitating higher replacement cost. A lower O&M cost norm would eventually result into higher R&M expenses, as the health of the equipment would deteriorate because of inadequate expenditure on the maintenance activities.

21.3. In order to maintain a plant in good condition and at sustained efficiency level, commensurate repair and maintenance would need to be carried out on a regular basis. In case plants are kept in a good condition, its life improves and it would be able to serve for a longer period in a reliable manner.

21.4. The Electricity Act 2003 under section 61 (d) provides that the Appropriate Commission while specifying the terms and conditions of determination of tariff shall be guided by, amongst others, the principle of safeguarding consumers' interest and at the same time, recovery of cost of electricity in a reasonable manner.

21.5. It may be observed that in spite of the improved productivity, there has been significant under recoveries in the O&M expenses because of the erroneous approach in fixation of O&M base cost and escalation rates. It may be appreciated that but for the improved productivity, the under recoveries would have increased further. The main reasons of the under recovery in O&M expenses of NTPC during the 2014-19 period are as under:

i. Non-consideration of variable pay (performance related pay), even though the same is considered as a cost to company package of employees under the DPE guidelines and being consistent with the industry practice

ii. Normalization of O&M expenses

iii. Inadequate provision of escalation rates adopted in tariff

iv. For determining the norms of O&M only stations with single unit type (size) configuration have been considered.

For 200 MW: Unchahar, Bokaro TPS, NLC, Bhilai NSPCL

For 500 MW: Simhadri, Talcher-Kanhia, Rihand

21.6. The fixation of O&M Cost basically consists of two parts:

21.6.1. Fixation of base O&M Cost for the first year of the tariff period: While fixing the base rate of O&M cost for the 2019-24 tariff period, the following may be considered by CERC.

21.6.1.1. **Inclusion of impact of pay revision in the base O&M expenses-** While fixing the O&M norm for 2019-24 tariff period, the impact of pay revision in the base year must be considered by the Hon'ble Commission. The pay revision is applicable from 01.01.2017 and therefore, its impact in the base year cost i.e. for FY 2018-19 must be considered.

21.6.1.2. **Variable Pay in the Base Cost:** The DPE Guidelines regarding pay revision provides that variable pay / Performance Related Pay (PRP) would depend upon financial and physical performance of the Company along with the performance ratings of the individual employee, and is integral part of the employee compensation package. It is therefore submitted that as PRP is part of compensation package of the employees and is considered in the CTC (Cost to Company) package of the employees (vide point (ii) of Annexure IV of DPE guidelines dated 26.11.2008), it should be allowed as part of employee expenses in tariff. Besides, this is also an industry practice.

Besides, PRP being part of the compensation package necessary for achieving targets of the organization set out by the Government and a tool to encourage individual employee's performance, is a **legitimate expense and cost to company** and should be considered as part of the employee expenses in a cost plus tariff approach while fixing the

O&M norms. This helps the organization to adequately reward good performance including cost cutting initiatives and drive performance culture in the organization. In turn, rationalizing manpower and improving Man: MW ratio over the years has resulted in reduction of employee cost and efficient operation lowering per unit cost giving direct benefit to the beneficiaries.

CERC has linked payment of PRP out of incentive earned for generation beyond 85% PLF. With increased RE capacity which is of must run category, the PLF and the corresponding incentive amount are bound to reduce substantially. Further, Performance of the company is not measured only in terms of PLF, but on an over all basis covering all dimensions of its operations. Since gains out of increased performance level and efficiency of plants/company such as savings in secondary oil consumption, reduction in cost of debt due to refinancing etc. are passed on to the beneficiaries, it is fair that the associated costs such as, PRP are also passed through.

The cost towards this is a genuine and reasonable cost and needs to be considered in tariff as mandated by Section 61 (d) of Electricity Act, 2003. In view of the above, it is submitted that the Variable Pay (Performance Related Pay) should be considered while fixing the norms of the O&M Cost for the period 2019-24.

21.6.1.3. **Change in approach for normalization of O&M expenses:** It is submitted that approach employed for normalization of actual O&M expenses to arrive at the base for setting O&M expenses for the tariff period 2014-19 was not appropriate as elaborated below.

The actual O&M expenses of 5 year period were normalized during the determination of norms for the tariff period 2014-19 by adopting the following procedure:

i. Any steep year on year increase in expenses incurred were normalized by escalating the previous year value by the average escalation rate determined for FY 2008-09 to FY 2012-13 which works out to be 7.01% (WPI) and 10.30% (CPI)

ii. Employee expenses of 2008-09 was generally higher than 2009-10, in such cases the actual O&M expenses for FY 2008-09 was derived by discounting the normalized O&M expenses for FY 2009-10 by 10.30%.

iii. Abrupt increase in security expenses in FY 2009-10 was normalized considering the net impact of introduction of service tax.

On account of the normalization in O&M expenses, the actual increase in O&M expenses during the previous tariff period for determination of base O&M expenses was not captured correctly.

An alternative to this approach would be to ascertain the overall five-year CAGR for the previous tariff period while determining the base O&M cost. If this five-year CAGR in growth of O&M expenses is within a reasonable range, then the same must be allowed. On account of normalization on year-on-year basis, the actual growth in O&M expenses is not captured correctly in the base. This leads to a low base cost for the future tariff period, which is not a true picture of the actual base O&M cost.

21.6.1.4. **Increase in sample set for consideration of norms for 200 MW and 500 MW:**

In the present approach, while determining the base O&M expenses for the respective unit size, only single-size unit type plants have been considered. The combination plants have been excluded while determining the base O&M expenses. For determining the norms of O&M expenses, only stations with single unit type (size) configuration have been considered.

- For 200 MW : Unchahar, Bokaro TPS, NLC, Bhilai - NSPCL
- For 500 MW : Simhadri, TalcherKanhia, Rihand

This makes the sample set for consideration of base O&M expenses really small and deviations in other combination plants are totally excluded from the base. Therefore, the complete data set of 200 MW and 500 MW plants is not captured while ascertaining the norms for 200 MW and 500 MW. This has to be broad based considering all NTPC stations.

21.6.1.5. **Inclusion of certain legitimate expenses:**

Following components of actual O&M expenses were not considered for formulations of norms:

i. Ex-gratia, incentives, productivity linked incentives and performance related pay were not considered as the same should be paid by the generating company from the increase in revenue due to reduced down time and efficient plant operations

ii. Community Development Expenses, Provisions, Loss of Store, Donations are expenses that cannot form a part of O&M expenses

iii. Expenditure of Capital nature as per accounting practice not claimed/disallowed in capital cost – Capital expenditure as per accounting practice which is either not claimed or disallowed in capital cost are not included in O&M expenses either and remain un-serviced in tariff .

The issue of PRP has been discussed in detail above. It is to be noted that community development expenses as part of the CSR activity is a legitimate expense and cannot be met from the profit generated by the company as is understood. Likewise, non-consideration of provisions in the base O&M expenses, reduces the overall O&M expenses of the company in the future years when the expense is actually incurred.

21.6.2. **Determination of escalation factor for the tariff period: Factors to be considered:**

21.6.2.1. In order to arrive at the actual O&M expenses, actual escalation factors for the period linked to WPI and CPI may be considered.

21.6.2.2. **Weightage of indices (WPI and CPI) to capture the actual escalation pattern:**

The percentage share of each of these categories of expenses in the total O&M expenses is as follows:

Employee Cost:	45-50%
R&M:	30-32%
Station overheads:	17-20%
Water charges:	4-7%

Since Employee Cost forms the major part of the O&M Cost, correctly capturing this element is essential for fixation of norms of O&M cost. While doing so, the following factors must be considered.

The employee salary & wages in a PSU like NTPC is decided by Department of Public Enterprises (DPE), Govt. of India, which is revised from time to time. As per the wage structure of PSUs, in order to compensate for the inflation/ price rise, the Dearness Allowance component (as % of Basic pay) payable to the employees is revised every quarter based on AICPI (IW) notified by Ministry of Labour.

Various elements of compensation package of the employee such as salary, PF, Gratuity, and other retirement benefits are dependent on the total salary (Basic + DA) and whereas the perquisites, allowance and HRA are linked to basic pay. Station overheads also comprise 60-70% of total overheads as salary on account of security, corporate offices etc. It is also seen that R&M expenses also comprise 50% of total cost towards the labor cost which is again linked to the man power cost.

Hence there is a case to suggest that Hon'ble Commission needs to consider adequate weightage of manpower related cost in the O&M expenses and needs to provide appropriate weightage to the salary growth into the escalation index.

Based on the above analysis, it can be construed that around 50% of the total O&M cost is directly related to manpower cost engaged in O&M activity of power plant and this manpower cost is generally increasing at about 7% per annum which is beyond the control of the generating companies.

Considering the above, it is felt that the current practice of weightage of 60% to WPI and 40% to CPI does not capture the reality in case of escalation of actual O&M expenses and it is suggested that the weightage of CPI should be at least 80% for capturing the escalation of the O&M expenses.

The actual increase in O&M as per data (2012-13 to 2016-17 without pay revision impact) submitted to CERC is 9.34% per annum as compared to 6.28% increase allowed p.a. by CERC under the current period. After including data for 2017-18 and 2018-19, the increase is going to be even higher

21.7. **Additionally, following need to be considered.**

21.7.1. Impact of GST on the O&M contracts, etc. to be included – GST became effective from 01.07.2017. The impact due to the change in law including GST needs to be considered separately while arriving at the base O&M expenses for the next tariff period. Averaging the O&M expenses for the 5 year would not capture the impact of GST which has been effective on for 6 months in FY 2017-18.

21.7.2. Capital spares on the normative basis based on the past data (0.55 lakh/ MW/year): The Commission up to 31.03.2014 has considered the capital spare consumed as part of O&M expense and has been included in the norm prescribed. Fixation on normative basis simplifies the tariff determination process as well as incentivizes savings. The same for 2019-24 prescribed on normative basis as Rs. 0.55 lakhs per MW per year.

21.7.3. **Ash Transportation Expenditure -** MOEF notification dated 25.01.2016 stipulates that cost of transportation of ash for road construction projects or for manufacturing of ash based products or use as soil conditioner in agriculture activity within a radius of 100 Km from a coal or lignite based thermal power plant shall be borne by such coal or lignite based thermal power plant and the cost of transportation beyond the radius of 100 km and up to 300 km shall be shared equally between the user and the coal or lignite based thermal power plant. The Commission has already allowed transportation cost of ash in case of some generating companies. The same may be uniformly applicable to all generators by provision in the Tariff Regulations for 2019-24.

21.8. **Alternatively, the Hon'ble Commission may fix norms on station to station basis based on past actuals as is being done in case of NHPC.**

21.9. **Fixation of O&M Cost Norm for Gas stations:**

While fixing the O&M cost norms for the gas stations, CERC may consider the following:

For the gas stations of older vintage, availability of spares is a major issue. In most cases, because of obsolescence and rapid change in technologies, spares availability is likely to emerge a major challenge in maintenance of these stations. CERC has been pleased to acknowledge this aspect and has allowed O&M Cost to some gas stations based on Long Term Service Agreement (LTSA) entered by such utilities. All the gas turbines stations need to be provided adequate coverage on uniform basis. The O&M expenses or repairs and maintenance expenses worked out on LTSA basis for a subsequent or new vintage should automatically be extended to the stations with older vintage as they are likely to face higher obsolescence as compared to the stations with newer vintage. Besides the machine size for older vintages is also lower. Therefore the norm of O&M expenses for such machines should be higher as compared to the machines with newer vintage.

21.10. **Flexible Operation -** In view of large-scale integration of renewables, certain thermal stations may be identified for flexing operations. Separate relaxed operating and O&M norms may be prescribed for such flexing stations or a normative per unit charge may be prescribed which shall be paid from the RLDC pool account as these units shall provide service to the Grid as a whole. As all thermal plants would need to flex to absorb variations of RE and low PLF regime which would impact the life of the machine and increase maintenance cost, it is submitted that O&M expenses may be scaled by 20% to address increased O&M expenses.

21.11. **New Environmental Norms -** Specific provision to allow expenditure towards installation of systems / equipment to comply the new environment norms may be provided. In addition increased O&M expenditure, consumption of chemicals, compensation for shutdown period and APC should also be allowed. Stations that make themselves compliant with new norms shall have higher ECR and put them in disadvantage vis-à-vis other stations. Accordingly, a mechanism may be developed so that stations with environment compliance systems may be preferable in MoD. It is suggested that the impact may be made part of Fixed Cost so the ECR remains unchanged.

21.12. **Taxes, Duties, Cess, etc.** - NTPC is recovering the expenditures on account of cess, duties etc. directly from the beneficiaries and these expenditure doesn't form part of O&M expenditure. Accordingly, the present mechanism may be continued and specific provision for pass on of these expenditure may be include in the Tariff Regulations.

21.13. **Escalation Factor for O&M Expenses -** The escalation factor based on actual escalation indices CPI and WPI in the last 5 years may be considered for fixing the normative escalation factor for O&M expenses. The normative escalation factor may be fixed with appropriate weight-age assigned to CPI and WPI. The suggested weight-age may be 80:20 for CPI : WPI. More weightage is provided to CPI as O&M expenses consists largely of employee expenses which is linked to CPI. Further, a provision may be provided in the Regulations to address sudden abrupt escalation due to unavoidable and uncontrollable factors including wage revision, change in law, service tax, duties and other statutory provisions. A provision to review the escalation rate may be provided in the Regulations if the variation between actual and normative escalation is more than 20% in any year.

21.14. **Impact of installation of pollution control system and mandatory use of treated sewage water by thermal plant on O&M cost -** In case of power plants which are within the specified municipal area, use of sewage water by power plant is mandatory as per law. As this is specific to certain plants, the same may be dealt on similar lines as in case of water charges. The cost of sewage water along with incremental cost incurred on account of treatment of the sewage water needs to be provided separately.

Similarly, O&M expenses norms need to factor additional expenses on account of installation of pollution control system including FGD and De-Nox systems anticipated in the tariff period 2019-24. Liberty may be provided to the generating company to approach the Commission with actual data in due course of time. Recommendation of CEA in this regard may be sought.

21.15. **Review of O&M cost based on the percentage of Capital Expenditure (CC) for new hydro projects -** In case of hydro projects, delay in COD is more likely due to geological surprises, land issues, environmental and forest issues. However, if the capital cost is allowed by the Commission after considering uncontrollable factors, then it would not be justified to reduce O&M expenses which is initially fixed as a percentage of capital cost. In any case, the norms are fixed by the Commission based on actual in the next control period.

21.16. **Review of O&M expenses of plants being operated continuously at low level (e.g. gas, Naphtha and R-LNG based plants) -** In case of continuous operation at low load, there is no change in the employee expenses and overheads cost component of O&M expenses which are essentially fixed in nature and not dependent on PLF. On the other hand, in case of cycling operations involving shut-downs and start-ups, R&M expenses would increase. With increased penetration of RE, cycling operation by gas stations is expected to increase further. The Consultation paper has also suggested that gas plants may be employed by the system operator for balancing purposes in the future. Therefore, it is submitted that there is need to study the actual impact on O&M expenses that is anticipated on account of increased cycling of gas plants to meet peaking and balancing requirement in the coming tariff period.

21.17. **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 -** When O&M norms are based on the past actual O&M expenses data of the station, the economy of scale on account of similar sized units is already factored in the data. Therefore, the rationale of reduction of O&M expenses by a multiplication factor is logically flawed. Therefore, it is submitted that multiplication factor may be restricted to upcoming units which achieved COD in 2019-24. The same may not be applicable to units already in operation and included in the base for working out the normative expenses.

21.18. **Have separate norms for O&M expenses on the basis of vintage of generating station and the transmission system -** Separate O&M norms for very old stations like Tanda and TTPS may be continued till they are phased out as per the CEA recommendation. As these plant are old increased O&M expense re required to sustain high operating PLF.

21.19. **Additional O&M Expenses for NTECL Vallur –** Additional O&M expenses may be provided to sea water based coastal plants in order to undertake frequent anti- corrosive painting of various structures, pipelines and equipment of main plant and off-site in view of the corrosive atmosphere. Further, use of special facilities like grab and pipe conveyor also require increased O&M expenses.

Fuel - Gross Calorific Value (GCV)

1) *Gross Calorific Value (GCV) in relation to thermal generation has been defined in successive tariff regulations issued by the Commission since 2001 as "the heat produced in kCal by complete combustion of one kilogram of solid fuel or one litre of liquid fuel or one standard cubic meter of gaseous fuel, as the case may be". GCV is used to compute the Energy Charge payable by the distribution companies/power utilities to the generating companies. The normative energy consumption admissible per unit of electricity generated has been specified by the Commission in the tariff regulations as normative Station Heat Rate (SHR) in terms of kcal/kWh. The ratio of SHR and GCV gives the quantity of coal used per unit of electricity generated. Therefore, GCV being used for the computation of energy input becomes extremely important as any increase/reduction in GCV decreases/increases the admissible coal consumption affecting the cost of power.*
2) *Energy Charge constituting about 60-70% of the total cost of generation tariff has major impact on cost to end consumers. In order to balance the interest of both*

the generating companies as well as the distribution companies (and ultimately the end consumers), the measurement of GCV of coal used needs to be as accurate as the true representative of the coal consumption is required.

3) *GCV of coal is measured at different points and accordingly, various GCV terminologies are used namely "GCV As Billed", "GCV As Received" and "GCV As Fired". "GCV As Billed", also called as "Invoice GCV" is indicated by the suppliers in the dispatch invoice and payment for the coal is made to the suppliers on the basis of "GCV As Billed". However, "GCV As Billed" is based on GCV measured in a controlled environment. "GCV As Received" is GCV measured at the generating station upon receipt of coal in the station. "GCV As Fired" is computed before feeding coal into coal bunkers of the generating unit for power generation.*
4) *The "GCV As Billed" is indicative of total energy content dispatched by the suppliers and normally paid for by the recipient stations. The "GCV As Received" is expected to be same as "GCV As Billed" barring minor transit losses. "GCV As Fired" is computed at the time of actual use of coal in the generating unit for power generation. For a coal consignment, "GCV As Fired" would be equal to "GCV As Received" minus the heat loss due to storage, as coal may undergo certain quality changes/degradation over the storage periods.*
5) *In the entire value chain from mine end to generating station end, the loss of GCV can take place on account of grade slippage at mine end, during transportation(transit with railway) and during storage (at generating stations). The generating companies generally have no control over the grade/GCV of coal received at their generating stations. There are several cases of grade slippages between the mine mouth and at the site of generating stations. Further, there is loss in GCV during transport of coal through Railway. Therefore, the generator may receive lower energy than what was billed by the coal companies. These are beyond the control of the generating companies.*
6) *Since the cost of slippage in grade of coal between the loading point and the site of generating station is ultimately passed on to the beneficiaries, this issue needs to be looked at in terms of risk allocation between the coal company, railways and the generating stations.*
7) *In case of imported coal, sampling and proximate analysis are being done at Free on Board (FOB) and at Cost Insurance Freight (CIF). The coal is transported by*

rail from port to the generating stations. Since the existing regulatory framework provides that the GCV is to be measured as on received basis at generating end, the same is followed for imported coal too. In case of imported coal, the GCV measurement is followed on Air Dried basis at CIF for billing purpose, whereas in case of domestic coal, the same is measured at the mine end.

Options for Regulatory Framework

1) *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.*
2) *Similarly, specify normative GCV loss between "As Received" and "As Fired" in the generating stations.*
3) *Standardize GCV computation method on "As Received' and "Air-Dry basis'' for procurement of coal both from domestic and international suppliers.*

22. **Comments / Suggestions – Fuel – GCV**

22.1. It is seen that from the discussions at various forums that there is a need to bring in clarity on this issue

22.2. In order to further understand the process of GCV measurement and payments methodology following may be considered :

22.2.1. **Moisture in Coal:** There are different ways of representing the moisture content in coal. Coal is heterogeneous mixture and hydroscopic in nature. Moisture in coal consists of inherent moisture (IM) and surface moisture (SM). Total moisture (TM) is a sum of inherent and surface moisture. Inherent moisture is an integral part of the coal seam in its natural state. The surface moisture is extraneous, which exists on the surface of coal and can be removed by evaporation at room temperature. Further, Equilibrated Moisture (EM) means the moisture content, as determined after equilibrating the coal sample at 60% relative humidity (RH) & 40 degree

Centigrade (as per IS:1350 Part I – 1984). Standalone GCV number has no meaning unless the moisture basis is simultaneously indicated.

22.2.2. **GCV of Coal:** Likewise, GCV of coal can be declared on various "basis" like "GCV on Air Dried" basis, "GCV on Equilibrated Moisture" basis, "GCV on Total Moisture" basis and "GCV on as Received" basis. "GCV as billed" by the coal companies is on EM basis. **It may be noted that GCV measured in the Bomb Calorimeter is always on "air dried basis" and is converted from one to another basis based on the percentage of various type of moistures present in the raw coal sample as per the following formulae.**

22.2.3. **Conversion of GCV:**

$$\frac{\text{GCV (TM) basis}}{(100-\text{ TM})} = \frac{\text{GCV (AD) basis}}{(100-\text{ IM})} = \frac{\text{GCV (EM) basis}}{(100-\text{ EM})}$$

For illustration, a typical coal sample (G11 grade) of say GCV of 4150 Kcal /Kg on EM basis and following moisture values on analysis can be represented by the following GCV measured on different basis:

Equilibrated Moisture (EM) - 5% (at 40 degree centigrade & 60 % RH for 24 hours as per IS 1350 part II)

Total Moisture (TM) - 11 % (as per IS 1350 part –II)

Surface Moisture (SM) – 7 %

Inherent Moisture (IM) - 4 %

GCV (EM basis) = 4150 Kcal /Kg

GCV (TM basis) = 3887 Kcal /Kg

GCV (Air Dried Basis) = 4193 Kcal /Kg

i.e., coal with same heat value (Kcal) received at station end will have less GCV (Kcal/Kg) (on TM basis) when compared to GCV (Kcal/Kg) on EM basis, which is provided by CIMFR and is used for coal billing by the coal company. Thus the same coal will show a GCV of 4150 kcal/kg on EM basis, GCV of 3887 kcal/kg on TM basis and GCV of 4193 kcal on AD basis.l

22.3. It may be concluded from above that for the same coal sample, GCV as on TM basis is less than "GCV on EM basis" i.e. "GCV as Billed" typically by around 280 to 350 kCal/kg depending up on the values of TM and EM.

22.4. **Mine end Sampling and GCV determination :**
Samples are collected by third party agency i.e. CIMFR is from wagon top for GCV measurement at mine end and total moisture, equilibrated moisture and GCV on Equilibrated Moisture basis are declared. Coal bills are raised by Coal companies to power utilities as per GCV grades/ price notification, which are based on the GCV on EM basis in line with the provisions of FSA.

22.5. **Station end Sampling and GCV determination :**
The coal when received at power station is again sampled from the wagon top by Third Party agency, i.e. CIMFR and total moisture, equilibrated moisture and GCV on EM basis are provided by them to the power utilities.

22.6. Coal as fired at the power station end contains both surface moisture and inherent moisture. Some of heat value of coal is lost as latent heat to evaporate surface moisture. Hence, the available useful heat for power generation is accordingly lower than the heat value of the coal. Hence, GCV on TM basis is lower than the GCV on EM basis i.e. GCV as Billed and "GCV on TM basis" is considered for computation of energy charge rate and used for billing purposes to beneficiaries.

22.7. **Loss of GCV inside a power plant:** It has been observed that there is a loss of GCV from point of "as received" to the boiler where coal is fired inside a power plant mainly due to following factors:

22.7.1. **Factors affecting GCV of coal sample taken from Wagon Top:** GCV is computed based on the wagon top sampling. During transportation of coal due there is a tendency of heavy ash/stones/ moisture to settle at the bottom and loss of moisture due to evaporation from the top layer of coal due exposure to atmosphere. As a consequence, wagon top samples give more GCV value than the representative value of total coal in the wagon.

22.7.2. **Loss in GCV during coal storage inside power plant:** There is a loss of GCV for the coal in stockyard inside the power plant, mainly due to oxidation and weathering effect. Further, rate of loss in GCV is more during initial period of storage, mostly due to loss in volatile content.

22.7.3. **Reduction in GCV during handling inside power plant:** GCV of coal decreases from unloading point to the boiler. There are minor unavoidable losses inside the power plant on account of handling of coal starting from unloading point to the boiler, mainly due to dust suppression measures used around coal conveyors and transfer points, loss in volatile matter during crushing of the coal, etc.

22.7.4. As GCV as fired is same as the GCV on TM basis and NTPC is having no control over it, difference on account of basis of measurement of GCV needs to be recognized while billing to the beneficiaries.

22.8. In view of the above it is submitted that :

22.8.1. Generator has no control over the grade slippage during transit and payment to the coal companies is made by the generator based on the GCV on EM basis as per the terms and conditions of the FSA.

22.8.2. As the coal is fired into the boiler containing both surface moisture (SM) and inherent (IM), the GCV considered for the purpose of billing ECR is on TM basis i.e. actual useful heat available in the boiler for producing steam.

22.8.3. There is around one grade difference in GCV on account of representation of GCV on EM basis and TM basis for same sample of coal on account of moisture (SM and IM) over which the generator has no control whatsoever.

22.8.4. Risk allocation between coal companies, Railways and generating station because of grade slippage during transit may not be workable. It may generate lot of new disputes and reconciliation process may be tedious and time consuming.

Therefore, it is suggested that:

- **Supply of coal should be provided at the station by the Coal Company i.e. the transfer of title of the coal to the generating station shall be at the station end.**

- **Payment to the coal companies based on GCV on TM basis (i.e. actual useful heat) and quantity "as received" at station end needs to be implemented and the same shall be considered for the purpose of billing of energy charges.**
- **It is further submitted that margin between "GCV as received" at station (wagon top) to "GCV As fired" in Pit head stations of 85-100 Kcal/kg and in Non-pithead stations of 105-120 kcal/kg as per CEA recommendation vide letter dated 17.10.2017 may be provided in the Regulations.**
- **The above methodology will require modifications of existing FSAs and also approval of the Ministry of Coal (GOI), and the Ministry of Power (GoI). Facilitation and support of the Hon'ble Commission in this regard is requested.**

22.9. **Form 15 / price of coal:** Coal stock lying in the station (i.e. opening quantity and value of coal) is not shown separately in the present format of Form-15. As per Form 15, the cost of coal and GCV considered for billing is considered based on coal received in that particular month. Whereas, practically the coal used for generation in a particular month consists of the coal which is received during that particular month along with the coal which is already there in stock. Thus, the average GCV and price of coal actually being used should be considered for billing instead of GCV and price of coal received during the month. Therefore, opening quantity and value of coal stock needs to be indicated in the format of Form-15.

Fuel – Blending of Imported Coal

1) The power plants in the country face shortage of fuel (coal/gas) due to shortage of supply from the supplier or due to transportation constraints. Coal India Ltd. has not been able to supply committed quantity of coal as per Fuel Supply Agreement. Coal supply also gets affected due to Rail transportation related constraints. Uncertainty about supply of gas continues, both in terms of availability and price. In the above circumstances, the generating stations are *either forced to procure fuel from spot market (in case of gas and coal) or to procure imported coal at higher prices.*

2) *Tariff Regulations, 2014 allowed procurement of balance coal from alternate sources like import/e-auction for blending. Under restrictions prescribed in the regulations relating to quantum/price of alternate coal, the generating companies meet shortfall in supply of coal under FSA through alternate sources (which are generally costlier). If power plants rely heavily on coal from alternative sources, the energy charges may increase substantially or the plant may have to be operated at lower PLF if distribution licensees do not give consent to blend higher percentage of imported coal than the threshold prescribed in the regulations.*
3) *There is difficulty in verification of GCV of blended coal, due to unavailability of separate value of GCV of domestic and imported coal on "As Fired Basis". It may therefore, be necessary to provide for payment of energy charges based on "As Received" GCV of domestic and imported coal with suitable margin and adjustment for arriving at "As Fired" GCV. This would require development of norms for such adjustment.*
4) *Alternatively, normative blending ratio may be decided in advance in consultation with the beneficiaries in terms of technical limitation of steam generator. The blending ratio in the domestic coal based plants may vary depending upon the quality of coal, the quality of actual coal being received, age of plant, unit loading etc.*
5) *The Central Commission, vide Third Amendment to Tariff Regulations,dated30.12.2012, has already incorporated the regulation for maintaining transparency in fuel procurement by generator and sharing of fuel prices including, fuel procurement through e-auction and imported coal.*

<u>Options for Regulatory Framework</u>

1) *Normative blending ratio may be specified for existing plant as well as new plants separately in consultation with the beneficiaries*

23. **<u>Comments / Suggestions – Blending of Imported Coal</u>**

23.1. Blending of indigenous coal with imported coal is permissible as per technical consideration of boiler design and quality of domestic coal as well as imported coal. Coal needs to be sourced from various alternate sources in case of shortage of domestic coal. Presently guidelines have been issued by the CEA vide their letter no. CEA/TE & TD–TT/2011/ F-8 dated 19/04/2011 which provides for blending ratio by weight of imported / high GCV coal to indigenous coal in the ratio 30:70 (or higher) while designing boilers.

23.2. It is accepted and recognized that presently there is shortage of domestic coal and stock of coal has depleted to 15.5 MT in June 2018 which is sufficient for 9 days only. In this regard, CEA vide its letter dated 04.07.2018 has asked utilities to assess their requirement of import coal for maintaining normative coal stock level of 35.5 MT in power plants.

23.3. Since the recovery of fixed charges of a power plant has been linked to the availability of the plant, generators may have import coal to mitigate the shortage of domestic coal availability. However, the amount of blending of imported coal in a power plant would depend on a host of other factors, such as, the GCV of the domestic coal, GCV of the imported coal (low GCV or high GCV), shortfall in supply of domestic coal from linked mines, boiler design, etc.

23.4. Hence considering all these factors, the blending of imported coal should be left to the generators to decide depending on the situations as mentioned above along with the boiler design. Only the station operating staff would be better placed to decide on these operational issues based on the operating data.

23.5. Moreover, while fixing any norm for blending of imported coal, it is to be recognized that it is not practically possible to accurately control the blending with the existing plant designs/ infrastructure so as keep the same within the prescribed limit.

23.6. Existing Tariff Regulations provides that prior consultation with beneficiaries shall be made where energy charge rate based on use of alternate fuel exceeds 30% of the base energy charge rate as approved by the Commission for that year or exceeds 20% of energy charge rate of previous month. The above dispensation checks the generator from indiscriminate blending of coal thereby having significant impact on the ECR. This mechanism has worked well and is adequate. Therefore, the mechanism may be retained.

23.7. In view of the above, it would not be appropriate to fix a norm for blending ratio. Blending of imported coal may continue on need basis and cost passed on based on actuals.

Fuel – Landed Cost

1) *The present regulatory framework provides for the computation of energy charges based on landed cost of fuel. The landed cost of fuel includes the cost components up to the delivery point of the generating stations. Further, as per the present regulations, the energy charges are directly pass through based on the formula specified for Energy Charge Rate (ECR) in the Tariff Regulations. The beneficiaries verify the bills or claims of the energy charge rate while making payment.*
2) *The generating company has to provide the necessary details of the cost included in the landed cost of fuel. Different generating companies follow different practices for supplying such information. Further, asymmetry of information for different fuel sources creates ambiguity for billing energy charges. There may be a need to specify the required information to be supplied and the standard procedure tube followed while claiming bills for energy charges*
3) *The approach for allowing pass through of the landed cost of fuel was evolved on the premise that the fuel cost is beyond the control of the generating companies as prices were administered. Subsequently, there have been several developments. The Government has opened the coal mine to private companies. Today, the generating company may procure coal either through Coal India Ltd, Open market, e-auction mode, captive mine etc. Further, the Government has also specified the flexible utilization of coal under the existing fuel supply agreement. The generating company has options to optimize the landed cost of fuel based on different procurement and transportation modes, considering the quality, source specific expenses etc.*
4) *The landed cost of fuel constitutes different components such as basic run of mine (ROM) price, sizing charges, surface transportation charges, royalty,*

stowing excise duty, fuel surcharge, cess etc. Further, the components may vary depending upon the source of coal. In case of railway transport, it involves basic freight, terminal charges, busy season surcharges etc. In case of imported coal, it includes the FOB price, over sea transportation, port handling charges, rail transportation, road transportation etc. As a result, there is wide variations in terms of cost and number of cost components involved in the landed fuel cost, changes in which cause corresponding fluctuations in the tariff. The energy charges largely depend on the fuel cost which is determined by the cost components allowable as part of tariff.

Options for Regulatory Framework

1) *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;*
2) *The source of coal, distance (rail and road transportation) and quality of coal may be fixed or specified for a minimum period, so that the distribution company will have reasonable predictability over variation of the energy charges.*

24. **Comments / Suggestions – Fuel – Landed Cost**

24.1. Standardization of coal cost components is not possible as there is wide variations depending on the source of coal as the supply to stations is from multiple mines of a subsidiary company / coal company as per the FSA. Coal supply can also be of different quality. Further, there are some state specific charges like MPGATSVA, MADA etc. However, the various heads under "other charges" is listed as under:

24.1.1. Sampling Charges: - This refers to the cost involved in process of coal sample collection, its contract execution at the stations before unloading of coal to assess the quality parameters on as – received basis.

24.1.2. Stone Picking Charges: -The contract is deployed for collection of stones or non-coal material while coal is transported on running conveyor belts.

24.1.3. Land License Fee: - The Railway charges the land license fee for the railway land over which NTPC's siding takes off from Indian Railway track.

24.1.4. Unloading Charges: -The labor and equipment's deployed for unloading of coal from wagons to track hopper / wharf wall for further transportation through conveyor belt etc.

24.1.5. Railway Retired Staff Salary: -The ex-railway staff is deployed for operation and maintenance of MGR & railway siding, MGR control room. The salaries & perks paid to them is referred through this head.

24.1.6. Crane Hiring Charges: -In case of derailment / accident of MGR wagons / locos, the railway crane is being deployed for restoration work. This is being paid to Railways.

24.1.7. Boulder breaking Charges: - Machines, like rock breaker etc. are deployed many times for breaking the big size coal boulders if necessary.

24.1.8. Test Wagon: - A set of calibrated wagons is being deployed by taking on hire from Railways for calibration of NTPC stations weigh bridges.

24.1.9. Liasioning Charges: - The agencies deployed at coal mines for inspection & quality of coal loading in wagons and for expediting the coal rake dispatches.

24.2. Under FSA coal companies have flexibility to supply coal from any of its mines, which can be nearer to the station or far away. Under implementation of flexible utilization policy of domestic coal, power utilities have option to get coal from Non-FSA coal companies also to optimize transportation charges. In addition to above, many times Railways also divert rakes to other NTPC stations on operational requirements, which is beyond control of power utilities. Therefore, it may be difficult to fix, decide or standardize/ source.

24.3. The present mechanism of charging coal cost based on actuals is serving beneficiaries well. The ECR of NTPC stations has reduced over a period of time despite substantial increase in coal cost / freight / tax & duties. The form 15 captures various cost components incurred in bringing the coal to the power plant which is also available online thereby providing transparency regarding landed price of fuel. Therefore, the present mechanism of allowing all cost components as part of tariff may be retained

24.4. Landed cost to include testing/ analysis of coal, stone picking and all charges that are incidental incurred to bring coal to power plant boundary

24.5. Generators do not have control over the pricing of coal, the tax structure as well as freight charges. Coal is also to be predominantly sourced from domestic sources and therefore, there is no significant flexibility available to the generators in matters of coal procurement. Therefore, any standardizationof the cost elements or the sources of coal is fraught with difficulties in implementation. At present, arranging fuel is the responsibility of the generator and Availability cannot be declared without fuel. In case the proposed standardizationof coal sources is implemented, the generators must be freed from the responsibility to arrange fuel and DC shall be allowed in full for the period except for machine outages.

24.6. Current Government policy permits flexible utilization of the Annual Contracted Quantity under the Fuel Supply Agreements at any of the power stations of the generators. Source standardization will reduce such flexibility and can be counterproductive.

Fuel – Alternate Source

1) The present regulatory framework provides that the generators resorting the alternate source of fuel, other than designated fuel supply agreement, require prior consultation only if the energy charge rate exceeds 30% of the base energy charge rate or 20% of energy charge rate of the previous month. These provisions were introduced w.e.f. 1.4.2014 in view of the shortage of fuel at that time.

Options for Regulatory Framework

1) Stipulate procedure for sourcing fuel from alternate source including ceiling rate

2) Rationalize the formulation keeping in view the different level of energy charge rates, as the fuel cost has increased since 1.4.2014

25. **Comments / Suggestions – Fuel – Alternate Source**

25.1. The need for alternate source is entrenched in the manner Normative Annual Contracted Quantities (ACQ)' is worked out by CEA for the FSA of Power Plants with coal companies. CEA works out the Normative ACQ quantity for 85% PLF for different category of power stations (based on size/efficiency parameter) considering the GCV of the grade of coal as provided by Coal Companies. This GCV is on EM basis. As the boiler consumes some heat from combustion of coal to evaporate the inherent and surface moisture of coal, the coal quantity worked out with GCV on EM basis is less than that coal quantity actually required. Further, there is some grade slippage during mining operations.

25.2. Still further, there is loss in quantity and quality of coal during coal dispatch, receipt, storage, handling and firing in the plants. As such, the ACQ quantities are much less than that actually required for the normative 85% PLF. And above all, the coal companies are either not able to supply the ACQ quantities, or tend to restrict the quantities to minimum trigger level", which is about 75% of the ACQ quantities. The above factors lead to shortfall of coal required to meet the normative requirement.

25.3. MoP has formed a committee under CEA to work out the normative requirement for different for ROM, and Washery-based power plants. However, there exists shortage of domestic coal, which calls for alternate sources like coal imports and e-auctions.

25.4. The present norms take care and protect the interest of consumers in limiting the volatility in energy charges due to blending of imported coal to meet the shortages. They ensure that generators optimize import. Considering the domestic coal production scenario, reliance on imported coal is likely to increase in the near future. GoI has already asked power plants to consider importing coal in case of coal shortage**. In view of the above, the present dispensation in this regard may continue.**

25.5. **Fuel Shortage scenario:** To meet the peak demand of the customers, in case of fuel shortage and to optimally use the coal as well station may be allowed to declare higher DC at peak hours and DC declared during the peak hour may be considered as DC for the whole day.

Operational Norms

1) The Tariff Policy dated 28th January, 2016 provides the guiding principle for fixation of operational norms as under:

- *Suitable performance norms of operations together with incentives and disincentives would need to be evolved along with appropriate arrangement for sharing the gains of efficient operations with the consumers. The operating parameters in tariffs should be at "normative levels" and not at "lower of normative and actual".*
- *The norms should be efficient, relatable to past performance, capable of achievement and progressively reflecting increased efficiencies and may also take into consideration the latest technological advancements, fuel, vintage of equipment's, nature of operations, level of service to be provided to consumers, etc.*

2) The regulatory approach evolved for specifying operation norms was based on historical data analysis and consideration of efficiencies, technological advancement, vintage etc. However, in case of existing projects, where projects specific notifications of Government of India existed or if there was a PPA entered between the parties, the norms specified therein were applied. In so far, as the operational norms in respect of PLF and Target Availability are concerned, these were separately laid down by the Commission.

Thermal Generation (Coal based)

Station Heat Rate

1) Station Heat rate (SHR) refers to the conversion efficiency of thermal heat energy into electrical energy and used for computation of energy charges. The Commission while framing the Regulations for terms and conditions of tariff for different tariff periods has been considering the operational data of the generating stations for the past 5 years. The methodology of considering 5 years data ensures that the generator is able to recover the cost of electricity in a reasonable manner and covers the reduction in the generation level. The heat rate norm specified during previous tariff periods are as under:

2009-14 Tariff Period	***2014-19 Tariff Period***

200/210/250 MW Sets - 2500 Kcal/kWh	*200/210/250 MW Sets - 2425 Kcal/kWh*
500MW and above - 2425 Kcal/kWh	*500MW and above - 2375 Kcal/kWh*
Coal & Lignite: GSHR= 1.065 X Design Heat Rate	*Coal & Lignite: GSHR= 1.045 X Design Heat Rate*
Natural Gas & RLNG: GSHR= 1.05 X Design Heat Rate	*Natural Gas & RLNG: GSHR= 1.05 X Design Heat Rate*
Liquid Fuel: GSHR= 1.071 X Design Heat Rate	*Liquid Fuel: GSHR= 1.071 X Design Heat Rate*

2) *The GCV measurement of coal was shifted to "As Received" basis for the purpose of energy charges computation in the Tariff Regulations for the period 2014-19 as per the advice of Central Electricity Authority*
3) *In the present scenario, most of the coal/lignite/gas based thermal power plants are running at low utilization (PLF) levels due to various reasons including shortage of coal/gas, lower demand etc. Machines working at lower PLF have adverse impact on the operational norms and hence, the existing heat rate norms for the new and existing generating stations are required to be reviewed along with the need for margin. The norms of heat rate will be over and above the heat rate guaranteed by the OEM based on actual performance data during the last five years.*
4) *The heat rate is a crucial parameter as it has substantial impact on tariff. The gain/savings on account of heat rate are to be shared with the beneficiaries. Therefore, heat rate is required to be specified giving due consideration to all relevant factors including shortage of domestic coal supply in the country. The heat rate norms would also require to be seen in the light of efficiency improvement targets achieved by the generating stations under the PAT scheme. The heat rate norms varies with the passage of useful life of the project due to degradation and therefore, the norms specified based on the recently commissioned plants may not be attainable by older plants.*

5) *The existing regulations provides for calculation of Gross Station Heat rate for new stations based on Designed Heat Rate with margin of 4.5%. This margin specified for gross station heat rate is based on recommendation of the Central Electricity Authority*
6) *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.*

26. Comments / Suggestions – Station Heat Rate

26.1. **Criteria for Specifying Heat Rate Norms:-**

In regard to operating norms, The Tariff Policy provides as under:

"Suitable performance norms of operations together with incentives and disincentives would need be evolved along with appropriate arrangement for sharing the gains of efficient operations with the consumers. Except for the cases referred to in Para 5.3(h)(2), the operating parameters in tariffs should be at "normative levels" only and not at "lower of normative and actuals". This is essential to encourage better operating performance. The norms should be efficient, relatable to past performance, capable of achievement and progressively reflecting increased efficiencies and may also take into consideration the latest technological advancements, fuel, vintage of equipment, nature of operations, level of service to be provided to consumers etc. Continued and proven inefficiency must be controlled and penalized."

26.2. Thus, the norms should be capable of achievement on a consistent basis. Actual operating conditions in future is expected to deteriorate further as compared to the existing situation, particularly on account of availability and quality of coal, addition of substantial capacity from renewable sources, grid parameters, higher availability of power from multiple generators, sellers, etc. which is likely to reduce the loading factor / PLF of thermal power stations. This would have a deteriorating effect on the Station Heat Rate (SHR). Norms for Station Heat Rate should be approved considering various operational constraints like partial loading /erratic load pattern, low

PLF and deteriorated coal quality as coal quality is expected to deteriorate further during the Control Period FY 2019-24. **Therefore, it is suggested that norms may be specified based on operating conditions anticipated in the future in addition to past actual data.**

26.3. Further, it is submitted that operating norms should be based on the anticipated national average performance of units in the country expected due to operational constraints elaborated above. It should not confined to NTPC stations alone but also include all units in the country including State Utilities / IPPs of relevant vintage as the norms prescribed by the Hon'ble Commission are guiding factors for the State Regulatory Commissions.

26.4. Alternatively, SHR norms may be based on the design parameters with appropriate operating margin to account for deterioration due to ageing, vintage, coal quality, low loading and operating constraints expected in future due to cyclical loading, partial loading etc. **Accordingly, it would be more appropriate to specify norms based on design parameters with appropriate operating margin to take care of lowering PLF of stations, ageing, etc**.

26.5. Further, it has been observed that there is increased partial loading and flexing of units for the last the years i.e. from 2015-16 to 2017-18. This is mainly due to increased renewable integration, fuel availability issues, low demand, etc. The actual heat rate achieved by the various NTPC Stations in the last three years is as under:

Sl. No.	Station	Norm	2015-	2016-17	2017-
1.	Bongaigaon	2362		2400	2454
2.	Barh-II	2295	2325	2412	2331
3.	Talcher-I	2375	2378	2487	2410
4.	Dadri -II	2378	2385	2401	2489
5.	Mauda-I	2401	2425	2426	2475
6.	Simhadri-I	2375	2387	2398	2427
7.	Talcher-II	2375	2377	2459	2364
8.	Farakka-I&II	2403	2398	2462	2422
9.	Rihand-I	2335	2359	2369	2328
10.	Dadri-I	2450	2404	2449	2545
11.	Simhadri-II	2375	2362	2381	2430
12.	Vindhyachal-II	2375	2363	2423	2369
13.	Unchahar-I	2450	2435	2468	2463

14.	Vindhyachal-III	2375	2356	2398	2367
15.	Vindhyachal-IV	2375	2357	2405	2357
16.	Vindhyachal-I	2450	2411	2479	2444
17.	Unchahar-2	2450	2431	2447	2452
18.	Kahalgaon-I	2450	2425	2451	2451
19.	Singrauli-I&II	2413	2388	2420	2402
20.	Farakka-III	2436	2376	2434	2467

It is evident from table above, that a large number of NTPC Stations are operating above the heat rate norms for the reasons mentioned above including stringent norms prescribed by the Hon'ble Commission for the period 2014-19. In most of the generating stations of NTPC, which is considered as one of the best operating utilities in the country, cannot meet the operating norms on consistent basis, it is submitted that there is need to revise the norms to make them achievable. Accordingly, it is submitted that norms may be formulated so that units/ stations could achieve the prescribed norms consistently keeping in view that there will be increased flexing of operation of units in the future.

26.6. **For 500 MW units a SHR of 2400 kcal/unit and for 200/210/250 MW units a SHR of 2475 kcal/unit may be considered as most of NTPC units are not able to meet the present norm.**

26.7. Station Heat Rate depends upon the following factors:

26.7.1. **AGEING OF MACHINE:** As on 30th June 2018, the age of NTPC coal based units in operation is tabulated as under:

S. No.	Unit size (MW)	Number of units	Average age
1	800	2	1.15
2	660	8	4.13
3	500 / 490	46	15.68
4	200 / 210 / 250	37	28.10
5	110 / 95 / 60	13	39.41

Majority of the 200/210/250 units (excluding Bongaigaon) have crossed 25 years of age. The heat rate figure will increase drastically if the anticipated pattern of PLF follows due to large scale integration of RE in the grid.

The turbine performance deteriorates with ageing during the operating cycle of the plant. This leads to deterioration in steam flow path and hence lower cylinder efficiencies of HP, IP & LP modules. These changes occur due to creep, inter-stage leakages, blade losses and seal leakages etc. Also the performance of turbine gets affected due to deposits on blade over a period of time. This deterioration in efficiency of turbine modules adversely affects the cycle operating heat rate. As per NTPC experience, it is possible to recover only 70% of heat rate deviation after capital overhaul. Thus, the losses increase with aging.

Cycling operations further deteriorates the efficiency of turbine module and boiler, a part of which is irreversible, even after maintenance. Additionally, turbine cycle performance deteriorates at part load due to increased throttling & increase deviation of parameters from the design condition. Similarly, boiler operation at part load requires higher oxygen at economizer outlet which results in increased loss in the boiler.

26.7.2. **OPERATING MARGIN:** The design unit heat rate is derived from the design TG heat rate and design boiler efficiency at the rated output as per the Heat Balance Diagrams (HBD) supplied by the manufacturer / OEM. In real time operation of power plants, it is not possible to achieve the design heat rate as deviations occur due to number of parameters which are uncontrollable. The most significant of these parameters are listed below:

26.7.2.1. Boiler Efficiency: Design boiler efficiency varies from 83% to 88% depending on **boiler design, ambient conditions and type of coal being fired.** Two major components of boiler losses are the dry flue gas loss and the wet flue gas loss**.** The actual operating dry flue gas loss and wet flue gas loss is appreciably higher than the design and operating efficiency of boilers is lower than the design value due to following technical reasons.

26.7.2.2. **Deterioration in Equipment Condition**: As per the experience at NTPC power stations, boiler efficiency deteriorates by 1 to 1.5 % from one boiler overhaul to the next overhaul on account of various factors which are as under:-

26.7.2.3. **Deterioration in Heat Absorption -** There is progressive furnace fouling and ash deposits on the heat absorption pressure parts which affect the heat transfer in the tubes in spite of soot blowers operation. The deterioration in heat absorption results in higher exit flue gas temperatures.

26.7.2.4. **Erosion of boiler components**: Due to erosive nature of Indian coals, components in pulverized coal and flue gas path like pulverized fuel burners, pipe orifices, expansion joints in gas ducts, etc. wear out and impact combustion and boiler efficiency adversely till their replacement in next overhaul.

26.7.2.5. **Deterioration in performance of Air Pre-heaters**: During operation of the boiler, the performance of air pre-heaters gets deteriorated progressively due to clogging, choking and erosion of heating elements. This affects thermal efficiency of air pre-heaters and increases the flue gas temperature.

26.7.2.6. Super Heater/ Re-heater Spray: The average value of spray loss has been found to be in the range of 80 to 100 TPH, which contributed to HR loss of about 3 kcal/kwh. The average RH spray levels are in the range of 30 - 50 TPH in NTPC stations. The impact on cycle heat rate is 3/7 kcal/kWh respectively for 200 & 500 MW Units.

26.7.2.7. Condenser Back Pressure: The condenser back pressure plays a vital role in the efficiency of the thermal power plant. Change in the water parameters (temperature, inlet flow and quality) adversely affects the unit heat rate. During most part of the year, the cooling water temperature observed to be varying from 28 degree Celsius to 36 degree Celsius as per the ambient conditions. Poor water quality and variation in ambient conditions (on seasonal basis) affect its performance. This in turn increases the operating back pressure of the condenser. As per the experience at some of our stations operating under open cycle, like, Farakka, Badarpur, Rihand, Singrauli, etc., water quality got deteriorated over the years due to:

26.7.2.7.1. Low inflow in the intake canal

26.7.2.7.2. Abnormal depletion in the reservoir levels

26.7.2.7.3. High silt level

26.7.2.7.4. Increase in total suspended solids/ weeds/ wooden debris.

26.7.2.7.5. Some stations like Dadri is using bore well water for few months in past couple of years during canal closure period resulting in condenser loss of around 50-60 kcal in stage-I units & if canal closure period is extended further then stage-II units will also having similar loss pattern.

26.7.2.7.6. In addition to the above reasons, condenser performance is also affected due to scaling of the tubes, plugging of the tubes in case of leakages and air ingress. Further, heat load on condenser increases due to decrease in turbine cycle efficiency over a period of time and hence leads to higher back pressure. Mostly we are getting opportunity to clean condenser during overhauling only, thereby adversely affecting condenser performance.

Based on the routine tests carried out for all the units, the average heat rate loss on account of condenser vacuum in 200 & 500 MW units is recorded to be in the range of **6-8 kcal/kWh.**

26.7.2.8. Main Steam Temperature: As per design, the turbines are designed to operate at the rated parameters and accordingly design heat rate is computed. Any reduction in steam temperature from the rated value (537 C in case of 500 MW Units) leads to increase in heat rate of the turbine.

In number of 500 MW Units installed (from Vindhyachal Stage-2 onwards) it is found that the rated main steam temperature is not achievable due to variation from design conditions due to factors stated above herein.. In some of the Units the temperature at turbine inlet is maintaining as low as 520C. This is leading to increase in turbine heat rate. In day to day operation of the units, it is being experienced that steam temperature fluctuates during operations like soot blowing, mill change over and load variation to meet the grid requirements. Based on the average data across the NTPC Units, the deviation in Main Steam temperature observed to be 2-5^{0}C in the Units.

26.7.2.9. Reheat Steam Temperature: As per design, the turbines are designed to operate at the rated parameters and accordingly design heat rate is computed. Any reduction in reheat steam temperature from the rated value (537^{0}Cin case of 500 MW Units) leads to increase in heat rate of the turbine.

In most of the 500 MW units installed it is found that the rated reheat steam temperature is not achievable due to variation from design conditions due to factors stated above herein. In some of the units the temperature at turbine inlet goes as low as 515 degree Celsius This is leading to increase in heat rate of turbine. In day to day operation of the units, it is being experienced that Reheat steam temperature fluctuates during operations like soot blowing, mill changeovers and load fluctuations. It is also observed that reheat steam temperatures get reduced on usage of spray to contain metal temperatures at times. Based on the average data across the 500 MW Units, the deviation in Re heat steam temperature observed to be 3-8^{0}Celsius in the Units.

In our new Supercritical units (660MW) of Barh & Mouda deviation in HRH temperature of around 20-25 degree Celsius due to difference in operating conditions from design conditions resulting in heat rate loss of approximately **12-15 kcal/kwh.**

26.7.2.10. Make-up Water: As per the design, turbine cycle heat rate is at 0% make-up. But, in power plant operation certain make-up is required as a part of cycle requirement which exists in the form of releasing non-condensing gases through de-aerator vents, blow down to contain silica in boiler drum, BFP gland seal leakages and turbine gland exhaust loss. This will be amounting to 0.5 to 0.7 % of the main-steam flow. Apart from the above, day to day soot blowing operations (wall blowing, LRSB and APH soot blowing), auxiliary steam consumption (fuel oil heating, atomizing steam & others), and routine sampling loss also lead to working fluid loss from the system. These losses are to be compensated with external make-up through condenser. The average make up water consumption observed to be **0.6- 0.7 % of MCR**.

As per the manufacturer’s data, 1% increase make-up water consumption leads to increase in unit heat rate of around 16 kcal/kWh. Based on the operating data, average deviation in cycle heat rate due to make-up water loss works out to be **8-10 kcal/kWh**.

26.7.2.11. Miscellaneous Loss: This includes all losses which are unaccountable - radiation losses, heat loss due to leakages, passing, cycle make-up, etc. and piping losses. Since design cycle heat rate is calculated from TG cycle heat rate and boiler efficiency at 100% load, piping losses are not covered in design heat rate, whereas the actual unit efficiency (based on input and output) also includes the losses in piping between boiler and turbine.

26.7.3. **COAL QUALITY:** Boiler manufacturer guarantees a certain boiler efficiency for a certain quality of coal and also recommends a set of operating conditions for efficient combustion (excess air, wind box pressure, damper positions) for the design coal. But there are very large variations in coal quality, especially, volatile matter & moisture at non-pit head stations. Due to continual variations in coal quality, continuous optimized regime operation for boiler is difficult. This is necessitating operation at higher oxygen levels, resulting in lower operating boiler efficiency. **Poor coal quality** further leads to additional losses as under:

- Higher firing rates in boilers lead to increase in mass flows of flue gas and higher than design velocities and accelerated erosion of pressure parts.
- Frequent soot deposition which demands more frequent soot blower operation, increasing make-up water consumption & potential steam erosion.
- Partial loading operation becomes unavoidable due to restriction on maximum coal firing rate.
- Running of an Additional Mill – With deterioration in coal quality, 210 MW units designed for 4 mill operation have to be operated with 5 mills, while 500 MW units, designed for 6 mill operations have to run with 7 mills. An additional mill affects operating performance adversely due to increase in the boiler exit flue gas temperatures by about 10^{o}C and

increased PA header pressure that result in higher air heater air-in-leakages & reduction in boiler efficiency.

- Higher ash content with abrasive nature leads to erosion in flue gas path leading to higher DFG (Dry Flue Gas) losses due to leakages.

It has been observed across the NTPC stations that the quality of coal has deteriorated over a period of time. Further, old boilers whose design efficiency was higher are operating at relatively lower efficiency due to the poor coal quality.

26.7.4. **PARTIAL LOADING LOSS:** Units are constrained to operate under partial loading occur due to low grid demand, etc. The Hon'ble Commission has provided compensation for partial load operation from 55% to 85% loading factor. **However, it is to be recognized that the loss due to operating at lower load cannot be totally recovered / compensated by operating at higher load later.**

26.8. **The Actual Operating Margin over Design Heat rate of various NTPC stations is tabulated as Under:**

Vintage	Station	Boiler Eff. (%)	Turbine HR (kcal/ kwh)	Design Heat Rate (kcal/ kwh)	Actual Opr. Margin	Average of Actual SHR (2016-17 & 2017-18)
500 MW						
<10 Years	**Kahalgaon-II**	83.29	1944	2334	2.89%	2401
	Korba-III	84.91	1945	2291	3.60%	2373
	Rihand-III	84.05	1932	2299	2.22%	2350
	Vindhyachal-IV	84.00	1932	2300	3.51%	2381
	Farakka-III	83.39	1944	2332	5.14%	2452
	Simhadri-II	84.50	1933	2287	5.19%	2406
	Sipat-II	85.87	1948	2269	3.06%	2338
	Dadri -II	85.34	1936	2269	7.79%	2445
	Mauda-I	84.10	1932	2297	6.74%	2452
> 10 years	**Vindhyachal-II**	87.71	1948	2220	7.91%	2396
	Vindhyachal-III	85.14	1945	2284	4.32%	2383
	Rihand-II	87.41	1995	2282	2.95%	2349
	Ramagundam-III	87.27	1944	2227	5.36%	2346

	Simhadri-I	87.22	1945	2229	8.22%	2413
	Talcher-I	87.43	1988	2274	7.68%	2449
	Talcher-II	87.32	1944	2227	8.21%	2410
200 MW						
>10 Years	**Unchahar-III**	85.23	1965	2305	6.22%	2449
	Unchahar-II	86.86	1965	2262	8.30%	2450
	Unchahar-I	84.67	1983	2342	5.29%	2465
	Vindhyachal-I	87.58	2021	2308	6.67%	2461
	Kahalgaon-I	87.73	2022	2305	6.38%	2452
	Dadri-I	87.30	1985	2274	9.84%	2498
660 MW						
<10 Years	**Sipat-I**	86.28	1904	2207	2.33%	2258
	Barh-I	83.70	1838	2196	8.00%	2372

In view of the above, a suitable operating margin may be provided as under:

For 200 MW (> 10 years) – 8.0%

For 500 MW (> 10 years) - 7.5%

For 500 MW (< 10 years) – 6.0%

For 660 MW (< 10 years) - 6.5%

26.9. **SHR for New Units / Station:**

26.9.1. For new Units/ Stations, Hon'ble CERC in Tariff Regulations 2014, in consultation with CEA has specified normative heat rate as a function of boiler efficiency and turbine heat rate with an operating margin of 4.5%. Further, Hon'ble Commission has specified the minimum boiler efficiency to 86% and turbine heat rate as minimum of the norm specified or as guaranteed by OEM. It may be appreciated that the Boiler Efficiency is largely a function of coal quality i.e. better the coal quality better the efficiency and poorer the coal quality the poorer the boiler efficiency. As an example, Kahalgaon Stage-I and Stage-II boilers were designed based on following coal quality:

Station	GCV	Fixed Carbon	Moisture	Ash	Volatile Matter
Kahalgaon-I	3200	27.49	13.0	42	16.9
Kahalgaon-II	2850	23.5	16.5	43	17.0

It is evident from above that design boiler efficiency largely depends upon the quality of coal considered for designing the boiler. Accordingly, reduction of boiler efficiency in new units largely is due to deteriorating coal quality, which contributes to increased heat loss from boiler. Although NTPC has adequately managed to order the plant in a most economical level by optimally choosing the boiler efficiency and turbine heat rate, still NTPC new stations are subject to operational loss incurred on account of restricting the minimum boiler efficiency to 86%. **In view of the above, for new units, instead of providing minimum boiler efficiency criteria, the operating margin should be allowed on the design boiler efficiency and design** turbine cycle heat rate.

Further, while preparing the technical specification for designing/ installing new units, prevailing norms of the CERC are used. Since thermal power plants have long gestation period, the unit is often commissioned in the next tariff period where the norms becomes more stringent. Accordingly, the same creates regulatory uncertainty**. In view of this the norms specified may be applicable prospectively for projects whose financial closure/ investment approval has not taken place. For new projects being commissioned in the current tariff period, norms of the previous tariff period during which Investment Approval was accorded may be applied.**

26.10. **Air Cooled Condenser -** Normative heat rate for plants with Air Cooled Condenser (ACC) may be specified. Water being a precious resource all efforts should be made to save the same. Adoption of ACC reduces water consumption substantially. Utilities should be encouraged to adopt ACC in terms of higher operating margin on heat rate as compared to plant with water cooled condensers. Performance of ACC is highly dependent on Dry Bulb temperature which varies widely and hence the plant heat rate. In order to compensate the same 2% higher operating margin should be allowed for units with air cooled condenser.

26.11. **Super critical units -** The actual degradation of heat rate only on account of partial loading @55% load is in the order of 6% depending upon the OEM. The degradation allowed by the CERC Regulation vide amendment dated 06/04/2016 is 3% for supercritical units. It is submitted that heat rate compensation @ 6% may be allowed.

GAS STATIONS

Station	NORM	2015-16	2016-17	2017-18
Anta	2075	2117	2091	2132
Auraiya	2100	2123	2144	2217
Dadri Gas	2000	2031	2039	2098
Faridabad	1975	1989	1993	1984
Kawas	2050	2065	2012	2037
Gandhar	2040	1989	1993	2077
Kayamkulam	2000	1994	2011	2015

26.12. With regard to the gas based stations from the above data, it can be seen that norms are too stringent and not achieveable., in view of deterioration in gas turbine, performance in last 3 years and projected partial loading in the coming years, the existing norms of station heat rate of **Anta, Auraiya, Dadri Gas and Faridabad** need to be relaxed by at least 50 kcal/kwh..

26.13. **Gas Stations in Open Cycle / MOPA basis –**Combine cycle gas stations need to operate in open cycle due to technical reason at each start and shut down till the steam parameters of steam turbine do not reach the rated parameters. With increased RE penetration the cycling of thermal stations, particularly gas stations has increased and would need to start/ stop frequently. It is necessary that Regulations clearly provide that number of hours in open cycle would form part of REA and ECR worked out accordingly. Specific provision / norm may be provided for Gas Stations operating in open cycle.

26.14. **Compensation Mechanism -** The station heat rate is to be fixed based on the loading factor as the previous fixation of tariff had considered a constant loading factor as SHR = 1.05*Design Heat Rate in case of natural gas and SHR= 1.071*Design heat rate in case of liquid fuel. Gas stations are not able to achieve the norms if operated at low load (below 80%). As gas stations are operating at part load with half / full module, the Station heat rate and APC needs to be fixed at different load factor and half module/full module operation. Partial load compensation joint exercise which have already been carried out done along with WRPC/NRPC and beneficiaries. The compensation may be as per loading factor of a particular time block (15 min/5min) and the payment of the same is to be done as per actual time load factor and Heat Rate/APC applicable as per the SG given to plant for operation and not to be averaged out for the year as the operational efficiency benefits of the station are compensated in that case.

Specific Secondary Fuel Oil Consumption

1) The existing norm for the Secondary Fuel Oil Consumption is 1.00 ml/KWh for lignite based 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 operations.

27. Comments / Suggestions:

Following table highlights the stations where the specific secondary fuel oil consumption (in ml/kwh) is more than the norms.

S.	STATION	NORM	2015-16	2016-17	2017-18
1	Farakka-I&II	0.50	**1.76**	**0.87**	**1.27**
2	Farakka-III	0.50	**1.59**	0.22	**0.73**
3	Mauda-I	0.50	**1.83**	**0.62**	**0.53**

27.1. **Part Load Operation in Front Fired Boilers -** Further, in case of Farakka Stage-II (2X500MW) boiler is front fired boiler where the fire ball is very unstable at partial loads as compared to corner/ tangentially fired boilers. With more variability in grid and demand pattern of Discoms, these units will be forced to operate at partial loads more frequently and require more oil support for stable operation at lower loads and for any minor disturbances in unit process such as mill change over etc. **It is submitted that relaxation of specific fuel oil consumption of 0.75 ml/kwh in case of Farakka and Mauda may be considered instead of 0.5 ml/kwh for specific stations.**

27.2. With rising share of renewable energy resulting in flexible operation of thermal power plants, requiring more start and shut-down operations and part-load operations, the normative secondary oil consumption may need to take care of the number of start and stop operations. Additional start-up and shut-down operations may be specified with additional secondary fuel oil consumption to be considered for each such operation in excess of the specified number not due to fault of the generating company.

27.3. Given the fuel shortage scenario and erratic load pattern of most beneficiaries, which is likely to continue in the next tariff period also, conditions of partial loading and backing down would require oil support for safe boiler operations. **Therefore, the existing norms may be suitably increased.**

<u>Auxiliary Energy Consumption</u>

1) *The existing norms of auxiliary consumption of coal based generating station varies from 5.25% for unit size of 500 MW and above to 8.5% for 200 MW series units with steam driven boiler feed pumps and electrically driven boiler feed pumps and relaxed norms for specific generating stations of smaller size. Auxiliary consumption for gas based generating station varies from 1.0-2.5%depending on open or combined cycle operation. The existing norm of auxiliary consumption of lignite based generating station is 0.5% more than coal based generating station with electrically driven feed pump and 1.5%more if the lignite fired station is using CFBC technology. The auxiliary consumption does not include colony power consumption and construction power consumption.*

2) *Presently, the auxiliary consumption of 800 MW is fixed based on 500MWsets. The auxiliary consumption of 800 MW sets may vary depending on the size of the unit and economies of scale.*
3) *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 part of 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.*

28. Comments / Suggestions – Auxiliary Power Consumption:

28.1. Auxiliary Power Consumption (APC) of NTPC coal stations has shown rising trend over the last five years due to increased partial loading, low demand conditions resulting in lower schedule and increased penetration of renewable energy sources. Moreover, coal quality has deteriorated continuously over the period as also reflected by the decrease in GCV.

28.2. It may be pertinent to mention here that CEA in its recommendation for formulation of APC norms for the period 2014-19 has suggested APC of 5.25% for 500 MW and higher sized units with steam driven BFPs installed after 01.04.2009 as under:

"AEC for 500 MW and higher size units installed after 1-4-2009 may be reduced by 0.75 % (three fourth percentage points). Thus the normative AEC for 500 MW and higher size units installed after 1-4-2009 may be taken as 5.25 % for units with Turbine driven BFPs and 7.75 % for motor driven BFPs. Additional AEC of 0.5 % may be allowed for units with induced draught cooling towers (IDCT) for condenser water cooling."

28.3. However, Tariff Regulations 2014-19 prescribed a norm of 5.25% for all 500 MW and higher sized units irrespective of vintage and configuration of auxiliaries except for cooling tower and MDBFP where addition APC was prescribed.

28.4. Following table shows that there are several stations of NTPC where the actual APC is more than normative APC.

NTPC Stations		**Norm**	**2015-16**	**2016-17**	**2017-18**
1	**Singrauli-I&II**	6.88	**7.32**	**7.82**	**7.71**
3	**Farakka-I&II**	6.47	**7.24**	**7.54**	**7.38**
4	**Ramagundam-I&II**	6.68	6.00	6.45	**7.77**
5	**Kahalgaon-I**	9.00	**9.54**	**9.74**	**9.20**
6	**Unchahar-I**	9.00	8.86	**9.18**	**9.28**
7	**Unchahar-II**	9.00	**9.42**	9.00	**9.25**
8	**Unchahar-III**	9.00	8.65	8.83	**9.11**
9	**Vindhyachal-I**	9.00	8.83	**9.15**	8.56
10	**Farakka-III**	5.75	**6.18**	**6.22**	**6.43**
13	**Mauda-I**	5.75	**7.93**	**6.74**	**6.60**
15	**Rihand-I**	7.75	**8.09**	**8.41**	**7.77**
16	**Rihand-II**	5.75	**6.45**	**6.23**	**5.84**
18	**Simhadri-I**	5.25	**5.53**	**5.42**	**5.98**
19	**Simhadri-II**	5.25	**5.61**	**5.55**	**5.99**
20	**Dadri-I**	8.50	8.17	**8.53**	8.32
24	**Talcher-I**	5.75	**7.30**	**7.80**	**7.99**
26	**Vindhyachal-II**	5.75	**5.98**	**6.33**	5.68

28.5. Further, in the current scenario, unit performance cannot be sustained during the coming years as unit loading is expected to be further lower in view of the following reasons:

- Domestic coal availability projected as per new FSA is only 65 % of Annual Contracted Quantity, which is very low and will lead to heavy partial loading in the coming years.
- Lower schedule/ lesser generation due increased penetration of renewable energy sources.
- Partial loading of older stations due to R&M works in ESP, installation of emission control systems to meet new environment norms
- Increased APC due to installation of FGD and emission control systems

APC is expected to increase further for the above foresaid reasons**. It is submitted that the present APC norms of coal stations be increased**

by 0.75 % and additional 2% APC for stations where emission control system is commissioned.

28.6. **Old Stations -** Separate norms for Tanda and Talcher needs to be continued.

28.7. Gas Plants - Considering the huge variation in the actual auxiliary consumption, this norm needs revision to the extent of at least 0.30% increase in auxiliary consumption for combined cycle gas based plants.

28.8. **Colony Power Consumption:**

Hon'ble Commission in the present Tariff Regulations has excluded colony consumption as part of auxiliary energy consumption as inclusion of the same was resulting in double recovery since the energy consumed in plant colony was also part of O&M expenses. However, this has been interpreted by the beneficiaries in a different manner and has resulted in sore point with certain beneficiaries.

Some states have interpreted exclusion of colony consumption from APC in a manner that for colony consumption Station/ NTPC should draw power from the area distribution licensee as consumer in which the station/ colony is physically located as the same is no more part of APC. However, Clause 2 (30) of EA 2003 clearly says that colony is an integral part of the generating station.

In view of above, a clarification may be included in the ensuing Regulations that the generators may continue to draw colony power from the plant even though the same is not part of APC. Alternatively, colony consumption may be treated as part of APC and corresponding charges may be excluded from O&M expenditure while formulation of the norms.

Normative Annual Plant Availability Factor

1) *In control period 2014-19, the target availability has been determined based on the data available for the past years. The recovery of fixed charges was linked to availability. The availability of 85% is specified with exceptions of specific plant-wise availability. The existing availability norms are uniform for all the generating*

stations. Now with the increase of private participation, access to imported fuel by private developers and technological improvement may have improved the availability. The issue of different availability norms for existing and new plants can be contemplated.

2) *Shortage of domestic fuel affects availability of the plants and their scheduling. The existing norm for availability may therefore to be revisited. In the event of bridging gap through e-auction or imported coal (other than fuel arrangement agreed in purchase agreement), the need of prior consent of beneficiary, maximum permissible limit of blending etc. also need to be deliberated.*
3) *As per present regulatory framework, the recovery of annual fixed charges is based on cumulative availability during the year. There may be a chances of declaring lower availability during the peak demand period when the beneficiaries may be required to resort to procurement from short term market to meet their demand. However, during low demand period, the generating station may declare higher availability so as to achieve the target cumulative availability on annual basis to recover the full annual fixed charges. In this process, the beneficiaries may not get the electricity when required at the time of high demand.*
4) *In case of partly tied up capacity, the plant availability factor for whole plant may not be relevant. The consideration of merchant capacity for the purpose of plant availability declaration is not relevant.*
5) *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;*

29. Comments / Suggestions – Normative Annual Plant Availability Factor

29.1. Availability of a unit/ station is largely depends on following two factors:

- Machine Availability
- Fuel Availability
- Water availability

Machine availability is controllable factor and depends solely on the O&M practices whereas availability of fuel / water is an uncontrollable factor over which Generator has no reasonable control.

Coal availability continues to be a concern due to

- Less coal production at the mines
- Logistic constrains on account of transportation
- Excessive prices of imported & E-auction coal

It is generally observed that pit-head stations have higher fuel availability than non-pit head stations. For NTPC stations the loss of DC due to non-availability of fuel is more in case of non-pit head stations when compared to pit-head stations.

Also there shall be increase in number of outages due to flexible operation reducing the overall availability of units. Further, units may be shut down for longer duration for installing environment compliant equipment. The shut down period may be exclude while calculating availability.

29.2. Further, in case of stations where FSA was signed after 01.04.2009, domestic coal linkage is limited to 68% PLF only (i.e. 80% of 85%). Moreover, restrictions in case of sourcing coal from alternate sources, such as, procurement of coal through imports or e-auction in the form of prior consent from beneficiaries is imposed by regulations. As the PLF is on the decreasing trend, there is a case for lowering the target availability of stations. Therefore, it is submitted that Hon'ble may consider the above factors while fixing target availability of coal based stations.

29.3. Further, the Average loss of availability due to non-availability of coal for NTPC pit-head and non-pit head stations is as follows:

Type of Station	**2017-18**
Pit-head	0.81
Non-pit head	7.61

It is evident from above that availability of station has a direct relation to the proximity to coal source and means of transport. There has been instances when the coal was not able to be transported to a non-pit head stations due to railway constrains leading to loss of availability.

29.4. **Accordingly, it may be more appropriate to specify target availability (80%) for pit-head stations and relatively lower target availability (68%) for non-pit head stations.**

29.5. Considering the coal shortage scenario, reliance on alternate costly sources of coal including imported coal and e-auction is likely to increase in the near future. However, the present dispensation on taking consent from beneficiaries in case of ECR increases beyond the prescribed limit is serving the purpose well and so may be continued.

29.6. NTPC stations comprise of units of varying size and configurations. Generally minor overhauls of duration 15-17 days and major overhauls of duration 40-45 days are planned at yearly intervals considering Boiler License requirements, and other maintenance activities required. Units are taken under shutdown for overhauls as per planned schedule arrived after due consultation with beneficiaries in RPC / RLDC forums. Generally overhauls are spread across the year as per the planned schedule so that availability is maintained to meet the grid demand. Therefore, mechanism exists for planning and undertaking overhauling so that it caters to power demand of beneficiaries. It is submitted RPC forums need to be used more effectively while planning overhauling schedules.

29.7. Presently, capacity charges are fixed on annual basis and the recovery of annual fixed charges is based on normative annual target availability. Shifting fixed cost recovery to a lower periodicity would distort the planning of planned shut downs for over hauls and generators would be compelled to rush in order to meet the target availability fixed for the lower periodicity thereby compromising safety norms. For example, if target availability is set on monthly basis, stations having two units of similar size may not go for over hauls (major or minor) of unit since there will be huge under recover of fixed charges due to reduced availability for month/ quarter due to planned shutdown. Considering a forced outage of 1-2% will further decrease the availability of the reduced period with no margin for increasing the availability due to reduced period causing under recovery of annual fixed charges.

29.8. Moreover, FSA providing coal linkage and transportation planning and logistics with railways are all based on annual basis. Increasing the availability in certain periods and lowering it at other times would require additional resources and cost. Therefore, monthly or quarterly or half yearly fixed cost recovery would only result in further increasing the risk of non-recovery of fixed charges. **Accordingly, the present dispensation of fixed cost recovery on annual cumulative availability basis may be continued.**

29.9. In many NTPC new stations, there has been significant under recovery of AFC on account of shortage of coal due to constraints of Coal Company and Railways. In spite of NTPC's best efforts to mobilise coal under the policy of flexible utilization of coal, there has been still a under recovery of about 1250 crores (NTPC + JVs) in the year 2017-18. Therefore, it is submitted that opportunity may be provided to the generator to make up for the under recovery in coming years if the generator is able to achieve availability higher than target availability. Similar provisions is available to hydro generators in case of shortage of water.

Transit & Handling Losses

1) *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;*
2) *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 substantial loss in GCV of coal due to grade slippage and loss in quantity.

3) *A regulatory option could be that the generating station shall only pay for coal "As Received" at the plant plus normative transmission loss of GCV and quantity as per CERC norms. This can be addressed in the Tariff Regulation by indicating GCV as "As Received at plant end" and customization of Form-15 regarding the GCV.*

30. Comments / Suggestions – Transit & Handling Losses

30.1. Presently, the norms for Transit and Handling loss of coal are as under:

- Pit Head stations: 0.2%
- Non Pit Head stations: 0.8%

30.2. Further, coal loss during transit in case of rail-fed stations is beyond control of NTPC due to the following reasons:

30.2.1. For many Railway rakes, where the standard tare (empty wagon) weight is considered based on the design weight of empty wagon, significant loss is being observed in coal received vis-à-vis coal quantity billed by coal company.

30.2.2. Theft and pilferage during transit.

30.2.3. Weighbridge accuracy

30.3. NTPC procures coal from different subsidiaries of Coal India Limited through Fuel Supply Agreements. The terms of payment are governed by the provisions of the FSA. NTPC pays to the coal company on declared grade basis and subsequently the coal bills are adjusted for quality of coal arrived at through sampling at mine end of the coal rake wise. It may be appreciated that with start of sampling by third party (CIMFR) at both ends i.e. at mine end and at station end the issue of grade slippage has reduced substantially. Further, any credit passed on by the coal companies is passed on to the beneficiaries.

30.4. If a generating company pays to coal companies as per the GCV as received at plant plus normative loss of GCV and quantity then the FSA has to be amended. This requires agreement with the coal companies/ Ministry of Coal.

30.5. It is therefore submitted that:

30.5.1. Coal billing to be based on **quantity and quality at unloading end** with allowance for GCV and Quantity loss inside the station

30.5.2. In the meanwhile, till the above is implemented Coal Pricing based on Third Party Sampling at mine end and GCV measured at Wagon Top at station end may be continued with an additional margin as recommended by CEA for losses insider power station

Allowance for Transit and Handling loss to be provided as per following:

- MGR: 0.2% (Handling loss)
- Rail / Road: 1.6% (1.4% transit loss + 0.2% handling loss)
- Road cum Rail (RCR): 1.8% [1.4% transit loss + 0.4% handling loss (two handlings)]
- Through Sea via Rail/Road: 2.0% [1.4% transit loss + 0.6% handling loss (three handlings)]

Incentive

1) *For generation, the incentive prior to 2009 was linked to normative PLF and 25 paise/kWh was paid for generation beyond normative PLF in case of thermal generating station. The incentive, in case of hydro generating station, prior to 2009was linked to the capacity charges and capacity-index. The incentive during tariff period 2009-14 was linked to normative availability and generation beyond normative availability was payable at the fixed charge rate for the stations which are more than 10 years old or at 50% of the fixed charge for the stations up to 10 years old. In case of hydro generating stations incentive was linked to the capacity charges (50% of annual fixed charges) and normative availability. During the Tariff Period 2014-19,incentive for coal based generating plant was again linked to normative PLF of 85%@ 50 paise*
2) *At present there is same incentive for availability during peak and off-peak period. There may be a need for introducing differential incentive during peak and off-peak periods. On the same consideration, there may also be a need for higher incentive for the storage and pondage type hydro generating station providing*

peaking support. At present, generation beyond the design energy is paid at 80 paise/kWh in case of hydro generating station, which may also need review

3) *As regards transmission system, incentive is being recovered only through monthly formula of billing and collection of transmission charges. In the absence of clear provision regarding reconciliation of annual transmission charges and incentive with monthly billing, the concept of NATAF specified by the Commission in Tariff Regulations, 2014 requires review*
4) *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*

Options for Regulatory Framework

1) *Review linking incentive to fixed charges in view of variation of fixed charges over the useful life and on vintage of asset - Need for different incentives for new and old stations;*
2) *Different incentive may be provided for off peak and peak period for thermal and hydro generating stations. Differential incentive mechanism for storage and pondage type hydro generating stations may also be considered*
3) *Review the incentive and disincentive mechanism in view of the introduction of compensation for operating plant below norms*
4) *Review the norms for availability of transmission system*

31. Comments / Suggestions – Incentive

31.1. In the 2001-04 & 2004-09 regulations, the recovery of fixed charges was linked to availability of the generating company but the incentive was linked to the Scheduled Generation beyond Target Availability for fixed charge recovery. With the introduction of ABT and merit order based dispatch system, the variable charge of the generators decided the dispatching/ scheduling of the generating station. In the 2009-14 Tariff Regulations, incentive was provided for plant availability above target availability while disincentive was in the form of under recovery of fixed charges in case the generator was not able to achieve the target availability. This provided suitable motivation for the generator to maintain the plant at higher operating condition without disturbing the merit order principle.

31.2. However, in the 2014-19, incentive was again linked to scheduled energy above the target availability at the rate of 50 paise per kwh. In this regard, it is submitted that some of the states are considering the incentive paid for the energy scheduled above 85% PLF as part of ECR in merit order scheduling. This principle is distorting the merit order dispatch and even the pit-head stations having lowest ECR are not getting scheduled beyond the target availability at certain periods whereas scheduling is being done from costlier stations.

31.3. Further, the dis-incentive to the generators is linked to the target availability whereas incentive is linked to the scheduled energy. Moving forward, with increased renewable penetration, the PLF of stations are going to further reduce in some cases even the cheaper station may be also scheduled less and may not reach PLF of 85% (current trigger level for incentive). It will be more appropriate to link the incentive to availability as Incentive and dis-incentive should be equitable. **It is submitted that Incentive may be linked to Availability**

31.4. Compensation mechanism for operating the plant below the normative levels. It may be appreciated that compensation mechanism was introduced by the Hon'ble Commission to compensate the generator for loss of efficiency in operation parameters namely heat rate, APC and specific oil consumption for operating the stations below the normative levels due to less requisition by beneficiaries. It may be pertinent to mention that the compensation mechanism is on cumulative basis i.e. if a generator achieves normative operating level on an annual basis then no compensation is admissible. Further, loss of efficiency when units are operated at lower loads then normative level cannot be made good by operating the unit above normative levels. Therefore a unit can earn incentive only if it is able to provide availability and generation when needed. Therefore, compensation may not be linked to incentive. Instead, it may be linked to availability and incentive at the rate of 75 paisa per unit may be provided for all plants.

Implementation of Operational Norms

1) *The new tariff regulations take effect from 1st April of the tariff period. The Tariff Regulations require the generating company or transmission licensee to file the petitions within 180 days from the date of notification of the regulations. Since the tariff determination is quasi-judicial function, there is a time lag between filing the petition and finalization/ issuance of tariff order. Till the issuance of final order, the generating company or the transmission licenses keep charging the tariff based on previous tariff order including operational norms. The operational norms notified by the Commission in new tariff regulations take effect much after the date of coming into force of new tariff regulations. Consequently, the benefits of the improved operational norms are passed to beneficiaries only after time lag of few months.*

Comments/Suggestions

2) *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.*

32. Comments / Suggestions – Implementation of Operational Norms

The operational norms of the new tariff period should be implemented from the effective date of control period as it reduces ambiguity in implementation of the revised operational norms. Further, having different sets of date for implementation of revised operational norms based on date of issuance of tariff order of generating stations will create a lot of confusion in the sector. Therefore, the same may be brought out in the Regulations.

Sharing of gains in case of controllable parameters

1) *The present regulatory framework provides for sharing of gains between generating company and beneficiaries in 60:40 ratio on account of improvement incontrollable factors such as Station Heat Rate, Auxiliary consumptions, secondary fuel oil consumption, refinancing of loan and the true up of primary fuel cost. Subsequent to above, the compensation mechanism has been introduced*

for operation in CERC (Indian Electricity Grid Code) (Fourth Amendment) Regulations, 2016. The compensation mechanism aims to provide compensation if generating plant is operated at improved norms than ones specified in the amended IEGC Regulations of 2016. In view of the compensation mechanism, it needs to be considered as to whether the ratio of sharing of benefit may be reviewed.

2) *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 compete for maximum PLF.*
3) *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.*

33. Comments / Suggestions – Sharing of gains

33.1. The present framework entails the sharing of financial gains by a generating company or the transmission licensee, as the case may be, on account of controllable parameters between generating company and the beneficiaries on monthly basis with annual reconciliation. Norms for SHR, APC and specific oil consumption are fixed by Hon'ble Commission based on actual data of the past. The generator is compensated for operating at part load from 85% to 55% only if it is on annual basis. However, the loss on account of operating at part load cannot be compensated by operating at loads greater than 85%. Compensation for part load operation and the need for technical minimum is more relevant and necessary as Discoms back-down CGS generation and at the same time run their higher ECR state generation violating merit order. The above provisions of sharing of gains and compensation are mutually exclusive. As some units/plants are required to operate on cycling load due to difference between peak and off peak load coupled with intermittent RE generation, compensation is justified for such operation if required on a consistent annual basis. Sharing of gains wherever applicable i.e.in stations running at base load and higher PLFs is already available

33.2. **Sharing of operational efficiency gains:** Regulations may be made equitable and sharing of gains should be both ways i.e. efficiency loss may also be shared with customers.

(Rs. Crores)

Year	Gains	Losses	Gains passed on to beneficiaries	Net gain retained by NTPC
2014-15	596.93	-303.29	238.77	54.87
2015-16	428.83	-199.92	171.53	57.38
2016-17	163.85	-559.99	65.54	-461.69
2017-18	280.45	-521.80	112.18	-353.53

33.3. **Suggestions regarding calculation of Sharing of gains on account of Controllable operational parameters:**

- $ECR_{Normative}$ to be calculated on cumulative basis i.e. considering cumulative (weighted average upto the month) LPPF, CVPF, LPSF & CVSF and normative operational parameters of GHR, SFC and APC as per Regulations.
- ECR_{Actual} also to be calculated on cumulative (weighted average upto the month) basis i.e. considering cumulative LPPF, CVPF, LPSF & CVSF and actual cumulative operational parameters of GHR, SFC & APC.
- Sharing Amount = ($ECR_{Normative}$ - ECR_{Actual}) x 0.40 x Schedule of Beneficiary
- Gain/loss amount to be shared with beneficiaries in each month. However, consideration of cumulative parameters in each month, as stated above, shall lead to annual reconciliation.

Sample calculation for gain/ loss sharing is as below:

Station Name: TPS							
Calculation of $ECR_{Normative}$		**Month-1**	**Month-2**	**…**	**…**	**..**	**Month-12**
GHR_NORMATIVE (KCAL/KWH)		2,450.00	2,450.00				
AUX_NORMATIVE (%)		9	9				
SFC_NORMATIVE (ml/KWH)		0.5	0.5				
LPPF_CUMULATIVE (Rs./MT)		2337.64	2368.00				

CVSF_CUMULATIVE (KCAL/L)		9469.00	9469.00				
LPSF_CUMULATIVE (Rs./KL)		53297.09	53440.45				
CVPF_CUMULATIVE (KCAL/Kg.)		3685.00	3696.00				
$ECR_{Normative}$ (Rs./KWH)		1.734	1.751				
Calculation of ECR_{Actual}							
GHR_ACTUAL_CUMULATIVE		2,425.00	2,419.00				
AUX_ACTUAL_CUMULATIVE		8.90	8.88				
SFC_ACTUAL_CUMULATIVE		0.45	0.46				
LPPF_CUMULATIVE (Rs./MT)		2337.64	2368.00				
CVSF_CUMULATIVE (KCAL/L)		9469.00	9469.00				
LPSF_CUMULATIVE (Rs./KL)		53297.09	53440.45				
CVPF_CUMULATIVE (KCAL/Kg.)		3685.00	3696.00				
ECR_{Actual} (Rs./KWH)		1.712	1.725				
($ECR_{Normative}$ - ECR_{Actual})	(A)	0.022	0.026				
Cumulative Schedule of Ben-	(B)	100,000,000	200,000,000				
Cumulative Sharing	**(C)=(A)x(B)x0.40**	**880,000**	**2,080,000**				
Sharing Amount for Ben-1	**(D)=Sharing**	**880,000**	**1,200,000**				

It is submitted that the above methodology may be adopted for calculation of gain/ loss sharing on account of controllable operation parameters.

Late Payment Surcharge/Rebate

1) *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.*
2) *Further, as per the existing regulations, the rebate is provided if payment is made within 2 days of presentation of the bill. Valid mode of presentation of bill (email, physical copy etc.), authorised signatory, and definition of two days (working days or including holidays) may need elaboration.*

34. Comments / Suggestions – Late Payment Surcharge/Rebate

34.1. Hon'ble Commission as far back as 2004 has held that LPSC is in the nature of a disincentive to promote efficiency and vide its order dated 16.01.2004 in respect of Terms and Conditions of Tariff i.e. 01-04-2004 has observed as follows:

"8.52 Late payment surcharge carries the rate of 1.5 % p.m. at present. The beneficiaries have argued in favor of reducing the late payment surcharge in view of falling interest rates. No doubt, there is decline in the interest rates. However, the Commission recognizes the transaction to be complete when the bill is paid for by the beneficiaries for the energy supplied or transmitted. We, therefore, prefer early settlement of the dues of the generating and the transmission utilities as non-payment or late payment of bills results in accumulation of huge arrears, which adversely affects the health of the State Electricity Boards as well as the generating and transmission utilities. We, therefore, are of the considered view that delay in payment deserves to be discouraged. On this view, there is a case to increase rate of late payment surcharge instead of reducing it. On the overall consideration of the matter, we are opting in favor of status quo. In our considered view, this should not be the cause for heart burning because the provision of late payment surcharge is invoked only when a beneficiary has defaulted in making timely payment of dues of the generating company or the transmission utility."

In terms of above present provision of Late payment surcharge may be continued.

34.2. Further, linking the late payment to MCLR may encourage in efficiencies in payment cycle by the beneficiaries. Moreover, the regulated entities may be barred from availing STOA.

34.3. Moreover, late payment surcharge paid by the beneficiaries in case of late payment beyond 60 days is treated as non-tariff income for NTPC as per the accounting principles. Accordingly, income tax is payable by generators on this additional income. Therefore, effective LPSC is less than 1.5% per month. It is submitted that LPSC may be made part of generation income for working out the effective tax rate as tax is being paid on the LPSC recovered.

34.4. **Presentation of Bill -** It is submitted that bills may be made available by the Generator in soft through email to the designated person of the Discom. As we are moving into the digital era, hard copies of the bill may be discontinued.

34.5. **Definition of 2 days –** At present beneficiaries can avail 2% rebate in case payment is made within a period of 2 days from presentation of bills. If payment is made after 2 days and within a period of 30 days 1% rebate is allowed. Billing would be done by the generators after publication of REA by the 6th of the present month and payments made by beneficiaries within 2 days i.e. by 8th of the month should be entitled for a rebate of 2%. It is submitted that in case of holidays, the next working day can be applicable. However, the carrying cost of delayed payment has to be provided recognizing the time value of money. Otherwise, payment may be made on the previous working day.

34.6. **Authorized signatory -** As bills are issued by NTPC through ERP in standard format requiring no signature, authorized signatory may not be insisted upon.

34.7. Rate of Late Payment Surcharge should be on annual basis.

34.8. **Clarification on computation of late payment surcharge -** Hon'ble Commission may clarify whether late payment surcharge to be levied only after receipt of payment or on accrual basis (i.e., on completion of 60 days from the bill date irrespective of payment received). Sample calculation of late payment surcharge is as below:

Bill Date	Bill Amount (Rs.)	Payment Received (Rs.)	Payment Date	60th Day from bill date (Excluding	No. of days beyond	No. of days in the Year	Rate of LPSC (Annualized) %	Late Payment Surcharge (Rs.)
(A)	(B)	(C)	(D)	(E) = (A)+60	(F)=(D)-(E)	(G)	(H)	(I)=(C)x(H/100) x(F)/(G)
04-	10,00,00,000	2,50,00,000	06-08-2018	06-04-2018	4	365	18	49,315
		3,50,00,000	6/19/2018	06-04-2018	15	365	18	2,58,904
		4,00,00,000	6/29/2018	06-04-2018	25	365	18	4,93,151
Total	10,00,00,000	10,00,00,000						
	Total Late Payment Surcharge (Rs.)							8,01,370

Non-Tariff Income

1) *The tariff determination under Section 62 of the Act follows the principle of cost of recovery which inter-alia provides the reimbursement of cost incurred by the generating company or the transmission licensee. 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.*
2) *Presently, the revenue from telecom business is adjusted at the rate of Rs. 3000/- per km, which was fixed in 2007. It may need review.*

35. Comments / Suggestions – Non-Tariff Income

35.1. 100% ash utilization by coal based plants and free transportation of ash within a specified range of the power plant is mandated by law. Income on account of sale of fly ash, if any, is separately held in a dedicated fund and utilized towards achieving 100% ash utilization and transportation of fly ash to various beneficiaries within the specified range requiring ash.

35.2. Tariff provides recovery of 95% depreciation. When an asset is disposed after it is rendered unusable 5% cost remains unrecovered which is partly compensated through sale of scrap.

35.3. Advances are provided by the Generator through the funds / return on investment of the company and is not serviced in tariff as costs incurred.

35.4. Therefore, NTPC deducts miscellaneous non-tariff income heads such as income on account of sale of fly ash, disposal of old assets, interest on advances, etc., while reporting its operation & maintenance expenses. Such expenses are therefore excluded from the O&M expenses data reported by NTPC to the Hon'ble Commission.

Standardization of Billing Process

1) *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.*
2) *Some of the States are imposing electricity duty on the actual auxiliary consumption which may be higher or lower than the normative auxiliary consumption. Such electricity duty is passed on to the beneficiaries along with the monthly bill. Whether electricity duty is to be linked with actual auxiliary consumption or normative consumption or lower of the two, may need to be specified.*

36. **Comments / Suggestions – Standardisation of Billing Process**

36.1. **Electricity Duty on APC:** As regards the levy of electricity duty, same should be payable as per actuals. Electricity Duty is not retained by the generator and is in fact, passed onto the Centre. Therefore, the same should be allowed to be billed on actuals irrespective of the normative auxiliary consumption. The approach in this regard should be uniformly adopted by all states

36.2. **Provisional Tariff:** Specific provision may be introduced for generating station for issuance of provisional tariff pending the main tariff petition as in case of transmission assets.

36.3. **Billing:** Annual Fixed Charges may be billed based on cumulative allocation rather than based on monthly allocation. Generator is having long term PPA before setting up the project. Short-term beneficiaries are not part of the regular allocation of power of the station. In order to ensure that the rate charged for power supplied to all the beneficiaries in a financial year, the fixed charges needs to be calculated and to be billed based on the cumulative availability of the beneficiaries during the year instead of monthly allocation of fixed charges

Tariff mechanism for Pollution Control System (New norms for Thermal Power Plants)

1) *As per the new Environment norms notified by Ministry of Environment, Forest and Climate Change, the TPPs would be required to install or upgrade various emission control systems like Flue-Gas desulfurization ("FGD") system, electrostatic precipitators ("ESP") system etc. to meet the revised standards. Recovery of the investment made during operation period in the form of additional capitalization through redesigning or retrofitting of plant and related operational costs require a mechanism in the tariff regulations.*
2) *Several generating companies have filed petition for approval of additional capital expenditure 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.*

Option for Regulatory framework

3) *There is likelihood of significant impact on tariff on account of compliance with these norms. Supplementary tariff could be determined considering the followings.*
   i. *The principle of bringing the generator to the same economic condition if it is considered as change in Law.*
   ii. *Technical specifications based on the difference in actual emission and revised emission, proposed technology, construction period, phasing plan for shutdown during the construction period;*
   iii. *Feasibility of undertaking implementation of new norms with R&M proposal for plants having low residual life, say, less than 10 years.*
   iv. *Change in Auxiliary Consumption and operation and maintenance expenses due to implementation of pollution control equipment.*

4) *Comments and suggestions are invited from stakeholders on*

i. *Possibility of reducing funding cost through suitable change in debt:equity requirements. Relaxation in funding from equity may be introduced and the rate of return on equity may be aligned with the interest on debt;*

ii. *"Debt Service obligation during construction period and recovery of depreciation" may be provided with the condition that such depreciation may be adjusted during the remaining period;*

iii. *As the level of emission is linked to actual generation, it would be appropriate to link recovery of supplementary tariff with the actual generation or availability or combination of both.*

37. Comments / Suggestions - Tariff mechanism for Pollution Control System (New norms for Thermal Power Plants)

37.1. Cost of pollution control system like FGD Flue-Gas desulfurization ("FGD") system, electrostatic precipitators ("ESP") system etc. are the sunk cost and are in form of direct capital investment consisting component of equity and loan. The treatment of such investment is no different from the investment made in any new project. Thus it may not be prudent to have two separate approaches for original investments made on the project and the additional investment for installing pollution control system which is required due to uncontrollable factors (statutory requirement). It is sincerely submitted that a uniform approach may be adopted for determining the additional fixed charges to the generator. Such investment may be treated as additional capitalization on account of change in law and serviced in tariff. Providing returns at the cost of debt on the equity portion is neither equitable nor fair as it would not provide any compensation to the additional risk of environmental compliance borne by the generators. If equity portion is also serviced at cost of debt, any under recovery would lead to situation where repayment of loan may be affected. Further, substantial investment on this account would be required in the next tariff period and all cost prudently incurred needs to be serviced in Regulations.

37.2. It is also submitted that as installation of such system is mandatory and a statutory requirement, incremental impact on the Auxiliary consumption or other operational parameters should be considered as uncontrollable and may be passed on to the beneficiaries. Alternatively an appropriate additional norm may be derived from existing data to be allowed for the projects which install such pollution control systems.

Renewable Generation by existing Thermal Generation Stations

1) *The Revised Tariff Policy dated 28th January, 2016 provides for setting up of renewable energy generation capacity by existing coal based thermal power generating station. The Policy provides that in case any existing coal and lignite based thermal power generating station chooses to set up additional renewable energy generating capacity with the concurrence of power procurers under the existing Power Purchase Agreements, the power from such plant shall be allowed to be bundled and tariff of such renewable energy shall be allowed as pass through by the Appropriate Commission. The Obligated Entities who finally buy such power would account this power towards their renewable purchase obligations(RPOs). Scheduling and dispatch of such conventional and renewable generating plants shall be done separately.*

2) *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 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.*

3) *The scheduling and dispatch mechanism of renewable generation can be as per the thermal power generation. The target availability and dispatch level, in this case, maybe pre-specified which may be 2% higher for every 10% renewable capacity addition and the annual fixed charges for the thermal project and renewable project maybe combined for deciding the tariff. The rate of return, land cost, operation and maintenance cost for such renewable capacity can be specified separately.*

38. Comments / Suggestions –Renewable Generation by existing Thermal Generation Stations

The existing mechanism for bundling RE generation set up at thermal power stations is established and is working well. In case of upcoming projects mandatory roof top solar generation is required to be set up as per the MOEF environment clearance. In such plants, the Capex of installing rooftop RE may be allowed along with Capex of thermal power plant. RE generation on this account would be provided at no further cost. Additional generation may be accounted and factored while fixing the APC norms.

The Govt. of India has issued mechanism for replacing thermal generation by RE generation in order to reduce emission and facilitate addition of RE capacity. It is submitted that implementation of the scheme may facilitated through appropriate changes in the Regulations. To facilitate addition of capacity under this scheme, the RE generation may be exempted from transmission charges and losses.

Commercial Operation or Service Start Date

1) *The commissioning of the generating stations and transmission systems and their commercial operation is declared after successful completion of the trial operation/run. In case of transmission system, it is ensured that an element of the transmission system is in regular service after successful charging and trial operation adequate load has delayed the trial operation and commissioning of the plants. There is also an issue of mismatch between the commercial operation of a generating station and the associated transmission systems which has had an impact on specifying COD and consequently, on the IDC of the generating station or the transmission system.*
2) *There may be a need to specify a methodology of trial operation for generating station and transmission system and ensuring regular use of service in case of transmission system. Similarly, the methodology of trial operation for bay equipment, Inter-connecting transformer, Reactors, Fixed Series Compensation, and transmission lines may need to be specified.*

3) *Data telemetry, communication and restricted governing mode of operation are requirements of system operator to monitor real time grid operation and for grid stability. There is a need to ensure completion of data telemetry and communication by RLDCs/ NLDC/ SLDCs for declaring COD of transmission system/ generating station and operationalization of Restricted Governing mode of Operation (RGMO) in case of generating station.*
4) *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 or for Indemnification Agreement.*

Comments/ Suggestions

5) *Comments and suggestions are invited from the stakeholders on possible options for dispute-free and practical mechanism for declaring commercial operation date. Comments and suggestions are also invited on the following.*
   a. *Addressing the shortcomings in existing methodology for the trial run of generating station and trial operation for transmission element through appropriate regulatory mechanism;*
   b. *Issue of trial operation and commissioning of the project when a generating station is ready but cannot be operated due to non-availability of load or evacuation system;*
   c. *Issue of acceptance of COD of transmission line if the generating project or upstream/ downstream transmission assets are not commissioned;*
   d. *Pre-requisite of completion of data telemetry and communication facilities for declaring COD of transmission system and operationalization of RGMO for declaring COD of generating station;*
   e. *Linking of commercial operation date with schedule commercial operation or schedule commencement date of the Power Purchase Agreement or Long Term Access Agreement respectively;*

f. *Linking the commercial operation date of the transmission system with the commissioning of the generating units or stations;*
g. *Separation of the commercial operation date of the unit or stations, the transmission element or system from the service start date under the contract.*

39. <u>Comments / Suggestions –Commercial Operation or Service Start Date</u>

39.1. At present Grid Code provides for successful trial operation a thermal generating unit shall run at Maximum Continuous Rating or Installed Capacity or Name Plate Rating for a continuous period of 72 hours with cumulative interruptions of not more than 4 hours with extension of trail run duration corresponding to period of interruption. Further, in case of partial loading or interruption the average load shall be equal to MCR / IC.

39.2. It may be pertinent to mention that running a thermal generating unit at constant load at MCR/ IC continuously for 72 hrs. is not possible. The unit load fluctuates due to coal quality variations, cut-in and cut-out of stand by mills/ equipment etc. Sometimes load fluctuation may be in the range of 8-10% due to mill change over or other process fluctuations, therefore to achieve an average unit load of MCR/ IC for continuous 72 hrs, units has to be run at loads greater than IC to make up for the partial loading which may not be suited for new units. Accordingly, for successful trial run average load for 72 hrs may be specified at 95% of MCR/ IC.

39.3. **<u>7 day Notice to Beneficiaries in case of Repeat of Trial Run</u>**: As per the above in case of interruptions of more than prescribed 4 hour at present, repeat trial run is required and a notice of 7 days is to be given to beneficiaries for repeat trial run to be conducted. It has been seen that there could be trial run interruption due to outage of any auxiliary equipment, malfunctioning of any relay and other minor reasons. Such problems could be attended to in a short period and trial operation can commence immediately thereafter. However difficulty has been face in implementing the provision as the repeat of trial run again requires a notice of minimum seven days. This delays the trial run and subsequent declaration of commercial operation. The 7 day notice period may have been kept to enable the beneficiaries be physically present and witness the trial run. However, the actual performance of the unit is assessed by the data of the energy meters installed at the power stations. Also, even when unit could be restored in short period, for repeat trial run one has to wait for 07 days, this cools down the machine and takes longer period for restart –up leading to increased fuel consumption which increases the capital cost. Accordingly, it is suggested that Hon'ble Commission could do away with the requirement of 7-day notice in case repeat trial run is started within 7 days of the interruption of trial run for which the notice was served onto the beneficiaries & RLDC. Delay of commercial operation is not in interest of either the generating company or the beneficiaries and is not the intent of the Regulations. Accordingly, provision related to 7 day notice to the beneficiaries in case of repeat of trial run if the same is started within 7 days of interruption of earlier trial run may be done away with.

39.4. **Interruption period of 4 hours**: The maximum interruption period allowed during the trial run is 4 hours. The period of 4 hours is considered less because once the unit trips the boiler temperature and pressure parameter reduces rapidly. The turbine temperature is less affected. To start rolling of turbine, raising of boiler steam parameters, as per the permissible gradient to match turbine metal temp takes considerable time. It takes around 7 hours from unit tripping to bring back unit parameters for synchronization and full load, including intermediate activities as given below:

i. Tripping analysis & rectification of tripping cause- approx. 1 hr.
ii. Achieving required chemical parameters for boiler light up & turbine rolling - approx. 1hr.
iii. HP heater charging, feed water loop change over, FW pump operation and wet to dry mode changeover require more than 90 min. Further load is raised as per prescribed ramp rate (as per the curve attached) to bring the unit to full load and stabilize.

It is seen that in case of tripping of the unit, it is not possible to bring back the unit to full load within the specified period of 4 hours due to inherent design of the system. Accordingly, total time of interruption may be increased to 8 hours for the trial run considering that each start up requires an average of 7 hours.

In case, when a generating station is ready but cannot be operated due to non-availability of load or evacuation system then may not be able to conduct trial operation as per the applicable provisions due to non-availability of the transmission system. In such cases, if the generator may demonstrate the readiness of its system by achieving 3000 rpm then the generating unit may be declared deemed COD and the Full Fixed charges may be allowed from the date of demonstration of readiness of systems by the generator.

39.5. Further, present provisions provides for recovery of transmission charges from the generator in case when the evacuation system is ready and generator is not ready. Regulations need to clarity that in such cases generator shall be liable to pay the AFC of the transmission system created specifically for evacuation from the station till COD of the generating station so that there is no additional burden on the beneficiary due to delay of generating station. Further in case of multiple generating units, AFC of associated transmission system corresponding to generating capacity declared commercial may be recovered through POC to be paid by the beneficiaries. The balance AFC of the transmission system corresponding to generating capacity not declared commercial may be paid by the generator. POC charges of entire system shall be payable by the beneficiaries from COD of the station.

39.6. Similarly, it is suggested that when generator is ready and evacuation system is not ready then liability of Annual Fixed charges, IDC and IEDC shall be on the transmission licensee.

39.7. Provisions of the Regulations shall be equitable. **Accordingly, similar penal provisions may be introduced in case of delay of non-commissioning of transmission lines.**

Energy Storage

1) Deployment of grid storage is at a nascent stage and there is no policy or regulatory framework as regards storage. However, its importance is well recognized. The need of grid level battery storage cannot be undermined in areas such as frequency regulation, renewable generation, generation shift etc. In this respect, a staff paper *was circulated on 4th January, 2017 underlining the need of energy storage system and various options for its uses.*

2) *In the paper, two different uses of energy storage for regulatory framework were considered, one as a part of the inter-state transmission system and other as a part of inter-state generation station. The grid level storage system established by the transmission system owner has similar characteristics to that of transmission because it acts as intermediary for conveyance of the electricity from generator to the procurer covered within the Section 79 (c) of the Act. 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.*
3) *The regulatory options available for implementation of the energy storage system for use are to combine the tariff with transmission and generation projects. Storage facility as a part of inter-state transmission system may be subjected to regulatory approval while storage facility as a part of the generating capacity may be as per the consent of the procurer for availing storage facilities.*
4) *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. Energy storage at transmission level can be used for overall optimization of power from the grid, irrespective of the owner of storage capacity and may be dispatched when needed. Such dispatch can be added in the drawl schedule of all beneficiaries of the region on ex-post basis. Alternatively, the energy storage at transmission level can be used as ancillary support services. The specific operational procedure can be devised for transmission level grid storage.*
5) *The annual fixed charges of energy storage system may be determined separately as per pre-specified operational and financial norms by the Commission. The energy storage at generation level would be used for storage of generation output. The supplier may use it for optimization of the generation dispatch specific to their designated beneficiaries within the power purchase agreement. The generating stations may use it to avoid the flexible operations due to frequent regulations. The specific operational procedure can be devised for generation level grid storage.*

6) *The annual fixed charges of the storage facility can be determined based on ramping rate, auxiliary consumption, Return on Equity (ROE), Interest on Loan, Depreciation, Operation & Maintenance cost and Interest on Working Capital.*

40. Comments / Suggestions – Energy Storage

Considering that the energy storage systems whether integrated with the generating plant or independent of the generating plant may be treated similar to the existing storage technology i.e. pumped hydro storage projects. The annual fixed charges for the same may be computed based on the major fixed cost parameters such as Return on Equity (ROE), Interest on Loan, Depreciation, Operation & Maintenance cost and Interest on Working Capital along with considering the operational parameters such as ramping rate, auxiliary consumption and life of the project/reinvestment to be made.

Alternative Approach to Tariff Design

1) *Tariffs for generating stations and transmission systems are determined by the Commission as per the terms and conditions specified in the Tariff Regulations as applicable from time to time. Currently, CERC (Terms and Conditions of Tariff) Regulations, 2014 are in place. The tariff regulations provide for detailed procedure for computation of different components of tariff and the generating companies / transmission licensees are required to file tariff petitions with requisite details in accordance with the provisions of the regulations. The Regulations provide for a two part tariff for a generation station, viz. Fixed Cost (Annual Fixed Charge – AFC) and Energy Charge (EC). For a transmission licensee the tariff comprises only the Fixed Charge.*

2) *The Annual Fixed Charge (AFC) is determined based on the admitted capital cost as on the Date of Commercial Operation (COD) after carrying out prudence check of the individual component of costs. In this process, the Commission examines vast data which is required to be submitted before it in respect of each of the components to arrive at permissible costs for recovery through tariff. Accordingly, substantial efforts are made towards determination of Annual Fixed Cost which constitutes on an average 30% – 40% of total cost of generation. It has often been argued by*

various stakeholders at different fora, that such a system of elaborate examination of data to determine AFC needs a revisit. It is in this context that an alternate approach to tariff determination is proposed.

Normative Tariff by Benchmarking of Capital Cost

1) *Capital cost is the starting point for tariff fixation. Therefore, the first question that arises is as to whether the capital cost could be determined on normative basis as against the existing practice of detailed cost component wise examination?*
2) *In order to benchmark the capital cost of various generating stations (sample size 30) of varying vintage, unit size, fuel type etc. was analyzed. The Normative Value of the capital cost per MW approved by the Commission during the year of Commissioning of respective sample plants was calculated by applying the normalization factor of 6.85%. The normalization factor was computed taking average of the WPI inflation from the FY 1988-89 to FY 2013-14. It was observed that the distribution of capital cost per MW is denser near the Mean and Median i.e. Rs.6.30 Crore/MW. However, the standard deviation for the above distribution was as high as Rs.2.44 crore/MW. It showed that the Capital Cost per MW of the sample plants varied from Rs.3.87 Crore/MW to Rs.8.74 Crore/MW.*
3) *This variation could be attributed to many factors such as cost of land & site development, project specific Sub/Super critical status of the Plant, technology & equipment and material handling system which includes distance from the Coal Mine etc. In case of COD delay, Interest during construction, financing charges, taxes and duties etc. might have impacted the total project cost. This high variation indicates a need to conduct a more rigorous component-wise analysis of Capital cost for generation as well as transmission projects and understand the deviation to figure out appropriate benchmark capital cost for thermal generation stations.*

4) *Views and comments are therefore being solicited on the following questions:*
   i. *Would it be advisable to undertake econometric analysis to arrive at benchmark capital cost?*
   ii. *What are the variables that should be considered for the purpose of determining Capital Cost on normative basis?*

iii. *Any other methodology for benchmarking the capital cost for generation and transmission projects?*

41. Comments / Suggestions –Benchmarking of Capital Cost

41.1. As regards fixing the Capital Cost based on benchmark norms, as rightly pointed out in the discussion paper that different projects have different features and site conditions, and the cost varies based on project specific or site specific features and, it may not be appropriate to consider the benchmark capital cost for determination of tariff.

41.2. Capital cost depends on host of factors including the choice of technology – sub critical /super-critical, equipment specifications, distance of coal & water source, type of coal used - domestic / imported and its ash content, geographic location, requirement of compliance to environmental norms like mandatory use of sewage water, FGD, etc., and market conditions. In other words, due to various factors, capital cost may vary widely across projects. Therefore, benchmarking capital cost may not very accurate and effective. Peculiarities of projects with respect to certain design requirements needs to be factored over and above the arrived benchmark cost. Updating of benchmark capital cost with data of new projects is also required for a robust model.

41.3. Most of the upcoming plants are of 660/800 MW unit size and number of units of similar capacities already in operation will not be adequate for appropriate sample size for benchmark for future units. The determination of capital cost seems to be cumbersome task without corresponding benefits and its impact on the stakeholders is also very high. Wide variations in the capital cost from project to project, would necessitate component wise prudence check, and hence this may become even more complex than separately taking up prudence check of all the projects as is being followed now.

41.4. Considering the same, the existing approach of prudence check of capital cost approval may be continued and the benchmark capital cost may be used only for comparison purpose to have a reference check.

Normative Tariff by fixing AFC as a percentage of Capital Cost

5) *As the next potential option for determination of tariff on normative basis, the possibility of fixing total AFC as a percentage of initial capital cost, is explored. In this context, sample size of 30 generating stations was examined to analyse the AFC of first year of operation as a percentage of the approved capital cost. It was observed that correlation coefficient between AFC approved for the first year of operation and approved capital cost was around 0.84. Similarly, correlation coefficient between average AFC approved per year (till FY 2016-17) and capital cost was 0.95. The significant correlation between AFC and capital cost indicates the possibility of benchmarking AFC as percentage of capital cost to save resources and time spent on conducting component wise prudence check. However, a further analysis showed Mean of AFC as percentage of Capital Cost as 22.55% and standard deviation for the distribution was as high as 7.17%.*
6) *The available data and the connected analysis highlights the necessity for a larger database facilitating bigger cluster-wise sample sizes and a more rigorous exercise, which could possibly facilitate drawing conclusions about whether AFC could be normatively determined by considering it as a percentage of capital cost.*
7) *In this regard, views/ comments are solicited on the following:-*
   i. *Whether it is a good idea to determine AFC as percentage of Capital Cost on normative basis?*
   ii. *What could be the possible methodology to establish the relation between AFC and Capital Cost so that it meets the interests of both buyers and sellers?*

42. **Comments / Suggestions – Normative Tariff as % of capital Cost**

As pointed out in the discussion paper itself, the normative AFC may result in high standard deviation, in such scenario adopting of this approach may not be a good idea which can result in exorbitant profits to one and losses to other.

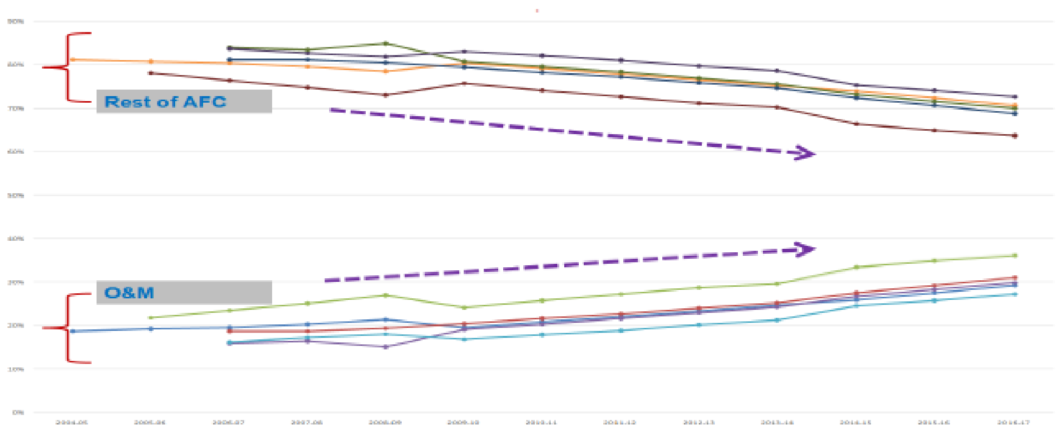
AFC can be determined as a percentage of capital cost on normative basis based on pre-determined factors fixed by the Commission for each year from COD to life of the plant. But before attempting to fix these factors, a large data base needs to be gathered so that the results are more accurate. Further, there needs to be true-up with the actuals every five years so that interests of both seller and buyer are protected. Certain unavoidable / uncontrollable / reasonable add-cap expenditures / expenditure on account of meeting new environmental norms / change in law / pay revision, etc., have to be allowed as an additional revenue stream by the Commission on a case to case basis. Further in order to have regulatory certainty, existing plants should be governed by the same set of tariff principles as applicable on their COD.

Normative Tariff by fixing each component of AFC as a percentage of total AFC

8) *Given the constraints as explained above, the option of determination of tariff on normative basis by fixing each component of AFC as percentage of total AFC was considered. A sample size of 30 generating stations was considered to examine trends of various components of AFC as percentage of total AFC. Accordingly, trajectories of each of the five components of annual fixed cost (i.e. return on equity, interest on loan, depreciation, operation and maintenance, interest on working capital etc.) of the generating stations of the same sample size were drawn for the period from CoD till 2016-17.*

9) *It was observed that for all generating stations, in general, the trend of component “Operation & Maintenance” was found to be increasing, while the other components were either decreasing or remained static. In order to further analyse, the “Operation & Maintenance” component was isolated, while keeping the remaining components as one group. Such segregation indicated clear trends. The graph for “Operation & Maintenance” and “Rest of the Components of AFC” for the generating stations with CoD from 2004 (sample size 10) onwards is provided below.*

"O&M" and "Rest of the Components of AFC" for the generating stations with CoD from 2004 onwards



10) *Therefore, in order to determine tariff on normative basis, as the next possible option, components of AFC could be clustered into two groups, i.e. "Group of AFC Components which escalate / increase over the period" and "Group of AFC Components which de-escalate / decrease over the period". Each group may be assigned with a factor (escalation or deceleration factor), as the case may be. Such increasing / decreasing factors will be determined by the Commission for each year separately.*

11) *However, the above analysis also highlights that the overall trend line impacted on account of two major factors, viz. "Additional Capitalization (Add. Cap) / De Capitalization (De Cap.)" and "Change in Control Period".*

12) *The component of "Additional Capitalization (Add. Cap.)" assumes significance as it causes change in the Capital Cost. The current provisions allow additional capitalization, primarily to meet the expenditure towards the left over works from the original scope of work. This Additional capitalization is permissible for a period from the CoD upto the "Cut-Off Date". The Regulations indicate "Cut-Off Date" as 31st March of the year closing after two years of the year of commercial operation of whole or part of the project, and in case the whole or part of the project is declared under commercial operation in the last quarter of a year, the cut-off date shall be 31st March of the year closing after three years of the year of commercial operation.*

13) *Hence, the generator has approximately three years duration beyond CoD for additional capitalization. Therefore, in order to provide regulatory certainty, the "Additional Capitalization" could be strictly restricted to the period between "CoD" and the "Cut-Off Date". This would imply that the "Capital Cost" as on "Cut-Off Date"*

would remain unaltered for the rest of the useful life of the plant. However, any reasonable expenditure in future, such as cost towards meeting new environmental norms etc. if considered uncontrollable / unavoidable may be treated as a separate stream of revenue and recovery could be allowed as a separate component on annuity basis.

14) *The next issue is surge/ dip owing to change of control period. As per current practice, for each control period, the revised tariff principles are made applicable on new as well as existing generating stations. Such revision in principles, viz. change of RoE, O&M etc. causes a sudden surge or dip in the trend of the respective components. Therefore, in order to provide regulatory certainty, it could be proposed that the revised tariff principles of each control period be restricted to the new plants commissioned during that control period only. In other words, the existing plants could continue to be governed by the same sets of tariff principles as applicable on their CoD.*

15) *In this context comments/ observations of stakeholders are invited on the following points.*

i. *Whether clustering the components of AFC based on their nature to increase/ decrease in order? Any other possible method to cluster the AFC components?*

ii. *What methodology should be adopted to determine the escalable (increasing)/ non-escalable (decreasing) factors?*

iii. *Whether escalable (increasing) / non-escalable (decreasing) factors should remain same for all plants/transmission systems (or) they be separate for each of the plants/transmission systems based on vintage / capacity / fuel type/ fuel linkages etc.*

iv. *Whether isolation of "Additional Capitalization" as a separate stream of revenue would provide for recovery of AFC on a normative basis in realistic terms?*

v. *Alternatively, do you suggest any other methodology to treat "Additional Capitalization" for determination of AFC on normative basis?*

vi. *Whether applicability of change in tariff principles in each control period for the new plants would allow regulatory certainty to the existing plants?*

vii. *Alternatively, is there any other methodology to minimize the impact on AFC on account of change in control period?*

43. Comments / Suggestions – Normative Tariff by fixing each component of AFC as a percentage of total AFC

Under the current approach, the Commission based on the historic performance of a particular projects or the industry practices either finalizes the normative cost parameters specific to each component (such as O&M expenses, IWC, RoE, Depreciation) or allows certain costs based on their actual expenses like Interest on Loan with provision of sharing of gains. Allowing the cost on such approach is well received and accepted by the generators as well as the beneficiaries. It also allows the generators to recover its cost and passes-on only the reasonable cost to the beneficiaries. Further, it provides flexibility to vary performance and financial norms as per the prevailing conditions and address various issues on account of external factors, change in law and other risks so as to have the optimum impact. Benchmarking various cost components as % of capital cost may result in un-accounted errors and uncertainties vis-à-vis the actual/prudent costs. Validation of such approved fixed cost parameters would also be possible only by comparing it with the actual or the benchmark costs in absolute amounts. Thus, if it is possible to approve each cost component on reasonable basis it as being done under the existing approach, it would not be prudent to use percentage benchmarking.

Moreover, claims of either under recovery of tariff by the Generator or over recovery of tariff by the beneficiaries would require component wise prudence check by the Regulator which would defeat the objective of simplification in the exercise determination of tariff. Therefore, if component wise detailed prudence would be anyway be necessitated, which is carried out through present approach of tariff determination very well, there seems no advantage in adopting the suggested approach. It is submitted that the present approach may be continued.

Principles of Cost Recovery - Approach towards Multi-Part Tariff (Differential Peak and Off-peak AFC recovery)

1) *The Commission introduced Availability Based Tariff (ABT) in the year 2000. Under the Availability Based Tariff (ABT), the annual bulk power tariff for supply of electricity from a generating station of a generating company as determined by the*

Central Commission comprises two components, viz. Annual Fixed Charges (AFC) and Energy Charge (EC). The fixed charges are payable fully on achieving the plant availability factor as per the benchmark level specified by the Commission. All the generating stations regulated by CERC are required to follow the scheduling and dispatch mechanism specified by the Commission. The generating station has to declare availability on daily basis. The failure to achieve the target plant availability factor leads to dis-incentive in terms of reduction of the fixed charges on proportionate basis, and there is a provision for incentive for actual generation above the target availability factor.

2) *In the emerging scenario of slackness in demand, growing penetration of RE, the overall utilisation of generation assets (PLF) has been decreasing. However, in the current circumstances, once the generator declares plant availability at the normative level of 85%, the distribution utilities are required to pay the AFC in full irrespective of scheduling of energy. There is a rationale behind this framework. The fixed cost is sunk as the asset is created to service the buyers on long term basis. Hence there is a need for certainty of recovery of investments. However, the changing circumstances have highlighted the need for a re-think on the approach of fixed cost recovery (based on uniform availability throughout the year). The proposition in the succeeding paras stems from this background.*
3) *The proposition is to introduce the system of differential AFC recovery linked to peak and off-peak periods in the following manner:-*
    1. *Off-peak component of AFC: The generating station has to declare a PAF of 80% for the year, which allows recovery of 80% of the AFC. Any slippage to meet the above norm would result in reduction in 80% of AFC in proportionate manner.*
    2. *Peak component of AFC: The remaining 20% of the AFC is recoverable from the beneficiaries, if the generating station achieves a PAF of 95% for the peak period, say of 4 months. During the currency of peak period, adherence to the norm of 95% PAF will be reconciled on monthly basis and slippages from this norm i.e. 95% upto the limit of 80%, would result in reduction in higher peak AFC for that month.*
    3. *The peak and off-peak months for each generating station will be declared bythe appropriate RLDC by considering load profile of beneficiaries.*

4) *The proposed mechanism also seeks to provide for a higher peak price, say at 25% over the off-peak price. Accordingly, the weightage factors can be calculated by considering:*
   i. *Recovery of 80% of AFC, upon declaration of 80% PAF during the year and remaining 20% of AFC upon achieving 95% PAF during the peak period, say of 4 months.*
   ii. *Higher peak price (i.e. by 25% over the off-peak price)*

5) *In this context, comments of stakeholders are invited on the following points.*
   i. *Does the proposal of differential recovery of AFC by segregating into peak and off-peak periods balance the need for both the buyers and sellers?*
   ii. *What could be the weightage factors for peak and off-peak periods along with the PAF for each segment?*
   iii. *What could be other mechanisms to arrive at peak and off peak AFC tariffs?*

44. Comments / Suggestions –Differential Peak and Off-peak AFC recovery

44.1. The following sample computation has been undertaken for Singrauli STPP Stage 1 and 2 under different scenarios on the proposed mechanism for differential peak and off-peak recovery of fixed charges.

Fuel and Capacity Charges:

Particulars	**Rs. crore**
Capacity Charge	825.91
Fuel Charge	1885.02
Total	**2710.93**

Scenarios: Plant Availability Factor & Plant Load Factor

Monthly PAF Profile	Scenario 1 (Actual)	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6
April	95.00%	95.00%	95.00%	85.00%	90.00%	90.00%
May	95.00%	95.00%	95.00%	85.00%	95.00%	100.00%
June	95.00%	95.00%	95.00%	85.00%	95.00%	95.00%
July	95.00%	95.00%	95.00%	85.00%	95.00%	95.00%
August	86.66%	80.00%	100.00%	85.00%	85.00%	80.00%
September	86.66%	80.00%	100.00%	85.00%	80.00%	80.00%
October	86.66%	80.00%	100.00%	85.00%	80.00%	80.00%
November	86.66%	80.00%	0.00%	85.00%	80.00%	80.00%
December	86.66%	80.00%	40.00%	85.00%	80.00%	80.00%
January	86.66%	80.00%	100.00%	85.00%	80.00%	80.00%

Monthly PAF Profile	Scenario 1 (Actual)	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6
February	86.66%	80.00%	100.00%	85.00%	80.00%	80.00%
March	86.66%	80.00%	100.00%	85.00%	80.00%	80.00%
PAF - Yearly	**89.44%**	**85.00%**	**85.00%**	**85.00%**	**85.00%**	**85.00%**
PAF - for non-peaking months	**86.66%**	**80.00%**	**80.00%**	**85.00%**	**80.63%**	**80.00%**
PAF for peak months	**95.00%**	**95.00%**	**95.00%**	**85.00%**	**93.75%**	**95.00%**
PLF - Yearly	**79.73%**	**85.00%**	**75.00%**	**65.00%**	**55.00%**	**45.00%**

Impact analysis of proposed differential peak and off-peak recovery of fixed charges

Particulars	Scenario 1 (Actual)	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6
Off-peak Fixed Charges	660.73	660.73	660.73	660.73	660.73	660.73
Peak Fixed Charges	165.18	165.18	165.18	147.79	163.01	163.01
Total approved AFC - Based on NAPAF	825.91	825.91	825.91	825.91	825.91	825.91
Benefit / (Loss)	**0.00**	**0.00**	**0.00**	**-17.39**	**-2.17**	**-2.17**

44.2. In all the above scenarios, the Annual Plant Availability Factor has been kept equal to the NAPAF i.e. 85% and if the existing approach is continued the generator would recover the full fixed charges. However it may be observed that with the proposed mechanism (in discussion paper) of introducing the differential peak & off-peak recovery of AFC there would be multiple scenarios wherein the generator would be incurring the losses. This clearly demonstrates that the proposed mechanism for differential peak and off-peak recovery of fixed charges is not revenue neutral and seems to benefits the procurers.

44.3. Further, the proposed mechanism differentiates between peak and off-peak months and not between peak and off-peak hours. With considerable expected solar capacity addition in the system, there will be huge demand variation within a day. Thus, having a differential peak and off-peak tariff would be more relevant as compared to monthly variation. The same will also be in line with Tariff Policy which clearly mentions that the Commission shall introduce differential rates of fixed charges for peak and off-peak hours.

44.4. Considering the fact that it is difficult for coal based plants to run with too much variation in load within a day, and they may have to compromise on their efficiency. The mechanism for Peak and off-peak differential tariff should be designed in such a way that any additional cost on account of loss in efficiency gets pass through and rather generating stations should be given some additional incentive for operating the plant with such flexibility.

44.5. Although in the discussion paper it is mentioned that the higher peak price (i.e. by 25% over the off-peak price) shall be provided, however same does not fit into the overall calculation. The same may be clarified.

44.6. The scheme proposed by the consultation paper providing Peak / off-peak season seems to be tilted towards the beneficiaries. NTPC stations being regional stations have beneficiaries across the region each having a different peak season. Maintaining 95% PAF during peak season of say 2 months during summer and 2 months during winter or 4 months at a stretch would require supply and stock of requisite fuel in the peak season and reduced supply during the balance period. In order to maintain such higher availability (95%) in a specific month or period, matching fuel tie-up would be recovered necessitating changes in FSA. Accordingly, enhanced coal supply and transport logistics to handle enhanced PAF and dispatch would be required. Further, risk due to forced outages / and other factors would increase for which there is no additional incentive. Therefore, higher efforts and risk to maintain 95% PAF needs to be incentivized accordingly. Otherwise it is a losing proposition for the generator. Such additional risk should be appropriately taken into account while allowing the Rate of return on Equity investment or increased peak tariff resulting in the form of possibility of earning additional fixed charges or incentive.

44.7. The Tariff Policy mandates peak and off-peak differential tariff on day basis. Therefore, the peak and off peak tariff may first be implemented on a day basis instead of season basis. This is also required as there is clear peak and off-peak demand on a daily basis. Moreover, this is easy to handle with respect to arranging fuel and other inputs. Already peak off peak tariffs have been introduced in consumer tariff by various SERCs.

Transparency in Billing and Accounting of Fuel

1) *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.*

45. Comments / Suggestions

It is to be noted that already detailed data related to procurement of fuel is given in Form 15. Form 15 for last 3 months is also available on the Company website. Therefore, transparency already exists in the present system.

Relaxation of Norms

1) *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.*
2) *In such situations, the present regulatory framework provides for relaxation of norms.*

46. Comments / Suggestions

46.1. The excess power consumption due to the installation of pollution control system and other requirements which are compulsory should be considered as uncontrollable for the generator and should be appropriately passed on the beneficiary.

46.2. **Additional Margin for MDBFP for 660 MW and 800 MW units:** APC of 2.5% has been allowed on account of MDBFP. However, in case of 660 and 800 MW supercritical units, additional power consumption on account of MDBFP (drawing power at GT terminals after stepping down of voltage) will be about 4%. This is due the fact that Steam-driven BFP draws motive power from IP exhaust and convert the thermal energy into shaft energy whereas in units with MDBFP electrical power is drawn by drive motor which involves losses due to multiple energy conversions stages such as LP turbine losses, Generator, Transformer, Motor and Hydraulic Coupling losses. Also for supercritical units more power is required due to increased boiler pressure and consequent increase in head required for boiler feed pump. Based on the actual plant data for 660 MW unit, the difference in APC between units with Steam Driven BFP and units with electrically driven BFP comes out to be 25.94 MW (i.e. 3.93%) against the provision of 16.5 MW (2.5%). The net heat rate of the plant nevertheless remains almost same in case of TD and MD BFP. The choice therefore does not affect the variable cost of electricity to the consumer. **Therefore, it is suggested that 4% additional APC may be allowed on account of MDBFP in supercritical units as the same are more suitable for flexing operations due to inclusion of more renewable power and rapid load changing requirements.**

46.3. **Additional Margin for Stations with Tube Mills:** For 500 MW Units (Vindhyachal-II, Talcher Kaniha-I & Unchahar-II) having tube mills, the power consumption of these mills are more than two times higher than the normal BHEL bowl mill units. So these units maintain high auxiliary power consumption and APC of these units likely to go above the norms due to further partial loading and deterioration in coal quality. Many times an additional mill is kept in service to cater to the higher feeding rates of coal due to poor coal quality. Such requirement leads to an additional power requirement in the order of 1400 to 1500 KW which further increase the auxiliary power consumption by about 0.3 %. Since for these units, design mill power consumptions is 2-3 times higher than normal mills, **the units having tube mills should be given additional APC margin of 1%.** Additionally as the units are becoming older, the same level of performance cannot be expected to be sustained as reflected in data.

46.4. **Additional Margin for Pipe Conveyor and Associated Conveyors:** In coastal plants, transportation arrangement for coal from the unloading berth to the CHP of the plant, pipe conveyors along with associated conveyors may be employed (for example in Vallur TPS-NTECL). **This requires additional margin of 0.5% in APC.**

46.5. **Additional Margin for Station with distantly located water source:** Additional APC of 0.5% may be provided for plants employing Reverse Osmosis (RO) / Desalination Technology for meeting water requirement from sea water/ cooling water requirement from sea water. If water source is beyond 5 km from the plant, additional relaxation of APC needs to be provided.

46.6. **Coal Quality Deterioration:** With deterioration in coal quality, auxiliary power of the units is increasing to meet the requirements of additional mill running apart from increased power consumption by ID & PA Fans. The impact of such deterioration in a typical 500 MW Unit is expected to be to the tune of 650 to 700 KW. This would increase the auxiliary power consumption by around 0.2% during the next tariff period.

46.7. **Cyclic Operations:** Also, cyclic operation of the stations is increasing on account of low Grid schedule and increasing renewable penetration. APC of the stations are increasing and the same will further increase if units are forced to two shift operation. With every such shut-down, start-up, the auxiliary power consumption of the unit increases and hence the same level of performance cannot be maintained on a sustainable basis in future. Provision for additional APC may be provided in such cases. One alternative could be that auxiliary energy consumed during plant/ unit shut down for start-up, preservation, R&M activities may not be considered as part of APC and may be settled as per DSM regulations as amended from time to time.

46.8. **New Environment Norms:** In order to meet the new environment norms, FGD, NOx control systems and ESP upgradation are being done. Installation of new system, such as, FGD, etc. will result in increase in APC. This increase in APC will vary from plant to plant depending upon the technology and configuration used for pollution control systems being installed. Further, for example, for limestone based FGD the by-product is gypsum. Additional systems are also required for handling these byproducts which require additional APC. Further, such systems are new in our country and have no adequate data base for considering additional APC on normative basis. However, such technologies/ systems is more prominent in developed countries. The details of such systems installed in other countries may not be suitable for Indian conditions as the same is dependent on coal quality, ambient temperatures etc. Accordingly, additional APC may be allowed on normative basis and the same may be trued up based on actuals. After some period, say next tariff period the same may be considered on normative basis as proper data base may be available then for fixing additional APC on account of pollution control system.

Merit Order Operation

1) *Though merit order is a dispatch issue, scheduling/ non-scheduling has its impact on purchase cost. It is seen that in respect of certain old plants having low fixed costs, their power may not get dispatched as the merit order is based on variable cost, which may be high.*

2) *The merit order operation is important for economic operation of the plants and optimum despatch of 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.*

47. Comments / Suggestions:

47.1. The merit order at present has a time lag of around 1.5 months as merit order is prepared after receiving bills by 10th or 15th of each month. However, the merit order scheduling is not transparent and uniform as the computation methodology varies from Discom to Discom.

47.2. It is further observed that the merit order dispatch data in real time is not made available transparently in public domain by the SLDCs, which make it difficult to check whether the Discoms truly follow the merit order principles or not. Discoms purchases power from multiple sources and is submitted to the SERCs on annual basis, therefore based on yearly average data it may seem that Merit order is being followed, however at 15 min time block level, priority might be given to state generating plants over other plants having higher cost efficiency. This does not only result in higher average cost of power for Discoms but also results in lower PLF for efficient plants. It is suggested that there should be a mechanism which enables the merit order data at 15 minute time blocks be made available in public domain to enable more transparency in operations.

47.3. National Merit Order Operation of NTPC Stations -

- All Generating stations of NTPC shall operate in the order of Least Energy Charge to Higher Energy Charge basis till the entire energy requirement of all the States is met.
- As the mechanism will result in utilization of cheaper ECR stations first the average cost of power would reduce.
- Original beneficiaries of any “station” shall have the first right to schedule as per their allocation
- Only URS power will go to other beneficiaries of the station as well as to other states not having allocation from the station
- Allocation from individual stations and billing mechanism would remain continue unchanged. The gains arising out of the mechanism would be shared with the beneficiaries in 50:50.

Goods and Service Tax (GST)

1) Goods and Services Tax (GST) has been introduced which has 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.

48. <u>Comments / Suggestions:</u>

48.1. It is requested that the actual impact (both the savings and additional cost) of the GST component may be allowed to be pass through the beneficiary.

48.2. Though electricity generation is outside the ambit of GST, based on our experience under the Service Tax laws, some components of the tariff such as fixed charges are not treated as exempt services and the tax authorities are raising demands on the generators. Therefore, the regulations shall make it clear that levy of GST on any component of tariff shall be recoverable from the beneficiaries.

49. Other Issues - Compensation for Flexible Operations

Following compensation may be given for stations identified for flexible operations

Effect	Compensation
Requirement of capex	Allow add-cap required for flexible operation for such stations
Reduced life	Higher depreciation in tariff may be allowed (life as 75% of life of other stations)
Increased Maintenance Expenditure	1.5 times the Norm for base load stations
Increased down time	Target availability of 70%

Since the benefit of flexi operation would be to all participants, alternatively an normative charge 50 paise/kwh may be considered which shall be paid from the RLDC pool account.

50. Other Issues - Compensation for New Environmental Norms

Following changes in tariff regulations for the ensuing period FY 2019-24 are required in view of the new environmental norms.

- **Capex Requirement:** To be allowed in capital cost as add-cap, subject to prudence check.
- **Increase O&M expenditure:** Additional 10%
- **Limestone cost** to be part of ECR and Working Capital
- **Shut down Period:** additional 45 days for each unit
- **Additional APC:** of about 2 %

A suitable mechanism needs to be provided so that stations that comply with new environmental norms are not disadvantaged vis-a-vis other stations in Merit Order operation.