57H/2018/CRU-CERC

JHABUA POWER

(32)

Ref No. JPL/JBP/COO/2018/1391 Date: 26-July-2018

To,

Shri Sanoj Kumar Jha,
Secretary,
Central Electricity Regulatory Commission (CERC)
3rd & 4th Floor, Chanderlok Building, 36, Janpath,
New Delhi-110 001
Email Id: secy@cercind.gov.in

Subject: Comments/suggestions on "Terms and Conditions of Tariff for the tariff period commencing from 1st April, 2019 – Consultation Paper thereof.

Ref:

1. CERC notice no. L-1/236/2018-CERC dated 24.05.2018
2. CERC notice no. L-1/236/2018-CERC dated 13.07.2018

Dear Sir,

This is with reference to your above referred office notices vide which CERC had invited comments/suggestions/objections from all the affected parties in reference to the subject cited consultation paper. Jhabua Power Ltd is a regional entity having 1X600 MW generating station in Seoni district of Madhya Pradesh (MP).

In this matter, please find enclosed (Annexure I) comments/suggestions from our end which we found relevant and may be considered while framing the draft Tariff Regulations 2019-24.

It is requested to consider the detailed points while finalizing the subject cited consultation paper.

Thanking You,
Yours Sincerely,

for

Janmejaya Mahapatra
Chief Operating Officer

Encl: Annexure I

Annexure: I

1.0 The prelude to the Chapter 7. Tariff Design:

The Chapters 1 to 6 of the Consultation paper, particularly those on Indian Electricity Sector-Availability & Cost of Supply (Chapter 3), Value chain of Electricity Generation and Supply (Chapter 4) and some key challenges (Chapter 5) capture the journey of the Indian Power Sector till now. They describe both the challenges faced as well as the numerous course-correction action initiated by GOI/MoP/CEA/CERC/SERCs. Some very important points to be noted are:-

a) The landed cost of power for the discoms sourced from coal-based thermal generating stations, has come down from Rs 2.65 per unit in 2009-10 to Rs .52 per unit in 2016-17. This has happened despite the fact that the coal cost has increased by 74.72 % (from Re 0.91 to Rs 1.59) and the transmission cost has increased by 34.38 % (from Rs 0.64 to Rs 0.86). The WPI has also increased by 43.76 % during this period.

b) The distribution cost has increased by 189.58% (from Re 0.48 to Rs 1.39) in the above period.

c) The total distribution cost was 29.78 % of the cost of supply in 2009-10, which has increased to 38.38 % in 2016-17.

d) While the average power purchase cost of the discoms has decreased by 5.16 %, the average cost of supply to the end consumers has increased by 31.56 %.

All the above facts clearly indicate that the devil lies in the distribution sector. Since this sector has been difficult to control due to various constraints, all regulatory efforts have been concentrated on the generation sector mainly through squeezing of the normatives. This has resulted in noticeable reduction in fixed cost and highly rationalized increase in the variable cost.

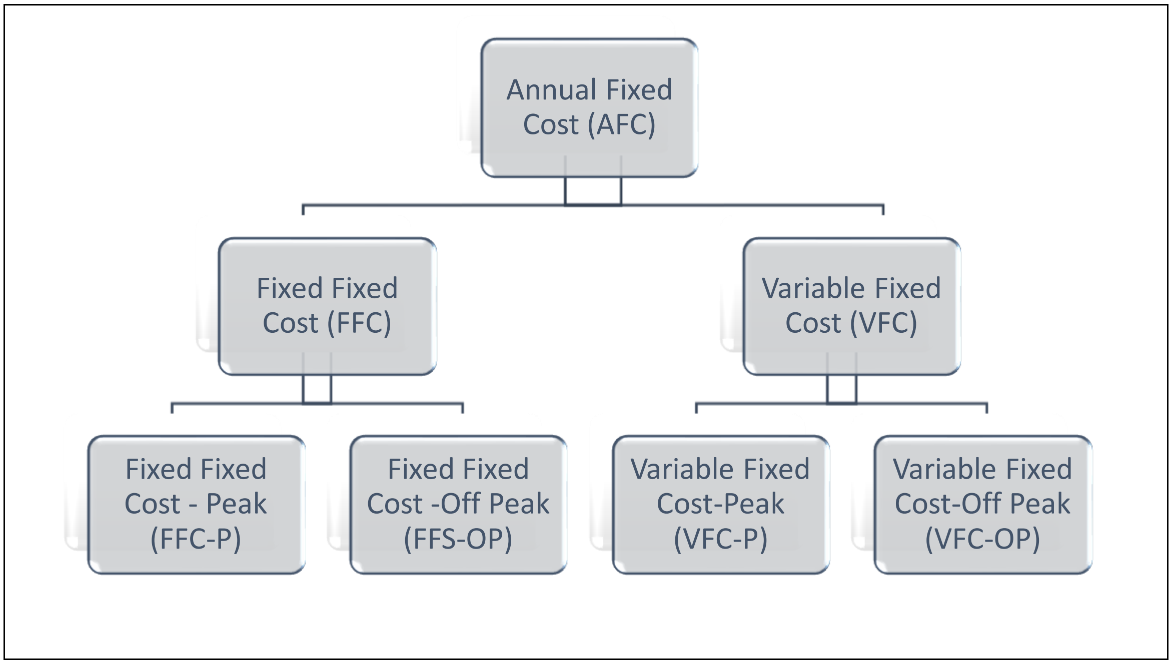
Keeping in view the present scenario of the power generation sector particularly with regard to coal-based thermal power generation (where more than 60,000 MW of assets are financially stressed), the draft amendments to National Tariff Policy also has recommended thorough overhaul of the distribution sector.

In this regard, it is suggested that no further stipulations, which directly or indirectly squeezes the operational and financial margins of a coal based thermal power plant should be initiated in the Tariff Regulation 2019-24.

2.0 **Tariff Structure – Thermal Generation Stations**

A combined reading of the contents of para 7.2: Thermal Generating Stations – Tariff Structure and Para 37.18 to Para 37.23: Principle of Cost Recovery – Approach towards Multi-Part Tariff brings to light a few contradicting aspects.

The tariff structure suggested is as follows:



2.1 Typical example with sample numbers would be helpful to further understand the scenario.

Annual Fixed cost as determined (AFC) = Rs 1500 Cr

Annual Fixed Fixed cost (AFFC) = Rs 1200 Cr
(80% of the total AFC)

Annual Variable Fixed Cost (AVFC) = Rs 300 Cr
(20% of the total AFC)

Bifurcating each of the above components into Peak and off-peak charges in the 80% & 20% proportions,

a) Annual Fixed Fixed Cost – Off Peak (AFFC-OP)

This will be applicable for 08 months and 80% would be realized.
So, AFFC-OP for 08 months = 1200*(8/12)*0.8 = 640 Cr

b) Annual Fixed Fixed Cost – Peak (AFFC-P)
This will be applicable for 04 months and will be rest of the AFC.
So, AFFC – P = Rs 1200 Cr – Rs 640 Cr = Rs 560 Cr.

c) Annual Variable Fixed Cost – Off Peak (AVFC-OP)

= 300*(8/12)*0.8 = Rs 160 Cr

d) Annual Variable Fixed Cost – Peak (AVFC-P)

= Rs 300 Cr – Rs 160 Cr = Rs 140 Cr

2.2 Therefore, during the Off-Peak months (08 months) the following will be applicable:-

AFFC–OP = Rs 640 Cr

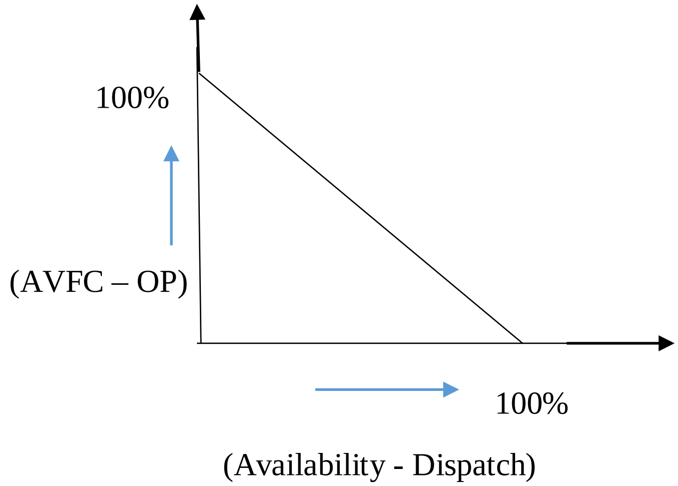
AVFC–OP = Rs 160 Cr

Total Fixed Cost realizable at 80% or more availability = Rs 800 Cr

The previously realizable value was Rs 1000 Cr (8/12*1500))

So, for 5% relaxation in availability (from 85% to 80%), there is a reduction in realizable AFC by
Rs 200 Cr.

Monthly AFC charges for 08 months becomes Rs 100 Cr instead of earlier Rs 125 Cr (20% reduction). If the provision at 7.2.6 which indicates linking the variable Fixed Cost to the difference between availability and dispatch, the above realization can further decrease based on the actual dispatch as per the graph below.



This is a whopping 27.2% reduction in monthly AFC. Debt Servicing Obligations remain constant throughout the year and such uncertainnities will further pushback the distressed assets.

The coal supplies from CIL are non-linear throughout the year and enough capital is required during the Off-peak months to procure coal whaich will be used during peak periods. Reduction in revenue during Off-peak months will reduce the capability of the generators to source adequate coal.

If a beneficiary is able to schedule a generator only upto 55%, then the realisable AFC for 08 months may decrease to Rs 728 Cr (Rs 640 Cr + 0.55*Rs 160 Cr), resulting in an efective monthly AFC of Rs 91 Cr (from the earlier Rs 125 Cr).

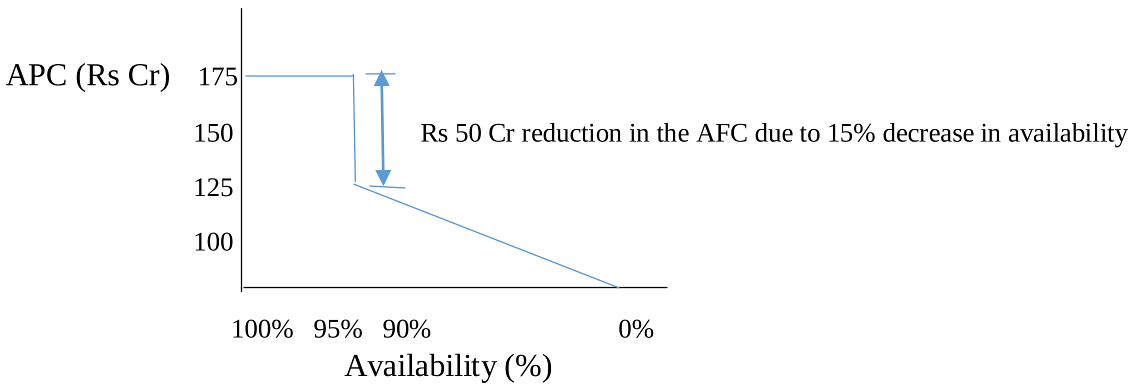
2.3 The following will be applicable during Peak months (04 months) :

AFFC–P = Rs 560 Cr
AVFC–P = Rs 140 Cr

Total Fixed Cost realisable at or more than 95% availability = Rs 700 Cr.
Monthly AFC for these 04 months = Rs 175 Cr.

Since the availability calculation is proposed to be settled every month, there is only an allowable outage period of 5% i.e. 1.5 days per month. A simple Boiler Tube Leakage requires a minimum period of 72 hrs.

The provision that (as given in Para 37.20.b) the slippage from this norm i.e. 95% upto the limit of 80% would result in reduction in the higher peak AFC for that month, essentially results in the realisation trend below.



Besides, the additional provision at 7.2.6 may further reduce the AFC if the scheduling given by the beneficiary is less.

2.4 The Proposed changes have extremely deteriorative impact on the AFC realisation of the generating companies. As highlighted in the above example :-

a) Maximum AFC recoverable at 85% annual availability & 85% average scheduling throughout the year =

= Rs 800 Cr + 4*[125+(50/3)] = Rs 1366.67 Cr

= Rs 800 Cr +4* Rs 141.67 Cr = Rs 1366.67 Cr

Possible under recovery = Rs 1500 Cr – Rs 1366.67 Cr = Rs 133.34 Cr

This is an effective under recovery of 8.88%.

b) Maximum AFC recoverable at 85% annual availability with 55% scheduling by beneficiary during off Peak months and 85% scheduling during peak months

= Rs 728 Cr + 4*Rs 141.67 = Rs 1295.41Cr

Possible under recovery = Rs 1500 Cr – Rs 1295.41 Cr = Rs 204.59

This is an effective under recovery of 13.64%.

3.0 Practical difficulties in implementing Peak and Off-Peak periods (Para 37.20)

A generating station is typically having multiple beneficiaries as well as multiple PPAs executed through different routes – Section 62/Section 63 etc.

Different beneficiary states may opt to choose different Peak Periods (continuous or non-continuous).

If a station has three beneficiaries, it may so happen that in any month of a year, one or the other beneficiary might be chosen to have a peak period. So, any outage of the unit will drastically decrease the fixed cost recovery from that beneficiary for which the peak period is under progress.

a) The sample calculation furnished above, indicates a significant under-recovery in the fixed costs. Based on the practical scenario being faced by most of the Thermal power stations, the under recovery in AFC can go up to 15%.
b) Further suggestion to settle the peak period availability on a monthly basis will further aggravate the situation.
c) Such changes should not be implemented at this junction and should be discussed further and kept in obeyance till the bigger problem of stressed assets are dealt with.

4.0 Integration of renewable generation with coal/lignite based thermal power plant (Para 7.6.4)

The energy generated is envisaged to be supplied at the Energy Charge rates and no additional capitalization is proposed. While the assets of the coal-based plant has been installed, this additional capital expenditure undertaken to generate renewable energy and reduce carbon foot-print is proposed to be disincentivised by putting forth a higher target availability for AFC, higher PLF for incentives etc.

Such measures are regressive in nature and will discourage renewable integration to coal-based power generation.

5.0 Complacency in the part of the generator subsequent to securing the PPA (Para 8.2)

A coal based power plant is installed and its annual Fixed Cost is determined by the appropriate commission based on the stringent normatives in place and the prudence check of all the expenses incurred. The variable cost is based on the landed cost of linkage coal and other normatives for APC, SHR & SFO.

Similarly, for PPAs based on competitive biddings (Section-63) the fixed and variable charges are competitively discovered. The discoms have executed the PPA based on their future demand projections and the generator had accordingly installed the thermal power plant.

The tariffs were therefore determined in a transparent manner as described above. Subsequently, in the event of a mismatch between the demand and supply, the clause suggests that the generating companies should compete with each other to reduce their cost of generation to get scheduled.

When the normatives are already squeezed, any attempt by a generator to compete to improve its position in the MOD in order to get scheduled will mean sacrificing a portion of the fixed cost which in turn will have adverse consequences in servicing of debt, maintenance of unit etc. Since the tariff determined by the appropriate commission is based on highly optimum normatives, it is no longer the ceiling tariff but is the most optimum tariff. There is absolutely no margin available to reduce the cost.

6.0 Optimum Utilization of capacity through identification of unutilized Capacity (UC) : Para 10.3

Suggestion as made in the Consultation paper that the genco and the discom can mutually agree on redefining the annual contracted capacity on yearly basis is a very simplistic view of the larger problem.

- Given the choice and the right of recalling the balance contract capacity in the subsequent year by paying a nominal fixed cost, it would be thrust upon the gencos by the discoms, particularly on the IPPs. It is a well-known fact that there are no initiatives from the discoms to execute fresh PPAs, even in the medium term. Linkage coal is not allowed for short term contract, so, a genco will not only find it difficult to find new buyers and power supply agreements but also will lose some quantum from the allocated quantity of coal of the FSA.
- Suggestion to aggregate the unutilized capacity and to bid out to discover the market price can only be adopted when the discoms come forward to procure power. Mere shifting of the responsibilities towards genco will further aggravate the problem of stressed assets.
- The discoms have also not been comfortable in the past to surrender power, even on day ahead basis, as per the terms of the PSAs which allow revenue sharing on the surrendered portion. The highly unreliable renewable energy along with its "Must-Schedule" status has given credence to their strategy of maintaining spinning reserves in the form of 'ON-bar' units with zero schedule.
- Further, provision of penalty for load shedding envisaged in the draft Tariff Policy will deter them from any such move where they may forego their right to the contracted capacity in the form of UC.

7.0 Determination of capital Cost (Para 11.9)

It has been proposed in the Consultation paper to calculate the RoE in two parts:

- Fixed rate of return say @ 15.5% (as allowed now) on the equity base which was envisaged in the investment approval, and
- A rate of return equal to the weighted average interest rate of loan portfolio for the additional equity put on account of cost escalation during project execution.

The above suggestion needs to be analyzed in the following prospective:

a) Each head of additional capital expenditure is thoroughly scrutinized during the process of tariff determination. The heads under "Uncontrollable reason for delay" have been restricted only to a very few reasons like natural calamities, war, industry wide strikes having a nation-wide impact and Change of law.
b) Commission has chosen to include critical reasons of project execution delay like land acquisition issues, ROW issues and supplier/ agency related issues under the 'Controllable Factors' though they are more often than not are beyond the control of the project developer. While assistance of district/state administration is required for the first two of the above problems, IPPs have little or no say in various matters concerned to large equipment supplier like BHEL.
c) Project developers would chose to play safe without making any efforts to reduce the capital expenditure by escalating the capital expenditure during the

investment approval to build up margin to protect the fixed rate of return and the equity base.

8.0 **Financial Parameters (Para 13)**

Present Approach as well as procedure to firm up the capital expenditure is adequate to capture the true expenditure and need not be altered. As has been appropriately pointed out in the consultation paper in para 11.8, shifting to benchmark/reference cost lacks availability of credible benchmarking of technology as well as capital cost.

9.0 **Depreciation (Para 14)**

It has been suggested in the Consultation paper to relook into the useful life of coal based thermal power plants based on international experience and extend it up to 35 years instead of the present 25 years. Most of the power stations, especially those owned by IPPs, are subject to highly cyclic scheduling by the beneficiaries, leading to severe creep as well as fatigue stress on the metallurgy, particularly on the boiler pressure parts and pipings. This will not only lead to increased O&M cost but also reduced useful life.

It is suggested that

a) The useful life of the coal based thermal plants be reduced to 20 years and accordingly, depreciation (AAD) for arriving at AFC be reduced to 10 years. The depreciation rate as per straight line method should accordingly be enhanced to 7%.
b) This is more relevant as long as the issues related to the integration of the renewables are resolved.

10.0 **Gross Fixed Assets (GFA) Approach (Para 15.2)**

It has been suggested in the Consultation paper to shift to modified GFA approach in view of the CEA report that no fresh investment is required to augment coal-based capacity till 2027.

In this context, the following as indicated in Chapter 15: Conclusion-India Vision 2040 of the Draft Natural Energy Policy (NEP) by Niti Aayog is worth mentioning:

15.6 Energy Mix

In an increased electricity share, while in the immediate run-up towards universal coverage of electricity it may not be viable to tap rooftop solar for homes, but by 2040 it would have become the norm. The share of solar and wind is expected to be 14-18% and 9-11% in electricity, and 3-5% and 2-3% in the primary commercial energy mix respectively. The advent of EVs will have helped curb a rise in share of oil and environment friendly gas would substitute oil in many uses.

However, the share of oil and gas would have almost maintained their shares of 26%

and 6.5% in 2015-16 to 25-27% and 8-9% in 2040, respectively. In spite of a more than three times increase in gas consumption, owing to large increase in total energy, the increase in gas would be less in percentage terms.
While coal would have risen in absolute terms (nearly double), but in relative terms, it would have reduced its contribution from 58% in 2015 to 44-50% in 2040. The overall share of fossil fuels would have come down from 81% in 2012 to 78% in ambitious pathway in 2040.

Therefore the installed coal based thermal generation capacity is expected to increase from the present 200GW to about 400GW by 2040. Assuming half of the present installed capacity would be retired during the next 20 years, annual addition of 15000 to 20000 MW of capacity would be required. Besides, this capacity would be critical in meeting the base load as well as in the form of balancing load.

Accordingly, the presently followed GFA approach should be followed in the new regulations.

11.0 Debt: Equity Ratio (Para 16)

It has been proposed in the Consultation paper to modify the normative debt-equity ratio to 80:20 for the new plants instead of 70:30 that is in force now. It has been reasoned that financial institutions are willing to extend finance up to a DE ratio of 80:20 depending on the credit appraisal of the utilities.
Keeping in view the state of the power sector, such a leeway may not be extended by any lending bank to any IPP. Does this suggest that government has envisaged that all future augmentation in coal-based capacity would come through PSUs like NTPC and state Gencos?

It is therefore suggested that the present normative of DE ratio of 70:30 may be followed, with the provision that any additional equity beyond 30% share be considered as debt.

12.0 Return on Investment (Para 17)

The Hon’ble commission had chosen to continue with the RoI approach while deliberating the 2014-19 Tariff regulations on the grounds of fluctuating interest rate, shallow debt market, not-so-good financial health of utilities and serious headwind being faced by the sector overall.

Since nothing much has improved since then and in fact, the health of the power sector has gone from bad to worse, there is no reason to shift approach.

13.0 **Rate of Return on Equity (Para 18)**

Suggestion have been made in the Consultation paper to lower the RoE, based, inter alia on the Draft National Electricity Plan 2016 by CEA which forecasts no further requirements of any new coal based plant. It has also been indicated that PLF of the thermal plants have come down due to higher capacity additions and increased availability of renewable energy.

The following needs to be considered the issue involved in the proper perspective :-

a) 15.6 Energy Mix:

In an increased electricity share, while in the immediate run-up towards universal coverage of electricity it may not be viable to tap rooftop solar for homes, but by 2040 it would have become the norm. The share of solar and wind is expected to be 14-18% and 9-11% in electricity, and 3-5% and 2-3% in the primary commercial energy mix respectively. The advent of EVs will have helped curb a rise in share of oil and environment friendly gas would substitute oil in many uses. However, the share of oil and gas would have almost maintained their shares of 26% and 6.5% in 2015-16 to 25-27% and 8-9% in 2040, respectively. In spite of a more than three times increase in gas consumption, owing to large increase in total energy, the increase in gas would be less in percentage terms.

While coal would have risen in absolute terms (nearly double), but in relative terms, it would have reduced its contribution from 58% in 2015 to 44-50% in 2040. The overall share of fossil fuels would have come down from 81% in 2012 to 78% in ambitious pathway in 2040.

Therefore the installed coal based thermal generation capacity is expected to increase from the present 200GW to about 400GW by 2040. Assuming half of the present installed capacity would be retired during the next 20 years, annual addition of 15000 to 20000 MW of capacity would be required. Besides, this capacity would be critical in meeting the base load as well as in the form of balancing load.

b) It has been widely accepted that the low demand growth is more of a system issue rather than a generic one. The poor financial health of the discoms have given rise to a sizeable quantum of latent demand which the Government trying hard to unlock. Once this happens, wide swing in load-generation balance are expected with intermittency of the renewables. Situation may get further aggravated if the stabilizing generation provided by the coal-based thermal power plants are ignored.

c) It will be incorrect to say that there is no disincentive for delay in completion of the project (Para 18.4) since interest during construction and other overhead expenses are disallowed by the commission for the periods of delay considered not “uncontrollable”.

It is therefore suggested that RoE should not be decreased at any cost in the presumption that no fresh investment needs to be encouraged in the coal-based generation. This is particularly important since India is yet to see the effect on integration of renewable energy and there has not yet been any major breakthrough in storage devices

14.0 **Cost of Debt (Para 19)**

There is no gainsaying the fact that IPPs cannot overlooked in meeting the capex requirement needed to meet the coal-based generation required till 2040 as outlined in the Draft National Energy Policy (NEP) by Niti Aayog. These utilities are primarily dependent upon banks and financial institutions.

Until the debt market matures and there is definite symptoms of improvements in the power sector (unlocking of latent demand, improvement in power purchase by discoms etc.), it is suggested to continue with the existing approach of allowing cost of debt based on actual weighted average rate of interest and normative loan.

15.0 **Interest on working capital (Para 20)**

It has been proposed in the consultation paper to look into the interest on working capital on the grounds of actual stock of fuel vis-à-vis the normative level of stock and maintenance spares.
It is well known that it is a monopolistic coal supply environment in India as far as linkage coal is concerned. The coal supply is affected both by unreliable production as well as unpredictable rake-supply by the railways. Coal stock is, more often, than not, is decided by Coal India/Indian Railways, in spite of upfront coal payments having been made well-in-advance. Therefore, disincentivising the gencos for lower coal stock will not be justified.

Similarly, while cost of spares are part of the O&M expenses, the interest on working capital required to fund it is only covered in the interest on working capital. Therefore, there is not much logic in reducing the O&M expenses by considering 15% of the maintenance spares cost to interest on working capital and should not be adopted.

16.0 **O&M Expenses (Para 21)**

Suggestions in the Consultation paper to review the escalation factor for determining O&M expenses to capture unexpected expenditure is an extremely well thought out initiative.

However, it needs to be considered that there is no significant reduction in O&M expenses due to part-load operations since most of the contributions like salaries, consumables, lubes, chemicals etc. remain more or less constant.

17.0 **Fuel – GCV (Para 22)**

It has been suggested in the consultation paper (Para 22.8(a)) to specify normative GCV loss between "As Billed" and "As received" at the generating station end and also specify normative GCV loss between "As Received" and "As Fired" coal.

While specifying the above, it is suggested that the following shall be considered:-

a) "As Billed" coal is as per the grading of coal based on analysis done in Equilibrated Basis (60% RH & 40°C)
b) The band of 300 Kcal for grading of coal is very wide.
c) Coal is one of the most heterogeneous substance.
d) CEA has already provided guidance on the approximate GCV loss expected between "As received" and "As Fixed" in its letter dated 17th October 2017 and further confirmed by the MOP letter dated 10th November 2017.
    - Loss in Pit head Stations: 85-100 Kcal/kg
    - Loss in Non-Pit Head Stations: 105-120 Kcal/Kg
e) The wide seasonal variation in moisture content of the supplied coal.

18.0 **Fuel- Blending of Imported Coal (Para 23)**

It is suggested in the Consultation paper that a normative blending ratio may be agreed to in consultation with the beneficiaries (ECR limitation) and generator (Technical limitation)

It is proposed that the stack emission norms should also be considered while specifying the normative.

19.0 **Fuel –Landed Cost (Para 24)**

It has been suggested in the Consultation paper to relook into the various components of landed cost of coal in view of the several developments like opening of mining to private companies, flexible utilization of coal under FSA, possibility of optimization of coal cost by adopting different procurement methods and means of transportation etc.

However, none of the above has crystallized and it may take at least 3 to 5 years for the results to be seen. Besides, a genco cannot change the mode of transportation at will to optimize the landed cost since this may result in violation of the norms specified in the Environment Clearance obtained from MOEF & CC.

Since the single player scenario in the coal sector is expected to continue for the next 3 to 5 years, the present practice of allowing all the components of landed cost as pass through may be followed in the Tariff regulations 2019-24 as well.

20.0 **Fuel – Alternate Source (Para 25)**

It has been proposed in the Consultation paper to stipulate procedures for sourcing fuel from alternate source including ceiling rate and rationalize the formula.
Para 24.3 of the consultation paper throws light on the different enabling provisions to source coal in view of the inability of coal India to meet the requirement (Para 23.1).

In view of the above, no further limitations are required besides the control metrics already in place.

21.0 **Operational Norms: Station Heat Rate (SHR) (Para 26.3.1)**

It has been proposed in the Consultation paper to have a relook into the normative SHR in view of the following:-

a) Machines which are subjected to continuous partial loading report adverse impact on the SHR.
b) Effect of aging needs to be factored in.
c) The extremely narrow margin of 4.5% allowed to take care of inefficiencies- both controllable and uncontrollable, are very difficult to comply with.

This has resulted in significant under recovery in energy charge rates.

While all the above proposals are positives, the margin of 4.5% may be increased to 5.5% keeping in view of the wide variation in coal quality, high humidity during monsoon and ambient temperature during summer.

22.0 **Operational Norms: Specific Secondary Fuel Oil Consumption (Para 26.3.7)**

It is proposed to increase the normative for SFO consumption to 0.75 ml/kWh in the view of the following:

a) Cyclic scheduling being provided by the discoms to the generating stations to absorb the intermittency of the renewables
b) Wide variation in coal quality sourced - different mines through linkage (SECL/MCL/NCL etc.), e-auction, market.

23.0 **Operational Norms: Auxiliary Energy Consumption (Para 26.3.10)**

It is proposed that necessary provisions be looked at so that quantum of LTA granted (generally granted after deducting normative APC from the contracted capacity) doesn't limit a generating station from increasing its declared capability because of lesser APC.

24.0 Operational Norms: Normative Annual Plant Availability (NAPAF) (Para 26.3.11 & 26.3.15)

It is proposed that the Normative Annual Plant Availability Factor (NAPAF) should be reduced to 80% in view of the following -

a) Materialization of linkage coal vis-à-vis Annual Contracted Quantity (ACQ) remains between 70% ~75%
b) Quantity available through e-auction is not adequate and generally much more expensive compared to linkage coal.
c) Imported coal may not be a feasible alternate fuel due to locational as well as technical constraints. This may also pose to be an environmental constraint in the future.
d) High ash content in coal results in higher corrosion in the boiler pressure parts and it is generally not possible to reduce the annual overhauling to less than 22 days.

It is also proposed that Deemed availability should be introduced to cover 70% non-availability on account of shortage of fuel or transmission constraint, in line with the provisions in other Standard Bidding documents for PPA through Section-63.

25.0 Operational Norms: Transit & Handling loss (NAPAF) (Para 26.3.16)

It is proposed that the transit loss for non-pit head stations be increased to 1.5%, based on the historical data.

26.0 Incentive (Para 27)

It has been proposed to link incentive to fixed charges and introduce different incentive for peak and off-peak period.
It has been observed in the past that the discoms, strategically under schedule a plant with higher than 85% availability so that the actual scheduling becomes less than 85% and the obligation to pay incentive is avoided. The incentive is even added to variable charges while deciding upon the Merit Order Dispatch.

- In view of the above it is suggested to implement an incentive methodology where the discoms shall be entitled to graded discount on scheduling energy more than 55% that is technical minimum. It may be staggered in steps of 5% where the discom will be entitled to 1% discount on the energy charge rate. Illustratively as follows:

Scheduling	**ECR Applicable**
0-55%	ECR
55-60%	0.99 ECR
60-65%	0.98 ECR
65-70%	0.97 ECR
70-75%	0.96 ECR
75-80%	0.95 ECR
80-85%	0.94 ECR
85-90%	0.93 ECR
90-95%	0.92 ECR
95-100%	0.91 ECR

- ECR applicable for the band shall be calculated as per the Grid Code 4th Amendment allowing for compensation due to portal trading for SHR and APC. The above discount will reduce the compensation amount due to be paid by the discoms as an incentive of higher scheduling.

27.0 Implementation of Operational Norms (Para 28)

It is suggested that the revised Operational norms may be followed from the effective date of the New Tariff Regulation since the calculation are fairly straight forward and are normally very clearly laid out in the Tariff Regulation.

28.0 Sharing of gains in case of Controllable Parameters

Since improvement in all the controllable parameters like Station Heat Rate, Auxiliary Power Consumption, Secondary Fuel Consumption etc. lead to reduction in carbon foot print, it is suggested that the complete benefit accrued be allowed to be retained by the generator.

However, benefits due to refraining of loans and true-up of primary fuel cost may be shared in the ratio of 50:50.

29.0 Non- Tariff Income (Para 31)

It has been suggested in the consultation paper to include income of an account of sale of fly ash for reducing the O&M expense.

Environment Rules, 2009 along with amendments as notified by MOEF & CC, require the gencos to make available fly ash to end user free cost up to a distance of 100 Km and bear the 50% cost up to a distance of 300 Km.

None of the previous tariff regulation ever considered the financial impact due to the on the bottom line of a genco.

Accordingly, it is suggested that the revenue against fly ash utilization, positive or negative may be made pass through.

30.0 Tariff Mechanism for Pollution control system (Para33)

It is suggested that the Tariff Regulation stipulate clearly how this new requirement as per change of law is captured/absorbed for the plants who have no/part PPA.

31.0 Alternative Approach to Tariff Design (Para37)

a) Normative tariff by Benchmarking of Capital Cost:

It is suggested not to benchmark the capital cost because besides the facts highlighted in the consultation paper which affect the cost (land and site development, project specific issue, sub/super critical status of the plant, technology and equipment etc.), the other most important factor which affects the capital cost is make and country of origin of equipment. The benchmarking of capital cost will considerably benefit one particular country.

b) Normative tariff by fixing AFC as a percentage of Capital Cost:

Most of the regulatory efforts is required to determine the capital cost. Once the capital cost is determined, determination of the Annual fixed cost is not cumbersome. Therefore, there is no immediate requirement of determining the AFC as a normative factor of the capital cost.

c) Normative Tariff by fixing each component of AFC as a percentage of total APC:

It is a forgone conclusion that the following components of the AFC will always go down in the years subsequent to previous year because of their very nature:

i. Return on equity: Due to decrease in capital cost and proportionate decrease of equity (Debt: Equity = 70:30).

ii. Depreciation: Due to decrease in capital cost and proportionate decrease in depreciation (Normative depreciation rates as specified).

iii. Interest on loan capital: Due to decrease in capital cost and proportionate etc. decrease in loan capital (Debt: Equity = 70:30).

iv. Interest on working capital: Due to decrease in AFC and corresponding decrease in amount of receivables for two months. May be partially offset by increase in ECR due to increase in cost of inventory (Coal, Oil, etc.).

Similarly, the normative O&M expense as stipulated in the Tariff Regulations increase year on year. Therefore, reaching a conclusion of escalable (increasing) and non-escalable (decreasing) doesn't necessitate any sample analysis.

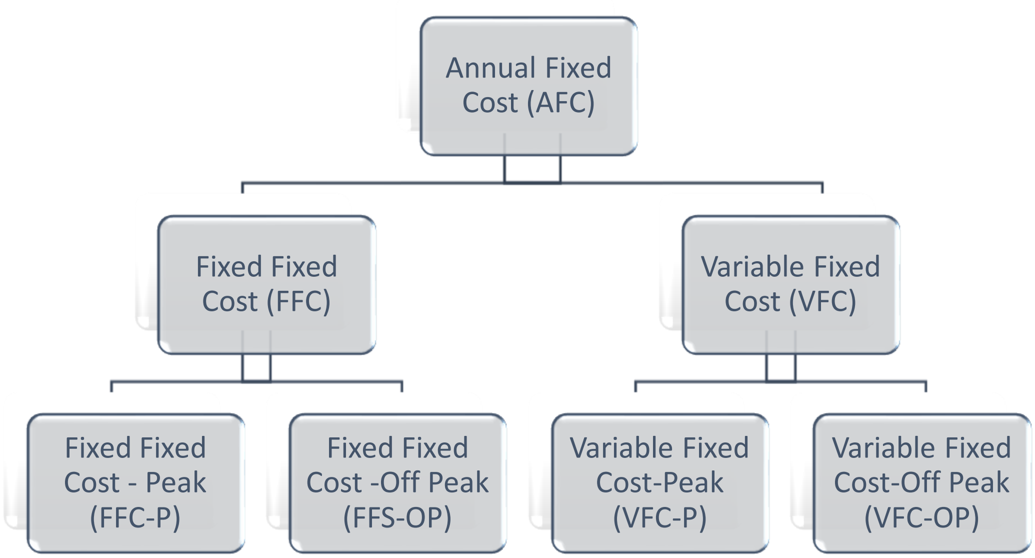
- Since the Tariff Regulations are amply clear on determination of the various components of APC subsequent to fixing up of the Capital Cost of the project, adopting a simplification approach may in turn create confusion.
- It is suggested that the tariff determination principles be applicable to stations based on their date of financial closure rather than CoD to provide regulatory certainty to the assumptions considered during the financial closure. This is still more relevant considering the extremely dynamic phase the sector is going through which is expected to continue in the future.

e) Principles of Cost recovery- Approach towards Multi-part tariff:

Tariff Structure – Thermal Generation Stations

A combined reading of the contents of para 7.2: Thermal Generating Stations – Tariff Structure and Para 37.18 to Para 37.23: Principle of Cost Recovery – Approach towards Multi-Part Tariff brings to light a few contradicting aspects.

The tariff structure suggested is as follows:



1. Typical example with sample numbers would be helpful to further understand the scenario.

   Annual Fixed cost as determined (AFC) = Rs 1500 Cr

Annual Fixed Fixed cost (AFFC) = Rs 1200 Cr
(80% of the total AFC)

Annual Variable Fixed Cost (AVFC) = Rs 300 Cr
(20% of the total AFC)

Bifurcating each of the above components into Peak and off-peak charges in the 80% & 20% proportions,

e) Annual Fixed Fixed Cost – Off Peak (AFFC-OP)

This will be applicable for 08 months and 80% would be realized.
So, AFFC-OP for 08 months = 1200*(8/12)*0.8 = 640 Cr

f) Annual Fixed Fixed Cost – Peak (AFFC-P)
This will be applicable for 04 months and will be rest of the AFC.
So, AFFC – P = Rs 1200 Cr – Rs 640 Cr = Rs 560 Cr.

g) Annual Variable Fixed Cost – Off Peak (AVFC-OP)

= 300*(8/12)*0.8 = Rs 160 Cr

h) Annual Variable Fixed Cost – Peak (AVFC-P)

= Rs 300 Cr – Rs 160 Cr = Rs 140 Cr

2. Therefore, during the Off-Peak months (08 months) the following will be applicable:-

AFFC–OP = Rs 640 Cr

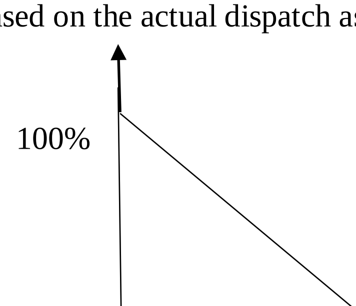
AVFC–OP = Rs 160 Cr

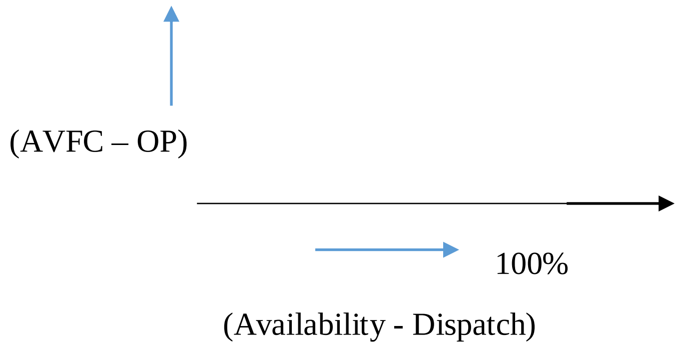
Total Fixed Cost realizable at 80% or more availability = Rs 800 Cr

The previously realizable value was Rs 1000 Cr (8/12*1500))

So, for 5% relaxation in availability (from 85% to 80%), there is a reduction in realizable AFC by
Rs 200 Cr.

Monthly AFC charges for 08 months becomes Rs 100 Cr instead of earlier Rs 125 Cr (20% reduction). If the provision at 7.2.6 which indicates linking the variable Fixed Cost to the difference between availability and dispatch, the above realization can further decrease based on the actual dispatch as per the graph below.





This is a whopping 27.2% reduction in monthly AFC. Debt Servicing Obligations remain constant throughout the year and such uncertainnities will further pushback the distressed assets.

The coal supplies from CIL are non-linear throughout the year and enough capital is required during the Off-peak months to procure coal whaich will be used during peak periods. Reduction in revenue during Off-peak months will reduce the capability of the generators to source adequate coal.

If a beneficiary is able to schedule a generator only upto 55%, then the realisable AFC for 08 months may decrease to Rs 728 Cr (Rs 640 Cr + 0.55*Rs 160 Cr), resulting in an efective monthly AFC of Rs 91 Cr (from the earlier Rs 125 Cr).

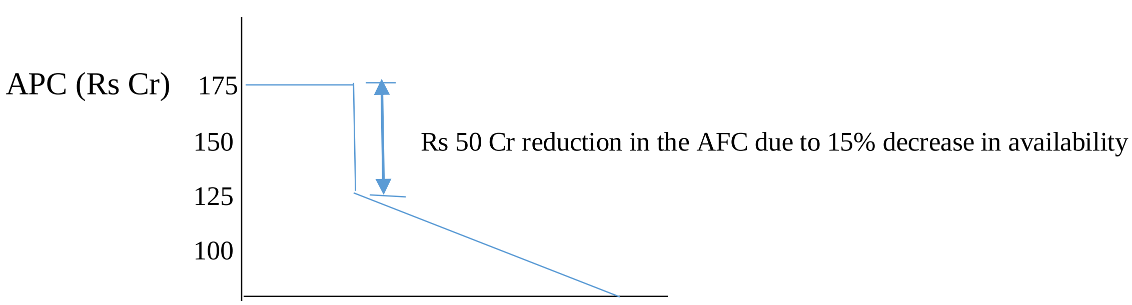
3. Therefore, during the Off-Peak months (08 months) the following will be applicable:-

AFFC–P = Rs 560 Cr
AVFC–P = Rs 140 Cr

Total Fixed Cost realisable at or more than 95% availability = Rs 700 Cr.
Monthly AFC for these 04 months = Rs 175 Cr.

Since the availability calculation is proposed to be settled every month, there is only an allowable outage period of 5% i.e. 1.5 days per month. A simple Boiler Tube Leakage requires a minimum period of 72 hrs.

The provision that (as given in Para 37.20.b) the slippage from this norm i.e. 95% upto the limit of 80% would result in reduction in the higher peak AFC for that month, essentially results in the realisation trend below.



100% 95% 90% 0%

Availability (%)

Besides, the additional provision at 7.2.6 may further reduce the AFC if the scheduling given by the beneficiary is less.

4. The Proposed changes have extremely deteriorative impact on the AFC realization of the generating companies. As highlighted in the above example:-

a) Maximum AFC recoverable at 85% annual availability & 85% average scheduling throughout the year =

= Rs 800 Cr + 4*[125+(50/3)] = Rs 1366.67 Cr

= Rs 800 Cr +4* Rs 141.67 Cr = Rs 1366.67 Cr

Possible under recovery = Rs 1500 Cr – Rs 1366.67 Cr = Rs 133.34 Cr

This is an effective under recovery of 8.88%.

b) Maximum AFC recoverable at 85% annual availability with 55% scheduling by beneficiary during off Peak months and 85% scheduling during peak months

= Rs 728 Cr + 4*Rs 141.67 = Rs 1295.41Cr

Possible under recovery = Rs 1500 Cr – Rs 1295.41 Cr = Rs 204.59

This is an effective under recovery of 13.64%.

32.0 **Flow process for determination of normative tariff (Para 37.22) :**

Sr No	Proposed Flow Process		Remarks
1	**"Existing" Generating Stations**	**"New" Generating Stations**	Benchmarking of

	Initial Capital Cost has already been approved.	Approval of initial Capital Cost and AFC for the first year by the Commission, till the Capital Cost is benchmarked and/or a correlation between Capital Cost and AFC is established for determination of AFC on a normative basis.	Capital cost is difficult to achieve in view of the large number of variables affecting it and its possible effects on the quality of assets that might be created. Since determination of individual components of AFC and in turn the AFC is fairly simple and straight forward subsequent to determination of Capital cost, there is no requirement of correlation factors.
2	Components of AFC be segregated into "escalable / increasing" and "non-escalable/ decreasing" segments Segment - 1 (Non Escalable/ decreasing) comprising of RoE, IoL, IoWC, Depreciation Segment -2 (Escalable) comprising O&M		Escalable (increasing) and non-escalable (decreasing) parts of the AFC are present due to their very nature. There is no requirement of categorizing them.
3	Current Regulations provide for "Add. Cap." as permissible for a period from CoD upto Cut-Off date		Present stipulations are in order and no change is required.
4	"Cut-off Date" means 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		Present stipulations are in order and no change is required.
5	**"Existing" Generating Stations**	**"New" Generating Stations**	Present stipulations are in order and no change

	Add. Cap be isolated and the components of AFC be derived without giving effect to Add. Cap. (from Cut-Off Date onwards)	Add. Cap be allowed till Cut-Off Date ("Capital Base" may vary during the period). However, upon reaching the Cut-Off Date, the Capital Cost be freezed.	is required.
6	Not part of the Consultation paper		Not applicable
7	**"Existing" Generating Stations**	**"New" Generating Stations**	Present stipulations are in order and no change is required.
	For each year the "CAGR" or the escalation / de-escalation factors, as the case may be, for the two segments of AFC (namely "O&M" & "RoE+IoL+IoWC+Dep") (without Add. Cap) are determined by the Commission.	For each year the escalation / de-escalation factors, as the case may be, for the two segments of AFC (namely "O&M" & "RoE+IoL+IoWC+Dep") (without Add. Cap) are determined by the Commission.	
8	No "Additional Capital", Compensation Allowance, Special Allowance be provided from the current control period		Present stipulations are in order and no change is required.
9	Uncontrollable/ unavoidable expenditure beyond the Cut Off Date, if any, which is considered reasonable and permitted by the Commission, be allowed as a separate stream on annuity basis		May be incorporated. These shall be beyond the expenses covered under **"Change in Law."**
10	Add. Cap. availed, be liquidated before the plant completes its useful life		May be incorporated.
11	From FY 2019-20 onwards till completion of useful life of plant the trajectory of AFC (including the trajectory for liquidation of Add. Cap) be derived		May be undertaken.
12	AFC be recovered by the Generating Company from the beneficiaries in two parts, i.e. Peak AFC and Off-Peak AFC		Keeping in view the huge under-recovery anticipated and has been clarified through examples, this should not be implemented.
13	As part of this, 80% of AFC be paid (guaranteed), upon declaration of 80% PAF during the year. Remaining 20% of AFC be		Keeping in view the huge under-recovery anticipated and has

	paid upon achieving 95% PAF during the peak period of 4 months, as declared by the concerned RLDC	been clarified through examples, this should not be implemented.
14	AFC Recovery (peak and off peak shares) be arrived at by considering the following • Peak price over off peak price • PAF (Off Peak & Peak) (%) • No. of Months (Off Peak & Peak) Weightage Factors for Peak and Off Peak components	Keeping in view the huge under-recovery anticipated and has been clarified through examples, this should not be implemented.
15	Month-wise trajectory AFC recovery for the rest of the useful life of the plant is arrived at	May be derived.
16	The operating and financial norms for any new control period need not apply on the existing plants	Should be implemented. However, the applicability of tariff negotiations should be based on the date of investment approval/financial closure rather than CoD to provide regulatory certainty.

33.0 **Relaxation of Norms (Para 39) :**

The suggestion in the consultation paper are extremely relevant and needs to be implemented. Besides the factors considered, the line loss taking place in the dedicated transmission lines (built by the generator) till the nearest CTU pooling station needs to be allowed beyond the normative APC, since the commercial billing is based on the ABT meters at the pooling station and not on the basis of Check meters at the generator Ex-bus (Switchyard).

34.0 **Merit Order Operation (Para 40) :**

Merit Order Operation based on Fuel charge indirectly encourages climate control based on the fact that the energy charge rate is dependent on efficiency of operation and landed cost of coal. Consideration of scheduling old and inefficient units based on the total cost of generation is contradictory to the whole exercise of reducing the carbon foot-print and therefore should not be implemented.
The time lapse of two months is generally not applicable keeping in view the inability of the generating station to maintain more than 7-10 days of stock.