NTPC COMMENTS

ON

DRAFT CERC (TERMS AND CONDITIONS OF TARIFF) REGULATIONS, 2019

1) REGULATION 17 - MODIFIED GFA APPROACH IN STATIONS THAT HAVE COMPLETED THEIR USEFUL LIFE

Draft Regulation Stipulation

*“**17. Debt-Equity Ratio**: (1) For new projects, the debt-equity ratio of 70:30 as on date of commercial operation shall be considered. If the equity actually deployed is more than 30% of the capital cost, equity in excess of 30% shall be treated as normative loan:*

Provided that:

i. where equity actually deployed is less than 30% of the capital cost, actual equity shall be considered for determination of tariff:

ii. the equity invested in foreign currency shall be designated in Indian rupees on the date of each investment:

iii. any grant obtained for the execution of the project shall not be considered as a part of capital structure for the purpose of debt : equity ratio.

Explanation-The premium, if any, raised by the generating company or the transmission licensee, as the case may be, while issuing share capital and investment of internal resources created out of its free reserve, for the funding of the project, shall be reckoned as paid up capital for the purpose of computing return on equity, only if such premium amount and internal resources are actually utilised for meeting the capital expenditure of the generating station or the transmission system.

(2) The generating company or the transmission licensee shall submit the resolution of the Board of the company or approval of the competent authority in other cases regarding infusion of funds from internal resources in support of the utilization made or proposed to be made to meet the capital expenditure of the

generating station or the transmission system including communication system, as the case may be.

(3) In case of the generating station and the transmission system including communication system declared under commercial operation prior to 1.4.2019, debt-equity ratio allowed by the Commission for determination of tariff for the period ending 31.3.2019 shall be considered.

(4) In case of the generating station and the transmission system including communication system declared under commercial operation prior to 1.4.2019, but where debt: equity ratio has not been determined by the Commission for determination of tariff for the period ending 31.3.2019, the Commission shall approve the debt : equity ratio in accordance with clause (1) of this Regulation.

(5) Any expenditure incurred or projected to be incurred on or after 1.4.2019 as may be admitted by the Commission as additional capital expenditure for determination of tariff, and renovation and modernisation expenditure for life extension shall be serviced in the manner specified in clause (1) of this Regulation.

(6) In case of generating station or a transmission system including communication system which has completed its useful life as on or after 1.4.2019, the accumulated depreciation as on the completion of the useful life less cumulative repayment of loan shall be utilized for reduction of the equity and depreciation admissible after the completion of useful life and the balance depreciation, if any, shall be first adjusted against the repayment of balance outstanding loan and thereafter shall be utilized for reduction of equity till the generating station continues to generate and supply electricity to the beneficiaries."

Comments / Suggestions:

1) In the Draft Tariff Regulations, Hon'ble Commission has proposed application of modified GFA approachto those stations that have completed their useful life as on 01.04.2019 or later.
2) This provision has serious implication on profitability of the old stations of NTPC consisting of 13160 MW capacity and having a share of around 30% in NTPC's generation. These stations generated around 86.25 BUs in 2017-18.
3) These old stations running at high PLF, being efficient and well maintained assets are the backbone of the power sector having average cost of Rs. 2.68 per unit in 2017-18. These old stations do not have relaxed operating norms and therefore require higher manpower and maintenance costs.
4) These stations have very low capital cost (Average of Rs. 1.53 crores per MW) and are fully depreciated. The average fixed cost for such coal stations was 83 paisa per unit for the year 2017-18. Most of them being pithead stations, their ECR is also low (Average of Rs 1.85 per Kwh). Being low cost stations, they clocked a high PLF of over 83% during 2017-18.
5) The proposed Draft Regulations shall reduce their returns significantly, for example, the 2000 MW Singrauli station will earn an annual return of about Rs. 10 crores. Similarly, 2100 MW Korba station will earn a return of about Rs. 14 crores. With reduced ROE, these old stations shall go into loss due to under recovery in O&M expenses, loss due to operational parameters, costs not allowed in tariff, etc. For Singrauli, even 0.5% deviation on higher side from heat rate would wipe out the entire annual return. Similarly, 1% deviation in availability shall wipe out the entire return.
6) There would be no incentive for the generator to run these old stations. NTPC may have to close such stations as these stations will no longer be profitable. Moreover, as these plants are strategically located pithead stations independent of Indian railway network, coal from these mines cannot be diverted to other stations.
7) Discoms shall be deprived of cheap power. As stated above, the average rate of supply from these stations in 2017-18 was Rs.2.68/ kWh. In case of possible closure of these plants, the cost of power purchase to Discoms would increase by

Rs.11152 Cr and Rs.15322 Cr considering alternate power @ Rs. 4.00 per unit and Rs. 4.50 per unit respectively. (State-wise impact is tabulated in Para 21 below).

8) The low cost of power from above coal stations has helped the beneficiaries keep their power purchase cost low over past years.

Beneficiary / State	Energy scheduled in 2017-18	Average Rate of Power from NTPC Stations >25 years
	(MUs)	(Rs/kwh)
Chhattisgarh	1498	1.90
Gujarat	4263	2.06
Maharashtra	7986	2.08
Madhya Pradesh	6439	2.13
Rajasthan	3472	2.16
Haryana	2111	2.25
Goa	2585	2.26
Punjab	2729	2.41
Uttar Pradesh	10929	2.50
Odisha	4487	2.97
Kerala	1777	3.05
Karnataka	2978	3.06
Bihar	8136	3.11
Andhra Pradesh	2591	3.12
Jharkhand	1555	3.12
Telangana	2110	3.13
Tamil Nadu	3476	3.14
West Bengal	3512	3.29
Delhi	4959	3.79
Others	8657	2.71
Total / Wt. avg.	**86250**	**2.68**

9) The Draft Tariff Regulations 2019 have proposed to reduce the equity of the stations that have completed their useful life by a quantum equivalent to difference between the accumulated depreciation as on the completion of useful life and the accumulative repayment of loan. The fixed charges, Return on Equity (ROE) in Rs. Cr. and in P/kWh presently and considering the provisions of Draft Regulations is as given below:

S. No	Station	2018-19				As per Draft Regulations			
		ROE (Post-tax)		Fixed Charges		ROE (Post-tax)		Fixed Charges	
		Rs. Cr.	P/kwh	Rs. Cr.	P/kwh	Rs. Cr.	P/kwh	Rs. Cr.	P/kwh
1	Singrauli	93	6.7	912	65.7	10	0.7	808	59.8

2	Korba-1&2	135	9.2	1005	68.9	14	1.0	859	60.5
3	Ramagundam-1&2	178	12.2	1068	73.2	18	1.3	860	60.6
4	Vindhyachal-1	114	13.4	737	86.4	11	1.4	593	71.2
5	Rihand-1	186	27.1	589	85.8	19	2.8	365	54.5
6	Farakka-1&2	243	21.8	930	83.5	25	2.3	583	53.8
7	Unchahar-1	74	26.1	312	109.6	8	2.7	220	79.2
8	Dadri-1	131	22.9	565	98.7	13	2.3	393	70.3
9	Kahalgaon-1	165	29.1	606	106.5	17	3.1	329	59.2
10	TSTPS-1	211	30.1	676	96.4	22	3.3	308	45.6
	Wtd. Avg.	**1531**	**16.8**	**7401**	**81.4**	**156**	**1.8**	**5318**	**60.1**

As shown above, the annual ROE for stations like Singrauli and Korba would be only about Rs. 10 Cr. and Rs. 14 Cr. respectively, which works out to 0.7 and 1.0 paise /kWh. The reduction in fixed charges for Singrauli and Korba would be 6 P/kWh to 8 P/kWh respectively.

10) In case regulated equity is adjusted to the extent of accumulated depreciation, the ROE will drop steeply by around 89% leaving only Rs.156 crore to operate 46 such units with all the risks such as relating to procurement and storage of fuel, keeping plant and machinery in perfect running condition, maintaining high operational efficiency parameters and compliance with stringent environmental and regulatory norms including 100% utilization of ash.

11) After adjusting for the under recovery on account of O&M expenses, existing contribution loss plus additional contribution loss on account of reduction in station heat rate in 200/250 MW units by 40 Kcal/kwh, disincentives, expenses towards CSR, performance related pay, provisions, etc., the proposed ROE linked to modified GFA will lead to huge losses. It is estimated that average per unit loss from some of these stations will be as high as 15 paise/unit. With no foreseeable revenues and huge losses in future, the assets of these stations will move towards impairment and NTPC may have to book impairment loss of approx. Rs.3000 crore. Under these circumstances, there is no justification to run these units. The erosion of ROE will also not auger well with investors resulting in depletion of shareholder wealth. The ratings of the company also will be affected leading to higher interest rates for the debt deployed as well as for fresh debt required to complete the projects under construction and would be counter-productive since cost of power for the consumers will rise.

12) The various norms such as O&M expenses, heat rate, etc., have been tightened over the years. Further earning on account of efficiency parameters is now to be shared with beneficiaries in the ratio of 50:50 instead of 60:40. This will further reduce the earnings. Further, under recoveries by way of O&M expenses and disincentive due to short supply of coal etc. have strained the earnings.
13) Considering the current ecosystem fraught with shortage of coal, non-availability of rakes by railways coupled with old meter gauged lines operated by railways, tightening of environmental norms, 100% disposal of ash, there is no margin of safety left with power generators. Even 2.5 % reduction in availability will lead to erosion of entire 156 Cr of ROE. Since there is no incentive to run these plants and their possible closure will not only affect NTPC adversely but will also deprive Discoms and ultimately consumers to access low cost power.
14) **Comparable Risk / Reward Ratio -**The gross ROE is only 1.8 paisa per unit on the 86.25 BUs generated by stations / units which have completed 25 years. This is even lower than 7 paisa per unit offered as margin on trading where no operational risk is assumed by trader.
15) **Past rulings of Honorable APTEL and Honorable SC in respect of NFA-** It was recognized by the Honorable Supreme Court in Rohtas Industries vs Chairman Bihar State Electricity Board, (AIR 1984 SC 657) that “the tariff fixation has to be so made, as to raise sufficient revenue which will not merely avoid any net loss being incurred during the financial year but will ensure a profit being earned, the rate of minimum profit to be earned being such as may be specified”. Taking cue from the aforesaid judgement of the Hon’ble Supreme Court, Appellate Tribunal for Electricity in case of Powergrid Corporation of India Versus CERC & Others held that “Appellant (Powergrid) is entitled to earn specified rate of return on the equity invested in the project in accordance with the law. Any mechanism by which the equity is gradually reduced proportionately reducing rate of return below the specified rate of return shall not be legal.”
16) Operational risks of thermal plants are much higher than hydro, RE or transmission projects. In case of thermal power plants there are increased risks in operation as plants get older. The increase in risks for such old plants is due to the following factors.

- As the machines get older, there would be increase outages and the station may not be able to meet the Target Availability norm on quarterly basis.
- The norms for operating parameters such as heat rate, APC, etc. are fixed based on average of all machines. In the draft Regulations, the heat rate norm for 200 MW units have been reduced from 2450 Kcal/kWh to 2410 Kcal/kWh. These old stations with old design units would not be able to meet the revised norms, which are fixed based on average of all units.
- Similarly, the norm for O&M expenses are fixed based on average of all units. As these stations are old, their maintenance cost is also high and there would be under recovery in the O&M expenses.
- Some of the expenditure on heads such as Performance Related Pay (PRP), Corporate Social Responsibilities (CSR), provisions, etc. are not allow by CERC as costs. Such expenses have to be met out of the return available to the generating stations.

All the above risks for these stations have to be met from meagre ROE indicated above.

17) The estimated profitability of Singrauli for the year 2019-20 is as given below:

Estimated Profitability of Singrauli (after Modified GFA) (in Rs. Crores)		
A	Capital Cost	1247.47
B= A*5%	Residual Equity (5% of capital cost)	62.37
C=B*15.5%	Profit/ RoE @ 15.5 %	9.67
D	Estimated Under-recovery in O&M viz-a- viz norms	-34.99
E	Loss due to operational parameters as per new norms	-12.36
F=C+D+E	Profit (+)/ Loss (-) of the station	-37.68

18) On lines of above the estimated profitability for other stations is as given below

Estimated Profitability of Stations (more than 25 years old)			
S. No.	**Name of Stations**	**Unit**	**Profit (+) / Loss (-) of the station**
1	Singrauli	Rs Crs.	-36.76
2	Rihand	Rs Crs.	12.84

Estimated Profitability of Stations (more than 25 years old)			
S. No.	**Name of Stations**	**Unit**	**Profit (+) / Loss (-) of the station**
3	Ramagundam-I&2	Rs Crs.	1.52
4	Korba-1&2	Rs Crs.	-11.69
5	Vindhyachal -1	Rs Crs.	-11.06
6	Farakka- 1&2	Rs Crs.	-92.30
7	Dadri-1	Rs Crs.	-68.77
8	Kahalgaon-1	Rs Crs.	-23.17
9	Unchahar-1	Rs Crs.	-17.59
10	Talcher-1	Rs Crs.	-39.50

19) As the stations would be get into loss, NTPC being a public listed company where about 40% of the shares are held by entities other than GOI, there would be pressure by the investors to shutdown such loss making stations. There would be no other option left to the generating company other than shutting down of such old stations. Possible closure of these stations generating cheap power would be wastage of scarce national resource and would deprive the beneficiaries of cheap electricity.

20) In case of possible closure of these stations due to loss, the increase in power purchase cost of beneficiaries would be significant, as they would have to purchase the alternate power from costlier stations. The average power purchase cost of Discoms would increase as shortfall in energy from such power plants would be met by costly power from alternate sources, which are at the bottom of the merit order.

21) As per rough estimates, the total impact on Discoms on account of purchasing the equivalent quantum of power from alternate source works out to more than Rs. 15,000 Crores. The state wise impact for procuring the equivalent quantum of alternate sources is given below:

S. No.	**States**	**Saving in Fixed Charges as per Draft Regulations (Rs. Crs)**	**Additional Financial burden due to purchase of power from alternate sources @ Rs. 4.00 per unit**	**Additional Financial burden due to purchase of power from alternate sources @ Rs. 4.50 per unit**
A	Northern Region States			
1	UP	188	-1638	-2185
2	Rajasthan	50	-638	-812
3	Punjab	56	-433	-570
4	Haryana	32	-370	-475
5	UK	19	-164	-353
6	J&K	32	-163	-221
7	Delhi	133	-105	-217
8	Himachal Pradesh	11	-51	-69
9	Chandigarh	3	-20	-25
B	Western Region States			
1	Maharashtra	73	-1536	-1935
2	MP	63	-1207	-1529
3	Gujarat	38	-826	-1039
4	Goa	22	-450	-579
5	Chhattisgarh	10	-314	-389
6	DNH	6	-137	-172
7	DD	4	-92	-115
C	Southern Region States			
1	Tamil Nadu	50	-300	-474
2	Karnataka	34	-279	-428
3	AP	31	-229	-358
4	Telangana	28	-184	-289
5	Kerala	19	-169	-258
D	Eastern Region States			
1	Bihar	346	-728	-1135
2	Odisha	200	-463	-688
3	WB	136	-251	-427
4	Bangladesh	19	-197	-251
5	Jharkhand	64	-137	-214
6	Assam	22	-42	-66
7	Sikkim	18	-32	-50
	Total	**1704**	**-11152**	**-15322**
Note: Impact on small states like Puducherry, Mizoram, Nagaland, etc. excluded. These states consume about 10% of the energy				

22) As can be seen from the above, putting these stations into loss and their subsequent possible closure is not in the interest of beneficiaries. The existing approach adopted so far encourages the generating company to maintain these stations in good condition so that the station can be effectively utilized beyond their useful life. This ensures that the economic benefit of cheap power from these stations is continued to be passed on to the consumers without much impact in tariff.

23) CERC Tariff Regulations of 2014-19: As per the Statement of Reasons (SOR) dated 24.04.2014, the Hon'ble Commission has opined that under Net Fixed Asset approach, the return will reduce significantly. As the investors have made investments based on GFA approach, changing the methodology of existing projects would have detrimental effect on the returns on the investments. Therefore, CERC has continued with the Gross Fixed Assets approach for computing fixed charges. The Commission has concluded in the SOR as under:

    "After considering all aspects in this regard, with a view to provide the regulatory certainty to the investors who have made investments in the sector on the basis of the Return on Equity approach linked to Gross Fixed Assets, the Commission has decided to continue with the existing method of Return on Equity".

24) In view of the above, it is advisable that there is sufficient incentive to run these old plants which have completed their useful life for overall interest of the beneficiaries as well as generators. **It is humbly submitted that the modified GFA approach is neither beneficial to the beneficiaries nor to the generators, it is therefore submitted that the modified GFA approach as proposed may not be given effect to.**

2) REGULATION 59 (C) -GROSS STATION HEAT RATE

"Norms of operation for thermal generating station

59. The norms of operation as given hereunder shall apply to thermal generating stations:

…

(C) Gross Station Heat Rate:

(a) Existing Thermal Generating Station

(i) For existing Coal-based Thermal Generating Stations, other than those covered under clauses (ii) and (iii) below:

200/210/250 MW Sets	***500 MW Sets (Sub-critical)***
2,410 kCal/kWh	*2,375 kCal/kWh*

Note 1

In respect of 500 MW and above units where the boiler feed pumps are electrically operated, the gross station heat rate shall be 40 kCal/kWh lower than the gross station heat rate specified above.

Note 2

For the generating stations having combination of 200/210/250 MW sets and 500 MW and above sets, the normative gross station heat rate shall be the weighted average gross station heat rate of the combinations.

Note 3

The normative gross station heat rate above is exclusive of the compensation specified in Regulation 6.3 B of the Grid Code. The generating company shall, based on unit loading factor, consider the compensation in addition to the normative gross heat rate above.

Comments/Suggestion:

A. **NORMS TO BE ALIGNED WITH CEA RECOMENDATIONS –**

The CEA vide its letter dated 10th Dec, 2018 to Hon'ble Commission has made its recommendations on the operating norms of thermal generating stations for the tariff period 2019-24.These CEA recommendations have been uploaded in the CERC website along with the Draft Regulations. The recommendations of CEA regarding heat rate as summarized as under:

a. 200/210/250 MW coal based units – 2450 kcal/kwh
b. 500 MW coal based units - 2400 kcal/kwh
c. Existing coal based units that have achieved COD between 01.04.2009 to 31.03.2014 and units that have achieved COD between 01.04.2014 to 31.03.2019 - Margin of 5% over the design unit heat rate (without separately specifying minimum boiler efficiency).
d. TTPS – 2830 kcal/kwh
e. Tanda – 2775 kcal/kwh
f. Gas Plants – Existing norms retained.

The Electricity Act 2003 has entrusted CEA with the statutory function to advise the Appropriate Commission on all technical matters relating to generation, transmission and distribution of electricity. It may be observed that the heat rate norms proposed in the Draft Regulations are in variation to those recommended by the CEA. The reasoning for deviating from norms recommended by CEA have not been elaborated in the Explanatory Memorandum. **It is humbly submitted that the operating norms for the tariff period 2019-24 may be aligned with the recommendations of CEA in this regard.**

B. **STATION HEAT RATE OF 200 MW UNITS:**

The Explanatory Memorandum has stated at Para 17.6.4 as under:

"The Commission observes that all 200 MW stations which are more than ten years in operations, have achieved heat rate lower than the approved norms as per the 2014 Tariff Regulations. As the five-year average works out to be 2381 kCal/kWh, taking correction factor into account as per Grid Code the Commission proposes the Heat Rate Norms for 200 MW series units at 2410 kCal/kWh."

With regard to the above, it is observed that:

i. It appears that in the Explanatory Memorandum, the Plant Load Factor (PLF) has been used instead of Loading Factor to compute thecompensated heat rate by applying of compensation factor as per the Grid Code.As loading factor is always equal to or greater than PLF, the compensated heat rate worked out as per the Explanatory Memorandum is lower at 2381 kcal/kwh instead of 2402 kcal/kwh. Detailed Calculations are as tabulated as under:

S.No.	Station	Norm	Actual Heat Rate (kcal/kwh)					
			2013-14	2014-15	2015-16	2016-17	2017-18	Average
1	Dadri-I	2410	2398	2407	2404	2449	2546	2441
2	Kahalgaon-I	2410	2424	2420	2425	2451	2453	2435
3	Unchahar-I	2410	2419	2417	2435	2468	2463	2440
4	Unchahar-II	2410	2414	2416	2431	2447	2453	2432
5	Unchahar-III	2410	2409	2412	2417	2442	2456	2427
6	Vindhyachal-I	2410	2403	2404	2411	2479	2444	2428
			Average					2434

S.No.	Station	Loading Factor (%)					Correction Factor (%)				
		2013-14	2014-15	2015-16	2016-17	2017-18	2013-14	2014-15	2015-16	2016-17	2017-18
1	Dadri-I	83.70	85.97	80.55	80.98	69.97	2.250	0.000	2.250	2.250	4.000
2	Kahalgaon-I	81.90	86.10	82.32	84.38	85.61	2.250	0.000	2.250	2.250	0.000
3	Unchahar-I	92.40	90.20	82.73	77.17	76.26	0.000	0.000	2.250	2.250	2.250
4	Unchahar-II	90.50	89.41	79.93	80.91	77.12	0.000	0.000	2.250	2.250	2.250
5	Unchahar-III	96.80	88.07	79.34	80.16	76.07	0.000	0.000	2.250	2.250	2.250
6	Vindhyachal-I	92.50	89.83	87.50	83.45	92.63	0.000	0.000	0.000	2.250	0.000

S.No.	Station	Compensated Heat Rate (kcal/kwh)						Corrected Heat Rate (kcal/kwh)					
		2013-14	2014-15	2015-16	2016-17	2017-18	Average 5 years	2013-14	2014-15	2015-16	2016-17	2017-18	Average 5 years
1	Dadri-I	2344	2407	2350	2395	2450	2389	2398	2407	2404	2410	2450	2414
2	Kahalgaon-I	2369	2420	2371	2396	2453	2402	2410	2420	2410	2410	2453	2421
3	Unchahar-I	2419	2417	2381	2413	2409	2408	2419	2417	2410	2413	2410	2414
4	Unchahar-II	2414	2416	2377	2393	2398	2400	2414	2416	2410	2410	2410	2412
5	Unchahar-III	2409	2412	2363	2388	2402	2395	2409	2412	2410	2410	2410	2410
6	Vindhyachal-I	2403	2404	2411	2425	2444	2417	2403	2404	2411	2425	2444	2417
		Average					2402	Average					2415

ii. As compensation is available only up to the norms, corrected heat rate is restricted up to the norms. Take for instance, the case of Unchahar II, where the actual heat rate for 2017-18 is 2453 kcal/kwhand correspondingactual loading factor is 77.12%. Considering the proposed norm of 2410 kcal/kwh, the compensated heat rate shall be 2398 kcal/kwh (i.e. 2453 – 2.25% × 2410). However, as compensation is available only up to the norms, the corrected heat rate shall be limited at 2410 kcal/kwh. It appears that the Explanatory Memorandum has considered unrestricted compensation for working the corrected heat rate which is not done actually in practice. In case norm is worked out considering unconstrained compensation, whereas the actual compensation would be available up to the norm, there would be under recovery of norms.

iii. The average corrected heat rate for 200 MW stations for the five year period from 2013-14 to 2017-18 works out to 2415 kcal/kwh instead of 2381 kcal/kwh.

iv. It may also be observed from the above tablesthat there is deterioration in heat rate in the last two years i.e. 2016-17 and 2017-18 due to increased penetration of RE generation which is also anticipated to continue and further increase in the 2019-24. In light of the above, additional margin of 1.5 % or 35 kcal/kwh may be provided on 2415 kcal/kwh to arrive at the norm for 200 MW units.

In view of the above, it is submitted that the existing heat rate norm of 2450 kcal/kwh may be retained for 200 MW units.

C. **HEAT RATE FOR 500 MW UNITS:**

The Explanatory Memorandum at Para 17.6.5 provides as under:

"500 MW series stations are segregated as per their vintage i.e. plants less than ten years old and plants which are more than ten years old. The actual heat rate data shows that SHR of almost all the coal based generating stations of NTPC is 2346 kCal/kWh for plants less than ten years old and 2351 kCal/kWh for plants more than ten years old. Therefore, the Commission proposes to retain the Heat Rate Norms for 500 MW series units to 2,375 kCal/kWh same as previous Tariff Regulation".

With regard to the above, it is observed that:

i. While considering plants more than 10 years old, Talcher-I and Talcher-II have been excluded. Norms are required to be framed considering the entire population of all applicable units in the base. Excludingcertain units on the ground that they are having higher heat rate as compared to the rest is not justified. If these units are excluded then they may be given relaxed norms on case to case basis. **It is humbly submitted that all the units may be included in the database for fixing of operating norms.**

ii. Moreover, while arriving at norms, Rihand-I has been considered which is having MDBFP and thus lower heat rate by 40 kcal/kwh. The same needs to be included.

iii. As regards the computation methodology, it appears that the Plant Load Factor (PLF) has been used instead of Loading Factor. Further, it appears that the Explanatory Memorandum has considered unrestricted compensation for working the corrected heat rate which is not done actually in practice. Detailed calculation is provided as under:

Sl.No.	Station	Norm	Actual Heat Rate					Average
			2013-14	2014-15	2015-16	2016-17	2017-18	
1	Ramagundam-III	2375	2360	2356	2358	2353	2352	2356
2	Simhadri-I	2375	2359	2350	2387	2398	2427	2384
3	Rihand-II	2375	2380	2355	2358	2368	2330	2358
4	Vindhyachal-II	2375	2352	2360	2363	2423	2369	2373
5	Vindhyachal-III	2375	2347	2348	2356	2398	2367	2363
6	Talcher-I	2375	2399	2370	2378	2487	2410	2409
7	Talcher-II	2375	2359	2352	2377	2459	2360	2381
			Average					2375

S.No.	Station	Loading Factor						Multiplication Factor				
		2013-14	2014-15	2015-16	2016-17	2017-18		2013-14	2014-15	2015-16	2016-17	2017-18
1	Ramagundam-III	94.10	98.49	94.55	92.45	91.87		0.000	0.000	0.000	0.000	0.000
2	Simhadri-I	92.80	95.04	87.52	87.34	74.37		0.000	0.000	0.000	0.000	4.000
3	Rihand-II	93.50	92.87	91.59	91.61	96.83		0.000	0.000	0.000	0.000	0.000
4	Vindhyachal-II	94.30	88.30	85.59	87.10	95.78		0.000	0.000	0.000	0.000	0.000
5	Vindhyachal-III	92.90	89.62	91.46	87.75	97.87		0.000	0.000	0.000	0.000	0.000
6	Talcher-I	93.20	96.21	97.60	95.06	94.16		0.000	0.000	0.000	0.000	0.000
7	Talcher-II	94.20	98.48	97.79	93.83	93.93		0.000	0.000	0.000	0.000	0.000

S.No.	Station	Compensated HR							Corrected Heat Rate					
		2013-14	2014-15	2015-16	2016-17	2017-18	Average 5 years		2013-14	2014-15	2015-16	2016-17	2017-18	Average 5 years

1	Ramagundam-III	2360	2356	2358	2353	2352	**2356**		2360	2356	2358	2353	2352	**2356**
2	Simhadri-I	2359	2350	2387	2398	2332	**2365**		2359	2350	2387	2398	2375	**2374**
3	Rihand-II	2380	2355	2358	2368	2330	**2358**		2380	2355	2358	2368	2330	**2358**
4	Vindhyachal-II	2352	2360	2363	2423	2369	**2373**		2352	2360	2363	2423	2369	**2373**
5	Vindhyachal-III	2347	2348	2356	2398	2367	**2363**		2347	2348	2356	2398	2367	**2363**
6	Talcher-I	2399	2370	2378	2487	2410	**2409**		2399	2370	2378	2487	2410	**2409**
7	Talcher-II	2359	2352	2377	2459	2360	**2381**		2359	2352	2377	2459	2360	**2381**
		Average					**2372**		**Average**					**2374**

iv. <u>The average corrected heat rate for 500 MW stations more than 10 years old for the five year period from 2013-14 to 2017-18 works out to 2374 kcal/kwh instead of 2351 kcal/kwh.</u>

v. It may also be observed from the table that there is deterioration in heat rate in the last two years i.e. 2016-17 and 2017-18 due to increased penetration of RE which is also anticipated to continue and further worsen in the 2019-24. <u>In light of the above, additional margin of around 25kcal/kwh (1-1.5 %) may be provided on 2375 kcal/kwh to arrive at the norm for 500 MW units.</u>

In view of the above, it is submitted that the heat rate norm of 2400 kcal/kwh may be provided for 500 MW units which are older than 10 years.

D. HEAT RATE OF UNITS ACHIEVING COD ON OR AFTER 1.4.2009:

a. The Draft Regulations in table at clause 59 (C) (b) (i) has specified minimum boiler efficiency of 86% for the units declared under commercial operation during the period 01.04.2009 to 31.03.2014 whereas the minimum boiler efficiency prescribed by the Hon'ble Commission in the Tariff Regulations for 2009-14 for such units/ stations so far was 85%. Changing the design minimum boiler efficiency to 86% from 85% retrospectively for units which were set up considering efficiency of 85% and in operation for 7-8 years is not fair and justified.

b. The Explanatory Memorandum at Table 55 has worked a margin of 5.28% over design unit heat rate considering design boiler efficiency of 86%. It may be seen from the table below that the margin of actual heat rate in last 5 years over design is 3.66% and the margin of actual heat rate in last two years over design is 3.70%.

S.No.	Station	Design Turbine Cycle HR	Design Boiler Eff	Unit Heat Rate	Norm	Average 05 years	Average last 02 years	Margin Over Design 05 years (%)	Margin over Design 02 years (%)
1	**Dadri -II**	1936	85.34	2269	2378	2385	2387	5.12	5.20
2	**Farakka-III**	1944	83.39	2332	2436	2404	2435	3.09	4.44
3	**Kahalgaon-II**	1944	83.29	2334	2425	2383	2401	2.11	2.89
4	**Korba-III**	1945	84.91	2291	2391	2358	2373	2.94	3.60
5	**Mouda-1**	1932	84.10	2297	2401	2459	2401	7.03	4.52
6	**Rihand-III**	1932	84.05	2299	2402	2359	2350	2.65	2.22
7	**Simhadri-II**	1933	84.50	2287	2375	2363	2375	3.31	3.85
8	**Sipat-II**	1948	85.87	2269	2375	2352	2338	3.68	3.06
9	**Vindhyachal-IV**	1932	84.00	2300	2375	2369	2381	2.99	3.51
								3.66	**3.70**

c. **Design Boiler Efficiency -**The efficiency of the boiler is largely the function coal quality i.e. better the coal quality better the efficiency and poorer the coal quality the poorer the boiler efficiency.

In order to substantiate the above fact following examples may be considered:

i. **Example 1:** Details of design coal parameters of Kahalgaon Stage-I and Stage-II boilers are as follows:

Station	Design Boiler Eff. (%)	GCV (Kcal/kg)	Fixed Carbon (%)	Moisture (%)	Ash (%)	Volatile Matter (%)
Kahalgaon-I	**87.73**	3200	27.49	13.0	42	16.9
Kahalgaon-II	**83.29**	2850	23.5	16.5	43	17.0

ii. **Example-2**: Barh Stage-2 (2X660 MW) and Sipat Stage-I (3X660 MW) are under commercial operation and are having same rated steam parameters and boiler dimensions. However, the design boiler efficiency as per OEMs is 83.7% and 86.27% for Barh Stage-II and Sipat Stage-I respectively. This is mainly due to the different coal quality available at these stations. The design coal parameters of these stations is as follows:

Coal Parameters	**Barh-II**	**Sipat-I**
GCV (Kcal/kg)	3300	3300
Carbon (%)	31.37	34.46
Hydrogen (%)	3.40	2.43
Nitrogen (%)	1.50	0.69
Oxygen (%)	7.75	6.64
Sulphur (%)	0.40	0.45
Carbonates (%)	0.30	-
Phosphorous (%)	0.28	-
Moisture (%)	15	12
Ash	40	43
Design Boiler Eff. (%)	**83.7**	**86.27**

It is evident from above examples that design boiler efficiency largely depends upon the quality of coal considered for designing the boiler and quality of coal available during the operation of boilers at real conditions.

d. **Deteriorating Coal Quality -**It may be pertinent to mention here that domestic coal quality is deteriorating day by day. In this regard many mines of coal companies have been re-graded in past couple of years. In view of the deteriorating coal quality coupled with grade slippage (on an average about two grades) which contributes towards increased heat loss from boiler it is almost impossible for boilers to achieve boiler efficiency of 85% and above.

e. **Consideration of Design Unit Heat Rate -**It is further submitted that NTPC has managed to order the plant in a most economical level by optimally choosing the boiler efficiency and turbine heat rate so that the design unit heat rate is equal to or better than the Unit Heat Rate specified in the relevant tariff regulations at the time of placing the order/ specifications. Still NTPC new stations are subject to operational loss incurred on account of restricting the minimum boiler efficiency to 86% /

86.5% on post facto basis. 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.

f. **CEA Recommendation -** It may also be appreciated that CEA in its recommendation for Heat Rate Norms for the period 2019-24 has specified minimum unit design heat rate instead of specifying the Turbine Cycle Heat Rate and Boiler Efficiency individually.

In view of the above, for units commissioned on or after 01.04.2009, instead of providing minimum boiler efficiency criteria for specifying unit heat rate, the operating margin should be allowed on the design unit heat rate. Accordingly, for units declared under commercial operation on or after 01.04.2009, minimum boiler efficiency may be prescribed as 85% or alternatively only units heat rate may be prescribed as submitted above.

E. **OTHER COMMENTS:**

1) 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.”

Therefore, the norms should be capable of achievement on a consistent basis.

2) **Consideration of operating conditions anticipated in future due to increase in RE generation -** The actual operating conditions for thermal power plants in India is expected to become unfavorable as compared to the existing situation, particularly on account of addition of substantial capacity from renewable sources, deteriorating quality of coal, grid parameters, 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). In addition to the actual data achieved in the past, norms for Station Heat Rate should be fixed considering various operational constraints anticipated in the future, like partial loading /cycling load pattern due to RE integration, low PLF and deterioration in coal quality. Therefore, it is suggested that norms may be specified based on operating conditions anticipated in the future in addition to past actual data.

3) **Norms should be fixed on National Level and not on Company level -** Further, it is submitted that operating norms should be based on the anticipated national performance of units across the country expected due to operational constraints elaborated above. It should not be restricted to NTPC stations alone but also include various units across 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 (SERCs).

4) **Additional Heat Rate for ECS –** There would be deterioration in heat rate on installation of NOx control system. It is submitted that enabling provision of adjustment of heat rate on account of installation of emission control system may be provided in the regulations.

3) REGULATION 51 - INCENTIVE DURING PEAK AND OFF-PEAK HOURS

Draft Regulation Stipulation

"51. Computation and Payment of Capacity Charge for Thermal Generating Stations:

…

(7) In addition to the capacity charge, an incentive shall be payable to a generating station or unit thereof @ 65 paise / kWh for ex-bus scheduled energy during Peak period and @ 50 paise / kWh for ex-bus scheduled energy during Off-Peak period corresponding to scheduled generation in excess of ex-bus energy corresponding to Normative Quarterly Plant Load Factor (NQPLF) as specified in Regulation 59 (B) of these regulations."

Comments / Suggestions

A) **INCENTIVE RATE:**

1. The existing incentive mechanism is proposed to be replaced by new dispensation wherein the incentive is linked to quarterly PLF instead of annual PLF. The incentive would be payable @ of 65 paisa per unit for ex-bus scheduled energy during peak hours in excess of ex-bus energy corresponding to NQPLF. The incentive is payable@ 50 paisa per unit for ex-bus scheduled energy during off-peak hours in excess of ex-bus energy corresponding to NQPLF. The Normative Quarterly Plant Load Factor (NQPLF) for incentive has been set at 85%.
2. **Rate of Incentive:** During the tariff period 2014-19, the rate of incentive was Rs. 0.50 per unit. Considering O&M escalation of 6.35% per annum during the period 2014-19, 50 paisa per unit in FY 2014-15 works to around 68 paisa per unit in FY 2019-20. It would be relevant to note that income tax is payable by generator and thus effectively only about 75%of the incentive amount available to the generator. **Further, as the incentive is payable only if the beneficiary has scheduled the power, it may be same for both peak and off-peak**

hours. Therefore, the incentive rate may be increased to Rs. 1.00 per unit for both peak and off-peak hours.

3. **Separate Eligibility for peak and off-peak hours**: The Draft Regulations provide differential rate for fixed charges and incentive for peak and off-peak hours. Availability has to be achieved separately for peak and off-peak hours. Annual Fixed Charges would also be computed separately. Therefore,the incentive computation may also be kept separate for peak and off-peak hours. The Draft Regulations provides NQPLF of 85% for incentive. If NQPLF for quarter (i.e. taking both peak and off-peak hours) is not achieved even though NQPLF is achieved during peak hours, it appears from the present draft that no incentive shall be payable. For stations which are likely to achieve the target availability but do not fall in the incentive zone (PLF > 85%), there would be no inclination to give higher availability during peak hours even if they are capable for the same. To give such stations a signal to give higher availability during peak hours and help the grid to meet the diurnal variation due to high RE capacity, it is necessary that incentive eligibility should be reckoned separately for peak and off peak hours instead of making the station eligible for incentive only when their average PLF for the period is more than NQPLF. It would also be in line with the concept of considering separate availability for peak and off-peak hours for recovery of Annual Fixed Charges. **Therefore, it is requested that the separate PLF may be computed for peak period and off-peak period and incentive may be provided by comparing the PLF of respective periods with the normative PLF during peak and off-peak periods.**
4. **Level of NQPLF:** The Draft Regulations have proposed NQPLF as 85% whereas NQPAF is set at 83%. The norm for availability has been reduced in view of the coal shortage scenario. However, NQPLF has been retained at 85% with increased RE capacity addition, the PLF of thermal stations will further go down. Even though thermal stations would be required to generate fully during evening hours but during the day they may be running at technical minimum. Thus, the average utilization of thermal stations will go down and the average PLF would reduce. It would be therefore appropriate that the level of NQPLF be reduced to 83%.It is submitted that the NQPLF for incentive may be set at 83%.
5. **Methodology of Computation of Incentive:** In addition to the above, another issue which needs consideration is applicability of incentive to be paid by

beneficiary. As of now the incentive is being paid only in case the overall PLF of the plant is more than normative level and is payable by the beneficiary who has scheduled the generation over and above the normative PLF corresponding to its allocation. That is, in case a particular beneficiary has scheduled the generation higher than normative PLF corresponding to its allocation and the normative PLF at the plant level has not been achieved, the beneficiary does not pay for higher utilization. The dual condition applicable for payment of incentive seem to favor only the Discom. **It is therefore requested that the Commission may allow incentive by not checking the PLF at total plant level but only at the level corresponding to the allocated power for a beneficiary i.e. in case a beneficiary schedules power more than the normative PLF corresponding to its allocation irrespective of PLF at plant level, the beneficiary should pay incentive on generation over the normative PLF.**

6. **Morning and Evening Peak**: It is also requested that the proposed minimum four hours of peak period may also be allowed preferably only in two stretches (corresponding to morning and evening peak) rather than in multiple stretches which may be declared in advance on monthly basis by respective RLDCs. This will be technically more practical for the generator to operate the power plant.

B) **Billing of Annual Fixed Charges:**

1) It may be noted that present regulations, 2014 (Regulation 30(2)) provides for recovery of part of AFC which includes O&M expenses and interest on loan in case unit is under shutdown due to R&M.

2) Present provision may be continued as the same is necessary as the generator would incur this minimum expenditure during shut-down of unit for R&M with no corresponding revenue to fund such expenses**.**

C) **REGULATION 51 (6) Definition of DCi**

It is submitted that DCi may be defined as average declared capacity (in ex bus MW), for the ith day of the period i.e. the month or the quarter or the year as the case may be, as certified by the concerned load dispatch center after the day is over

4) REGULATION 52 - MARGIN IN GROSS CALORIFIC VALUE (GCV) OF COAL AS RECEIVED ON ACCOUNT OF STORAGE AT GENERATING STATION

Draft Regulation Stipulation

"52. Computation and Payment of Energy Charge for Thermal Generating Stations:

(1) The energy charge shall cover the primary and secondary fuel cost and limestone consumption cost (where applicable), and shall be payable by every beneficiary for the total energy scheduled to be supplied to such beneficiary during the calendar month on ex-power plant basis, at the energy charge rate of the month (with fuel and limestone price adjustment). Total Energy charge payable to the generating company for a month shall be:

Energy Charges = (Energy charge rate in Rs./kWh) x {Scheduled energy (ex-bus) for the month in kWh}

(2) Energy charge rate (ECR) in Rupees per kWh on ex-power plant basis shall be determined to three decimal places in accordance with the following formulae:

a. For coal based and lignite fired stations:

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

b. For gas and liquid fuel based stations:

ECR = SHR x LPPF x 100 / {(CVPF) x (100 – AUX)}

Where,

AUX =Normative auxiliary energy consumption in percentage.

CVPF = (a) Weighted Average Gross calorific value of coal as received, in kCal per kg for coal based stations less 85 Kcal/Kg on account of variation during storage at generating station;

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

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

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

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

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

LC = Normative limestone consumption in kg per kWh.

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

LPPF = Weighted average landed price of primary fuel, in Rupees per kg, per litre or per standard cubic metre, as applicable, during the month. (In case of blending of fuel from different sources, the weighted average landed price of primary fuel shall be arrived in proportion to blending ratio)

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

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

Comments/Suggestion:

1) One of the parameters to compute the Energy Charge Rate (ECR) of coal stations is the Gross Calorific Value (GCV) of coal. The Draft Tariff Regulations has proposed to providea margin for 85 kcal/kg in GCV as received considering the loss in GCV during storage and handling in the generating station.

2) This is a welcome step as Hon'ble Commission has rightly appreciated that there is an unavoidable lossin GCV during storage and handling within the generating station from GCV as received (measured at wagon top) to the GCV of coal as fired in the boiler. This loss in GCV is beyond the control of the generator.

3) **CEA Recommendation:**The CEA in response on this issue referred by the Ministry of Power and the Hon'ble Commission has given its recommendation in this regard vide its letter dated 20.03.2018.

The recommendations from CEA is after consultation with specialist Central Government Institutes working in the area of power and coal and involved in sampling and testing of coal, such as, CIMFR and CPRI, considering studies carried in various national and international papers and also after acknowledging the factors considered by State Regulators has recommended considering the margin of 85-100 kcal/kg for pit head plants and 105-120 kcal/kg for non-pit head plants.

4) However, the Draft Regulations have proposed a uniform margin of 85 kcal per kg without differentiating between pithead and non-pithead stations. The proposed GCV margin of 85 kcal/kg would be inadequate for non-pithead stations. **It is submitted that the separate GCV margins for pithead and non-pit head stations may be allowed in line with the recommendations of the CEA.**

5) REGULATION 68 - REBATE

CERC Draft Regulation Stipulation

"68. Rebate. (1) For payment of bills of the generating company and the transmission licensee through letter of credit on presentation or through National Electronic Fund Transfer (NEFT) or Real Time Gross Settlement (RTGS) payment mode within a period of 2 days of presentation of bills by the generating company or the transmission licensee, a rebate of 2% shall be allowed.

Explanation: In case of computation of '30 days', the number of days shall be counted consecutively without considering any holiday. However, in case the last day or 30th day is official holiday, the 30th day for the purpose of Rebate shall be construed as the immediate succeeding working day (as per the official State Government's calendar, where the Office of the Authorised Signatory or Representative of the Beneficiary, for the purpose of receipt or acknowledgement of Bill is situated).

(2) Where payments are made on any day after 2 days and within a period of 30 daysof presentation of bills by the generating company or the transmission licensee, a rebate of 1% shall be allowed.

Comments/Suggestion:

1) The Draft Regulations have reduced the period of receivables from two months to 45 days.Thus, a period of 45 days has been given to the beneficiaries for payment of bills.
2) However, the rebate of 2% for prompt payment of bills within 2 days from presentation of bills has also been retained. Itis submitted that the rebate paid to beneficiaries is financed out the receivables accounted for in working capital in tariff. By allowing a rebate of 2% on presentation of bill, the beneficiaries get 2% on advancing payment by 45 days. The rebate then becomes disproportionate to the carrying cost of money for 45 days. Therefore, it creates a deficit between what is paidas rebate and what is recovered in tariff. The rebate needs to be aligned in line with the receivables of 45 days.

3) **In view of the above, it is submitted that rebate of 2% on payment of bills within 2 days from presentation of bills be reduced to 1.5%. i.e.(45/60) × 2%**

6) REGULATION 69 - LATE PAYMENT SURCHARGE

Draft Regulation Stipulation

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

Comments/Suggestion:

1) **Rate of Late Payment Surcharge (LPSC):**

   i. The Hon'ble Commission in its order dated 16.01.2004 in respect of Terms and Conditions of Tariff i.e. 01-04-2004 has held that Late Payment Surcharge is in the nature of a disincentive to promote efficiency:

   "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 <u>the provision of late payment surcharge is invoked only when a beneficiary has defaulted in making timely payment of dues</u> of the generating company or the transmission utility." Emphasis supplied.

ii. The Hon'ble Commission has recognized that in view of the importance of timely payment of dues, there is a case for increase in late payment surcharge. Surcharge rate is intended to act as a deterrent against late payment and thus prevent accumulation of outstanding dues. Therefore, the proposed reduction in rate of late payment surcharge from 1.50% per month to 1.25% per month when the interest rates are increasing will result in increased default levels further resulting in accumulation of huge arrears. Thiswould adversely affects the financial health of both the Discoms and generators and shall be counter-productive to the power sector.

iii. In view of the above, reduction in rate of LPSC from 1.5% per month to 1.25% is not justified. **It is submitted that, the existing rate of 1.50% per month for LPSC may be retained for the enforcing timely payments of bills and to avoid adverse impact on the financial health of the power sector.**

2) **Effective LPSC Rate:** Moreover, late payment surcharge paid by the beneficiaries in case of late payment 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 only 3/4th of 1.25% per month.

3) **Rate of Surcharge may on Annual Basis instead of Monthly Basis–** As LPSC is on monthly basis, the rate for each day of delay in the month of February is more as compared to that in January, March, etc. As period of surcharge may fall in more than one calendar month, rate of surcharge would slightly vary due to the number of days in that month. In order to have uniform

rate for each day of delay, LPSC may be specified on annual basis instead of monthly basis.

4) **Clarification on Computation Methodology of late payment surcharge –** The Hon'ble Commission may clarify whether late payment surcharge is to be levied only after receipt of payment or on accrual basis (i.e., on completion of 45 days from the date of billing 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 the date of billing)	No. of days beyond 60 days	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)**
04-05-2018	10,00,00,000	2,50,00,000	08-06-2018	04-06--2018	4	365	18	49,315
		3,50,00,000	19-06-2018	04-06-2018	15	365	18	2,58,904
		4,00,00,000	29-06-2018	04-06-2018	25	365	18	4,93,151
Total	10,00,00,000	10,00,00,000						
	Total Late Payment Surcharge (Rs.)							8,01,370

7) REGULATION 28 - SINGLE-PART TARIFF FOR STATIONS WHICH HAVE COMPLETED 25 YEARS OF USEFUL LIFE

CERC Draft Regulation Stipulation

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

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

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

Comments/Suggestion:

1) The Draft Regulations has proposed to provide an option to the generator to enter into an agreement with the Discoms where the total tariff inclusive of the fixed cost and the variable cost for the generating station (single-part tariff) as determined under 2019-24 regulations, shall be payable on scheduled generation instead of the existing arrangement of separate payment of fixed cost based on availability and energy charge based on schedule. Discoms also have the first right of refusal to enter into such arrangement. On refusal by Discom to enter into such arrangement, generator shall be free to sell the electricity from the station in open market in manner it deems fit.

2) The Explanatory Memorandum at clause 3.5.8 has stated that this option will be available to thermal generating stations which have neither undertaken R&M nor availed Special Allowance.

3) In view of the above, it emerges that the options available to thermal generating stations that have completed its useful life are as under:
    a. R&M,
    b. Special Allowance
    c. Single part Tariff

   As per the Explanatory Memorandum, these options are mutually exclusive. In other words, a station which has undertaken R&M or availed Special Allowance cannot avail single part tariff. **It is submitted that the variance between the Draft Regulations and the Explanatory Memorandum may be clarified.**

4) **Single part tariff would result in under recovery of Fixed Charges:**
   Under the single part tariff mechanism the tariff for a station is inclusive of both the fixed cost as well as the variable (energy) cost calculated at a normative generation level. A sort of incentive and disincentive is inherent in the single-part tariff depending on the level of scheduling. If the station is not able to generate up to the normative generation level, it suffers a shortfall in fixed cost recovery corresponding to the shortfall in generation. On the other hand, generation above the normative generation level yields additional revenue, i.e., a surplus over the fixed and variable cost of the station. The incentive and disincentive are linearly linked to the annual PLF of the generating station which is beyond the control of the generator. In deficit scenario, most of the plants would most likely be able to recover their fixed cost of generation. However single-part tariff would result in under recovery of costs in case of surplus scenario.

5) **No assurance of receiving any fixed charges for making plant available:**

   It may be observed that the above option / right to procure power under single-part tariff given to the Discoms would be the obvious choice for any of the beneficiaries as the same would make the Discom free from any fixed cost liability for the entire control period without any commitment. Generator on the other hand would be responsible for making the plant available for the Discoms without any assurance of payment of fixed charges.

6) **Disadvantage in Merit Order Scheduling -**Although stations which have completed their useful life inherently have lower fixed charges, single composite tariff would put them in a disadvantage with regard to merit order scheduling by Discoms as compared to other stations with two part tariff.

7) For regulatory certainty, the accepted principle needs to be consistently applicable to both the old as well the new stations. Also choice between the options is logical only if both the generators and Discoms are given a level playing field. With the given options, Discoms would be selective for choosing the plants and would obviously choose single-part tariff for plants having higher variable charge and may continue with two-part tariff only for the plants which have lower variable charge.

8) Under such case the generators would be adversely impacted owing to the following factors:
   a. PLF of stations with higher variable cost would further reduce as entire single part tariff would be taken into consideration under MOD for purpose of scheduling. Also with reduced PLF their operating parameters would worsen again resulting in increase on cost of generation.
   b. Huge fixed cost under-recovery as it is obvious that such plants will not be able to operate at normative PLF levels.

9) **In view of the above, to keep a balance between the interest of Discoms and the generators the two-part tariff is considered to be the most suitable mechanism for tariff determination for all thermal power plants.**

10) Further the Draft Tariff Regulations provides for determination of fixed charges only on annual basis and there is no specific provision to compute the per unit fixed charges which may be required in the proposed arrangement. It is requested that the Commission may provide the specific mechanism to compute per unit fixed charge at a certain generation level. It is also requested that if the above mechanism is considered, an option should be provided wherein per unit

fixed charge may be computed on the pre-agreed estimated generation (estimated PLF) and not on the basis of normative PLF.

11) **Alternate Proposition -** It is anticipated that the PLF under single part tariff shall reduce significantly as compared to the existing level. Therefore it is suggested that the per unit fixed charges under single part may be fixed at operating level of 68 %. Further, the per unit fixed charge rate should be fixed so that it generates enough incentive to operate the plant on sustained basis. In order to provide a level playing field all thermal stations and to avoid under recovery of fixed charges in old stations adopting single part tariff, it is proposed that the following options based on single part tariff may be considered as under:

   a. **Single part tariff may be provided on existing AFC for 2018-19 with nominal escalation for the next tariff period, or**
   b. **Single part tariff on nominal per unit AFC fixed at operating level of 68% or say Rs. 1.00 per unit.**

8) REGULATION 72 - SHARING OF NON-TARIFF INCOME

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

a) Income from rent of land or buildings;

b) Income from sale of scrap;

c) Income from statutory investments;

d) Interest on advances to suppliers or contractors;

e) Rental from staff quarters;

f) Rental from contractors;

g) Income from advertisements;

h) Interest on investments and bank balances;

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

<u>Comments/Suggestions:</u>

1) **(b) Income from sale of scrap -**

Scrap is generated out of spares and plant and machinery. In both the cases 90% of capital cost(so far) is recovered from tariff and 10% is un-serviced for life of plant. The income from sale of scrap even does not cover even the salvage value cost (10%) of these assets. Further, company also incurs certain administrative cost on disposal of asset.Besides that, all the sale of scrap is not from the admitted part of the capital cost and even if it is part of admitted cost, the same is deducted from the admitted capital cost in the event of decapitalization.

Further, Hon'ble Commission does not consider the loss on disposal of asset as allowable/claimable expenses. Therefore, it is grossly unfair to transfer the benefit of something which has not been serviced by the beneficiary and any such sharing now proposed is not fair.

2) (c) Income from statutory investments

NTPC borrows in a basket and then the loans/bonds are allocated to specific projects depending on requirement. The borrowing is done on its balance sheet strength as against project financing. The robust financials help in reducing the cost of borrowing thereby lowering the IDC in construction stage and thereafter optimizing the Annual Fixed cost in operational phase. This results in lowering the cost of generation which ultimately benefits the beneficiaries. In case of NTPC, certain deposits are required to be made as per Section 18 (7) of the Companies Act 2013:

"Every company required to create Debenture Redemption Reserve on or before the 30th day of April in each year, invest or deposit, as the case may be, a sum which shall not be less than fifteen percent, of the amount of its debentures maturing during the year ending on the 31st day of March of the next year, in deposits with any scheduled bank, free from any charge or lien (inter alia)".

The quantum of income on statutory investments is insignificant and in any case same is funded through ROE hence the same is not required to be shared.

3) (d) Interest on advances to suppliers or contractors

The major portion of this income is usually adjusted in the package cost in case of new stations as well as Renovation & modernization. The advance to supplier/contractors is provided to facilitate suppliers or contractors to complete the job in economical cost otherwise the same shall increase the project cost.

4) (h)Interest on investments and bank balances

Generally, the investments and interest thereon is out of ROE. In any case, operating and financial efficiencies are already being shared with beneficiaries in ratio of 50:50.

In view of the above, CERC, may not consider any sharing of non-tariff income. As it is, the generator has to bear the under recoveries in O&M caused by various expenditures not allowed by the regulators like CSR, Ex-gratia, PRP etc. and to cover various business & operational risks.

Sharing all such incomes with beneficiaries will be against the principle of "Unjust enrichment" i.e. obtaining a benefit by one party at the expense of another. The principle of unjust enrichment is an underlining principle behind a plethora of judgments to bring justice and uphold the pillars of equity.

9) REGULATION 27 - SPECIAL ALLOWANCE

Draft Regulation Stipulation

"27. Special Allowance for Coal-based/Lignite fired Thermal Generating station:

(1) In case of coal-based/lignite fired thermal generating station, the generating company, instead of availing R&M may opt to avail a 'special allowance' in accordance with the norms specified in this Regulation, as compensation for meeting the requirement of expenses including renovation and modernisation beyond the useful life of the generating station or a unit thereof and in such an event, upward revision of the capital cost shall not be allowed and the applicable operational norms shall not be relaxed but the special allowance shall be included in the annual fixed cost:

Provided that such option shall not be available for a generating station or unit for which renovation and modernization has been undertaken and the expenditure has been admitted by the Commission before commencement of these regulations, or for a generating station or unit which is in a depleted condition or operating under relaxed operational and performance norms;

(2) The special allowance shall be available for a generating station which has availed the special allowance during the tariff period 2009-14 or 2014-19 as applicable from the date of completion of the useful life.

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

(4) In the event of availing special allowance, the expenditure incurred or utilized from special allowance shall be maintained separately by the generating station and details of same shall be made available to the Commission as and when directed to furnish details of such expenditure.

(5) The special allowance allowed under this Regulation shall be transferred to a separate fund for utilization towards Renovation & Maintenance activities, for which detailed methodology shall be issued separately."

Comments / Suggestions:

1) The Draft Regulations has proposed that the option of Special Allowance shall be availableto those stations which have availed Special Allowance during the tariff period 2009-14 or 2014-19 as applicable from the date of completion of the useful life. Those stations which will complete its useful life during the tariff period 2019-24 shall not be able to avail Special Allowance.

2) **Comparison of increase in Tariff on account of Special Allowance vis-a-vis R&M:**It is submitted that the special allowance proposed as per the draft regulations at Rs. 9.5 lakh/MW translates to nearly 14 paise/unit. However, expenditure on Renovation & Modernisation (R&M) of plants incurred (as per CEA)is inexcess of Rs. 2 Crores/MW with life extension 15 years translates to incremental tariff of nearly 46paise/unit (levelised).

Illustration:

a. **Special Allowance Route:**

Station Installed Capacity	2000	MW
Special Allowance Norm	9.5	lakh/MW
Special Allowance Admissible	19000	Rs. Lakhs
ESO at 83%	13524	MUs
Incremental Impact of Special Allowance per unit	0.14	Rs/kwh

b. **R&M Route:**

Station Capacity	2000	MW
R&M Expenditure (as per CEA)	200	lakh/MW
Total R&M Expenditure	4000	Rs. Crs
ESO at 83%	13524	Mus

Incremental Impact of R&M (per unit levelised)	0.46	Rs/kwh

Note: The impact of O&M expenses and IWC pre and post R&M ignored. Debt rate considered is 9%

3) Since option of availing special allowance has not been provided to stations which would be completing their useful life during the tariff period 2019-24, such stations shall have to necessarily go for R&M route for sustained operation beyond its useful life as per the Draft Tariff Regulations.

4) It is evident from above illustration that R&M route would result in additional financial burden on the beneficiaries as compared to special allowance route which provides an economic option. Restricting a cheaper option would obviously not be the intent of the Regulations. **In view of above, it would be more appropriate that the option of availing special allowance should remain open for all units/ station which have completed useful life including those stations that would be completing useful life in the next tariff period i.e. during 2019-24.**

5) **Escalation in Special Allowance Norm during the tariff period:** The Draft Regulations has proposed a flat rate of Special Allowance @ Rs. 9.5 Lakhs per MW without any escalation during the tariff period 2019.24 compared to the existing rate of Rs. 9.6 Lakhs per MW in 2018-19. The Commission had also provided escalation of 6.35% on Special allowance applicable during 2014-19. It may be noted that while carrying out R&M, the prices of material as well as the manpower cost are subject to inflation**. Accordingly, it is submitted that the escalation rate applicable to O&M expenses may be allowed for special allowance year on year basis to cover the cost of escalation of material as well as man power.**

6) **Need for Separate Fund -**The Draft Regulations 27 (5) has proposed creation of a separate fund for utilization towards Renovation & Maintenance activities, for which detailed methodology shall be issued separately. While the explanatory memorandum at Para 3.5.4 has recognized that the

dispensation of special allowance ensures availability of electricity from old plants beyond their useful life at an economic rate with no increase in capital cost it has also mentioned that often beneficiaries are not sure whether the amount claimed under special allowance is actually being spent by the generating companies. It may be mentioned in this regard Regulations provide that the expenditure incurred or utilized from special allowance shall be maintained separately by the generating station and details of same shall be made available to the Commission as and when directed to furnish details of such expenditure.

7) The special allowance is given in regulations for units which have completed 25 years and covers the expenditure towards Renovation and Modernization of units, etc.Further, data regarding year wise utilization of special allowance as required under the Tariff Regulations has been furnished as part of data for framing of the Tariff Regulations 2019. The cumulative utilization pattern shows that actual expenditure is higher than the allowance given by Commission.

8) The works are awarded from time to time and most of the works are having tenure of one year or more. The expenditure is staggered and does not have one to one matching with yearly allowance given in the regulations. On a yearly closing date there may be short term mismatch in allowance vis-a-vis expenditure but in totality the expenditure exceeds the special allowance received. Since NTPC old plants are having PLF of over 83%, their operating and maintenance condition is impeccable.

9) Creating a fund for utilization of special allowance will only incur administrative cost and put a burden on scare human resources. The treatment of tax in case of creation of fund or routing it directly through P&L account will remain the same.Moreover, it may be noted that separate funds are usually created to save the unutilized funds for their specific usage at a later date / period. As the special allowance is mostly utilized for R&M activities within the same year or in the following year, there may not be any requirement to separately form a fund**. It is submitted that Creation of a fund may not be necessary and the proposed provision may be deleted.**

10) REGULATION 30 - Return on Equity on Additional Capitalisation

Draft Regulation Stipulation

"30. Return on Equity:

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

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

Provided that:

i. *Return on equity in respect of additional capitalization after cut-off date within or beyond the original scope shall be computed at the weighted average rate of interest on actual loan portfolio of the generating station or the transmission system;*

ii. *In case of a new project, the rate of return shall be reduced by 1.00% for such period as may be decided by the Commission, if the generating station or transmission system is found to be declared under commercial operation without commissioning of any of the Restricted Governor Mode Operation (RGMO) or Free Governor Mode Operation (FGMO), data telemetry, communication system up to load dispatch centre or protection system based 66 on the report submitted by the respective RLDC;*

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

Comments/Suggestions:

1. The Draft Regulations have proposed that the return on equity in respect of additional capitalisation after the cut-off date within or beyond the original scope shall be computed at the weighted average rate of interest on actual loan portfolio of the generating station.
2. The Explanatory Memorandum has stated at Para 2.5.6 as under *"The Commission has also proposed to clearly segregate the a) additional capitalisation within the original scope and up to cut-off date, b) additional capitalisation within original scope and after cut-off date and c) additional capitalisation beyond the original scope, in terms of treatment of these w.r.t rate of return on equity. It has been proposed that equity component up to 30% of the additional capital expenditure incurred after the cut-off date, whether within the original scope or not, shall be serviced at the weighted average rate of interest."*
3. Para 11.5.13 of explanatory memorandum states as under *"Further, the Commission intends to allow the existing rate of 15.50% in respect of the equity component (up to 30% or as approved by the Commission) of the capital cost up to the cut off date only. In respect of any additional capitalization after cut-off date whether within or beyond the original scope of work, the equity component is proposed to be serviced at the weighted average rate of interest on actual loan portfolio. This provision is not proposed to be applied in case of additional capital expenditure on account of Renovation and Modernisation after useful life."*
4. **Effective Return if Add-cap is Serviced at Debt Rate -**

   If equity invested in additional capitalisation is serviced at weighted average rate of interest on actual loan portfolio, it would have two-fold impact on the generator. Firstly, the equity invested / to be invested by the generator shall now be serviced at weighted average rate of loan instead of the entitled post-tax return at rate of return on equity.

   Secondly, as the generator has to bear the income tax on the return on equity being serviced at the weighted average interest on loan, the post-tax rate of return on such equity shall be effectively 75% of the weighted average interest on loan.

   To illustrate, if the weighted average interest on loan is 8%, the effective return on equity on additional capitalisation would be only 6%. This would discourage the generator from making equity investments on additional capitalisation. Further, retrospective lowering of rate of return on investments pertaining to add-cap which have been made considering 15.5% post-tax return to weighted average rate of interest will shake the lenders confidence and affect the cash flow of the generating company. This may reduce the credit rating of the generating company. As a result overall rate of interest on loan shall increase. This dispensation will result in overall increase in interest rate for the power sector.

5. **Impact on generation tariff:** The intention of the proposed dispensation to lower generation tariff by servicing add-cap at interest rate on loan may not actually deliver the desired benefit. Increase in debt financing or 100% debt financing shall increase the rate of interest on loan as the risk of lenders shall increase. To illustrate, as per extant regulations, the weighted average actual interest on loan is say 8% and the post tax rate of return on equity is 15.5%, then the weighted average cost of capital (WACC) at Debt/Equity ratio of 70:30 works out to 10.25%. If the interest rate on loan increases to say 11% due to 100% debt funding under the proposed dispensation, then the WACC would be 11%. This would result in increase in tariff.

6. **Different rates for different Companies for servicing additional capitalisation -** The proposed dispensation shall result in different rates for servicing of equity invested in add-cap for different companies as per the weighted average actual interest of loan of that company.

7. **Perverse Incentive to Increase the Interest Rate -** As per the extant regulations interest on loan is allowed as per actuals. There is no incentive to lower interest rate. As equity invested in add-cap is proposed to be serviced at actual interest rate on loan, the proposed dispensation shall provide perverse incentive to increase the rate of financing. The bankers will stand to gain by higher rate. Therefore, it is submitted that normative debt rate may be adopted instead of actual debt rate.

8. As Regulation 29 provides for additional capitalization on account of Revised Emission Standards, it is understood that the same shall be also serviced at actual debt rate.

9. 100% debt funding is not practical to source from the market. The additional capital expenditure incurred on projects is funded from both debt and equity. With regard to the implementation of the revised emission control norms, the cost of installation of Flue Gas Desulphurization (FGD) equipment is in the range of Rs. 30-75 lakhs per MW depending on unit size and configuration. Considering the overall portfolio of NTPC thermal plants where FGD is required to be installed, the total capital investment requirement for installation of FGD equipment would be approximately Rs.20000 Crores. Sourcing such huge quantum of funds only in form of debt is not possible. Therefore, additional capital expenditure on installation of FGD equipment will have to be necessarily funded by both internal resources / equity and debt.

10. It is presumed that servicing of ECS at debt rate shall not provide for any pass through of tax on actual basis, which the generator shall have to pay on funding the part of investment sourced from internal resources as equity. In other words, while equity shall be serviced at debt rate in tariff, the generating company would have to additionally bear income tax on any equity which is invested in additional capitalisation. The actual differential would thus be the post-tax rate of return minus the actual debt rate serviced in tariff. (i.e., around 13%). The effective rate of return would be only 6% when the actual debt rate is 8% as enumerated in para 4 above. Therefore, generator would go for 100% debt for the investment in ECS.

11. Moreover, while the equity invested in ECS in a new plant would be serviced at rate of return on equity, the equity invested in ECS in an existing plant would be serviced at debt rate as per the Draft Regulations. This would create a disparity between applications of principle to new and existing stations which would not be desirable.

12. Servicing add-cap on ECS at debt rate provides only compensation or cost servicing assuming that the entire investment is funded by debt alone. The risk factors associated with equity investment in power plant has not been considered. Therefore, the risk premium has been considered as zero. However, there are many risks associated with ECS as under:

    a. Loss of availability due to shutdown period on account of ECS installation, coal shortage, equipment breakdown, etc
    b. Increased O&M costs
    c. Increased operational parameters like APC and heat rate.

    Therefore, as risk free return has been considered, it is submitted that the generator may be compensated for any likely loss of fixed charges due to shutdown on account of installation of ECS.

13. In case the investment is sourced entirely on debt alone, the interest rate would increase as lenders would charge higher interest rate on loans in the absence of any equity participation. This would increase the supplementary tariff for the ECS. As a result, the benefit of reduction in tariff on ECS as intended by the Draft Regulations shall not materialize but shall be counterproductive.

    In view of the above, the Hon'ble Commission may consider servicing of equity invested in additional capitalisation including that on revised emission control norms at the rate of return on equity.

11) REGULATION 32 - RATE OF INTEREST FOR LOAN CAPITAL

Draft Regulation Stipulation

“32. Interest on loan capital:

(1) The loans arrived at in the manner indicated in Regulation 17 of these regulations shall be considered as gross normative loan for calculation of interest on loan.

(2) The normative loan outstanding as on 1.4.2019 shall be worked out by deducting the cumulative repayment as admitted by the Commission up to 31.3.2019 from the gross normative loan.

(3) The repayment for each of the year of the tariff period 2019-24 shall be deemed to be equal to the depreciation allowed for the corresponding year/period. In case of decapitalization of assets, the repayment shall be adjusted by taking into account cumulative repayment on a pro rata basis and the adjustment should not exceed cumulative depreciation recovered upto the date of de-capitalisation of such asset.

(4) Notwithstanding any moratorium period availed by the generating company or the transmission licensee, as the case may be, the repayment of loan shall be considered from the first year of commercial operation of the project and shall be equal to the depreciation allowed for the year or part of the year.

(5) The rate of interest shall be the weighted average rate of interest calculated on the basis of the actual loan portfolio after providing appropriate accounting adjustment for interest capitalized:

Provided that if there is no actual loan for a particular year but normative loan is still outstanding, the last available weighted average rate of interest shall be considered:

Provided further that if the generating station or the transmission system, as the case may be, does not have actual loan, then the weighted average rate of interest of the generating company or the transmission licensee as a whole shall be considered.

(6) The interest on loan shall be calculated on the normative average loan of the year by applying the weighted average rate of interest.

(7) The changes to the terms and conditions of the loans shall be reflected from the date of such re-financing.

(8) In case of dispute, any of the parties may make an application in accordance with 70 the Central Electricity Regulatory Commission (Conduct of Business) Regulations, 1999, as amended from time to time, including statutory re-enactment thereof for settlement of the dispute:

Provided that the beneficiaries or the long term transmission customers shall not withhold any payment on account of the interest claimed by the generating company or the transmission licensee during the pendency of any dispute arising out of re-financing of loan."

Comments/Suggestions:

1. It is requested to the Hon'ble Commission that allowing the normative rate of interest may be considered, as the same will incentivize fiscal efficiency in the sector and generators will try to negotiate lower rates with the financial institutes. The existing Regulations provide for norms for almost all operational and financial parameters. As debt rate is a market driven parameter the same may also be easily benchmarked / linked 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.
2. 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.
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.
4. With the existing approach of interest on debt on actual basis, the incentive to lower the cost of debt is very nominal. It is suggested that investor may incentivized to secure lower cost of debt. The benchmark may apply uniformly to

all entities based on average credit rating of all the entities in the sector and provide for adequate margin to take care of fluctuations in the market interest rates and could be linked to publicly available benchmarks such as 10 year 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 + 350 bps. This would also take care of movements from time to time in the interest rate conditions.**

12) REGULATION 34 - COAL STOCK TOWARDS WORKING CAPITAL REQUIREMENT

"34. Interest on Working Capital:

1) The working capital shall cover:

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

i. Cost of coal or lignite and limestone towards stock, if applicable, for 15 days for pit-head generating stations and 20 days for non-pit-head generating stations for generation corresponding to the normative annual plant availability factor or the maximum coal/lignite stock storage capacity whichever is lower;

ii. Advance payment for 30 days towards Cost of coal or lignite and limestone for generation corresponding to the normative annual plant availability factor;

iii. Cost of secondary fuel oil for two months for generation corresponding to the normative annual plant availability factor, and in case of use of more than one secondary fuel oil, cost of fuel oil stock for the main secondary fuel oil;

iv. Maintenance spares @ 20% of operation and maintenance expenses specified in Regulation 35 of these regulations;

v. Receivables equivalent to 45 days of capacity charges and energy charges for sale of electricity calculated on the normative annual plant availability factor; and

vi. Operation and maintenance expenses for one month."

Comments/Suggestions

1. The Draft Regulations has reduced the cost of coal towards stock for non-pit-head generating stations from 30 days to 20 days. It is seen that the Hon'ble CERC has reduced norm of coal stock based on actual coal stock maintained by the thermal plants in the last 5 years.

2. It is a fact that most of the non-pithead plants are operating at less than the normative coal stock, but that is because of lower coal supply by CIL and its subsidiaries.Further, it is to be noted that the lower coal stock being maintained by the thermal plants is not intentional and is attributed mainly to low supply of coal by coal companies and transportation bottlenecks. Coal shortage is a major issue plaguing power sector. It is submitted that in spite of continuous efforts of generators to build up coal stock-up to the required level, coal shortage problem is largely beyond the control of the generator. Generating companies face huge risk of fixed charge recovery due to lower coal stock. Today there is a need to put clear responsibility on the coal supplying companies to ensure that at least 1 month of coal stock is available for non-pithead stations so that they don't have to rely on e-auction / imported coal. But reducing coal stock in working capital because coal companies are unable to supply coal is a counterproductive measure that will further increase the risk of fixed charge recovery and thus badly hit the financial / cash performance of generating companies.

3. The risk of coal unavailability already lies with the generator as arranging fuel is the responsibility of the generator. Therefore, in case of coal shortage the generator will not be able to meet target availability which would result in under recovery of capacity charges. There is already under recovery of fixed charges in many NTPC stations due to coal shortage. Under recovery of fixed charges on account of coal shortage was Rs. 800 crores in 2017-18. The under recovery in fixed charges on account of coal shortage in 2018-19 (till Dec 2018) is Rs 483 crores so far.

4. Further as per the draft Tariff Regulations, the generators will now have to maintain the plant availability separately for peak and off-peak hours. In such scenario having an adequate coal stock at the generating station would become all the more crucial. Thus it is requested that the coal stock to be considered for working capital requirement should be considered on requirement basis and not on the historical data of actual stock maintained.

In view of the above submissions, Hon'ble CERC is requested to retain 30 days coal stock for non-pithead stations for the period 2019-24.

13) REGULATION 35 - Operation and Maintenance Expenses

"35. Operation and Maintenance Expenses

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

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

(in Rs Lakh/MW)

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

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

Provided that Operation and maintenance of generating station and the transmission system of Bhakra Beas Management Board (BBMB) and SardarSarovar Project(SSP) shall be determined after taking into account provisions of the Punjab Reorganization Act, 1996 and Narmada Water Scheme, 1980 under Section 6-A of the Inter-State Water Disputes Act, 1956 respectively.

…"

Comments/Suggestions

The norms of O&M expenses have been worked out without giving due impact of hike in minimum wages by States & Center and also the roll out of GST wef. 1.7.2017.

1. **Impact of Super normal hike in rate of Minimum wages as Repairs & maintenance service cost:**

   Out of O&M cost allowed under tariff, employee cost constitutes around 55% followed by repair and maintenance services constitute about 20% in FY 2017-18 as shown in table below.

(Rs in Crores)

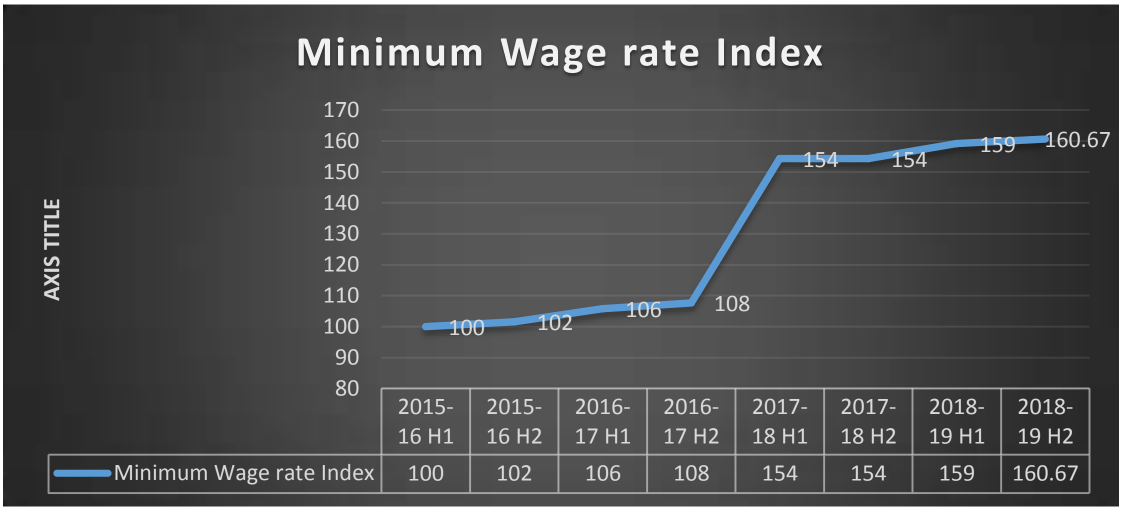
Major Heads of O&M	Cost for FY 2017-18	%
Employee Cost	5152.85	55%
Repair & Maintenance	3147.14	34%
Materials	1250.94	13%
Services	1896.21	20%
Other O/H	1071.65	11%
Total	**9371.64**	

Note: The above data excludes expenses on account of Security, Water Charges and Capital Spare consumption

The repair maintenance service cost is directly related to the minimum wages notified by the Chief Labor Commissioner – Central. These rates are basically category wise (unskilled, semi-skilled, skilled and highly skilled) and city category wise (Type A, B and C). The rates are applicable to the concerned station as per the district they are situated in. As per the data released by the Chief Labor Commissioner – Central, there was a super normal increase of 43% in wages on17th March 2017 effective from 1.4.2017 for different notified areas-A,B&C. Since NTPC's stations have pan-India presence, the wage hike impacted contractual labour cost across the country in all the areas. The labour cost constitutes about 60% of Repair and Maintenance cost.

	A Area	B Area	C Area
Unskilled	43.11	42.97	42.94
Semi-Skilled/ Unskilled Supervisory	42.75	42.86	42.86
Skilled/ Clerical	42.70	42.75	42.86
Highly Skilled	42.87	42.70	42.75
Increase in Minimum wages	**43% increase**		

As may be seen from the following graph, the wage increase is linear ever since. The wage indices are published bi-annual in each period there is a hike. Such increases are irreversible and need to be considered while fixing O&M norms for the future control period.



Thus, the actual R&M cost of Rs. 1312.50 (for FY 2015-16) will translate to 3.42 lakhs/MW (considering 38,384 MW capacity of 2015-16). This, if escalated to next 3 years at escalation rate of 3.2% p.a. will become Rs.3.76 lakh/MW. However, if actual escalation in wage is added to base data, the R&M service cost will work out to 5.21 lakh/MW at 3.20% escalation rate. Thus the increase on this account will be Rs 1.45 lakhs/MW(i.e. 5.21-3.76).

2. <u>Twofold Impact of GST on O&M- on Services and Materials</u>

The tax rate on services has increased from 15% (from Service Tax regime) to 18% (GST regime). This has negative impact of around Rs. 80 Cr. per annum, on claimable expenditure base of ~Rs 3250 cr. pertaining to various services (excluding CSR, Security, Water Charges, Performance Related Pay, Provisions, etc.)

In addition, the impact of GST is even more pronounced in case of works contract services. After abatement (30% in erstwhile service tax) the service tax which used to be 10.5% (70% of 15%), has increased to 18%. In the absence of data on the same, the additional tax impact approximately works out to be Rs. 15-20 crores not considered in Rs. 80 crores mentioned above.

The impact of GST on material part is also considerable, as the material procurement by NTPC was under two broad ways namely procurement under local VAT and procurement against under Form C. Procurement against C forms, which constitute more than 80% of total procurement, there is large negative tax impact. On the data of 2016-17 the net impact calculated after adjustment of savings accruing out of GST is (-) Rs. 30 crores against the material consumption of Rs. 1250 crore per annum. The Total annual impact of GST will be around more Rs. 110 crores calculated for the year 2017-18 at equivalent MWs of 41683. This translates to Rs. 0.27 lakhs/MW.

Thus the total impact of minimum wages and GST works out to be Rs. 1.72 lakhs / MW (1.45+0.27).

Since GST was implemented from July1, 2017, the compensation for the same is required to be allowed from that date and **at least Rs 2 lakhs per MW needs to added to normative O&M cost allowed by CERC for the year 2019-20.**

3. Escalation rate applied to O&M Cost

CERC has linked the rate of escalation in O&M to basket of WPI and CPI in the ratio of 60:40. However, WPI is not representative of economic indicators for calculating inflation since it skips the prices of non-commodity sector like services, which forms around 75% of our GDP.

In fact, Reserve Bank of India has also discarded measuring inflation on WPI indicator w.e.f April 2014 as is evident in their "Report of Working Committee to revise and strengthen the Monetary Policy Framework."

In the context of NTPC around 75% of O&M expenses comprises of services including employee benefit expenses, payment to contractual labors for repair and maintenance, horticulture etc. This is also in line with CPI:WPI weightage of 75:25 in case of hydro station allowed by CERC.

As per CERC working, the per annum escalation in O&M expenses for the control period 2019-24 is estimated as 3.20% per annum only considering CPI:WPI weightage of 40:60. Extending the same weightage as applied to Hydro stations, the escalation works out to 5%. The same is also in line with renewable tariff regulation 2017 issued by CERC.

4. **<u>Normalization of O&M Expenses:</u>**

The Explanatory Memorandum at page 147 observes as below:

"e) Where steep year on year increase in expenses under various heads were observed, the Commission normalised the same suitably by applying the average escalation rate of WPI (1.49%) or CPI (5.76%), depending upon the nature of expenses , on the preceding year's corresponding expense figure."

Hon'ble Commission while seeking actual operational data for last 05 years, i.e. for the period 2012-17 has sought justification for head-wise variations in O&M Expenses, if the year on year variation is more than 10%. NTPC has provided the same as per the prescribed format. With regard to the methodology adopted for normalization of O&M expenses under various heads the following observations are submitted for consideration of the Hon'ble Commission, as under:

- It may be pertinent to mention that the steep increase in expenditure is generally due to one-time periodic expenditure in a particular year the benefit of which is reaped by the beneficiaries for the next few years. For example, NTPC carries unit overhauling (O/H) as per the planned maintenance schedules i.e. annual overhauling is carried out on annual basis for every unit and capital overhauling is carried out once in 4-5 years. Accordingly, during a year where capital overhauling of one or more units is carried out there would be steep rise in repair and maintenance expenditure due to increased maintenance and consumption of spares in that year. The benefits of more power made available to beneficiaries in subsequent years, increased efficiency, less forced shut-downs etc. of this increased expenditure due to capital O/H is reaped in subsequent years. Normalizing such genuine expenditure whose benefit is availed in subsequent years is not justified.

- Similarly, in other O&M heads such as insurance, legal expenses etc there would be sudden increase in expenses is due to change in premium paid to the insurance company due to statutory guidelines or addition of new units or increase in legal expenditure towards arbitration. Normalizing such expenses is not justified.

In view of above, normalization of O&M expenses heads due to periodic expenditure, statutory guidelines or addition of new units / equipments / systems for which justification has been provided by NTPC and the benefit of the same is reaped in subsequent years may not be done.

5. Inclusion of Provisions

Hon’ble Commission has not considered the expenses booked under provisions while working out O&M norms. In this regard, it is submitted that provisions are made in the Books against certain liabilities that would arise in the future against certain expenditure/ works already carried out. If such provisions is excluded from the O&M norms there would always be under-recovery when such liability/ provisions is discharged/ met in the future. Accordingly, a genuine expenditure would remain un-serviced. **In view of this, expenditure under the head provisions may be included while working out O&M norms.**

14) REGULATION 29 – Allowance of Additional O&M Expenses on Emission Control System/FGD Equipment

1. Although Draft Regulations have proposed to allow the additional capitalization on account of Revised Emission Control / FGD equipment, it is submitted that the Hon'ble CERC has not provided for any provision for additional compensation for O&M expenses incurred on operation of Emission Control System / Flue Gas desulphurization (FGD) equipment.As FGD is a new mandatory requirement under Change in Law and the O&M expenditure would be incurred over and above the capital cost on a recurring basis for operation of FGD, O&M expenditure for FGD should be admissible.
2. CEA is in the process of developing the norms for O&M expenses for Emission Control System / FGD. The MOP, GOI Notification for generating companies dated 30.3.1992, provides for normative O&M expenses as percentage of capital cost as under:
   (i) at the rate of 2.5% of the actual capital expenditure subject to ceiling capital expenditure as provided in the power purchase agreement: or
   (ii) at 2% of the actual capital expenditure on ceiling on capital expenditure provided in the power purchase agreement together with actual expenditure on insurance.

   Therefore, in the absence of past actual data regarding O&M expenses for Emission Control System / FGD, the Commission may consider allowing O&M expenses for FGD equipment equal to 2% of the actual capital expenditure incurred on installation of FGD equipment.

3. It would be pertinent to mention here that in a similar matter of Adani Power Limited v/s Uttar Haryana BijliVitran Nigam Limited and Dakshin Haryana BijliVitran Nigam Limited in petition no. 104/MP/2017, the Hon'ble CERC has allowed the O&M expenses provisionally at the rate of 2% per annum of the capital cost of FGD, subject to adjustment in the light of the norms to be prescribed by CEA.

4. In view of the above, the Hon'ble Commission may allow additional O&M expenses on Emission Control System / FGD at the rate of 2% per annum of the capital cost of FGD, subject to notification of norms for O&M expenses by CEA in due course of time.

15) Additional Submission - Continuation of the 'Compensation Allowance' provision as per the CERC Tariff Regulations for the period 2014-19

1. It is observed that the Draft Regulations has proposed to discontinue with the dispensation of normative 'Compensation Allowance' provided in the Tariff Regulations for the period 2014-19 to meet expenses on new assets of capital nature not covered under additional capitalization.
2. It is humbly submitted that the above dispensation may be continued as it avoids tedious and time consuming regulatory prudence exercise to check several minor items and there is no revision in capital cost. It is submitted that separate compensation allowance is effective way to allow expenses on new assets of capital nature which are not admissible under the additional capitalization provisions.
3. The issue of overlap between compensation allowance and O&M expenses is not correct.Compensation Allowance is for capital expenses of minor nature and is different from the items covered under O&M expenses which are of revenue nature and as such there is no overlap between the two.
4. Therefore, it is submitted that provisions of 'Compensation Allowance' as per the existing regulations may be continued or may be allowed at rate of Rs. 1 lakh / MW per year with escalation as per inflation rate.

16) REGULATION 11 - In-principle Approval in Specific circumstances

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

Comments/Suggestions:

Hon'ble Commission in the draft regulations is pleased to consider in-principle approval of capital expenditure on account of change in law events or force majeure conditions. In certain cases substantial capital expenditure may be required in a new/existing units/stations due to technological/obsolescence or for efficiency improvement or necessitated for sustained and reliable operation of stations. Such expenditure may not be covered under change in law or force majeure conditions but may be beneficial to both generators as well as beneficiaries. Such expenditure may be met by the generator from its own funds, however the same may not be admitted by the Hon'ble Commission as there is no enabling/ corresponding provisions in the ensuing Tariff Regulations; in such case genuine expenditure may not get serviced while the benefits is being passed on to the beneficiaries. In order to have regulatory certainty in principle approval may cover all such expenditures not covered under regulations but have substantial impact on the generators as well as the beneficiaries.

It is submitted that the in-principle approval may be taken where the estimated expenditure which exceeds Rs. 50 crores(instead of Rs. 100 crores proposed in Draft Regulations) or 10% of capital cost whichever is lower.

17) REGULATION 26- Consent for undertaking Additional Capitalisation on account of Renovation and Modernisation

"26. Additional Capitalisation on account of Renovation and Modernisation:

(1) The generating company or the transmission licensee, as the case may be intending to undertake renovation and modernization (R&M) of the generating station or unit thereof or transmission system or an element thereof for the purpose of extension of life beyond the originally recognized useful life for the purpose of tariff, shall file a petition before the Commission for approval of the proposal with a Detailed Project Report giving complete scope, justification, cost-benefit analysis, estimated life extension from a reference date, financial package, phasing of expenditure, schedule of completion, reference price level, estimated completion cost including foreign exchange component, if any, and any other information considered to be relevant by the generating company or the transmission licensee.

Provided that the generating company or the transmission licensee, as the case may be, making the applications for R&M will not be eligible for Special Allowance under these regulations.

Provided further that, the generating company or the transmission licensee intending to undertake renovation and modernization (R&M) shall be required to obtain the consent of the beneficiaries or the long term customers, as the case may be, for such R&M and submit the same along with the petition.

…"

<u>Comments/Suggestions:</u>

1. The Draft Regulation has proposed that consent of beneficiaries needs to be taken by the generating company intending to undertake the R&M of the plant. The consent would have to be submitted along with the petition.
2. It may be mentioned here that the Hon'ble Commission during the finalization of the Tariff Regulations 2014 had opined as under:

"…Commission is of the view that it may not be practical to implement this suggestion and in any case, the Commission approved the renovation and modernization expenditure after detailed prudence check."

3. It is humbly submitted that the generating company is already required to file the petition for approval of R&M proposal of a plant before the Commission and all the beneficiaries are respondents to such petition. Therefore, beneficiaries get ample opportunity to share their concerns / objections / suggestionsand voice their dissent to the proposal. Inclusion of such provision would only delay the process and is therefore undesirable. As the Commission shall decide on the proposal taking into consideration the observations of all beneficiaries, it is requested that such additional provision of prior consent by beneficiaries may be deleted.

18) REGULATION 51 - Computation of Capacity Charges and Energy Charges

"51. Computation and Payment of Capacity Charge for Thermal Generating Stations:

(1) The fixed cost of a thermal generating station shall be computed on annual basis, based on norms specified under these regulations, and recovered on monthly basis under capacity charge. The total capacity charge payable for a generating station shall be shared by its beneficiaries as per their respective percentage share or allocation in the capacity of the generating station. Capacity Charge for the month shall be recovered in two parts viz., Capacity Charge for Peak period of the month and Capacity Charge for Off-Peak period of the month.

(2) The Capacity Charge rate for Peak hours shall be 25% more than that of Off-Peak hours. The Capacity Charge payable to a thermal generating station for a calendar month shall be calculated in accordance with the following formulae:

…"

Comments/Suggestions:

1. The Draft Regulations has proposed that Target Availability has to be achieved in peak & off-peak hours in a day separately. The number of peak hours in a region shall be declared on monthly basis by the concerned RLDC in advance and the number of Peak hours in a day shall not be less than 4 hours. The Capacity Charge Rate for peak hours shall be 25% more than capacity charge rate for off-peak hours. If the cumulative peak period PAF achieved during a quarter is more than the specified NQPAF for peak period and the cumulative Off-Peak period PAF achieved during the quarter is less than the specified NQPAF for Off-Peak period, the loss in recovery of Capacity Charge for Off-Peak period shall be off-set against the notional gain on account of over-achievement in Peak period, subject to the ceiling of full recovery of Capacity Charge for Off-Peak period. However, if the cumulative peak period PAF achieved during the quarter is less than the specified NQPAF for peak period and the cumulative Off-Peak period PAF achieved during the quarter is more than the specified NQPAF for Off-Peak period, the loss in recovery of Capacity Charge for Peak period shall not be off-set against the notional gain on account of over-achievement in Off-Peak period.
2. The introduction of differential fixed charges for peak and off-peak hours in a day is a welcome step which would facilitate better utilization / management of available generation resources by Discoms to meet the peak load. With regard to differential rates for fixed charges for peak and off-peak hours in a day, the Tariff Policy mandates as under:

   "The Appropriate Commission may also introduce differential rates of fixed charges for peak and off peak hours for better management of load."

3. As time of day tariff has already been introduced by many States, there was need of differentiation of fixed charges for peak and off-hours in the generation sector also. This would incentivize generators to declare higher availability during peak hours. The Discoms would be benefitted by availability of more power during peak hours under the same PPA. Presently, Discoms are forced to purchase costly power on short term basis or from markets to meet peak demand. This dispensation would provide them more capacity available during peak hours at no

extra cost. However, generators need to be incentivized to declare more availability during peak hours by providing commensurate rate of fixed charges during peak hours as compared to off-peak hours. Otherwise, the generator may not be inclined to declare more during peak hours. Any way the maximum liability of the Discoms is restricted to the Annual Fixed Charges. In view of the above, it is submitted that rate of fixed charges during peak hours may be at least 1.5 times that of off-peak fixed charge rate.

4. The same is evident from the IEX tariff for last few years where the difference in peak and off peak hours is much more than 1.25 time.

Summary	FY 18	FY 19
Peak	392	505
Non Peak	304	374
Ratio : (Peak / Off peak)	1.29	1.35

5. There are certain central generating stations that have beneficiaries located in other regions. In case of such stations, different peak hours may be declared by concerned RLDCs that would be applicable to such generating stations thus making declaration of DC by generators difficult. In such cases, it is proposed that peak hours may be declared by NLDC instead of RLDCs.

20. **REGULATION 36: Input Price for variable charges:**

(3) The input price of lignite from the integrated mine shall be determined by the Commission for which appropriate regulations shall be notified separately. Till such time, the Commission shall continue to adopt the guidelines specified by the Ministry of Coal, Government of India.

Comments & Suggestions:

It is submitted that similar to the proposed provision regarding continuation of guidelines specified by MoC in case of lignite till notification of separate regulations by Hon'ble Commission, the input price of coal from the integrated coal mine may also be determined by the Commission by adopting the principles/ guidelines for input price of lignite specified by the Ministry of Coal in case of NLC, till such appropriate regulations notified separately by the Commission in this regard.

21. **REGULATION 37: Date of Commercial Operation:**

37. Date of Commercial Operation: (1) The date of commercial operation in case of an integrated mine shall mean the date declared by the generating company on occurrence of earliest of the following milestones unless otherwise stated in the project report:

a) Beginning of the financial year immediately after the year in which the 25% of rated capacity as per mining plan; or

b) Beginning of the financial year immediately after the year in which the value of production is more than total expenditure; or

c) two years of touching of coal or lignite;

(2) The input price for supply of coal from of the integrated mines prior to date of commercial operation shall be considered at the notified price of Coal India Limited for the corresponding grade of coal supplied to the power sector.

Comments & Suggestions:

1. It is submitted that in addition to the occurrence of any one of the three milestones proposed in draft regulations, it may also be ensured that for declaration of commercial operation at least 75% of the plant & machinery as per the investment approval is ready for use.

2. There are certain statutory levies and other charges like crushing, sizing, surface transportation which have to be necessarily incurred to bring the coal to mine loading point. Therefore these charges have to be included to work out the input cost of coal. It is therefore submitted that the input price for supply of coal from of the integrated mines prior to date of commercial operation may be calculated summing up notified price of Coal India Limited for the corresponding grade of coal supplied to the power sector, including surface transportation charges, crushing charges, applicable statutory taxes, levies, cess etc.

22. **REGULATION 38: Application for determination of Input Price:**

The generating company shall file a petition before the Commission as per Annexure- I (Part IV) for determination of the input price for the variable cost along with the tariff petitions for one or more generating stations in accordance with the provisions of these regulations.

Comments & Suggestions:

It is submitted that Annexure- I (Part IV) may be uploaded**.**

23. **REGULATION 39: Capital Cost:**

(2) The expenditure incurred for development of the integrated mine by the generating company up to date of commercial operation shall be considered for the purpose of capital cost and the expenditure incurred after the date of commercial operation till the date of achieving target capacity shall be treated as capital work in progress (CWIP) and shall be capitalized on year to year basis as additional capital expenditure corresponding to the coal production level specified in the progressive mining plan or actual production, whichever is higher;

Comments & Suggestions:

Capital work in progress (CWIP) shall be capitalized on year to year basis as additional capital expenditure as when the asset declared as put to use.

24. **REGULATION 40: Additional Capitalization after commercial operation up to date of target capacity:**

    (2) Capital expenditure incurred after the date of commencement of production up to the date of achieving target capacity shall be recognized as capital work in progress and admitted as additional capital expenditure during the respective years of the tariff period corresponding to the production targets envisaged in the as per progressive mining plan;

    Comments & Suggestions:

    Capital expenditure incurred after the date of commencement of production up to the date of achieving target capacity shall be recognized as capital work in progress and admitted as additional capital expenditure during the respective years of the tariff period as when the asset is declared as put to use.

25. **REGULATION 42: Debt: Equity Ratio:**

    Debt-Equity Ratio of 70:30 to be considered as on date of Commercial Operation for a particular coal mine. Actual equity in excess of 30% of the capital cost shall be treated as normative loan and in case actually equity deployed is less than 30% the actual equity shall be considered. The Debt: Equity ratio shall be applied to the capital cost of each year arrived after considering the Written Down Value of assets as per the industry practice followed in coal sector which may be as per Income Tax Act, 1961 or as per the Companies Act, 2013.

    Comments & Suggestions:

    It is submitted that the guidelines dated 02.01.2015 issued by Ministry of Coal for NLC for tariff period 2014-19 provide for Gross Block Methodology with Debt-Equity ratio of 70:30. It is therefore submitted that the Debt: Equity ratio may be applied to the capital cost based on Gross Fixed Asset Block method.

26. **REGULATION 42B: Operation and Maintenance Expenses:**

The Operation and Maintenance expenses of mine shall be determined based on the original project cost for first year and thereafter, it shall be escalated at the average rate of wholesale price index (WPI) for each financial year.

Comments & Suggestions:

Operation maintenance cost increases year-wise as per the production plan, in the ramp up period of mine. Accordingly operation and maintenance cost till the year mines achieves its rated production capacity (PRC) may be determined based on project cost estimate/RCE. As escalation by WPI year wise, does not take care measure variations of O&M expenses like variation of fuel cost in Mining, O&M expenses as actual may be considered.

O&M cost shall also include outsourcing / MDO cost for coal production and overburden removal. The Operation and Maintenance expenses of mine may be based on estimated expenditure to be incurred from anticipated COD taking into consideration of MDO cost per Ton and the escalation clause given in the LOA. The O&M expenses may be trued up at the beginning of next tariff period.

27. **REGULATION 42C: Interest on Working Capital:**

(i)Input cost of coal towards stock, if applicable, for 15 days of coal production corresponding to the normative production level as per the approved mining plan;

(ii) Consumption of stores and spare including explosives, lubricants and fuel @ 15% of operation and maintenance expenses;

Comments & Suggestions:

1. To meet the requirement of coal for uninterrupted operation of Thermal station it is essential to maintain coal stock at pithead over and above the stock applicable for thermal generating stations. Stock of coal is also necessary to deal with additional requirements of the power station at times, to continue operation in the event of strike or any outside disruptions, during monsoon etc. Thus it is proposed to consider one month stock in the working capital in addition to other components.
2. In case of out sourcing/ MDO mode of operation of mine, consumption of stores and spare including explosives, lubricants and fuel @ 15% of operation and maintenance expenses.

   For mine is being worked departmentally with owner's own equipment, for consumption of stores and spare including explosives, lubricants & fuel cost, there is no basic data available. Therefore, the same may be decided subsequently when sufficient data is available.

28. **REGULATION 45: Determination of input price:**

(1) The input price of coal sourced from the integrated mine shall be derived based on the production cost and shall comprise following components:

(a) Capital Cost;

(b) Depreciation;

(c) Interest on loan capital;

(d) Return on equity;

(e) Interest on working capital; and

(f) Operation and maintenance expenses

Comments & Suggestions:

It is suggested that the input price of coal sourced from the integrated mine may include Mine Closure expenses and capacity utilization of 85% may be considered for recovery of costs.

Mine Closure Expenses: It is submitted that Guide lines dated 02.01.2015 issued by Ministry of Coal for NLC for tariff period 2014-19 provide for such mine closure expenses for calculation of cost of coal. In view of the above, Mine closure expenses may be allowed as per the annual Mine Closure Cost calculated based on the guideline issued from time to time by the MoC in this regard.

Capacity Utilization: Achieving Capacity utilization of 85% of the total capacity of mines for the relevant year may be considered for recovery of production costs. Hon'ble Commission in case of NLC has also considered a capacity utilization factor of 85%. CIL has also adopted 85% capacity utilization as cut-off for the development of a project and the same is considered while preparing the Detailed Project Report.

29. **Definitions: Auxiliary Power Consumption**

(5) ***'Auxiliary Energy Consumption' or 'AUX'*** *in relation to a period in case of a generating station means the quantum of energy consumed by auxiliary equipment of the generating station, such as the equipment being used for the purpose of operating plant and machinery including switchyard of the generating station and the transformer losses within the generating station, expressed as a percentage of the sum of gross energy generated at the generator terminals of all the units of the generating station:*

Provided that auxiliary energy consumption shall not include energy consumed for supply of power to housing colony and other facilities at the generating station and the power consumed for construction works at the generating station and integrated coal mine;

Comments / Suggestions:

1. In terms of above definition, the energy consumed in the housing colony of the generating station is excluded from Auxiliary Power Consumption (APC). It may be noted that the Electricity (Removal of Difficulty) Fourth Order, 2005, notified under the Electricity Act 2003 provides that the housing colony of generating station shall be deemed to be an integral part of its activity ofgenerating electricity and the generating company shall not be required to obtain Licence for supply of such electricity.
2. However, some beneficiaries are misinterpreting the exclusion of colony consumption from APC with the generator losing the right to supply electricity to its housing colony directly from the generating station implying that the generating company has to source this power for its colony and other associated facilities as the customer of local Discom. The Discoms of Bihar in case of Kantiare raising various disputes in this regard and are demanding for purchase of HT Tariff for supply of electricity for colony consumption. Similar difficulties were faced in Simhadri and other stations of NTPC.
3. The Regulations or the Statement of Reasons need clearly spell out that exclusion of Colony Power from APC is only for the purpose of fixing the norm for APC and housing colony of generating stations shall continue to get power from the generating station. The absence of the same is giving rise to disputes based on interpretation as enumerated above.

4. In view of above, it is requested to provide a clarification that the generating station shall continue to supply power to housing colony and associated facilities directly from the generating stationas per the Electricity Act 2003 without becoming a customer of the local Discom.

21 Definitions: De-capitalisation

*(17) **'De-capitalisation'** for the purpose of the tariff under these regulations, means reduction in Gross Fixed Assets of the project as admitted by the Commission corresponding to inter-unit transfer of assets or the assets taken out from service;*

18. Capital Cost:

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(5)(b) De-capitalisation of Assets after the date of commercial operation on account of replacement or removal on account of obsolescence or shifting from one project to another project

Comments:

Hon'ble Commission in the past tariff periods (2001-04; 2004-09; 2009-2014 and 2014-19) has uniformly treated the inter-unit transfers as temporary in nature and has excluded the capitalization and corresponding decapitalization in the books of units and ignored such entries for the purpose of tariff. In this regard, Hon'ble Commission in its various tariff / true-up order has observed as follows:

"The Commission while dealing with applications for additional capitalization in respect of other generating stations of the petitioner has decided that both positive and negative entries arising out of inter-unit transfers of temporary nature should be ignored for the purposes of tariff"

In case the inter-unit transfer of assets are treated as de-capitalization with no corresponding provision of capitalization, an admitted item initially in one project may get de-capitalized due to inter unit transfer and may not be admitted in other station as there is no corresponding/ relevant regulation for allowing the same. In such case, as the asset will be part serviced the generator will always lose in such cases, whereas the beneficiaries would continue to draw the benefit at the station.

It may be pertinent to mention that inter–unit transfers help in reducing the cost / tariff. NTPC has large fleet of units of similar sizes with almost similar design/ technology and layouts. In such case, the spare and other movable assets are shared and kept as pooled items providing service to various stations. This keeps the requirement of number of spares/ inventory low and reduces tariff. In case inter-unit transfer is treated as de-cap, then the number of spares and requirement of replacement assets will increase thus increasing the capital cost. Further, this may also lead to loss of generation in case of equipment failure as pooling of the same will be done away with.
In view of above submissions and to have regulatory certainty, inter unit transfer may be continued to be treated as exclusion for the purpose of tariff.

22 Definitions – De-commissioning

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*(18) **'De-commissioning'** means removal from service of a generating station or a unit thereof or transmission system including communication system or element thereof, after it is certified by the Central Electricity Authority or any other authorized agency, either on its own or on an application made by the project developer or the beneficiaries or both, that the project cannot be operated due to non-performance of the assets on account of technological obsolescence or uneconomic operation or a combination of these factors;*

Comments:

After the end of useful life or technological obsolesce or under the direction of appropriate authority, there may be need to retire the power station. In such cases, expenditure would be incurred towards decommissioning of power station. Typically, it takes about two to three years to completely decommission a power station after it is shut down, during which there would be requirement to incur expenditure towards employee cost, power charges, water charges, administrative expenses, etc. When a power plant is shut down permanently, the revenue ceases to exist but there would be requirement of funds to meet the decommissioning expenses. In case of mining operation, expenditure incurred towards mine closure is assured to mine owner.

In view of the above, there is a need to provide funds for meeting the expenditure during the decommissioning period. For meeting such expenses, a normative value (in lakh/MW) may be provided as a part of fixed charges to the generator under the head “Decommissioning Charges” during the fag end of the station. These charges would act as kitty for the generator during the decommissioning period.

23 Regulation 3) Definitions – Fuel Supply Agreement

*(27) **‘Fuel Supply Agreement’** means the agreement executed between the generating company and the fuel supplier for generation and supply of electricity to the beneficiaries;*

Comments:

The above definition is not used in the provisions of the regulations and hence is redundant. Accordingly, it may be removed.

24 REGULATION 8) TARIFF DETERMINATION

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(ii) In case of commercial operation of units of generating station or elements of the transmission system on or after 1.4.2019, the generating company or the transmission licensee shall file a consolidated petition, in accordance with the provisions of Procedure Regulations, combining all the units of the generating station or all elements of the transmission system which are anticipated to achieve the date of commercial operation during the next two months from the date of application;

Comments:

Investment Approval of the project provides estimated cost of the project and includes combined estimated cost of all the units and the balance of plant including land and other associated infrastructures. Further, phasing / schedule COD of subsequent units as per investment approval is about 04 to06 months for 200/210/250 MW, 500 MW and above units respectively. Tariff Regulations of past periods has also prescribed similar interval of time for declaration of COD of subsequent units.

In terms of above provisions, a generating station declaring COD of units on or after 01.04.2019 has to make application for determination of tariff each time the units are about to be declared COD. Further, it may not be reasonable to carry out prudence check if the cost estimate of whole station is compared with one unit at the first instant.

In view of above, in case of new project, application for determination of tariff on new project may be allowed for the whole station unit-wise based on anticipated expenditure as on anticipated COD dates.

25 REGULATION 9 - APPLICATION FOR DETERMINATION OF TARIFF:

(1)……………..

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Provided also that where interim tariff of the generating station or unit thereof and the transmission system or element thereof including communication system has been determined based on Management Certificate, the generating company or the transmission company shall submit the Auditor certificate not later than 60 days from date of granting interim tariff.

Comments / Suggestions:

On declaration of commercial operation of a unit/ station thereof, it takes time for preparation of books of account as on date of COD. All payments released upto the COD is towards capital works in progress pertaining to all the units under construction of a project. However, on COD only part of these works relating to the completed works of the corresponding units get capitalized and the rest remains in capital work in progress (CWIP). It may be appreciated that segregation of payments/ liabilities towards capitalized items and CWIP takes time. After the reconciliation of all the expenditure, the Books and Financial Statements are prepared and audited internally. Certification of statutory auditor takes further some time as the same is checked by the statutory auditors and same depends upon the availability of auditors.

In view of above, at least 90 days may be allowed from the date of actual COD of the station for submission of audited accounts.

26 Regulation 9 - Application for Determination of Tariff:

(2) In case of an existing generating station or unit thereof, or transmission system or element thereof, the application shall be made by the generating company or the transmission licensee, as the case may be, within a period of 180 days from the date of notification of these regulations, based on admitted capital cost including additional capital expenditure already admitted and incurred up to 31.3.2019 (either based on actual or projected additional capital expenditure) and estimated additional capital expenditure for the respective years of the tariff period 2019-24 along with the true up petition for the period 2014-19 in accordance with the CERC (Terms and Conditions of Tariff) Regulations, 2014.

…………………………….…

12. Truing up of tariff for the period 2014-19: The tariff of the generating stations and the transmission systems for the period 2014-19 shall be trued up in accordance with the provisions of Regulation 8 of Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2014 along with the tariff petition for the period 2019-24. The capital cost admitted as on 31.3.2019 based on the truing up shall form the basis of the opening capital cost as on 1.4.2019 for the tariff determination for the period 2019-24.

Comments / Suggestions:

In terms of above, it is required to file true-up petition for the period 2014-19 and tariff petition for 2019-24 simultaneously. The closing capital cost of tariff period 2014-19 i.e. as on 31.03.2019 becomes the opening capital cost for the tariff period 2019-24 i.e. as on 01.04.2019. The capital cost admitted by the

Hon'ble Commission based on projected add-cap for the tariff period 2014-19 is to be trued up and the same would change due to difference in projected add-cap and actual add-cap. After the finalization of closing capital cost for the period 2014-19 as per true-up of the corresponding years, the same would be considered for tariff petition for the period 2019-24.

Accordingly, at least one month is required for filing of tariff petitions for the period 2019-24 after filing of true-up petitions for the tariff period 2014-19.

Further, Clause 8 (9) of Tariff Regulations 2014 provides as below:

> *(9) The generating company or the transmission licensee as the case may be, shall make an application, as per* ***Annexure-I*** *to these regulations, for carrying out truing up exercise in respect of the generating station or a unit or block thereof or the transmission system or the transmission lines or sub-stations by 31.10.2019.*

Accordingly, the true-up petition is to be filed by 31.10.2019 for all existing units/ station. In terms of above, further one month is required to file Tariff Petition for the period 2019-24 after true-up exercise. Therefore, it is requested that tariff petitions for the period 2019-24 may be filed by 30.11.2019.

27 Tariff Application for Emission Control System

9. Application for determination of tariff:

………………

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

………………...

29. Additional Capitalization on account of Revised Emission Standards:

……………

(4) After completion of the implementation of revised emission standards, the generating company shall file a petition for determination of tariff. Any

expenditure incurred or projected to be incurred and admitted by the Commission after prudence

Comments / Suggestions:

The contract for installation of FGD and other emission control system (ECS) is being awarded for the whole station (all the units) at a time so as to save cost. The installation of ECS in all the units of a station may take 2-3 years depending upon the number of units in a station and phasing of the shutdown so that optimum power could be made available to the customers. Accordingly, capital as well as the operating expenditure after the installation of ECS in the first unit may remain un-serviced for 3 years since application for determination of same is to made after actual capitalization duly certified by the Auditor in existing generating station and further time is required for grant of tariff after following due procedure.

In view of above, application may be admitted on the projected basis and interim supplementary tariff may be allowed subject to true-up based on auditor certificate after actual capitalization as is the practice adopted for additional capitalization in general. The above proviso may be modified accordingly.

28 Regulation 9 - Application for determination of Tariff:

....

(5) The Commission shall grant final tariff in case of existing and new projects, after considering the replies received from the respondents, and suggestions and objections, if any, received from the general public and any other person permitted by the Commission including the consumers or consumer associations.

Comments:

It is suggested that a procedure may be laid down by the Commission for inviting suggestions from the general public and any other person permitted by the Commission including the consumers or consumer associations so as to have effective participation and at the same time ensure that the tariff determination process is not delayed unduly by procedural hurdles.

29 *REGULATION* 18 - CAPITAL COST OF SEWAGE TREATMENT PLANT

(2) The Capital Cost of a new project shall include the following:

………………..

(3) The Capital cost of an existing project shall include the following:

……………………

Comments:

Clause 6.2 (5) of Tariff Policy provides as below:

Quote

The thermal power plant(s) including the existing plants located within 50 km radius of sewage treatment plant of Municipality/local bodies/similar organization shall in the order of their closeness to the sewage treatment plant, mandatorily use treated sewage water produced by these bodies *and the associated cost on this account be allowed as a pass through in the tariff.* ***Such thermal plants may also ensure back-up source of water to meet their requirement in the event of shortage of supply by the sewage treatment plant.*** *The associated cost on this account shall be factored into the fixed cost so as not to disturb the merit order of such thermal plant. The shutdown of the sewage treatment plant will be taken in consultation with the developer of the power plant.*

Unquote

Point of Delivery (PoD) of such mandatory treated sewage water (SW) may be different for different plants/ Municipal Corporations (MCs) as per the geographical location and topography of the area and as negotiated between the parties. In case, the PoD of treated SW is at the STP installed by the Municipal Corporations, then the power utility has to lay pipelines and install booster pumps for transporting the treated SW to the thermal plant. Even if the PoD is at the plant boundary, the thermal power plants may have to install systems such as pipelines/ booster pumps, instruments etc. to transfer such treated SW to the point of use by the thermal station.

It may so happen that MCs may only provider treated SW from its Sewage Treatment Plant (STP) outlet (as in case of Mouda STPS). It may be pertinent to mention that water from STP is not be suitable for use in thermal power plants. In such case, a Tertiary Treatment Plant (TTP) would need to be installed by the power utilities to retreat water from STP and make it suitable for use inside thermal plants. Installation of Tertiary Treatment Plant is capital intensive (in case of Mauda STPS tentative expenditure of Rs. 240 Crores is envisaged for constructing TTP).

In view of above, laying of pipelines and installation of other equipment, systems and TTP including measurement instrumentations, shutoff / regulating valves, pumps, etc., will require capital expenditure. Such expenditures which is mandatory in nature as per the Tariff Policy may be allowed in tariff for the use of treated sewage water.

In view of above, any capital expenditure incurred towards installation of equipment and systems for STP may be allowed as part of capital cost and corresponding regulations may be included in the above provisions and Regulations 23, 24 & 25 of the Draft Regulations.

30 REGULATION 19 - PRUDENCE CHECK OF CAPITAL EXPENDITURE:

………….

*(3) The generating company or the transmission licensee, as the case may be, shall furnish the package wise capital cost for execution of the existing and new projects as per **Annexure-I** along with tariff petition for creating a database of benchmark capital cost of various components.*

Comments:

NTPC Stations consisting of 46 number of units totalling an installed capacity of 45 GW comprise of units of different vintage. As on date about 27000 MW capacity is more than 10 years old (even 15-20 years old) and for such stations package-wise capital cost as on COD/ Cut-off date of unit/ station may not be available. Accordingly, Hon'ble Commission may exempt stations older than 10 years from providing package-wise details of capital cost. Moreover, the cost of very old projects may not be useful for creation of database.

31 25. ADDITIONAL CAPITALISATION BEYOND THE ORIGINAL SCOPE:

1) The capital expenditure, in respect of existing generating station or the transmission system including communication system, incurred or projected to be incurred on the following counts beyond the original scope, may be admitted by the Commission, subject to prudence check:

………………..

Comments:

In some of the pit-head stations of NTPC about 20% - 40% of the coal requirement is met out coal supplied by the coal companies through Indian Railways. Further, it is observed that in the year 2017-18 there was acute coal shortage in the country and NTPC stations faced under-recovery of about Rs. 800 Crores due to short supply of coal from the coal companies and congestion in Indian Railways. In the present fiscal, there is hardly any improvement in the coal supply by the coal companies of CIL. On the other hand, the beneficiaries has to procure such power from alternate sources including short term market. The cost of such power is always higher than long term power.

In view of the above NTPC has to procure/ arrange coal from the alternate sources including import of coal and from its own mines (Pakrih-Barwadih and Dulanga mines would start commercial operation during new tariff period i.e. 2019-24).In such case, NTPC would supply coal to stations through Indian Railways including pit-head stations where shortage is observed. In such a situation fuel receiving system of various stations may need up gradation/ improvement.

The Hon'ble Commission in the earlier Tariff Regulations has allowed capital expenditure necessitated on account of modifications required or done in fuel receiving system arising due to non-materialisation of coal supply corresponding to full coal linkage for circumstances not within the control of the generating stations.

In view of above, capital expenditure on account of modifications required or done in fuel receiving system arising due to non-materialisation of coal supply may be provided in the above add-cap clause.

32 REGULATION 30 - ADDITIONAL ROE OF 0.5%

…………………

Comments:

Hon'ble Commission in the past has allowed additional RoE of 0.5% for stations commissioned within the timeline specified in the Tariff Regulations and has observed as follows in the Explanatory Memorandum of Draft Tariff Regulations 2014-19:

"2.1.3 ……… Further, the Commission in its previous Tariff Regulations did not specify any provisions with respect to the standardization of the construction period. However, the Commission in Tariff Regulations, 2009, in order to boost the construction efficiency and faster completion of the projects, established standard construction period for new projects. According to this regulation, if the construction of such project is *completed on specified time, the project is entitled for additional RoE to the extent of 0.5% over and above base rate of return on equity. Such additional return on equity will continue over a useful life of the assets unless it is reviewed by the Commission for the projects already qualified for additional ROE."*

In the Draft Regulations, Hon'ble Commission has discontinued with the provision of the additional RoE of 0.5% for timely completion of the projects saying that the said provision has practically became irrelevant in case of generating stations, as the projects are not getting commissioned within the specified timelines.

It may be appreciated the projects in the past have contested and all-out effort were made to meet the time lines specified by the relevant tariff regulations. Discontinuation of the additional RoE may deprive such projects, which were commissioned within time line, of the reward. Further to have regulatory certainty the projects availing additional RoE may be allowed to do so throughout the useful life.

33 REGULATION 33 - DEPRECIATION:

…………..

Provided also that any depreciation disallowed on account of lower availability of the generating station or generating unit or transmission system as the case may be, shall not be allowed to be recovered at a later stage during the useful life and the extended life.

Comments:

Depreciation is cost towards wear and tear of the assets/ units. In a cost plus regulated business all admitted cost is to be service and depreciation should be allowed upto the salvage value. In case of lower availability, the generator is penalized as its returns/ RoE is reduced and further loose on account of under-recovery of other cost components of Annual fixed Charges such as O&M. Interest on loan etc. Disallowing the recovery of full depreciation cost for the assets in service tantamount to double penalizing the generator. Accordingly, unrecovered depreciation on account of lower availability may be allowed to be recovered during the extended life as this would avoid tariff jump for beneficiaries as well as the generator would be able to recover the depreciation cost upto the salvage value.

34 REGULATION 48 - TRANSIT AND HANDLING LOSSES

48. Transit and Handling Losses: *The landed cost of coal or lignite during the month shall include the transit and handling losses as per the following norms:-*

Thermal Generating station	*Distance of Generating Station from source of fuel*	*Transit and Handling Loss (%)*
Pit head	*-*	*0.20%*
Non-pit head	*Up to 1000 KM*	*0.80%*
	Above 1,000 KM	*1.20%*

Provided that in case of pit head stations if coal or lignite is procured from sources other than the pit head mines which is transported to the station through rail, transit and handling losses applicable for non-pit head station shall apply:

Provided further that in case of imported coal, the transit and handling losses applicable for non-pit head station shall apply.

Comments / Suggestions

1) The Draft Regulations has retained transit cum handling loss of 0.2% for pithead stations and 0.8% for non-pithead stations where distance of generating station from fuel source is less than 1000 km. It has proposed to provide 1.2% transit and handling loss in case of non-pithead stations where distance of generating station from fuel source is more than 1000 km.
2) **Transit & Handling Loss for Non-pithead stations -**It is submitted that transit and handling loss of 1.2% may be provided to all non-pithead stations as transit loss and handling loss of non-pithead stations does not exhibit strict correlation to distance as per past data. In case of non-pithead stations the transportation of coal is through a different agency namely the railways which is mainly responsible for higher losses as compared to pithead stations where transportation is in house means by dedicated MGR.
3) **Additional loss for Multiple Handlings -**In view of multiple handlings involving rail and road route in many stations, additional handling loss @ 0.2% per one handling may be provided. In case coal is transported through rail-cum-road (RCR) route involving one additionalhandling, transit and handling loss of 1.4% may be provided. In case coal is transported through

rail cum sea cum road (RSR) route, transit and handling loss of 1.6% (including 0.4% handling loss for two additional handlings) may be provided.

35 ADDITIONAL POINT – OPERATION OF GAS STATIONS UNDER ANCILLARY SERVICES

(i) Gas Stations Operations under Ancillary Services:-

RLNG based generation is being scheduled during peak demand periods and the same is being dispatched mostly under the ancillary services. It is proposed that planning of gas stations operations may be given to Regional Power Committees/RLDC/POSOCO so that fuel tie up planning can be done in accordingly in advance as per the anticipated requirement. The following is proposed in this regard

- On a quarterly basis, the demand from the gas stations may be assessed by the RLDC and accordingly, quantum of RLNG requirement would be planned taking into account the available domestic gas.
- Based on this plan, Generator shall procure RLNG on commitment basis and the energy charge of generation on Gas & RLNG would be pass through to the beneficiaries on a pro-rata basis.

(ii) Gas Stations as Peaking Plants:-

With increasing penetration of renewables, gas stations are required to perform key role in meeting peaking and balancing load requirement. Recently, CEA along with POSOCO conducted peaking operation at Dadri gas station. Accordingly, suitable norms for peaking operation need to be formulated.

36 REGULATION 53 - DECLARATION OF FUEL SOURCE-WISE AVAILABILITY

53. Declaration of Availability and Dispatch in case of thermal generating station: The generating company shall declare day ahead availability or any revision thereof in respect of generating station for each fuel source which may be differentiated in terms of their price and calorific value and the beneficiaries shall have an option to schedule the power based on their merit order dispatch.

Comments / Suggestions

The coal based generating station may provide separate availability on the following three types of coal, namely,

a. Domestic Coal including MOU coal
b. E auction coal
c. Imported coal.

It is submitted that fuel sources may mean different coal sources / mines under the same FSA or coal sourced under different FSAs. It would be practically difficult to stack coal from numerous mines It is proposed that the term "*for each fuel source which may be differentiated in terms of their price and calorific value" may be replaced with "domestic coal (including MOU Coal), e-auction coal and imported coal".*

37 Regulation (24)(2)(c) - Additional Capital Expenditure on Obsolescence of C&I Systems and aging of battery systems.

Comments / Suggestions

It is submitted that due to rapid change in technology, especially in C&I systems, such as, DDC MIS, Data Acquisition System, SOE and PLC, these systems become obsolete in around 5-7 years, and are required to be necessarily replaced to take care of the availability of equipment and improve reliability of operation. This is because maintenance of these systems becomes difficult due to non-availability of spares and obsolescence of technology. Further, battery systems need to be replaced due to aging. It is therefore requested that any expenditure on account of replacement of

C&I systems due to obsolescence should be allowed to be capitalized under additional capitalisation within original scope and after the cut-off date (Regulation 24 (2)).

Accordingly a new proviso may be added to after Regulation (24)(2)(c)
"(d) The replacement of the asset is necessary on account of obsolescence and replacement of battery due to aging."

38 APC for Dedicated Transmission Lines

In line with the provisions notified in the connectivity and LTA regulations (sixth amendment), the electrical power losses occurring in the dedicated transmission line owned by generating company from the generating station up to pooling station should be excluded from the ceiling APC values as specified in norms of operation for thermal generating stations under the regulations.

Further, for generating station where power evacuation is planned at two different voltage levels, losses occurring in the interconnecting transformers (between the two evacuation levels) should not be considered for calculation of APC values as specified in norms of operation for thermal generating stations under the regulations since these losses are dependent the share of power evacuated through two voltage levels and incidental power flow from one voltage level to other as per the prevailing network conditions.

39 Additional O&M Expenses for Dedicated Transmission Lines

The CERC connectivity and LTA regulations notified that

(8) "Provided that a thermal generating station of 500 MW and above and a hydro generating station or a generating station using renewable sources of energy of capacity of 250 MW and above, other than a captive generating plant, shall not be required to construct a dedicated transmission line to the point of connection and such station shall be taken into account for coordinated transmission planning by the Central Transmission utility and Central Electricity Authority".

However vide amendment in the connectivity and LTA regulations (sixth amendment) the following was notified

(8) “The dedicated transmission line from generating station of the generating company to the pooling station of the transmission licensee (including deemed transmission licensee) shall be developed, owned and operated by the applicant generating Company. The specifications for dedicated transmission lines may be indicated by CTU while granting Connectivity or Long term Access or Medium term Open Access

Provided that in case of a thermal generating station of 500 MW and above and a hydro generating station or a generating station using renewable sources of energy of capacity of 250 MW and above, CTU shall plan the system such that maximum length of dedicated transmission line shall not exceed 100 km from switchyard of the generating station till the nearest pooling substation of transmission licensee”

Currently the O&M expenses in terms of lakhs/MW for generating station are allowed to be included in fixed cost allowable to the generator. However the O&M expenses norms are specifically for the power plant excluding the dedicated transmission line. Subsequent to introduction of dedicated line in scope of generator it is proposed that O&M charges for the dedicated line (in terms of lakhs per kilometer) and the bays at remote end substation (in terms of lakhs per bay) as per the rates specified for transmission licensees should also be allowed to be recovered by the generator over and above the present O&M expenses norms.

40 REGULATION 59 (D) - SPECIFIC OIL CONSUMPTION FOR FRONT FIRED BOILERS

Specific Oil Consumption (SoC) of a tangentially/ cornered boiler is a function of percentage unit loading and number of start-ups/ shut-downs. However, in case of front fired boilers SoC is a function of percentage unit loading, number of start-ups/ shut-downs and number of mill changeover over a specified period.

It may be appreciated that in day to day operation of units in both type of boilers i.e. tangentially fired and front fired boilers, mill changeover is a daily phenomenon. This changeover is done for operational reasons and for maintenance requirements of mills due to regular wear and tear of mill parts during coal pulverizing process. Due to this fact, Designer/ OEM provides for minimum 02 nos. of additional mills (for all unit sizes) i.e. one for daily maintenance and other available as hot-stand-by in case of emergencies/ break-down of running mills.

It is known fact for a fuel to get ignited (catch fire) conditions for combustion in the form of appropriate temperature (ignition temperature) and oxygen is required. For safe burning of coal inside boilers during operation, certain checks and balances are built into the C&I logic system (permissive and protections) by OEM to avoid accidents due to insufficient ignition energy. One of such logic is the "ignition permit" that ensures to provide ignition temperature for mill to be taken into service. It may be pertinent to mention that a mill becomes self-sustained after 50% loading otherwise it needs continuous ignition temperature support from other supporting sources.

In case of tangentially fired boiler the ignition temperature/ permit/ support is available from two sources i.e. (i) Adjacent self-sustaining mill in service and/ or (ii) from secondary oil support. However, in case of front fired boilers ignition temperature/ permit/ support is available from only one source i.e. from secondary oil support. Accordingly, every time a mill in a front fired boiler is taken in service oil support is required to taken as per design/ OEM specifications otherwise mill cannot be started. Further, oil support is required until the mill loading becomes adequate for self-sustaining. It may be appreciated that, mill changeover is a daily activity as all mills is to be given for daily maintenance in rotation (one mill at a time for daily maintenance).

Similarly, oil support is also required for stopping the mill in order to avoid any unburnt pulverized coal being fired into the boiler. If oil support is not taken during stopping there may be case than fire of that mill/ elevation may extinguish due to low load of mill and unburnt mixture of pulverized fuel may form explosive mixture inside the boiler which may cause accidents.

In view of above, it is required to take oil support for every mill changeover in case of wall fired boilers. Accordingly specific oil consumption of the units having front fired boiler is more when compared to tangentially fired boilers. In case of Farakka-II, Ramagundam-I and other new super critical units of NTPC such as Solapur, Lara, Kudgi etc. are front fired units. In this regard OEM provided documents/ logic diagrams is attached at Annexure-

Accordingly, additional Normative Specific Oil Consumption 0.5 ml/kwh may be allowed for front fired boilers as per the inherent design.

41 REGULATION 47

Components of Landed cost of Primary Fuel: The landed cost of primary fuel for any month shall include base price or input price of fuel corresponding to the grade and quality of fuel and inclusive of statutory charges as applicable, transportation cost by rail or road or any other means, and loading, unloading and handling charges.

Provided that procurement of fuel at a price other than Government notified prices may be considered, if based on competitive bidding through transparent process, for the purpose of landed fuel cost;

Provided further that landed cost of primary fuel shall be worked out based on the actual bill paid by the generating company including any adjustment on account of quantity and quality;

Provided also that in case of Coal or Lignite thermal generating station, the Gross Calorific Value shall be measured by third party sampling and the expenses towards the third party sampling facility shall be reimbursed by the beneficiaries.

Comments/Suggestions

It is submitted that the coal procured from CIL through MOU route is at rates linked with the notified price. Therefore this regulation may provide that coal sourced through MOU route from CIL / its subsidiaries based on notified prices would also be considered.

42 REGULATION 49

Provided further that copies of the bills and details of parameters of GCV and price of fuel i.e. domestic coal, imported coal, e-auction coal, lignite, natural gas, RLNG, liquid fuel etc., details of blending ratio of the imported coal with domestic coal, proportion of e-auction coal shall also be displayed on the website of the generating company.

Comments/Suggestions

Under this clause different beneficiaries would seek a variety of information from time to time. It may be useful to incorporate format for providing information to beneficiaries in this regard.

43 REGULATION 66

Recovery of Statutory Charges: (1) The generating company shall recover the statutory charges imposed by the State and Central Government such as Electricity duty, water cess by considering normative parameters specified in these regulations. In case of the Electricity duty is applied in the auxiliary consumption, such amount of electricity duty shall apply on normative auxiliary consumption of the generating station (excluding colony consumption) and apportioned to the each beneficiaries in proportion to their schedule dispatch during the month.

Comments/Suggestions

It may be appreciated that Hon’ble Commission in the past has allowed the expenses such taxes, royalty, cess, electricity duty, etc., levied by statutory authorities to be recovered from the beneficiaries on actuals as reimbursement. Accordingly, these expenses paid by the generator to State Govt. or its instrumentality is being recovered based on the actual payment made. Allowing such expenses on normative basis may lead to over-recovery or under-recovery burdening the beneficiaries or the generator which is not the intent of regulations.

Accordingly, in order to have regulatory certainty, these expenses may be allowed to be recovered on actual as reimbursement from the beneficiaries. It is therefore submitted that the above parameters should be on actual basis and not on normative basis.

44 REGULATION 70

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

Comments / Suggestions

Draft regulations has proposed computation on monthly basis with annual true up. It is submitted that the cost of coal and oil, many times, changes on retrospective basis when the bills/ adjustments for past period are received. Therefore, heat rate, APC and specific oil gains may undergo change. Doing it on monthly basis would also be cumbersome. Therefore, it is suggested that it may be done on annual basis.

45 Station Specific Issues - Simhadri

a. **Regulation -59(E): Auxiliary Energy Consumption**

Normative APC for Stations with NDCT has been fixed as 5.75 % for stations based on cooling water from both river and sea water. Due to usage of sea water, station requires additional auxiliary power compared to river based stations due to following reasons as under:

- Sea water is used for condenser cooling & ash water transportation by the station as per the design. In general the specific gravity of sea water is higher by around 2 to 3% than that of river water. This requires additional pumping power compared to the river based power plants.

- Further due to the inferior quality of sea water (conductivity) compared to river water, the cycles of concentration (COC) has to be maintained below 1.5 (For river based power plants COC maintained is around 3.0) as per the design. To maintain the same, more makeup is needed & more blow down is needed. This in turn increases the pumping power of the system.
- It is therefore submitted that the above factors needs to be given due consideration while fixing the tariff norms of APC for coastal power plants using sea water.**The additional APC comes to around 0.13% at loads of 85% to 100%. During the conditions of poor quality of intake sea water this increases to around 0.23%.** The detailed calculations are as shown below.

	CW SYSTEM BLOW DOWN & POWER CALCULATIONS			
SWEET WATER SYSTEM:				Rated HEAD (Mtrs)
	TOTAL CW FLOW INCLUDING ARCW	**120000**	**TPH**	
	COC	**3**		
	EVAPORATION LOSS	**1036**	**TPH**	
	CW BLOW DOWN	**518**	**TPH**	
	TOTAL MAKE UP	**1554**	**TPH**	
	CW PUMPING POWER	**11.445**	**MW**	28
	MAKE UP PPNG POWER	**0.21332**	**MW**	40.3
	BLOW DOWN PPNG POWER	**0.056462**	**MW**	32
	TOTAL PUMPING POWER	**11.71478**	**MW**	
SEA WATER SYSTEM:				
	TOTAL CW FLOW INCLUDING ARCW	**120000**	**TPH**	
	COC	**1.5**		
	EVAPORATION LOSS	**1036**	**TPH**	
	CW BLOW DOWN	**2072**	**TPH**	
	TOTAL MAKE UP	**3108**		
	ADDL BLOW DOWN REQD FOR SEA WATER BASED SYSTEM	**1554**	**TPH**	
	CW PUMPING POWER	**12.5895**	**MW**	28
	MAKE UP PPNG POWER	**0.469305**	**MW**	40.3
	BLOW DOWN PPNG POWER	**0.248433**	**MW**	32
	TOTAL PUMPING POWER	**13.30724**	**MW**	

Additional power reqd for Sea Water based system		**1.592455**	**MW**	
Impact on APC for 2x500 MW stage		**0.159246**	**%**	
REMARKS:				
1	Sp gravity considered for Sea water	**1.1**		
2	Sp gravity considered for Sweet water	**1**		
3	Pump efficiency considered to be 80%			

b. <u>SL No.35 (1) Operation & Maintenance Expenses:</u>

- O&M expenses (20.38 Lakh/MW) have been fixed same for all river based and coastal based stations.
- Simhadri and Vallur being a coastal power station, the impact of corrosion & erosion on the structures is on higher side compared to the river based power plants. So there is need for additional care to avoid corrosion.
- To combat the same, proper care is being taken by increased periodical maintenance of the structures. This is increasing the Repair & Maintenance cost of the power station. This needs to be given due consideration while fixing the tariff norms for O&M expenses.

It is submitted that Additional O&M expenses of 0.5 lakhs per MW may be provided for coastal stations.

NTECL Vallur –

1. Additional O&M expenses for Desalination plant - Additional O&M expenses of 441 lakhs per year for 2014-15 escalated @ 6.35% for desalination plant as allowed by CERC in 2014-19 tariff order over and above normative O&M expenses needs to continue towards meeting expenses incurred.
2. Additional APC of 0.94% for pipe conveyor allowed by CERC in 2014-19 tariff order over and above normative values needs to continue.

46 Regulation 18 (2) (k)

(2) The Capital Cost of a new project shall include the following:

…………………………...

…………………………….

(k) Expenditure on account of biomass handling equipment, if any, for co-firing;

Comments / Suggestions:

No provision is given in draft for retrofitting biomass handling equipment in older power plant and including its cost in capital cost of plant

Provision may also be done for retrofitting biomass handling equipment in older power plant and including its cost in capital cost of plant.

47 REGULATION 52(3)

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

Comments / Suggestions:

It is submitted that the limit of 20% on increase in energy charge rate due to blending of alternate fuel (imported coal/ biomass fuel) is not adequate for pithead plant. Therefore, the limit of 20% on increase in energy charge rate due to blending of alternate fuel (imported coal/ biomass fuel) may be increased to 30%.

48 Regulation 52(4)

1) *52 (4) Where the biomass fuel is used for blending with coal, the landed price of biomass fuel shall be worked out based on normative consumption as specified in these regulations or actual consumption, whichever is lower, and landed price discovered at the receiving end of the generating station, inclusive of taxes and duties as applicable;*

Comments / Suggestions

It is submitted that normative consumption of biomass fuel where it is blended with coal is not mentioned anywhere in this regulation. Therefore, it is suggested that normative consumption definition for biomass fuel may be specified.

49 Other Comments Related to Biomass Co-Firing

1) **Heat rate/APC compensation for biomass co-firing -**Further, as per policy of MoP, dated 17 November 2017, increased cost of generation on account of using biomass pellets viz. cost of pellets, APC, HR etc. shall not be taken into account for the purpose of merit order dispatch of electricity. Therefore, it is proposed to consider the heat rate deterioration due to decrease in boiler efficiency and increase in APC in CERC regulation based on results of long term biomass co-firing. Further, it is proposed that merit order in case of biomass co-firing shall be calculated based on specific coal consumption only whereas billing may be done corresponding to specific consumption of blended fuel (coal and biomass).
2) **RPO and RGO for biomass co-firing -**Beneficiary availing power from biomass co-firing facility may avail RPO in proportion of it is paying for increased cost due to biomass co-firing .This way older plants having negligible fixed cost may continue to run while generating cheaper electricity while reducing carbon emission from it through biomass co-firing.
3) **Incentive to biomass co-firing plants -**In addition to heat rate and APC compensation, incentive of 25-50 paisa per Kwh of biomass power generated may be paid to promote biomass co-firing nationwide.

50 REGULATION 59 - RELAXED TARGET AVAILABILITYFOR NEW UNITS:

59. The norms of operation as given hereunder shall apply to thermal generating stations:

(A) Normative Quarterly Plant Availability Factor (NQPAF)

(a) For all thermal generating stations, except those covered under clauses (b), (c), (d), & (e) - 83%

Provided that for the purpose of computation of Normative Quarterly Plant Availability Factor, annual scheduled plant maintenance shall not be considered.

Comments / Suggestions:

1. **Provision of Cut-off Date -**The Hon'ble Commission has provided the provision of cut-off date for new unit which provides that the generator shall erect, commission and put to use all associated equipment and systems of the station before the cut-off dates that they can be capitalized for inclusion in the capital cost for the purposes of servicing in tariff.
2. **Need for Stabilization Period -**It is submitted that there are various teething problems encountered while commissioning of new units, more so in the supercritical / green field projects. There are issues related to various technical / design issues which need time to resolve. Therefore, there is need of a stabilization period during which relaxed target availability may be provided.
3. **CERC Regulations -**The CERC Tariff Regulations 2001-04 provided stabilization period of 180 days for coal based units when relaxed operating norms of heat rate, specific oil and APC was provided. This dispensation was continued in the next tariff Regulations for 2004-09 and was applicable till 31.03.2006.
4. **CEA Recommendation -**CEA in its recommendation of Operating Norms for the tariff period 2019-24 has provided target availability of 68.5% in the first financial year (FY) after COD. The actual availability achieved by NTPC units after COD till cut-off date in recent years is tabulated as under:

DC - PIT HEAD STATIONS (%)												
Station	**COD**	**FY 09-10**	**FY 10-11**	**FY 11-12**	**FY 12-13**	**FY 13-14**	**FY 14-15**	**FY 15-16**	**FY 16-17**	**FY 17-18**	**FY 18-19**	**Average**
Rihand Stg-III (U#5 & U#6)	Nov'12, Mar'14				62.65	90.25	83.42	85.74				80.51
Vindhyachal Stg-IV (U11 & U12)	Mar'13, Mar'14				24.40	91.52	86.44	95.05				74.35
Vindhyachal Stg-V (U#13)	Oct'15							94.40	90.88	99.07		94.78
Korba Stg-III (U#7)	Mar'11		71.72	76.76	94.76							81.08
Sipat Stg-I (U#1, U#2 &U#3)	Oct'11, May'12, Aug'12			71.00	80.54	89.63	89.01					82.54
Farakka Stg-III (U#6)	Apr'12				70.65	86.84	84.64					80.71
Kahalgaon Stg-II (U#5,U#6, U#7)	Mar'10	65.12	68.77	64.77								66.22
DC - NON-PIT HEAD STATIONS (%)												
Station	**COD**	**FY 09-10**	**FY 10-11**	**FY 11-12**	**FY 12-13**	**FY 13-14**	**FY 14-15**	**FY 15-16**	**FY 16-17**	**FY 17-18**	**FY 18-19**	**Average**
Unchahar Stg-IV (U#6)	Sep'17									14.34	3.79	9.06
Dadri Coal Stg-II (U#5, U#6)	Jan'10, Jul'10	56.68	84.57	100.22	91.75							83.30
Mouda Stg-I (U#1, U#2)	Mar'13, Mar'14				1.36	49.86	83.45	97.42				58.02
Mouda Stg-II (U#3, U#4)	Feb'17, Sep'17								89.46	43.90	71.22	68.19
Solapur Stg-I (U#1)	Sep'17									49.67	81.91	65.79
Simhadri Stg-II (U#3, U#4)	Sep'11, Sep'12			89.80	75.42	85.89	90.50					85.40
Kudgi Stg-I (U#1, U#2, U#3)	Jul'17, Dec'17 Sep'17									86.07	73.79	79.93
Barh Stg-II (U#4, U#5)	Nov'14 Feb'16						83.00	90.20	82.13	88.33		85.91
Bongaigaon Stg-I (U#1, U#2)	Apr'16 Nov'17								98.06	69.40		83.73

It may be observed that majority of the units are unable to achieve target availability in the first 2-3 years after COD. **In view of the above, it is suggested that relaxed target availability norm of 68.5% may be provided to new units from COD till cut-off date for the purpose of stabilization.**

51 REGULATION 59 (E) - ADDITIONAL AUXILIARY ENERGY CONSUMPTION

(E) Auxiliary Energy Consumption:

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

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

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

Comments / Suggestions:

ADDITIONAL APC FOR MDBFP

Draft Regulations provides for additional APC of 2.25% for units 600 MW and above greater for electrically driven boiler feed pumps (MDBFP) has been retained at 8%. The same is inadequate for the following reasons as under:

1. A steam driven BFP (TDBFP) draws motive power in form of steam drawn from IP (Intermediate Pressure) Turbine exhaust and converts the heat energy in the steam to shaft power of BFP. Turbine of TDBFP is designed to rotate at high RPM (about 6000 rpm or so), i.e., at the pump speed (to develop enough pressure to pump water in to boiler operating at a pressure of 247 ksc) avoiding the need for hydraulic coupling and gears for increasing the speed and hence are more efficient. However, in case of MDBFP which draws motive power from electrical motor (speed of about 1500 rpm) involving more losses due to multiple energy conversions stages i.e. losses in generator, transformers, hydraulic coupling, gears, etc.
2. Accordingly, the auxiliary power requirement for units having MDBFP exceeds the present provision of additional APC of 2.5% as compared to units having TDBFP. Further, based on the actual plant data for 660 MW, the difference in APC between units with TDBFP and with MDBFP comes out to be 25.94 MW (i.e.

25.94/660x100 =3.93%) against the present provision of 16.5 MW (i.e. 2.5%) which is further proposed to be reduced to 14.85 MW (i.e. 2.25%) in the draft tariff regulations.

3. It may be pertinent to mention that at Barh Stage-II (2X660 MW), OEM has provided a MDBFP of 18.7 MW (name plate rating) catering to a load of 50% (i.e. 330 MW) during start-ups and shut-downs. Accordingly, for 660MW units having MDBFP only, two such MDBFP would be required for full load operation with total power rating of 37.4 MW (i.e. 18.7x2). Considering MDBFP operating at 90% of name plate rating for full load operation the power consumption would be about 33 MW, i.e.an additional auxiliary power consumption of 5%. (i.e.33/660*100).
4. In view of the above, additional APC of 2.25% for units having electrically driven BFPS is not adequate; instead additional APC of at **least 4%** is required. **Accordingly Tariff Regulations may provide APC of 9.75% for units having electrically driven BFPs.**

ADDITIONAL AUXILIARY POWER CONSUMPTION FOR EMISSION CONTROL SYSTEM (ECS)

Additional APC on account of ECS has not been proposed in the Draft Regulation. It is submitted that enabling provision of additional APC on account of retrofitting of ECS (with SOx and NOx) required for the specific unit/project in order to comply revised environmental norms may be provided in the Regulations as per recommendations of CEA expected in this regard in due course of time.