एनटीपीसी
NTPC

एनटीपीसी लिमिटेड
(भारत सरकार का उद्यम)
NTPC Limited
(A Govt. of India Enterprise)

Ref No: 01:CC:CD:737-D
Date: 20.02.2024

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

Subject: Submission of comments/ suggestions on draft CERC Tariff Regulations, 2024 for the tariff period from 1.4.2024 to 31.3.2029

Sir,

This has reference to the Public Notice No L-1/268/2022/CERC dated 04.01.2024 seeking comments and suggestions from stakeholders on the draft CERC Tariff Regulations, 2024 for the tariff period from 1.4.2024 to 31.3.2029.

Please find enclosed comments/ suggestions of NTPC on the draft CERC Tariff Regulations, 2024 **at Annex-B** for your kind consideration. It is also requested that NTPC may be allowed to submit any additional submissions, if required.

The summary of the comments/ suggestions is also attached **at Annex-A** for your ready reference.

Thanking you,

Your faithfully,

(Ajay Dua)
ED (Commercial)

ANNEXURE-A

NTPC Comment on draft CERC Tariff Regulations 2024

S.N.	Regulation No.	Brief aspect of Regulation	NTPC Comments	Reference of detailed comment at Annexure-B
1.	General	Adequate Resource Generation for Capacity Addition in Thermal Generation.	Thermal capacity addition by NTPC is to play a major role in meeting future capacity demand of country 72 GW by 2031-32. To meet this capacity addition adequate internal resources of fund, need to be generated for meeting the equity requirement of more than 69,900 Cr for NTPC capacity addition plan of 23,300 MW. Considering business risks and global decarbonization environment an overall regulation conducive for creation of adequate internal resources is needed.	Sl No .1
2.	70 (C) & (E)	Normative Gross Station Heat Rate & Auxiliary Power Consumption (APC): Station Heat Rate Norm tightened: • 200 MW units – 2400 kcal / kwh (Existing 2430 kcal / kwh); • 500 MW units – 2375 kcal / kwh (Existing 2390 kcal / kwh) Stations achieving COD after 1.4.2009: 1.04 × Design heat rate for 500 MW & above (Existing - 5% margin) APC of 500 MW & above units (Without IDCT): - 5.25% (existing 5.75)	• 200 MW & 500 MW old units will incur loss based on past 2-year performance. • The proposed heat rate & APC norms are very stringent and will result in operational losses for pit head stations from the start of the tariff period. • Sharing of gains not factored in formulation of norms. • Operating margin for 500 MW units after 01.04.2009 reduced to 4% from 5%. Operating margin does not depend on unit size so it should be kept same for all units. • About 26 GW (operating above 85% loading) would start incurring losses (Rs 112 Cr/Year) from the first year of operation itself as not able to get compensation benefit proposed with tighter norms. • Similarly for APC, the NTPC stations of capacity of about 12.5 GW (operating above 85% loading) will incur loss. • In totality, NTPC will incur loss to the tune of about Rs 128 Cr/year despite operating at more than 85% loading factor. **In view of above existing heat rate norms & heat rate margin may be retained. Existing APC norms of 5.75% for 500 MW & above units (without IDCT) may be retained.**	Sl No .2

3.	New addition	Incorporation of Part load compensation as recommended by CEA in Draft CERC Tariff Regulations 2024	Norms worked out by CEA considering its own degradation factor. Considering degradation factor lower than that recommended by CEA would call for modification in norms. **Degradation factors recommended by CEA to be included in the Tariff Regulations.**	Sl No .3a
4.	New addition	Part load compensation on normative basis only instead of existing dispensation of norms or actuals, whichever is lower	a) There would be a net loss to the generating company (311 Cr/year) due to present dispensation of part load compensation on lower of normative and actuals. b) Tariff Policy stipulates that the operating parameters should be at "normative basis" only and not at lower of normative and actuals. **Part load compensation should be on normative basis instead of "normative or actual whichever is lower".**	Sl No .3b
5.	New addition	Heat rate compensation factor recommended by CEA due to part load operation for the tariff period of 2024-29 is inadequate.	For Supercritical unit, deterioration in heat rate at 55% load varies from 6.1% to 9% as against 6% proposed. For subcritical units (500 MW units), deterioration in heat rate at 55% load varies from 7.71% to 8% as against 7.6% proposed by CEA. **Part load compensation factor due to heat rate deterioration may be increased.**	Sl No .3c
6.	New addition	Heat Rate degradation factor for air cooled condensers	CEA recommendation has not specified Heat Rate degradation factor separately for units with air cooled condensers which needs to be included in Regulation.	Sl No .3d
7.	New addition	Start-up Oil Consumption for Super Critical Units during Cold start-ups	The oil consumption norms of 110 KL per start allowed to Super Critical units during cold start-up is not adequate. **Oil consumption of 350 KL per start for cold start-up condition may be provided to supercritical units.**	Sl No .3e
8.	62(6)	**Rate of Generation incentive:** a) Peak hours – 75 paisa/kwh (Existing- 65 paisa per kwh). Off-peak hours - 50 paisa/kwh	The rate of incentive has been maintained at the same level since last 10 years. Considering inflation, **incentive rate may be increased to Rs. 1.00/kwh for off-peak hours & Rs. 1.30/kwh for peak hours.**	Sl No .4
9.	70(A) &70 (B)	Relaxation in NAPAF/NAPLF	NAPAF/NAPLF may be reduced to 80%. 5% relaxation in NAPAF/NAPLF should be provided to coal stations after completion of useful life (25 years) rather than 30 years	Sl No .5
10.	44 (3)	ROE for Integrated Mines: Return on equity for integrated mines allowed at base rate of 14%.	RoE needs to be commensurate with the risks in mining sector (geological surprises, harsh weather conditions, flooding, integrated risk with generation business etc). **RoE of 15.5% to be allowed for Integrated mine at par with thermal generating stations from existing 14%.**	Sl No .6

11.	30 (3)	RoE on Addcap beyond the original scope, ECS, Change in Law, and Force Majeure at SBI 1 Yr MCLR plus 350 bps, subject to a ceiling of 14%.	Investment in add cap beyond original scope carries same risk as original scope add cap. ECS & Addcap is an integral part of coal-based station and its cost recovery linked with that of the main plant. **It is suggested that RoE on all add cap (including ECS) be at par with that of thermal generating stations at 15.5%.**	Sl No .7
12.	60 (1)	GCV of coal: GCV of coal on 'as received' basis with third party sampling certified by Ministry of Coal recommended agency.	MoP is empaneling Third Party Sampling agencies for sampling and analysis of coal through the Power Finance Corporation (PFC). **Wording "agency certified by the Ministry of Coal" may be replaced by "agency certified by the Ministry of Power".**	Sl No 8 (b)
13.	60 (1)	GCV of coal: In absence of third-party sampling, Maximum loss allowed between GCV of coal "as billed" & "as received" is 300 kCal/kg for Pit-head and 600 kCal/kg for Non-Pit Head stations.	Clarification may be provided that **loss in GCV between as billed & received shall be on Equilibrated Moisture (EM) basis. For the purpose of billing to the Discoms, GCV received at station shall be further adjusted with the moisture correction.**	Sl No .8(c)
14.	60 (1)	GCV of coal: Clause 60 (1) (i) of draft Regulations provides maximum loss in GCV of 300 kcal/kg for stations with integrated mine, whereas proviso to the regulation 60 (1) (i) has proposed no loss in GCV from Integrated mines.	• CERC has proposed the maximum loss of 300 kcal/kg for Pit-head based generating stations or generating stations with Integrated mine pithead stations and 600 kCal/kg for non-Pithead stations. The proviso to same regulation provides there shall be no loss in GCV for stations getting coal from integrated mines. CERC may clarify the contradiction in Regulation 60 (1) (i). • **Integrated mines are supplying coal to various stations with distance varying from below 100 km to more than 1500 km. There, is direct correlation in distance and GCV loss.** • **A loss of 300 kCal/kg between 'as Billed' and 'as Received' GCV to be provided to integrated mine in addition to moisture correction.**	Sl No .8 (d)
15.	36(1)	Additional expenses to be included in the O&M norm of Coal Stations	a) Consumption of capital spares < 20 Lakhs: Rs 1 Lakh/MW/Year. b) Additional capitalization of minor assets < 20 Lakhs: 0.7 Lakh/MW/Year. c) Disallowed capital expenditure met out of O&M expenses: Rs 1.4 Lakh/MW/Year d) Increase in O&M expenses due to increased flexibility (100% to 55% loading): Rs 2 Lakh/MW/Yr Additional O&M cost for future addition of Manpower: About Rs 0.5 Lakh/MW/Yr	Sl No .9

16.	36(3)	Normative O&M expenses of Gas Stations reduced to 17.2 Lakh/MW/Yr (in FY 24-25) from 20.2 Lakh/MW/Yr (in FY 23-24).	a) Number of start-ups in Gas stations have increased from 881 in 2019-20 to 2063 in 2023-24 (up to Q3). b) Avg. EOH consumption/unit/year increased by 2.5 times. • **Additional O&M expenses norm of Rs 2 lakhs/MW/Yr may be provided due to increased wear and tear.**	Sl No .10 (e)
17.	36 (3)	Start-up cost in open cycle & combined cycle of Gas Statiion	**Additional O&M expense of Rs. 3.24 Lakh/MW/year may be provided for compensation of start-up expense of Gas Station.**	Sl No .10(f)
18.	36 (3)	Additional expenses to be included in the O&M norm of Gas Stations	• Consumption of capital spares < 20 Lakhs: Rs 1 Lakh/MW/Year. • Additional capitalization of minor assets < 20 Lakhs: 1 Lakh/MW/Year. • Disallowed capital expenditure met out of O&M expenses: Rs 1.35 Lakh/MW/Year	Sl No .10 (g)
19.	36(6)	Monthly recovery of ash transportation expenses not provided in Draft Regulations.	• **Suitable provision may be provided in the Tariff Regulations 2024 for reimbursement of Ash Transportation expenses on a monthly basis,** for avoiding accumulation of carrying cost	Sl No .11
20.	39(2)	Run of Mine (ROM) Cost Formula Revised by including Actual Production	Considering fixed coal reserves in the mine, any additional production in a year above the quantity specified in the Mine Plan shall result in under recovery of Annual Extraction Cost over the life of the mine. **Proposed formula of ROM Cost may be revised.**	Sl No .12
21.	52(2)	Adjustment on account of shortfall in GCV (GCV Adjustment) in Integrated Mines	CERC to allow the GCV adjustments in case the actual GCV is more than mid-value of the declared grade by 300 kCal/kg. **Since the definition of ATQ has been changed, therefore, the GCV Adjustment formula under Regulation 52(2)(b) may also be revised accordingly.**	Sl No .13
22.	51	Adjustment on account of Shortfall of Overburden Removal	OB adjustment for shortfall may be considered at the end of the life of mine instead of 3 years as proposed. If CERC decides to keep overburden adjustment in the final regulations, • OB adjustment for shortfall may be considered at the end of 5 years instead of 3 years as proposed. • The OB Adjustment formula may be revised to exclude O&M exp. • The error in the formula of OB adjustment may be rectified.	Sl No .14

23.	64(4)	Blending of imported coal (@ 6%) allowed on Station basis instead at Generating company level.	Considering the constraint involved in supply of domestic coal, MOP, GoI also issued direction to all GENCOS to import coal for blending "at company level". **Generating company may be allowed quantum of blending of imported coal at company level.**	Sl No .15
24.	21(5)	Project implementation: In case of delay due to concerned authority (forest clearance, NHAI clearance, railways approval, Govt. land acquisition), up to 90% of delay condonation will be allowed.	As per established regulatory practice, in case delay is condoned by CERC after prudence, the increase in capital cost is allowed in tariff. **It is suggested that the clause may be deleted.**	Sl No .16
25.	33(6)	Depreciation of new projects: shall be as per specified rates in the initial 15 years (existing 12 years) & the remaining depreciation shall be spread over the balance useful life.	a) Most of the banks avoid going for longer tenor like 18-20 years considering the Asset Liability mismatch. b) The borrowings for longer tenure would lead to higher cost of borrowing. **The existing regulatory provisions may be retained (initial depreciation recovery in 12 years).**	Sl No .17
26.	32(6)	Interest on Loan for New Projects: At the Weighted Average Rate of Interest (WAROI) on actual loan portfolio of generating company.	a) Interest Rate Differentials will impact debt servicing. b) Allocation of FERV among beneficiaries of both new and old stations will poses a challenge. **The existing regulatory provisions may be retained (IoL on project specific basis).**	Sl No .18
27.	17	Regulation 17	Regulation 17 may be removed entirely as it could lead to confusions due to different interpretations by utilities. In case recovery of tariff is based on schedule generation, then a condition of minimum off-take by the beneficiaries may be imposed which will take care of recovery of capacity charges. Alternatively, it is suggested that the recovery of capacity charges may be linked to availability factor as is being presently done.	Sl No .19
28.	70 (C) (d)	Gross Heat Rate Norms of Coal Stations for Entire Operational Life. Heat rate norms shall remain unchanged for the remaining	• Adopting tighter Heat rate norms as proposed in draft for life will result in perpetual loss for many stations. It is difficult for the generator to accommodate mid-course	Sl No .20

		operational life for the unit commissioned till 31.3.2024	tightening of the norms. Project capital cost as discovered through bidding depends on the design parameters specified by the generator. • **Operational norms may be fixed for the operational life based on the norms prevailing as per the extant regulations at the time of investment approval or award of the units.**	
29.	3(45)	Definition of integrated mine	Definition of Integrated Coal mine may also include the mines owned/developed by Subsidiary Company(s) of a Generating Company for supplying coal to the plants of the Generating Company	Sl No .21
29.	34	IoWC reduced by 0.25% (From SBI 1 Year MCLR +350 basis points to SBI 1 Year MCLR +325 basis points).	Freight Advances to Railway, Deposit with Water Authority, recovery of FERV, delay in receipt of credit notes from coal companies are not covered in working capital. **Existing provision of IWC may be retained (SBI-MCLR+350 bps).**	Sl No .22
30.	New addition	O&M Expenses for Dedicated Transmission Line	O&M of dedicated transmission line is not a part of the O&M norms of stations. As per CERC GNA Regulations, all generators are now mandated to execute and carry out O&M of dedicated transmission lines. **O&M and IWC charges for these dedicated transmission elements may be allowed as admissible to transmission utilities.**	Sl No .23
31.	New addition	Auxiliary Energy Consumption (AEC) of Dedicated Transmission Lines.	Clarification may be provided that norms for AEC for the station are excluding losses in dedicated transmission line. **The actual losses in a dedicated transmission line shall be recoverable from the beneficiaries separately.**	Sl No .24
32.	70(D)(b)	Secondary Fuel Oil Consumption Norms for front fired stations: 1.0 ml/kWh	Instead of the phrase front fired boilers, the phrase "Wall fired" may be used as the wall fired may be front, rear, or side wall or combination of the three.	Sl No .25
	CLAUSE WISE COMMENTS			
33.	2	Scope and Extent of application	In case of projects where consent of beneficiaries has already been sought in the 2019-24 tariff period, the requirement of seeking a fresh consent from the beneficiaries till 31.03.2026 may be dispensed.	Sl No .26
34.	3(5)	ATQ in respect of Integrated Mine	welcome step considering that the mining operations encounter various uncertainties/risks which are not captured during exploration as exploration is done on sampling basis.	Sl No .27

35.	3(63)	Project definition.	Integrated Energy storage system may also be added in the "Project" definition.	Sl No .28
36.	3(88)	Operational life	Machines have been / are being awarded considering useful life of 25 years. specifying operational life as 35 years for coal-based stations does not call for specifying design life of power plant equipment as 35 years or else it will result in additional capital cost of equipment and in turn increased tariff.	Sl No .29
37.	9(1)	Application for determination of tariff.	There is no provision for provisional tariff for commencement of billing after COD till the interim tariff is granted by Commission. Enabling provision for filing of tariff petition on tentative/projected figures as on anticipated COD (instead of audited figures), as provided in Tariff Regulations 2019 may be provided.	Sl No .30
38.	10(3)	Determination of Tariff	Penal interest rate @ 1.2 times of SBI MCLR plus 100 bps on this excess amount recovered is not fair and therefore the above provision may be dropped. It is suggested that the excess amount recovered shall be refunded to the beneficiaries with simple interest at the rate of 1-year SBI MCLR plus 100 basis points	Sl No .31
39.	10(7)	Interest on refund or recovery of Differential Tariff	The generating company takes all efforts to refund money to beneficiaries without any undue delay. LPSC in case of delay in refund by generating company may be beyond 45 days from the issuance of order.	Sl No .32
40.	10(8) &13(5)	Determination of Tariff: provision for interest on under billing.	There is no provision for interest on under billing on true-up in Reg 10(8) . Both rate of interest for recovery and refund of differential tariff may be same. capacity charges need to be based on percentage allocation share of beneficiaries for the respective period.	Sl No .33
41.	10(7), 10(8) & 13 (5)	Truing up of tariff for the period 2024-29.	EMI payment principle is always subject to interest assessments. Interest may be allowed during the period of billing of six-monthly instalments also	Sl No .34
42.	19(2) (p) & 19 (3) (g)	Enabling Flexible Operation at Lower Loads	Increase in maintenance costs, Forced Outages, reduction in plant life due to accelerated aging may be compensated on account of flexible operation.	Sl No .35
43.	19(5) (a)	Computation of capital cost for projects acquired through NCLT	Consideration of historical GFA of the project instead of acquisition price would reduce the revenues and thereby result in continued financial stress on acquirer.	Sl No .36

44.	22(1) (b)	Controllable and Uncontrollable Factors	Not all contractor delays are controllable. New clause may be added for contractual related issues not attributable to generating company or transmission licensee including but not limited to non-performance of contractor due to NCLT, supply disruptions, change in legal status of vendors, insolvency of contractors, termination, and retendering, etc. leading to delay in projects.”	Sl No .37
45.	22(2)	uncontrollable factors	Delays on account of forest clearances may also be considered	Sl No .38
46.	23(d) (iv)	Initial spares for GIS	No need of 6% spares clause for GIS as separate clause of Brownfield and greenfield GIS provided.	Sl No .39
47.	26(1)	Additional Capitalisation beyond the original scope	Addcap pertaining to installation of Carbon Capture, Utilisation & Storage (CCUS) system, ammonia/ methanol co-firing and Railway infrastructure for transportation of Limestone /Gypsum may be allowed.	Sl No .40
48.	28	Special allowance	Escalation as per O&M expenses escalation rate of 5.9% need to be provided.	Sl No .41
49.	30(iii)(a)	RoE linked to ramp rate	CEA Ramp rate guidelines are very stringent. It is proposed to continue the existing guidelines in case of Ramp rate assessment.	Sl No .42
50.	30(3)(i)	Rate of RoE to be reduced by 1.0% in case found lacking of FGMO for new projects.	Reduction in ROE may be for the period of non-compliance only.	Sl No .43
51.	30(3)(ii)	Rate of RoE to be reduced by 1.0% in case found lacking of FGMO for existing projects	Requirement of FGMO or PFR may be relaxed for the older units since there would be requirement of major turbine and control system renovation.	Sl No .44
52.	30(3)(ii)	Ramp Rate of 3.0% for Gas Stations	Ramp rate of 1% per minute should be considered for gas station operating in combined cycle instead of 3%.	Sl No .45
53.	34(a),36(7) &64(5)	Biomass Co Firing as per MoP Policy	Considering mandatory requirement of co-firing biomass, cost of biomass for 20 days and Advance payment for 30 days for the cost of biomass may be included in working capital. Additional O&M and degradation in heat rate and APC on account of biomass co-firing may also be provided.	Sl No .46

54.	34 (A) &(C)	Requirement of Higher Inventory in coal &Gas stations for calculation of WC. Fuel cost of Gas Stations for calculation of WC	Maintenance spares -coal stations 50% of O&M exp. Maintenance spares for Gas stations -100% of O&M exp. For calculation of IOWC, Fuel cost for 15 days may be **increased to 30 days**.	Sl No .47
55.	35	Regulatory Framework for Decommissioning	Enhancing the depreciable base from 90% to 95% (which is in line with the Companies Act 2013). Capital spares stock that are not serviced to be allowed as deemed consumption during decommissioning.	Sl No .48
56.	36(7)	Additional O&M expenses due to any change in law or Force Majeure	The proviso in which only more than 5% of normative O&M expenses are allowed for year, may be deleted.	Sl No .49
57.	36(9)	Income generated from Gypsum sale to be reduce from O&M of ECS	Income generated from the sale of gypsum shall be shared on 1:1 basis to incentivize the generator for sale of gypsum.	Sl No .50
58.	37(2)	Input price adoption till determination by CERC.	The input price NTPC mines may be higher than Coal India notified price due to higher stripping ratio. Interim input price of up to ninety per cent (90%) of the input price claimed in case of new integrated mine from the date of filing of tariff petition may be granted.	Sl No .51
59.	39(4)	Adherence to the Mining Plan.	Regulation may be revised as For any deviation in coal production beyond the Sanctioned Capacity of the Mine, generating company shall submit approval / certificate from the Coal Controller or the competent authority.	Sl No .52
60.	50 (1)	Recovery of Input Charges for integrated mines.	Input price of NTPC mines may not be comparable to the Coal India notified price. Commission may waive off requirement of prior consent from beneficiaries in case energy charge rate based on input price of coal from integrated mine exceeds by 20% of energy charge rate based on notified price of Coal India Limited for the commensurate grade. Pertinently the requirement of fixation of the input price of coal from such integrated mine(s) based on the notified price of Coal India Limited for the commensurate grade of coal in a month may also be waived off	Sl No .53

61.	55	Quality measurement of coal supplied	Collection and preparation of coal sample for laboratory testing is carried out in accordance with the IS 436 (Part-1/ Section-1)- 1964 and sample analysis is carried out in accordance with IS 1350 (Part 1 & 2). The same may be additionally mentioned in the above regulation.	Sl No .54
62.	59	Transit and Handling Losses for multi-mode coal transportation	Separate transportation loss of 0.6% for each leg of transportation (Rail & Road) needs to be considered along with handling loss of 0.2%. **Transit and Handling loss of 1.4% for multi-mode coal transportation may be considered.**	Sl No .55
63.	62(1)	Regarding sharing of capacity charges.	to have uniformity, it may be clearly defined in the Regulations that peak and off-peak hours entitlement to be considered for apportionment of Capacity Charges for peak period and Capacity Charges for off peak period respectively. Accordingly, all the RPC to provide entire details in REAs	Sl No .56
64.	62(5) and 65(4)	Incentive for providing Primary Frequency Response (PFR)	Beta may be considered as 1 when PFR performance is 70%.	Sl No .57
65.	62(7)	Redundant para.	The above paragraph is redundant and hence same may be removed. Similar clause was there in Tariff Regulations, 2019 which was kept for the dispensation of High Demand / Low Demand Season (HDS/LDS) were effective from 01.04.2020 instead of 01.04.2019.	Sl No .58
66.	64(1)	Modification required.	The phrase "with fuel and limestone price adjustment" may be replaced with "with fuel and limestone price and fuel's calorific value adjustment".	Sl No .59
67.	64(3)(a)	Additional sp oil for operating below 55%.	it is requested to include additional Specific Oil Consumption of 0.2 ml/kWh recommended by CEA in the CERC Tariff Regulations 2024	Sl No .60
68.	Regulation 70 (A)&(B)	Revision of NAPAF & NAPLF considering transition to RE & flexible operation	A) In this transition phase of power sector, there is a requirement to review NAPAF/NAPLF. It is proposed that NAPAF/NAPLF may be reduced to 80%. B) Above 5% relaxation in NAPAF/NAPLF may be extended to gas-based stations also.	Sl No .61
69.	70(C) (b) (i)	Maximum TG Cycle Heat Rate (for Units with Pressure/SHT/RHT: 270 kg/cm2(abs) / 600°C/ 600°C) Reduced from 1800 kcal / kwh to 1790 kcal /kwh	For a 7°C change in both MS and HRH temperatures, the HR improvement would be around 7 kcal/kwh. **Review the maximum turbine cycle heat rate for Ultra-Supercritical parameters. In addition, Optimization of plant at both 100% and 55% TMCR load, Boiler Efficiency based on Coal Quality may be considered.**	Sl No .62

70.	70(c)(b)(ii)	Heat Rate norm for Kanti Stage-II	Past actual data reveals that the Five-Year Average Heat Rate for Kanti TPS is 2581 kcal/kwh. **Review the proposed norms and not to specify norm stringent than the past actual achieved by the Kanti-II**	Sl No .63
71.	70 (E)	Auxiliary Energy Consumption (AEC)	Majority of the new projects developed are brownfield projects where the opportunities for optimizing the system and layout are restricted, results in longer distances and hence higher APC. **APC for brownfield project to be increased beyond earlier value of 5.75%.** Also following is to be provided: • Additional APC for Talcher Stage-I having Tube and Ball Mills. • Additional APC for Simhadri Station using Sea Water. • Additional APC for Vallur having Piped Conveyors, load graber & desalination plant. • Additional APC for Equipment's/ systems being installed to comply with Statutory requirements. • Additional APC for R&M of ESPs • Additional APC for Biomass co-firing • Additional APC for units having electrically driven BFPs.	Sl No .64
72.	70 (E) (f)	Norms of Auxiliary Energy Consumption for Emission Control System (ECS)	APC of Dry Sorbent Injection System to be given APC for Selective Non-Catalytic Reduction System (SNCR) to be provided.	Sl No .65
73.	70(F)	Norms of Consumption of Reagent for ECS	**Normative Limestone consumption may be specified** instead of Formula for normative specific consumption. **Consumption varies when imported coal is being fired in DSI, so correction for imported coal to be provided**.	Sl No .66
74.	70(F)(1)(a)	Supplementary ECR formula.	A margin in GCV of 85 kcal per kg for loss in calorific value during storage within the station for computation of ECR. However, it appears that same has been missed out in the above formula for working out supplementary ECR.	Sl No .67
75.	79(2)	Rebate.	Where payments are made on any day after 5 days and within a period of 30 days of presentation of bills by the generating company or the transmission licensee, a rebate of 0.5% shall be allowed.	Sl No .68

76.	84	Sharing of non-tariff income	Gain realized by selling of scrap should not be shared.	Sl No .69
77.		Stringent Heat Rate norms for Bongaigaon Station (3x250MW)	Operational norms applicable at the time of award of projects should be retained	Sl No .70
78.		Operational norms for TSTPS	The normative Heat Rate may be kept at 2390Kcal/kwh (instead of 2375) in line with regulation 2019-24. Talcher STPS-I may be considered as a special case to allow the APC as 7.50%.	Sl No .71
79.	New addition	Transit & Handling Loss for North Karanpura Station	Transit & Handling loss of 0.8% (as applicable for transportation of coal through Rail) may be provided to North Karanpura station where 100% coal is being transported through truck.	Sl No .72
80.	New addition	Compensation for Synchronous Condenser, STATCOM, etc	Cost recovery mechanism for compensation devices, such as, synchronous condenser, STATCOM, etc. may be included. Also, incentives for providing inertia in the grid, and fast dynamic reactive power may be provided.	Sl No .73
81.	New addition	Aspects Related to Energy Storage System (ESS)	Provision related to definition and capital expenditure on account of installation of ESS may be provided.	Sl No .74
82.	New addition	Add cap for decarbonisation	Additional capitalisation under the head of ammonia/ methanol co-firing, CCUS and integration of thermal energy storage need to be included.	Sl No .75
83.	New addition	Flexible Operation at Lower Loads	Regulation may include the expenditure for specific aspects (minimum load – 40%/ 55% & ramp rates).	Sl No .76
84.	New addition	Additional O&M expenses to be provided for Coastal projects	Due to corrosive nature of sea weather, huge expenses are being incurred in maintaining structural health. **Additional O&M expenses to be provided for Coastal projects**.	Sl No .77
85.	3(24),3(32), 21 (5) ,65, 66 & 71	Aspects Related to Hydro: • Design Energy related to Hydro. • Definition of 'Force Majeure', • IDC &IEDC	• Definition of 'Design Energy' applicable for a Pump Storage Project (PSP) may be included in TR 24-29. • Pandemic may be included in definition of 'Force Majeure'. • Maximum condonation of delay may allowed up to 100% in case delay is account of concerned authority.	Sl No .78

		• Excess energy in reference to net saleable design energy kept unchanged. • Computation and Payment of Capacity Charge and Energy Charge for Hydro Generating Stations. • Computation and Payment of Capacity Charge and Energy Charge for Pumped Storage Hydro Generating Stations. • Norms of Operation for Hydro Generating Stations.	• ECR for excess energy/secondary energy may be increased to at least "**150 paisa per kWh**" (existing "**120 paisa per kWh**") • Second proviso to Regulation 71 (B) may be modified. • APC of PSP to include the energy consumed during pumping operation. **APC for PSP may be increased by 1.0%.**	

NTPC Comments on Draft CERC (Terms and Conditions of Tariff) Regulations 2024

1) **Adequate Resource Generation for Capacity Addition in Thermal Generation:**

   a) **Need for capacity addition to meet the growing demand**: As per the Ministry of Power meeting held on 27th Sep 2023 to review capacity addition, coal capacity addition of 72 GW is required to meet the demand in 2031-32. To achieve this, a massive capital investment of Rs. 7,20,000 Crores is required considering a capital cost of Rs. 10 Crores per MW. The corresponding equity deployment amounts to Rs 2,16,000 Crores, considering a debt equity ratio of 70:30.

   b) **Resource generation required for capacity addition:** Currently, due to resurgent demand and slower thermal capacity addition in recent years, the gap between demand and supply, particularly during peak hours, is increasing and expected to widen in the future. This scenario presents a compelling case for creating a conducive environment to attract investment in the generation sector. Thermal generation is required to bridge the gap between demand and supply.

   c) Further, aligning to the nation's requirement of capacity addition, NTPC Group is planning to add 23,300 MW Thermal Capacity (15,200 MW under planning & 8100 MW under construction). This would require a Capital investment of Rs. 2,33,000 Crores (@ Rs. 10 Crores per MW) and Equity investment of Rs 69,900 Crores (D/E ratio of 70:30). To garner the huge equity requirement, NTPC's generation of internal resources would play a pivotal role.

   d) **Considering the added business risks in the present situation and the general perception against thermal generation in an era of global decarbonization, and the requirement of substantial capacity addition in thermal generation, the Hon'ble Commission is requested to provide an overall regulation conducive for creation of adequate internal resources that can be ploughed back for thermal capacity addition.**

This is required for ensuring reliable and adequate power supply for the economic growth of India.

2) **Regulation 70(C)&(E) - Normative Gross Station Heat Rate & Auxiliary Power Consumption (APC):**

   a) The Draft regulations has proposed following gross heat rate norms & APC for thermal generating stations for the tariff period 2024-29:

      i. Heat Rate of Coal stations (COD before 01.04.2009): 200 MW units - 2400 kcal / kwh & 500 MW units – 2375 kcal / kwh.

      ii. Heat Rate of Coal stations (COD on or after 01.04.2009) – 500 MW and above units - 1.04 × Design unit Heat Rate.

      iii. APC of 500 MW & above units (Without IDCT): - 5.25%

   b) The proposed heat rate norm and APC norm & operating heat rate margin have been considered by the Hon’ble Commission as per the recommendation of CEA vide letter dated 19.12.2023.

   c) It has been stated in the said CEA’s letter that the norms have been worked out by CEA after detailed analysis of the operational data of the last 5 years (2018-19 to 2022-23), design data and OEM data.

   d) As per the existing mechanism of sharing of gains, it may be noted that certain stations which operate better than norms are required to share the financial gain with beneficiaries on 50:50 basis. Whereas the stations operating worse than the norm have to bear the entire loss themselves. Therefore, it is submitted that the same is required to be considered while finalizing the norms, otherwise there will be an overall financial loss to the generating company on account of operating norms. The sample calculation explaining the implication of sharing of gains in detail is as under:

Particulars		**Station 1** (2 x 500 = 1000 MW)	**Station 2** (2 x 500 = 1000 MW)
Actual Heat Rate (in kCal/kWh)	(1)	2380	2420

Average actual Heat Rate (kCal/kWh)	(2)	2400	
Proposed norm for 2024-29 Tariff Period arrived based on average of past actual heat rate (kCal/kWh)	(3) = (2)	2400	
Gain (+)/ Loss (-) between norms and actual heat rate (kCal/kWh)	(4) = (3)-(1)	20	-20
Sharing of gains as per CERC Regulations (kCal/kWh)	(5) = (4) * 0.5 If (4)>0	10	Nil
Impact to Generating Company (kCal/kWh)		10	(-) 20
Overall Gain (+)/ Loss (-) to Generating Company after sharing of gains (kCal/kWh)	(6)	[10 + (-) 20] = (-) 10	

Sharing of gains is also applicable to sharing of gains on APC.

e) Therefore, the norms worked out on the basis of averaging of actual operating parameters would result in generating company incurring losses due to present dispensation of sharing of gains. In view of this, the norms should be suitably relaxed to offset the effect of sharing of gain, so that generating company does not incur losses on account of operating norms.

f) Further, CEA has recommended the operating norms considering the degradation factor (as per the table of degradation factor in its recommendation).

g) The proposed heat rate & APC norms are very stringent and will result in operational losses for pit head stations from the start of the tariff period. To explain this case further, operating data of stations for the 2-year period from 2021-22 and 2022-23 have been considered for NTPC coal stations.

h) The stations which are operating above loading factor of 85% in the 2-year period (2021-23) has been considered. Since these stations are operating above 85% loading factor, there would not be any impact on account of degradation factors. NTPC Stations of about 26 GW capacity is operating at a loading factor of more than 85%.

i. **Units with COD before 01.04.2009: About 14 GW:**

a) **200 MW Units**

i. 200 MW units are generally old units. Despite that stringent heat rate norms of 2400 kCal/kWh has been proposed for these 200 MW units.

ii. Actual average heat rate of two (2) Stations (Vindhyachal St-I & Kahalgaon St-I operating @ loading factor of 85%) during the past two (2) years is about 2421 kCal/kWh against the proposed heat rate norms of 2400 kCal/kWh.

iii. Therefore, these stations would incur financial loss of about Rs 33 Cr. / year due to stringent heat rate norms.

iv. These stations have completed useful life of more than 25 years. It is estimated that the performance of stations would deteriorates with ageing of machines during the operating cycle of the plant, which in turn adversely affects the heat rate. Hence, norms should be fixed keeping in view the unit capability of achievement on a consistent basis.

v. **Hence, existing norms of 2430 kCal/kWh for 200 MW units may be retained.**

b) **500 MW Units**

i. There are seven (7) stations of about 8 GW capacity which are operating at a loading factor of more than 85%.

ii. Actual average heat rate of these Stations (@ loading factor of 85%) during the past two (2) years is about 2374 kCal/kWh against the proposed average heat rate norms of 2370 kCal/kWh. Actual average APC of these Stations (@ loading factor of 85%) during the past two (2) years is about 6.31% against the proposed average APC norms of 6.23%.

iii. The stations of about 5 GW capacity operating worse than the norm whereas the stations of about 3 GW capacity are operating better than the norms and are required to share the financial gain with beneficiaries on 50:50 basis.

iv. Accordingly, these stations would incur financial loss of about Rs 27 Cr/Yr.

v. It is estimated that the performance of stations would deteriorates with ageing of machines during the operating cycle of the plant, which in turn adversely affects the heat rate. Hence, norms should be fixed keeping in view the unit capability of achievement on a consistent basis.

vi. **Hence, existing norms of 2390 kCal/kWh for 500 MW units may be retained.**

c) **Combination of 200 MW & 500 MW Units**

i. Singrauli & Korba Stage-I&2 (Combination of 200 MW & 500 MW units) are old units which have completed useful life of 25 years.

ii. Actual average heat rate of two (2) Stations (Singrauli & Korba Stage-I&2) during the past two (2) years is about 2383 kCal/kWh against the proposed heat rate norms of 2385 kCal/kWh.

iii. However, actual average APC of these Stations during the past two (2) years is about 7.10% against the proposed average APC norms of 6.77%.

iv. Therefore, these stations would incur financial loss of about Rs 24 Cr. / year due to stringent APC norms.

v. These stations have completed useful life of more than 25 years. It is estimated that the performance of stations would deteriorates with ageing of machines during the operating cycle of the plant, which in turn adversely affects the operating parameters. Hence, norms should be fixed keeping in view the unit capability of achievement on a consistent basis.

d) **COD after 01.04.2009: (Total Capacity of around 11.7 GW):**

a) There are Nine (9) stations which are operating at a loading factor of more than 85%.

b) The stations of capacity of 6 GW are operating worse than the norms whereas the stations of capacity of 5.7 GW are operating better than the norms and are required to share the financial gain with beneficiaries on 50:50 basis.

c) As the sharing of operating heat rate margin is not considered while finalizing the norms, these stations would incur financial loss of about Rs 44 Cr/Yr.

d) **Hence, existing operating heat rate margin of 5% for units achieving COD on or after 01.04.2009 may be retained to offset the effect of present dispensation of sharing of gains.**

i) Similarly for APC, the NTPC stations of capacity of about 12.5 GW (operating above 85% loading) are performing worse than the norms whereas the stations of capacity of 13.3 GW (operating above 85% loading) are performing better than the norms and are required to share the financial gain with beneficiaries on 50:50 basis.

j) In totality, NTPC will incur loss to the tune of about Rs 128 Cr/year despite operating at more than 85% loading factor. Details of total loss suffer by NTPC on account of heat rate & APC despite operating above 85% loading factor is attached at **Annexure-1**.

k) The Hon'ble Commission has reduced the operational margin from 5% to 4% for Unit size ≥ 500MW. In this regard, the Explanatory Memorandum to the Draft Regulations at S.no. 18.6.13 has stated the Hon'ble Commission's view as under:

"With regard to existing operating margin allowed over and above the design heat rate for coal based generating stations which have achieved COD after 1.4.2009, CEA based on the technical analysis carried out has recommended a margin of 4% over and above the design heat rate as against the existing operating margin of 5% except for 200/210/250 MW Sets for which CEA has proposed to retain 5% margin. Based on CEA's recommendations, the Commission proposes to adopt the same."

l) However, it is submitted that the operating margin does not depend on unit size so it should be kept same for all units. Operating margin depends upon variations from the design conditions in various parameters, such as, in coal quality, changes in ambient conditions, variation in operating conditions, Load fluctuations, Ramping up/down, etc. These operating conditions are becoming more stringent day by day and more so in the future, so operating margin should increase rather than reduce. Further, due to mandatory cycling requirements there will be more start-up/shut down and load fluctuations expected in future. **Therefore, it is submitted that operating margin to be further increased from earlier allowed norms of 5%.**

In view of above, while adopting the principle of sharing of gains as stipulated in the Tariff Policy 2016 and taking into account the implication of sharing of operational gains with the beneficiaries, following is suggested.

A) Existing heat rate norms of 2430 kCal/kWh & 2390 kCal/kWh for 200 MW & 500 MW units achieving COD before 01.04.2009 may be retained.

B) Operating heat rate margin of 5% as per existing CERC Tariff Regulations 2019 for units achieving COD on or after 01.04.2009 may be retained.

C) Existing APC norms of 5.75% for 500 MW & above units (without IDCT) may be retained.

3) **Part-load compensation:**

a) **Incorporation of Part load compensation as recommended by CEA in Draft CERC Regulations:**

CEA vide letter dated 19.12.2023 has recommended the operating norms for thermal generating stations for the tariff period 2024-29 as under:

i. Heat Rate of Coal stations (COD before 01.04.2009) - 200 MW units - 2400 kcal / kwh & 500 MW units – 2375 kcal / kwh.

ii. Heat Rate of Coal stations (COD on or after 01.04.2009) – 500 MW and above units - 1.04 × Design unit Heat Rate.

iii. Degradation factor for Heat rate & APC for part-load operation.

iv. CEA has specifically stated the following for working out the heat rate & APC norms of thermal generating stations, which is extracted as below:

Quote

"………..

 # The normative heat rate values are arrived after applying the degradation factors given in table at F(1)(i) for coal/lignite based generating stations. In case degradation factors given in table at F(1)(i) are modified, the normative heat rate values need to be corrected accordingly and vice-versa.

…………………..

The Auxiliary energy consumption values are arrived after applying the degradation factors given in table at F(1)(ii) for coal/lignite based generating stations. In case degradation factors given in table at F(1)(ii) are modified, the Auxiliary energy consumption values need to be corrected accordingly and vice-versa."

Unquote

v. While operating norms as recommended by CEA have been adopted by Hon'ble Commission in draft CERC Tariff Regulations 2024, but the normative degradation factor (for Heat rate & APC) recommended by CEA for part-load operation have not been included. The impact of adopting any degradation factor other than that recommended by CEA along with the norms of heat rate and APC is illustrated with the help of a sample calculation.

vi. Let us assume that the actual heat rate of the station for a year is 2456 kCal/kWh at actual loading factor of 67%. The operating heat rate margin of (Say 4%) is arrived by applying the heat rate degradation factor of 5.1% specified by CEA at a loading factor between 65-70%.

Particulars	**CEA degradation factor**	**Lower degradation factor**
Actual Heat Rate (kCal/kWh)	2456	2456
Actual Loading Factor (L.F) (%)	67%	67%
Degradation factor for correction of Heat Rate (%)	**5.1%**	**4.5%**
Normative Heat Rate @ 85% L.F (kCal/kWh)	2456/ (1+5.10%) = **2337**	2456/ (1+4.5%) = **2350**
Design Unit Heat Rate (kCal/kWh)	2247	2247

Operating Margin over design Heat Rate (%)	(2337 – 2247) /2247 x 100 = **4.0%**	(2350 – 2247) /2247 x 100 = **4.6%**

- *On a similar line, heat rate & APC norms can also be worked out.*

Therefore, considering any lower degradation factor instead of the CEA recommended degradation factor results in lower heat rate margin, which is not intended. If lower degradation factor (Say 4.5%) is considered by Hon'ble Commission, the operating heat rate margin of (Say 4.6%) needs to be allowed to the generating station.

vii. **Since the degradation factors for heat-rate and APC applicable for part-load operation recommended by CEA for coal & gas-based stations are a part of the heat rate and APC norms recommended by CEA, it is required to include degradation factors recommended by CEA in the CERC Tariff Regulations 2024 with effect from implementation of Tariff Regulations 2024.**

b) **Part load compensation on normative basis:**

i. The current dispensation of part load compensation allowed is based on norms or actuals, whichever is lower. This results in overall loss to generating company on account of part load operations. This is because stations performing better than compensated norms is restricted to actuals while that of stations performing inferior to the compensated norms is restricted to the compensated norm.

ii. It is submitted that more than 22 GW of NTPC stations are operating below 85% loading during the period of FY 2021-23. Based on the current dispensation of part load compensation i.e., norms or actuals, whichever is lower, there would be a net loss to the generating company which is explained as follow:

a) Around 15.4 GW of stations operating below 85% loading would only be able to recover the losses fully on account of degradation. However, around 7.0 GW of the stations operating below 85% loading would not be able to recover the losses fully on account of degradation and would incur losses.

Particulars	**Capacity (GW)**	**Indicative Loss (Rs Cr/Yr.)**
Capacity of Stations where losses are fully recovered	15.4	0
Capacity of Stations where losses are not fully recovered	7.0	-311
Net Loss (-) (Rs Cr)	**22.4**	**-311**

Details as per Annexure-2

iii. Further, current dispensation of part load compensation is also not aligned with the Tariff Policy which stipulates that the operating parameters should be at "normative basis" only and not at lower of normative and actuals.

iv. **In view of the above, Part-load compensation on operating parameters (Heat rate and APC) may be provided on normative basis instead of existing dispensation of lower of normative and actuals.**

c) **CEA Recommendations dated 19th Dec 2023 - Requirement of further enhancement in part-load Degradation Factors:**

i. CEA has recommended the Heat rate deterioration for part load of 55% for Supercritical units as 6%. It may be noted that the deterioration is more than the specified values for 55% Load (varies from 6.1% to 9%). **In this regard CERC is requested to increase the specified values for part load deterioration in Heat Rate**.

ii. CEA has recommended the Heat rate deterioration for part load of 55% for Sub-critical units as 7.6%. It is submitted that as per design the deterioration at part loads is more than the specified values (For example at 55% Load HR deterioration varies from 7.71% to 8% for different 500 MW subcritical fleets of turbine). **In this regard CERC is requested to increase the specified values for part load deterioration in Heat Rate.**

iii. Further it is again emphasized that in view of upcoming part load operation as projected by CEA, utilities have no option but to specify part load heat rate guarantee also along with rated load heat rate guarantees. With such a combination of rated and part load guarantees the design points gets shifted away from 100% and optimized by various OEMs. This shifting varies from OEM to OEM. In view of this any isolated value at rated load itself may not be met as per proposed norms even after optimization. So, it is submitted to specify the heat rate deterioration at part load considering the optimization of plant at both 100% TMCR load and part load. So, proposed norms to be reviewed with this consideration and accordingly re-consult with all turbine OEMs before finalizing the turbine cycle heat rate limits both at 100% load and at part load.

d) **Provision for Heat Rate Degradation Factor for Units with Air Cooled Condensers:** Presently, CEA has not provided degradation factor for heat rate in units with air cooled condensers. Hon'ble Commission is also requested to please specify the heat rate deterioration for part load for Air Cooled Condenser based units also.

e) **Start-up Oil Consumption for Super Critical Units during Cold start-ups:**

i. CERC IEGC Regulations (4th amendment) provides oil consumption norms after seven (7) start up per unit and attributable to reserve shut down.

ii. The norms of oil consumption for start-up were fixed by Hon'ble Commission in April 2016 during which only few super critical units were in operation & representative data was not available.

iii. The oil consumption norms of 110 KL per start allowed to Super Critical units during cold start-up condition is not adequate.

iv. The time taken for cold start up from Pre-boiler light up activities to grid synchronization takes around 36 hours in super critical units, which is much more as compared to subcritical units (around 13 hrs). Due to the high start-up time including boiler light up with oil support and hot clean-up process prescribed for Super Critical units, the typical oil consumption for cold start up in Super Critical units is about 350 KL/start as against the oil consumption of 110 KL/start allowed in the CERC IEGC Regulations (4th amendment).

v. The details of start-up oil consumption in super critical units are tabulated as under:

Stations	Particulars of Cold Start-ups	Unit	18-19	19-20	20-21	21-22	22-23
SOLAPUR STPS (2 x 660 MW)	Number of Cold starts- ups	Nos.	3	13	13	17	15
	Oil consumption for Cold starts- ups	Kl	2243	4141	3605	3685	3885
	Oil Consumption per Cold start ups	**kl/Start Up**	**748**	**319**	**277**	**217**	**259**
KUDGI STPS (3 x 800 MW)	Number of Cold starts- ups	Nos.	14	23	12	14	16
	Oil consumption for Cold starts- ups	Kl	4479	8213	3511	4889	4565
	Oil Consumption per Cold start ups	**kl/Start Up**	**320**	**357**	**293**	**349**	**285**
LARA STPS (2 x 800 MW)	Number of Cold starts- ups	Nos.			19	7	10
	Oil consumption for Cold starts- ups	Kl			6010	1759	2616
	Oil Consumption per Cold start ups	**kl/Start Up**			**316**	**251**	**262**
TANDA ST-II (2 x 660 MW)	Number of Cold starts- ups	Nos.		1	1	7	6
	Oil Consumption per Cold start ups	Kl		383	515	1764	2532
	Oil Consumption per Cold start ups	**kl/Start Up**		**383**	**515**	**252**	**422**

As evident from above, the oil consumption for cold start up in Super Critical units is about 350 KL/start. **Therefore, oil consumption for cold start-up of supercritical units may be enhanced to 350 KL against 110 KL per start up.**

In view of above, following may be considered:

A) Since the degradation factors for heat-rate and APC applicable for part-load operation recommended by CEA for coal & gas-based stations are a part of the heat rate and APC norms recommended by CEA, it is required to include degradation factors recommended by CEA in the CERC Tariff Regulations 2024 with effect from implementation of Tariff Regulations 2024.

B) **Part load compensation on operating parameters (Heat rate and APC) may be provided on normative basis instead of existing dispensation of lower of normative and actuals.**

C) **Part load degradation factor for heat rate may be suitably enhanced as submitted in 3(c) above.**

D) Heat rate deterioration for part load for Air Cooled Condenser based units be specified separately.

E) Oil consumption for cold start-up of supercritical units may be enhanced to 350 KL against 110 KL per start-up.

4) **Regulation 62(6) - Generation Incentive:**

a) Clause 62 (6) of the draft regulations proposes as under:

> *"In addition to the capacity charge, an incentive shall be payable to a generating station or unit thereof @ 75 paisa per kwh for ex-bus scheduled energy during Peak Hours and @ 50 paisa per kwh for ex-bus energy scheduled during Off-peak hours corresponding to scheduled generation in excess of ex-bus energy corresponding to Normative Annual Plant Load Factor (NAPLF) achieved on cumulative basis, as specified in Clause (B) of Regulation 70 of these regulations."*

b) Hon'ble Commission has been providing generation incentive to promote higher generation from cheaper stations. The rate of generation incentive applicable in various tariff periods is tabulated as under:

S. No.	Tariff Period	Rate of Incentive (Paisa per kwh)
1	2001-04	1) 50% of the fixed cost/kwh at normative PLF for generation between normative PLF and up to 90% PLF subject to ceiling of 21.5 paisa/kwh. 2) For generation beyond 90% PLF, incentive shall be @ 50% of the incentive payable under (1) above.
2	2004-09	25.0 paise per kwh.
3	2009-14	1) Stations in commercial operation for < 10 years as on 1st April of year: 50% of fixed cost. 2) Stations in commercial operation for ≥ 10 years as on 1st April of year: 100% of fixed cost.
4	2014-19	50 paisa per kwh
5	2019-24	Peak hours: 65 paisa per kwh Off-peak hours: 50 paisa per kwh

c) It may be seen that the rate of incentive was doubled from 25 paisa per kwh in 2004-09 period to 50 paisa per kwh in 2014-19 period. However, the incentive rate of 50 paisa per kwh has been stagnant since last 10 years. Only change that was made during 2019-24 period was the differential incentive rate (of 65 paisa per kwh for peak and 50 paisa per kwh for off-peak hours) become effective from 01.04.2020.

d) It is submitted that generation from low cost ECR stations needs to be maximized so that Discoms' power procurement costs can be reduced. This will also reduce the burden on the railway network and ease congestion in transportation logistics.

e) Capacity Charges are not payable on generation which is eligible for incentive. Moreover, incentive is payable only if the Discoms actually schedule such power.

f) It may be pertinent to point out that Discoms schedule this power as per their needs thus avoiding costly purchases. So, generators need to be incentivized to make more cheaper power available through suitable incentive.

g) In this regard, the market price of power also is an appropriate price signal. The average RTC price of electricity in Power Exchanges in **2022-23 was Rs. 6.25 / kwh**. The price of electricity in peak hours is still higher and often touches the ceiling price of Rs. 10 per kwh

h) It is required that the incentive rate needs to be doubled considering inflation and market price of electricity as was done in the previous tariff periods.

It is therefore suggested that incentive rate may be increased to Rs. 1.00 per kwh for off-peak hours & Rs. 1.30 per kwh for peak hours to incentivize higher generation from cheaper ECR stations and thus lower the power procurement cost of Discoms.

5) **Regulation 70(A) & 70(B): Consideration of Stations that have completed 25 years from COD against 30 years:**

a) The Draft Regulation has proposed as under:

Normative Annual Plant Availability Factor (NAPAF)

(a) 85% for all thermal generating stations, except those covered under clauses (c), (c), (d) & (d)

(b) 80% for coal and lignite based generating stations completing 30 years from COD as on 31.03.2024.

………

Normative Annual Plant Load Factor (NAPLF) for Incentive:

(a) 85% for all thermal generating stations, except for those covered under clause (b) below

(b) 80% for coal and lignite based generating stations completing 30 years from COD as on 31.03.2024.

……….

b) It is submitted that the Approach Paper had proposed the above dispensation for old stations completing 25 years on or after 01.04.2024 as a special measure to incentivize old stations.

c) As per existing regulatory framework, useful Life of thermal stations is 25 years from CoD.

d) Further, Tariff Regulations considers useful life of 25 years for various tariff elements (such as, Depreciation of assets, debt servicing, Provision of R&M and Special Allowance, etc.).

e) These old stations are mostly pithead stations supplying cheaper power to beneficiaries at nominal tariff.

f) The Discoms shall be benefitted by continued operation of these stations.

Therefore, it is requested that NAPAF and NAPLF of 80% may be made applicable for stations completing 25 years from COD on or after 01.04.2024 (instead of 30 years proposed by Draft Regulations).

6) **Regulation 44(3) - Rate of Return on Equity for Integrated mines**: The Draft Regulations has proposed return on equity for integrated mines at base rate of 14%. It is suggested that following factors may be considered for fixing rate of return on equity for integrated mines as under:

a) It is submitted that the return on equity needs to be commensurate with the risks. Mining sector face significant developmental & operational risks like huge area of land acquisition, environment clearances, Rehabilitation and Resettlement of huge number of Project affected Persons, geological surprises, direct exposure to extreme weather conditions like torrential rains, flooding etc.

b) Land acquisition in mining is a continuous process. Land is acquired as and when mining progresses and mining operations carry risk of land acquisition during the entire mine life due to socio-political factors.

c) In case of integrated mine, the business risks in thermal generation business also highly affect the mining activities and recovery of cost may be affected if the coal requirement of the linked plant is affected.

d) It is submitted that in cases of MDO operated mines, there is lesser investment in the plant & machinery and the level of RoE available with the company is not sufficient to absorb high risks inherent in the mining sector. It will adversely affect further investment in the sector.

e) It is worth submitting that the major capital investment in case of Coal Mining is in the form of land (lease hold as well as free hold). In case of free hold land no depreciation is flowing as a part of Annual Extraction Cost, whereas in case of lease hold land amortization is done over the useful life of mine or lease period whichever is less. Further, in case of lease hold land amortization is spread over the period of (around 25-30 years). The time recovery of depreciation does not match with the loan repayment period for Bank and Financial Institutions. Consequently, debt repayment must be met out of the return on equity, which results in lower IRR on such investment in coal mining. In consideration of the same, the mismatch in cash flow needs to be addressed by giving higher RoE.

f) It is also submitted that the working group in its report on 'Regulatory Framework for Input Price of Coal or Lignite from Integrated Mine' has observed as under:

   *5.3.1…….. **<u>The captive mine is also a part of the project of generating station and aimed to serve the electricity produced from that generating station.</u>** The coal extracted from the integrated mine is not allowed to sale for commercial purpose. **<u>The generating company allocate fund to captive mine in the same manner as followed for generating assets</u>**. The approach for consideration of equity for the rate of return as followed in case of generating station may also be adopted for the captive mine.*

   ……..

5.3.5 ***Since the funding mix for mine is proposed to be similar to that of Power generation, the rate of return admissible for power…***

g) It is further submitted that prior to the Second Amendment to the CERC Tariff Regulations, 2019, Hon'ble Commission considered RoE of 15.5% for integrated mines as per the Ministry of Coal guidelines dated 02.01.2015 for 2014-19 period. With the reduced RoE of 14% as proposed under the Draft Regulations, the returns of the coal mining company shall be affected adversely. As an example, with 14% RoE, RoE is only around Rs 47 Cr (6.7 %) of the annual turnover (Rs 700 Cr) in the case of NTPC's Dulanga integrated coal mine.

h) **It is therefore submitted that the Hon'ble Commission may be pleased to enhance the RoE from the existing 14% to 15.5%, at par with the thermal generating station.**

7) **Regulation 30(3)- Rate of Return on Equity Additional Capitalization on account of Emission Control System (ECS) and additional capitalization beyond original scope of work, change in law and force majeure:**

a) The Draft regulations has proposed that Return on Equity (RoE) in respect of additional capitalization beyond the original scope, including additional capitalization on account of the emission control system, Change in Law, and Force Majeure shall be computed at the base rate of one-year marginal cost of lending rate (MCLR) of the State Bank of India plus 350 basis points as on 1st April of the year, subject to a ceiling of 14%.

b) The RoE prescribed in the Tariff Regulations is not only a critical factor for profitability of the generating company but also for the long-term sustainability of the generation business. The investment in above said capital expenditures carries the same cost of equity. Differentiating the return on equity in such investments results in lower return to the generating company.

c) The returns allowed on equity in a cost-plus timeline is also germane to the interest rate prevailing during that period. It is observed that the interest rates have been on a rising trend post the pandemic. The 1-year SBI-MCLR which is a benchmark for bank's cost of funds has increased from 7.0% (10.06.2020) to 8.5% (08.05.2023) which is an increase of ~21%. In an increasing interest rate regime, the return on equity requirement of the investors also tends to increase to offset the associated risk.

d) Significant investments of around Rs. 30,000 crores are being incurred on ECS to make these plants environmentally compliant. Further, ECS is an integral part of power generation in a coal-based station and its cost recovery linked with that of the main plant. Therefore, any differential return on equity on such investments which are integral part of the generating station and required for core generation activity is not justified. On similar lines, additional capitalization beyond original scope is also incurred to sustain generation and performance of the main plant.

It is therefore suggested that return on equity on Additional Capitalization on account of Emission Control System (ECS) and additional capitalization beyond original scope of work, change in law and force majeure may be at par with that of thermal generating station, i.e., 15.5%.

8) **Regulation 60 - Gross Calorific Value of Coal:**

a) **Draft Regulations provide as under:**

(1) The gross calorific value for computation of energy charges as per Regulation 64 of these regulations shall be done in accordance with 'GCV as Received';

*Provided that the generating station shall have third party sampling done at the billing end and the receiving end through an **agency certified by the Ministry of Coal** and ensure recovery of compensation as per Fuel Supply Agreement(s) and pass on the benefits of the same to the beneficiaries of the generating station*

*Provided further that in the absence of any third-party sampling through an **agency certified by the Ministry of Coal**, the GCV shall be considered on the basis of 'as billed' by the Supplier less:*

i. Actual loss in calorific value of coal between as billed by the supplier and as received at the generating station, subject to maximum loss in calorific value of 300 kCal/kg for Pithead based generating stations or generating stations with Integrated mine and 600 kCal/kg for Non-Pit Head based generating stations.

No loss in calorific value between 'GCV as billed' and 'GCV as received' is admissible for generating stations procuring coal from Integrated mines or through the import of coal.

b) **Certification of Agency for Third party Sampling:**

i. The Draft regulations provide that gross calorific value for computation of energy charges as per Regulation 64 shall be done in accordance with "GCV as received". Further, it is proposed that the generating station shall have third party sampling done at the billing end and the receiving end through an agency certified by the Ministry of Coal and ensure recovery of compensation as per Fuel Supply Agreement(s) and pass on the benefits of the same to the beneficiaries of the generating station.

ii. It is submitted that the Ministry of Power is empanelling Third Party Sampling agencies for sampling, sample preparation, testing and analysis of coal at loading end for Power Sector through the Power Finance Corporation (PFC). Accordingly, in the above regulation, the wording "agency certified by the Ministry of Coal" may be replaced by "agency certified by the Ministry of Power, GoI".

iii. **It is suggested that the certification of third party may be by the Ministry of Power, GoI.**

c) **Maximum loss between GCV as billed by Supplier & GCV as received at generating station to be on same measurement basis (i.e., both on Equilibrated Moisture (EM) basis):**

i. The Draft regulations have proposed that in the absence of any third party sampling through an agency certified by the Ministry of Coal, the GCV shall be considered on the basis of 'as billed' by the

Supplier less Actual loss in calorific value of coal between as billed by the supplier and as received at the generating station, subject to maximum loss in calorific value of 300 kCal/kg for Pit-head based generating stations or generating stations with Integrated mine and 600 kCal/kg for Non-Pit Head based generating stations.

ii. **It may be clarified in the Regulations that the loss in calorific value as stipulated between GCV as billed & GCV of coal received at station, shall be calculated on Equilibrated Moisture (EM) basis. However, for the purpose of billing to the beneficiaries / discoms, GCV received at station shall be further adjusted with the moisture correction.**

d) **Loss in Calorific Value of Coal in case of Integrated Mines:**

i. While clause 60 (1) (i) of the draft Regulations provides maximum loss in calorific value of 300 kcal/kg for generating stations with integrated mine, the proviso to the above regulation has proposed that no loss in calorific value between ‘GCV as billed’ and ‘GCV as received' is admissible for generating stations procuring coal from Integrated mines or through the import of coal. **Therefore, Hon’ble Commission may like to kindly clarify the contradiction in clauses in Regulation 60 (1) (i).**

Further, in respect of the generating stations procuring coal from integrated mines, following is submitted.

ii. It is submitted that some of the NTPC generating stations linked with the integrated mines are pithead generating stations (such as Darlipalli, Lara, etc.) while others are non-pithead generating stations (Tanda-II, Barh-II, Barauni-II, etc). Moreover, few captive mines, such as Pakri Barwadih is a basket mine, envisaged to supply to many NTPC stations.

iii. Further, in case of Integrated mines allotted to NTPC, the transportation distance between the mine and generating station is as high as 2000 plus kilometres (e.g., around 500 kms in case of

Kerendari coal mine to Tanda-II Station, 2020 km in case of Pakri Barwadih Mine to Kudgi Station Distance).

iv. It is submitted that there is a direct corelation between the loss in calorific value and the transportation distance of coal from the integrated mine to the generating station.

Though the generating company is having control on the operations of the integrated mines, there is requirement of providing for certain technical loss on account of transportation of coal from integrated mine to non-pithead stations located at varying distances.

It is therefore, suggested that loss in calorific value of 300 kcal / kg (in addition to the moisture correction) may be provided between Mine end GCV, and station end GCV, as under:

Sr. No.	Distance between Mine and Generating Station	Difference between Mine End GCV (EM Basis) & Station End GCV (EM Basis)
	(km)	(kCal/Kg)
(i)	Distance (0 - 100 Km)	0
(ii)	Distance (101 - 500 Km)	75
(iii)	Distance (501 - 1000 Km)	150
(iv)	Distance (1001 - 1500 Km)	225
(v)	Distance (>1501 Km)	300

v. Further, it is pertinent to mention that in the Draft Regulations, the Hon'ble Commission has proposed the dispensation of maximum loss of 300 kcal/kg for pithead stations and 600 kCal/kg for non-Pithead generating stations considering the effect of transportation distance involved between the coal mine and the generating station on the loss in calorific value of coal.

vi. **In view of the above, a loss of 300 kCal/kg between 'GCV as Billed' and 'GCV as Received', in addition to the moisture**

correction, may be provided for integrated mines supplying coal to end-use generating station.

vii. **Accordingly, the last clause of the above regulation may be revised as under: "No loss in calorific value between 'GCV as billed' and 'GCV as received' is admissible for generating stations procuring coal through the import of coal."**

9) **Regulation 36(1) - O&M Expenses of Coal Stations:**

a) Following additional O&M expenses norm (for 2024-25) may be added over O&M expenses norm arrived based on actual O&M expenses data (of FY 18-19 to FY 22-23).

  i. Consumption of capital spares < Rs 20 Lakhs: Rs 1 Lakh/MW/Yr.

  ii. Additional capitalization of minor assets < Rs 20 Lakhs: Rs 0.72 Lakh/MW/Yr.

  iii. Disallowed capital expenditure (as it was not falling in any add cap provisions) met out of O&M expenses: Rs 1.4 Lakh/MW/Yr.

b) **Increase in O&M expenses due to increased flexibility from 100% to 55%**: **Rs 2 Lakh/MW/Yr.**

i) Units are generally designed to operate on base load condition and all the components are accordingly designed for certain creep life and certain fatigue life in terms of number of starts/ cyclic operation.

ii) As the operation regime changes and moves away from base load operation to cycling load operation due to integration of renewable station into the grid, the component life is consumed at a faster rate.

iii) CEA vide notification dated 25.01.2023 has directed all thermal generating stations to achieve uniform technical minimum of 55% within one year and released plan for achieving uniform technical minimum of 40% by 2030.

iv) Frequent flexible operation will cause increase in failure rate and more frequent replacement of components such as Superheater & Reheater tubes, Water wall tubes attachment, turbine rotor, turbine valves & casing castings, Air Preheater Cold end, Condenser Tubes, Degeneration of insulation of Generator & Transformers etc.

v) Due to failure of such components on many occasions, the thermal generating station ends up in making losses due to under recovery in Annual Fixed Charges.

vi) CEA in its report dated 21.02.2023 had recognized that flexible operation leads to a higher rate of deterioration of components.

vii) Staff paper of commission in its addendum dated 03.07.2023 to Approach paper for 24-29 Tariff Regulations had also recognised the aspect of flexible operation and observed that impact on life of components increases with increase in flexible operations.

viii) The addendum to the Approach Paper has suggested increased annual O&M expenses as 9%, 14% & 20% at different loading of 50%, 45% and 40% respectively.

ix) It is submitted that the additional O&M expenses norms of about **Rs 2 Lakh/MW/Yr.** (from 100% to 55%) may be provided over O&M expenses norm for addressing these aspects.

b) Additional O&M cost for future addition of Manpower: About Rs 0.5 Lakh/MW/Yr.

i) It is submitted that NTPC has been recruiting manpower on annual basis based on its O&M needs for present capacity and future capacity additions.

ii) In past 2-3 years, due to COVID-19 epidemic, recruitment of manpower was affected, which led to shortfall in manpower as per NTPC requirements.

iii) As the things have been normalised, NTPC is recruiting additional manpower as per requirement for sustainable operation of stations.

iv) This would lead to increase in employee expenses beyond the 5-year average value of past control period (2018-19 to 2022-23).

v) It is submitted that the additional O&M expenses of **Rs 0.5 Lakh/MW/Yr** may be provided for recruitment of additional manpower for sustainable operation of stations.

2) In view of the above, additional O&M expenses (for 2024-25) of Rs. 5.6 Lakh/MW/Yr over O&M expenses norm arrived based on actual O&M expenses data may be provided as under:

Sno	**Item**	**Additional O&M expenses for 2024-25 (Rs. Lakhs/MW/Yr)**
1	Consumption of capital spares < 20 Lakhs	1.0
2	Additional capitalization of minor assets < 20 Lakhs	0.7
3	Disallowed capital expenditure met out of O&M expenses	1.4
4	Increase in O&M expenses due to increased flexibility	2.0
5	Additional O&M cost for future addition of Manpower	0.5
6	**Additional O&M expenses norms (for 2024-25) over O&M expenses norm arrived based on actual O&M expenses.**	**5.62**

10) **Regulation 36(1) - O&M Expenses of Gas Stations:**

a) Draft Regulations has reduced the Normative O&M expenses for gas stations to Rs. 17.22 Lakhs/MW in FY 24-25 from 20.19 Lakhs/MW in FY 2023-24.

b) **Change in Operational Pattern -** Gas stations are playing crucial role in meeting the increased peak demand of the country. They are increasingly deployed during peak-hours on daily basis which has resulted in daily start-stop operations. As a result, total number of start-ups in NTPC gas stations have increased multi-folds from 881 in 2019-20 to 2063 in 2023-24 (up to Q3). Accordingly, number of start-ups have increased from 0.4 per station per day in 2019-20 to 1.27 per station per day in 2023-24.

c) **Equivalent Operating Hours -** As per the specifications / criteria of OEM, the Equivalent operating hours (EOH) of the gas turbine increases by an average of 20 hours during each start-up. Since, Overhaul frequency of gas turbines is determined based on EOH, earlier completion of the allotted EOH leads to shorter overhaul intervals, thereby increasing maintenance costs. The average EOH consumption per unit per year has increased by 2.5 times.

d) Presently part-load compensation provides compensation for degradation in heat rate and APC only from 85% to 55% loading. However, there is no compensation mechanism in place to take care of additional O&M expenses due to frequent start-ups of gas stations.

e) Increase in O&M Expenses due to frequent start-ups:

   i. Increased wear & tear leading to increase in O&M expenses.

   ii. Overhaul frequency of gas turbines is determined based on the Equivalent Operating Hours (EOH), which increases by an average of 20 hours during each start-up.

   iii. Hence, inspection is required to be done in an interval of 13.5 months instead of 34.5 months, resulting in increase of the maintenance costs.

   iv. **Hence, it is submitted that additional O&M expenses norm of Rs 2 lakhs per MW may be provided due to increased wear and tear due to frequent start-stop operations.**

f) **Compensation of Start-up Costs:**

   i. **Start-up costs in Open Cycle Mode:**

      a) Fuel cost for rolling of machine to 3000 rpm and synchronization.

b) Heat rate degradation from synchronization to technical minimum of 55%.

c) APC for Gas Turbine (GT) start-up & during / after shut-down.

d) The start-up cost on account of (a), (b) and (c) above works out to **Rs. 1.55 lakh / MW / year.**

ii. **Start-up costs in Combined Cycle Mode:** Normally, start-up costs get absorbed if gas stations remain in operation for longer periods. Presently, with frequent start-ups, start-up costs have become significant and require to be compensated separately.

a) GTs are run in low load till synchronization of Steam turbine (ST) resulting in extra costs in addition to that incurred in open cycle (due to incremental Heat rate deterioration of GTs at part-load).

b) APC of ST auxiliaries during start-up & during / after shut-down.

c) Additional O&M expenses on account of (a) and (b) above works out to **Rs.1.69 Lakhs per MW per year.**

- **The total Additional O&M expenses on account of (i) and (ii) above works out to Rs. 3.24 Lakhs per MW per year.**
- **Alternatively, instead of providing start-up costs as additional O&M expenses, start-up costs may be compensated on a per start-up basis as under:**

a) **Start-up cost in Open Cycle mode: Rs. 2.21 lakhs per start-up.**

b) **Start-up cost in Combined Cycle mode: Rs. 30 lakhs per start-up.**

g) Other Additional Components:

i. Consumption of capital spares < 20 Lakhs: Rs 1 Lakh/MW/Year.

ii. Additional capitalization of minor assets < 20 Lakhs: Rs 1.00 Lakh/MW/Year.

iii. Disallowed capital expenditure met out of O&M expenses: Rs 1.35 Lakh/MW/Year.

h) In view of the above, additional O&M expenses (for 2024-25) of Rs. 8.59 lakhs per MW over O&M expenses norm arrived based on actual O&M expenses data may be provided as under:

S. No.	Item	Additional O&M expenses for 2024-25 (Rs. Lakhs / MW)
1	Increased wear & tear due to frequent start-ups.	2.00
2	Compensation for start-up expenses	3.24
3	Consumption of capital spares < 20 Lakhs	1.00
4	Additional capitalization of minor assets < 20 Lakhs	1.00
5	Disallowed capital expenditure met out of O&M expenses	1.35
6	Additional O&M expenses norms (for 2024-25) over O&M expenses norm arrived based on actual O&M expenses.	8.59

11) **Provision for Monthly Billing of Ash Transportation Expenses:**

a) Considering the variable and irregular nature of expenses on ash transportation across the coal-based stations, Hon'ble Commission, while fixing the draft norms of O&M expense for the 2024-29 tariff period, did not include the expenditure incurred on account of transportation of ash.

b) In this regard, the Hon'ble Commission has opined in the explanatory memorandum has under:

"Expense on account of ash transportation are allowed by the Commission on case-to case basis after due prudence, as transportation of ash is not a constant and predictable operational activity and may differ significantly by factors such as distance between the plant and the beneficiaries and the diverse nature of beneficiaries, such as Cement Industries, Traders, Brick Manufactures, among others. Further, the costs associated with handling and transporting ash are treated separately. Therefore, due to the variable and irregular nature of ash disposal activities, such expenses have not been considered for computing the O&M expense Norms."

c) MOEF&CC notification dated 31.12.2021, which is statutory in nature, mandates all generating stations for 100% utilization of ash.

d) It may be pertinent to mention here that the Hon'ble Commission vide its order dated 28.10.2022 in Petition No 205/MP/2021 had recognized the MOEF&CC Notification dated 31.12.2021 as a 'change in law" event and allowed the recovery of the expenditure incurred on a monthly basis towards the utilisation of ash, subject to prudence check at the time of truing-up of tariff.

e) The MOEF&CC Notification dated 31.12.2021 stipulates a continuing obligation on all generating stations to comply with the provisions of 100% ash utilization during 2024-29 period also.

f) The ash transportation expenditure is recurring in nature. The deferment of recovery of the said expenditure from the beneficiaries would lead to accumulation of these costs and therefore, attract carrying cost. This is neither in the interest of the Discoms nor the generating station. To avoid implication of carrying cost, the recovery of the said expenditure from the beneficiaries may be allowed on a monthly basis on similar lines as in the tariff period 2019-24.

g) Hon'ble Commission is already allowing separate recovery of water charge expenses, security expenses & expenses on capital spare consumption.

h) It is suggested that the mechanism of monthly billing of expenditure incurred on account of ash transportation as allowed vide order dated 28.10.2022 in Petition No 205/MP/2021 may be provided in in Tariff Regulations 2024.

i) **In view of above, following may be considered:**

   i. **Suitable provision may be provided in the CERC Tariff Regulations 2024 for reimbursement of the Ash Transportation expenses on actual basis.**

   ii. **The recovery of the said expenditure may be allowed on a monthly basis as per auditor certificates, with a provision of truing-up at the end of tariff period.**

   iii. **Accordingly, the following provision may be appended to Regulation 36 (1) (6) of CERC Tariff Regulations 2024**

"(6a) Expenses incurred by the generating company on account of ash transportation expenditure shall be allowed to be recovered from the beneficiaries on a monthly basis based on the auditor certificate, which shall be subject to truing up at the end of the tariff period. The details regarding the same shall be furnished along with the truing up of tariff for the prudence check."

12) **Regulation 39(2) – Revision of Run-of-Mine (ROM) Cost Formula by including Actual Production:**

a) Draft Regulations provides as under:

39(2): Run of Mine Cost of coal in case of integrated mine allocated through allotment route under Coal Mines (Special Provisions) Act, 2015 shall be worked out as under:

ROM Cost = [(Annual Extraction Cost / (ATQ or Actual production whichever is higher) + Mining Charge] + (Fixed Reserve Price).
Where,
(i) Annual Extraction Cost is the cost of extraction of coal as computed in accordance with Regulation 43 of these regulations;

(ii) Mining Charge is the charge per tonne of coal paid by the generating company to the Mine Developer and Operator engaged by the generating company for mining, wherever applicable; and
(iii) Fixed Reserve Price is the fixed reserve price per tonne along with subsequent escalation, if any, as provided in the Coal Mine Development and Production Agreement.

i. *ROM Cost = [(Annual Extraction Cost / ATQ or Actual production, whichever is higher) + Mining Charge] + (Fixed Reserve Price)*

ii. *Annual Target Quantity (ATQ) has been revised to 85% (from 100%) of quantity specified in Mining Plan.*

iii. *Capital cost is to be recovered over the mine life in the form of Annual Extraction Cost (AEC).*

b) Hon'ble Commission vide Explanatory Memorandum to the subject Draft Regulations has stated that "in case the quantity extracted is more than the ATQ but less than the quantity specified in the mine plan there shall be no incentives that the generating company shall be entitled to and in such cases for computation of ROM price the higher of the ATQ and actual quantity extracted shall be considered." However, in case actual quantity extracted is more than the mine plan, recovery of proportionate Annual Extraction Cost has not been dealt in the Draft Regulations.

c) It is worth submitting that the captive mines are playing a significant role in ensuring fuel security for meeting the rapidly growing power demand in the country. The production from captive mines also helps in reducing the requirement of the costly imported coal.

d) It is submitted that in many cases the production beyond the Mine Plan quantity (up to peak rated capacity) is carried out to ensure the availability of coal for power generation. Such increased domestic coal extraction lowers the cost of power to Discoms by reducing the dependence on imported coal.

e) It is submitted that the Capital cost is serviced over life of mine through Annual Extraction Cost (AEC) comprising of depreciation, Interest on loan, RoE, Interest on WC, O&M expenses etc. Considering that the coal reserves are fixed in the mine, without pro-rata AEC recovery, any additional production in a year above the quantity specified in the Mine Plan shall result in under recovery of AEC over the life of the mine.

f) **Allowing the recovery of proportionate fixed charges on pro-rata basis for production beyond the quantity specified in the mine plan shall act as a stimulus in enhancing the fuel security and prevent the under recovery of fixed charges over the life of the mine.**

In view of the same, the proposed formula of ROM Cost may be revised as under:

ROM Cost = [(Annual Extraction Cost / Coal Quantity) + Mining Charge] + (Fixed Reserve Price)

Where Coal Quantity shall be:

(i) ATQ or Actual production, whichever is higher, when the coal quantity extracted is less than or equal to the coal quantity specified in the mine plan.

(ii) Quantity as per Mine Plan, when the coal quantity extracted is more than the coal quantity specified in the mine plan.

13) **Regulation-52(2): Adjustment on account of shortfall in GCV (GCV Adjustment):**

a) Draft Regulations provides as under:

"(1) In case the weighted average GCV of coal extracted from the integrated mine(s) in a year is higher than the declared GCV of coal for such mine(s), no GCV adjustment shall be allowed.

……………………..

(2) In case the weighted average GCV of coal extracted from the integrated mine(s) in a year is lower than the declared GCV of coal of such mine(s), the GCV adjustment in that year shall be worked out as under:

…………………

(b) Where the integrated mine(s) are allocated through an allotment route under the Coal Mines (Special Provisions) Act, 2015:

GCV Adjustment = [(Annual Extraction Cost/ATQ) + (Mining Charge)] X [(Declared GCV of coal – Weighted Average GCV of coal extracted in the year)/(Declared GCV of coal)]

Where,

Annual Extraction Cost is the cost of extraction of coal as computed in accordance with Regulation 43 of these regulations;

Mining Charge is the charge per tonne of coal paid by the generating company to the Mine Developer and Operator engaged by the generating company for mining, wherever applicable; and

Declared GCV of coal shall be the average GCV as per the Mining Plan or as approved by the Coal Controller."

b) It is submitted that quantity and quality of geological coal reserves of the entire coal block are estimated based on the geological studies carried out during preparation of Geological Report of a mine. Based on Geological report, total extractable coal reserves and weighted average coal quality for the entire mine is estimated in Mining Plan. However, actual coal quality during operational phase varies from year to year depending upon the coal seams exposed. Accordingly, during the operational phase of the mine, supply of coal is based on the quality of the coal declared by the Coal Controller.

c) It is pertinent to submit that the quality of coal declared by Coal Controller is based on the random sampling carried out in coal seams/sections to be mined in the next financial year. Due to the heterogeneous nature of the coal, Coal Controller declares such quality in terms of grades from G1 to G17, each having a band of 300 kCal/kg. The grade of the coal declared by Coal Controller is also used for making payment of Royalty and other statutory payments. It is worth mentioning that Coal India (CIL) is also pricing the non-coking coals as per the said grades having different GCV ranges. Therefore, GCV variations up to 300 kCal/kg is an accepted criterion.

d) It is further submitted that due to the heterogeneous nature of coal and different seams mined in a year, it is possible that the actual quality of the coal may not be same as that of the quality declared by the Coal Controller, and it is expected that there may be variations of up to 300 kCal/kg.

e) **In view of the above, it is submitted that the shortfall in actual quality beyond 300 kCal/kg from the mid-value of the declared grade may be considered by Hon'ble Commission for quality (GCV) adjustment.**

f) It is further submitted that during certain years actual quality of coal may be better than the declared coal. If suitable adjustments are not allowed, then the generating company may not be in a position to make up the losses incurred on account of adjustments made for shortfall in GCV.

g) It is also worth mentioning that the quality adjustment provision in the Cost-Plus mines of CIL is applicable for both negative as well as the positive variation in the coal quality.

h) **GCV adjustments in case the actual GCV is more than mid-value of the declared grade by 300 kCal/kg.**

i) **Modification in GCV Adjustment Formula: It is respectfully submitted that in consideration of the above-mentioned submissions and also taking into consideration the change in definition of ATQ, the GCV Adjustment formula under Regulation 52(2)(b) may be revised as under:**

Regulation 52(2)(b): *Where the integrated mine(s) are allocated through an allotment route under the Coal Mines (Special Provisions) Act, 2015, GCV Adjustment shall be allowed in case the actual weighted average GCV of coal extracted in the year is beyond ± 300 kCal/kg from the mid-value of the grade declared by the Coal Controller:*

*GCV Adjustment = [(Annual Extraction Cost/**Coal Quantity**) + (Mining Charge)] X [(Declared GCV of coal – Weighted Average GCV of coal extracted in the year) / (Declared GCV of coal)]*

Where,

i) *Annual Extraction Cost is the cost of extraction of coal as computed in accordance with Regulation 43 of these regulations;*

ii) *Coal Quantity shall be:*

a) *ATQ or Actual production, whichever is higher, when the coal quantity extracted is less than or equal to the coal quantity specified in the mine plan.*

b) *Quantity as per Mine Plan, when the coal quantity extracted is more than the coal quantity specified in the mine plan.*

iii) *Mining Charge is the charge per tonne of coal paid by the generating company to the Mine Developer and Operator engaged by the generating company for mining, wherever applicable; and*

iv) *Declared GCV of coal shall be the average GCV as per the Mining Plan or* ***mid-value of the grade declared by the Coal Controller.***

14) **Regulation 51: Adjustment on account of Shortfall of Overburden Removal (OB Adjustment):**

Draft Regulations provides as under:

The generating company shall remove overburden as specified in the Mining Plan. In case of a shortfall of over burden removal during a year, the generating company shall be allowed to adjust such shortfall against excess of overburden removal, if any, during the subsequent three years.

In case of excess of overburden removal during a year, the generating company shall be allowed to carry forward such excess for adjustment against the shortfall, if any, during the subsequent three years.

Where the shortfall of overburden removal of any year is not made good by the generating company in accordance with Clause (2) of this Regulation, *the adjustment on account of the shortfall of overburden removal (OB Adjustment) for that year shall be worked out as under:*

OB Adjustment = [Factor of adjustment for shortfall of overburden removal during the year] x [Mining Charge during the year + Operation and Maintenance expenses during the year]

Where,

Factor of adjustment for the shortfall of overburden removal during the year shall be computed as under:

[(Actual quantity of coal or lignite extracted during the year x Annual Stripping Ratio as per Mining Plan) - (Actual quantity of overburden removed during the year/ Annual Stripping Ratio as per Mining Plan)]/ (Annual Target Quantity);

Annual Stripping ratio is the ratio of the volume of overburden to be removed for one unit of coal or lignite as specified in the Mining Plan.

Mining Charge is the charge per tonne of coal or lignite paid by the generating company to the Mine Developer and Operator engaged by the generating company for mining, wherever applicable.

Mining Charge and Operation and Maintenance expenses shall be in terms of Rupees per tonne corresponding to the Annual Target Quantity.

a) Regarding OB adjustment, it is submitted that OB adjustment may be considered at the end of mine life instead of 3 years as proposed. In this regard, following are submitted:

   i. It is submitted that based on the geological studies carried out, reserve of coal and overburden in mines have been estimated in advance. Therefore, the total overburden to be removed during lifetime of the mine is fixed. If lower quantity of overburden is removed in one-year, higher overburden shall be required to be removed in subsequent years.

   ii. It is submitted that in case of mines where MDO has been appointed, savings due to less overburden removal shall be reflected in Mining Fee / Charge and accordingly the MDO agreement provides for adjustment of mining fee in case stripping ratio or overburden removal is less than that provided in the Mining Plan. The formula provided in the MDO Agreement for payment of Mining Fees takes care of the adjustments due to change in the stripping ratio/ overburden removal vis-à-vis that envisaged in the mining plan. In case of lower requirement of overburden removal, less amount would be paid to MDO and benefit of the same would be passed in the Mining Charge onto the beneficiaries automatically.

iii. It is further submitted that Mining is done as per availability of land and seam of coal, which may vary from mine plan and may not be possible to adjust the same within next three years.

iv. Mining Plan is prepared based on the borehole data from the Geological report. Boreholes are spaced 400m (approximately). During mine operations, additional information regarding OB/Coal obtained through infilling / drilling in the year of operation. Mining sequence may vary due to the geological surprises obtained through infilling drilling, which lead to variation in coal/OB/Strip ratio for that year with respect to Mining Plan. Any such variation occurs at any year of mine operation during the life of mine. Hence, OB adjustment for shortfall may be considered at the end of the life of mine.

v. **In view of the above, it is respectfully submitted that OB adjustment for shortfall may be considered at the end of the life of mine instead of 3 years as proposed.**

b) Alternatively, it is submitted that if the Hon'ble Commission decides to retain overburden adjustment in the regulations, following is suggested:

A) **OB adjustment for shortfall may be considered at the end of 5 years instead of 3 years as proposed.**

B) **OB adjustment formula may be revised to exclude Operation and Maintenance Expenses.**

C) **Inadvertent Error in OB adjustment Formula may be rectified.**

<u>OB adjustment for shortfall may be considered at the end of 5 years instead of 3 years as proposed.</u>

i. It is suggested that the overburden adjustment as per the MDO Agreement may be excluded while determining mining charge during the year so as to avoid doubling of OB removal adjustment. (One based on the provisions of CERC Regulations and second as per the existing MDO Agreement's Mining Charge Adjustment provision).

ii. It is submitted that as per the Cost Accounting Standards on Overburden Removal Cost (CAS-23) issued by Cost Accounting Standards Board, the stripping ratio shall be reviewed periodically, at least every five years, to consider changes in geological factors such as actual behaviour of the soil and the ore body. The same practice of review of stripping ratio is followed in Coal India also. It is therefore suggested that in line with the provisions issued by Cost Accounting standards board and the practice being followed in coal mining sector, the adjustment of excess removal of overburden or short removal of overburden may be allowed to be adjusted for subsequent five years.

<u>OB adjustment formula may be revised to exclude Operation and Maintenance Expenses.</u>

1. It is further submitted that in case of MDO operated mines of NTPC, O&M expenses are fixed in nature and does not depend on overburden handled. Moreover, as per the draft Regulations, the O&M expenses shall be trued up based on the actual O&M expenses for the tariff period ending on 31.03.2029. Therefore, in the formula specified for OB adjustment, O&M expenses may be excluded. It is suggested that the OB Adjustment formula may be revised as under:

*OB Adjustment = [Factor of adjustment for shortfall of overburden removal during the year] x [Mining Charge during the year + ~~**Operation and Maintenance expenses during the year**~~]*

Inadvertent Error in OB Formula:

1. **Inadvertent Error in OB Formula:** It is also respectfully submitted that in the formula for calculating "Factor of adjustment for the shortfall of overburden removal during the year" there is an inadvertent error which is resulting is wrong calculation of the factor of adjustment.

   i) *Factor of adjustment for the shortfall of overburden removal during the year shall be computed as under:*

   [(Actual quantity of coal or lignite extracted during the year x ***Annual Stripping Ratio as per Mining Plan****) - (Actual quantity of overburden removed during the year/ Annual Stripping Ratio as per Mining Plan)]/ (Annual Target Quantity);*

   In terms of the units of the respective components of the formula, the given formula can be written as:

   = *[(Tonne x m^3/Tonne) – (m^3/(m^3/Tonne))/(Tonne)]*

   = *[(m^3 – Tonne)/Tonne]*

It may be observed that as per the given formula, the factor of adjustment is not dimensionless. It is therefore submitted that the formula may be rectified as under:

i) *Factor of adjustment for the shortfall of overburden removal during the year shall be computed as under:*

[(Actual quantity of coal or lignite extracted during the year ~~***x Annual Stripping Ratio as per Mining Plan)***~~ *- (Actual quantity of overburden removed during the year/ Annual Stripping Ratio as per Mining Plan)]/ (Annual Target Quantity);*

In terms of the units of the respective components of the formula, the given formula can be written as:

= *[(Tonne) – (m^3/(m^3/Tonne))/(Tonne)]*

= *[(Tonne - Tonne)/Tonne]*

Same is elaborated with the help of illustration as below:

	Units	Impact as per Draft Regulation, 2024	Impact as per Proposed Formula
Actual quantity of coal or lignite extracted during the year	Tonne	1,00,000	1,00,000
Annual Stripping Ratio as per Mine plan	m^3/Tonne	2	2
Actual quantity of overburden removed during the year	m^3	2,00,000	2,00,000
Annual Target Quantity (ATQ)	Tonne	1,00,000	1,00,000
OB Adjustment Factor Formula		[(Actual quantity of coal or lignite extracted during the year x **Annual Stripping Ratio as per Mining Plan**) - (Actual quantity of overburden removed during the year/ Annual Stripping Ratio as per Mining Plan)]/ (Annual Target Quantity)	[(Actual quantity of coal or lignite extracted during the year ~~**x Annual Stripping Ratio as per Mining Plan**~~) - (Actual quantity of overburden removed during the year/ Annual Stripping Ratio as per Mining Plan)]/ (Annual Target Quantity);
OB Adjustment Factor as per above Formula	-	1.00	0
Mining Charges During the Year	Rs. /Tonne	700	700
O&M Expenses during the year	Rs. /Tonne	100	100
OB Adjustment	Rs. / Tonne	800	0
Quantity of Coal supplied in the year	Tonne	1,00,000	1,00,000
Excess OB Adjustment due to error in OB Adjustment Formula	**Rs. Crore**	**8**	**0**

As illustrated above, mining company shall incur a loss even though actual overburden is exactly equal to the quantity as per the Mine Plan.

In view of the above, the error in the formula of OB adjustment may be rectified.

15) **Regulation 64(4) - Blending of Imported Coal:** Use of an alternative source of fuel supply shall be permitted to generating station up to a maximum of 6% blending by weight.

a) In the past, there have been shortages in domestic coal in the country along with increase in demand, which necessitated intervention by the GOI at national level to import coal to ensure uninterrupted supply of power.

b) Although efforts are being taken up to maximize the production of coal by CIL and its subsidiaries, increasing production by captive / integrated mines by generating companies and by the recent initiative of GOI of awarding commercial mines, shortfall in domestic coal supply may still be faced by power plants in the future.

c) Hon'ble Commission in its draft CERC Tariff Regulation 2024 has allowed the maximum of 6% blending of imported coal by weight at station level, after which prior consultation is required with beneficiaries.

d) Generating Stations receive coal from various sources such as CIL, SCCL, E-Auction etc. Due to shortfall in supply of domestic coal, generating station sometime opt for higher blending of imported coal subject to technical feasibility. This would further facilitate building up domestic coal stock position at their power plants for smooth & sustained operation during periods of high demand.

e) Considering overall shortfall in domestic coal and transportation constraints due to railway network congestion, etc., non-pithead stations require imported coal for meeting such shortfall in domestic coal supplies.

f) Allowing maximum blending of imported coal of 6% by weight at Station level may not serve the purpose as disruption in supply of domestic coal either from coal companies or through rail network can make it difficult for generating station to meet the gap in the total coal required for generation of electricity on sustained basis.

g) Considering the constraint involved in supply of domestic coal, MOP, GoI from time-to-time also issued direction to all GENCOS to import coal for blending "at company level" instead "at station level".

h) It is also felt that the process of prior consultation with the beneficiaries in case of breach of ceiling Limit of 6% needs to be avoided as this results in practical difficulties in implementing the directions of the GOI regarding blending of imported coal. Since multiple beneficiaries are involved, consultation with all the beneficiaries would take time & create practical difficulties in its implementation.

i) **In the scenario of increasing energy demand and considering that the increase in supply of domestic coal is not commensurate with the coal requirement, generating company may be allowed quantum of blending of imported coal at <u>company level (instead of station basis)</u> as per direction / guidelines / advisory of GOI issued from time to time.**

16)**Regulation 21(5) - Project Implementation**

a) Clause 21 (5) of the Draft Regulation provides that in case of activities like obtaining forest clearance, NHAI Clearance, approval of Railways, and acquisition of government land, where delay is on account of delay in approval of concerned authority, in such cases maximum condonation shall be allowed up to 90% of the delay associated with obtaining such approvals or clearances.

b) In the existing regulatory mechanism, the Hon'ble Commission after condoning delay on account of factors not attributable to the generating company has been allowing the increase in capital cost due to such delay.

c) However, The Draft Regulation has proposed that in case of activities like obtaining forest clearance, NHAI Clearance, approval of Railways, and acquisition of government land, where delay is on account of delay in approval of concerned authority, irrespective of delay being caused due to uncontrollable factors and beyond the control of the generating company, and thereby condoned by the Hon'ble Commission in such cases maximum condonation shall be allowed up to 90% of the delay associated with obtaining such approvals or clearances.

d) The generating company makes continuous efforts in pursuing the concerned authorities for grant of necessary clearances. In this regard, NTPC has been proactively pursuing various statutory authorities for necessary clearances employing both formal and informal ways. Issues are escalated at appropriate levels with the district administration, State Government, and other concerned authorities at State and Central Govt. levels for obtaining necessary statutory clearances. Meetings are also held with high level authorities of the State and Central Govt. including at the level of concerned Secretary, Principal / Chief Secretary, etc.

e) Critical issues in NTPC project implementation are also being raised to the concerned ministry / CEA for suitable intervention. It may be pertinent to mention that project monitoring is being carried out by PMO through PRAGATI Portal. In additional to the various structured interventions, the above issues are also expedited through informal channels with concerned authorities.

f) Therefore, penalizing the developers by restricting the delay condoned to maximum 90% even though delay is not attributable to the developer will increase the risks of developer which may dissuade future investments in the power sector.

g) It is submitted that it is an established principle of law that no one can be punished for something where he has been found not guilty, in this case where delay has been condoned by Hon'ble Commission. It may be pertinent that present regulations provide for disallowance of capital cost in cases where delay is not condoned. Therefore, it is submitted that in case delay is condoned by the Hon'ble Commission, corresponding capital cost is required to be admitted in tariff.

h) **It follows that any delay due to concerned authority for forest clearance, NHAI clearance, approval of railways, Govt. land acquisition, if condoned by Commission, 100% delay needs to be allowed. Therefore, it is suggested that the above clause may be dropped.**

i) **In view of the above, it is suggested to continue with the existing approach of condoning 100% of the delay on account of activities like obtaining forest clearance, NHAI Clearance, approval of Railways, and acquisition of government land, where delay is on account of delay in approval of concerned authority.**

17) **Regulation 33(6) - Depreciation for New Projects:**

a) The Draft regulations has proposed that depreciation of new projects shall be as per specified rates in the initial 15 years (existing 12 years) & the remaining depreciation shall be spread over the balance useful life of the project beyond 15 years.

b) In Tariff Regulations 2019-24, the depreciation rate for Plant & Machinery was 5.28% for initial completed 12 years which roughly matches with the repayment schedule of the term loans. The Draft Regulations has instead proposed depreciation rate of 4.22% for initial 15 years. Considering the fact that the construction of thermal power plants normally takes 52-60 months, the total loan tenor should be around 20 years to match the repayment as per depreciation provided in the Draft regulations for new stations.

c) However, standard term of loans from banks has door-to-door tenor of 15 years (3 years moratorium plus 12 years annual repayment). Presently, there is not much liquid market available for longer tenor loans like 18-20 years. Most of the banks avoid going for such longer tenor considering the Asset Liability mismatch.

d) Similar is the case with the Bonds market, where Bonds more than 10 years have few takers with high coupon rate. As mentioned above, the borrowings in this scenario would be difficult apart from the higher cost of borrowing, which will eventually lead to increase in the project cost.

e) Re-financing cost of the loans may also become an issue, as during rollover, the interest rate may go-up and serviceability of such rollover cost has not been explicitly mentioned in draft regulation.

In view of the above, the provisions as per the CERC Tariff Regulations 2019-24 may be retained.

18) **Regulation 32(6) - Interest on Loan for New Projects:**

a) The Draft regulations has proposed Weighted Average Rate of Interest (WAROI) based on actual loan portfolio of generating company or in absence of such rate, 1-year SBI-MCLR as applicable as on 1st April of relevant financial year shall be considered.

b) It is suggested that the interest on the loan for new stations may be based on the Weighted Average Rate of Return on Interest (WAROI) of the Generating station, as in Tariff Regulations 19-24, instead of the Generating Company for the following reasons:

i. **Interest Rate Differentials will adversely impact debt servicing:** The historical borrowings have interest rate differentials with the new ones. Considering the interest rate of company in these cases will not be justified for individual stations across the company as tariff is on station basis. Company WAROI contains all such loans with their proportionate weightage. Currently, low-cost ECBs for new thermal power projects are not being extended by multilateral / bilateral funding agencies. The upcoming stations will need to be financed from the debt at the rate available in the present domestic market which may be significantly higher from the earlier borrowings. As such the WAROI for a new station will depend upon the sources of finance deployed to such project and due to the fact that low-cost ECB's form multilateral/bilateral/DFIs are not deployed, such projects shall be financed through high cost domestic borrowings, hence higher WAROI. However, the low-cost ECBs availed earlier will continue to be in the portfolio (until repaid completely), it will lower the overall WAROI of the company computed based on all the loans. Therefore, the interest on loans (WAROI) for new stations shall be higher than the WAROI of the company, it will adversely impact the debt servicing of such project.

ii. **Differentiation between Regulated and Non-regulated business of Company:** The NTPC loan portfolio consists of loans used for both regulated and Non-regulated business of the company. Further, loan portfolio also contains borrowings for acquisitions of projects/companies. The term and conditions on loans in non-regulated industries is quite different and have differential interest rates.

iii. **Project Specific Loans:** Further, multiple thermal power stations have been financed with foreign currency loans having specific rates for those projects.

iv. **Implementation Issues:**

a) If the two units of station are commissioned in two tariff periods i.e., one unit during 2019-24 period and another unit in 2024-29 period, determination of applicable interest rate will be a difficult exercise and may lead to confusion.

b) **Allocation of FERV:** The allocation of FERV among beneficiaries of both new and old stations will poses a challenge. FERV on actual loan repayment is being recovered based on actual loan portfolio depicted in Form 13. In the absence of form 13 specific to project, recovery of FERV from beneficiaries will pose a problem for the generator.

c) The passing of benefits of refinancing create problem for the generator

In view of the above, the existing provisions of interest rate on project basis as per CERC Regulation 2019-24 may be retained.

19) **Regulation 17 - Special Provisions for Tariff for Thermal Generating Station which have Completed 25 Years of Operation from Date of Commercial Operation:**

a) Draft Regulations provide as under:

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, including provisions for target availability and incentive, where in addition to the energy charge, capacity charges determined under these regulations shall also be recovered based on scheduled generation.

b) Regulation 17 may be removed entirely as it could lead to confusions due to different interpretations by generator and Discoms and may result in avoidable litigations.

c) In case Regulation 17 as proposed in Draft Regulations is retained, which specifies recovery of tariff based on schedule generation, generator may not be assured of recovery of capacity charges. Further, the Parties may mutually agree for a target availability. Since these old stations which are depreciated assets, and returns are very less, therefore incentive rate may also be mutually decided by the Parties as proposed in the Regulations. **However, in case recovery of tariff is based on schedule generation, then a condition of minimum off-take by the beneficiaries may be imposed which will take care of recovery of capacity charges.**

Accordingly, following is suggested:

"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, including provisions for minimum off-take, target availability and incentive, where in addition to the energy charge, capacity charges determined under these regulations shall also be recovered based on scheduled generation."

d) Alternatively, it is suggested that the recovery of capacity charges may be linked to availability factor as is being presently done. Accordingly, following is suggested:

"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 mutually agree on an arrangement for recovery of tariff based on the agreed target availability and incentive. However, capacity charges shall be as determined under these Regulations and energy charge rate shall be as per the operating norms under these regulations."

20) **Regulation 70(C)(d) - Gross Heat Rate Norms of Coal Stations for Entire Operational Life:**

a) The Regulations 70 (C) (d) of the Draft Regulations has proposed that the gross station heat rate norms (fixed as per the tariff regulations 2024) of coal stations or units thereof (except for stations for which relaxed norms have been specified) and commissioned till 31.3.2024 shall remain applicable for such stations for the remaining operational life. The relevant provision is extracted as under:

"The Gross Station Heat Rate norms as specified in sub-clauses (a) and (b) of this clause, in respect of the coal and lignite based generating stations or units thereof (except for the generating stations or units thereof for which relaxed norms have been specified) and commissioned till 31.3.2024 (before 2009 and after 2009) shall remain applicable for such generating stations or units thereof for the remaining operational life of the respective generating stations or units thereof."

b) The Explanatory Memorandum at S.No. 18.6.14 has elaborated the Commission's view regarding introducing Lifetime Operational Norms extracted as under:

"18.6.14 With regard to SHR Norms of the coal and lignite based generating stations or units thereof (except for the generating stations or units thereof for which relaxed norms have been specified) and commissioned till 31.3.2024 (before 2009 and after 2009), degradation of actual SHR in such generating stations is observed which is attributable to the increased backing down of thermal generating stations to accommodate the rapid integration of renewable energy. Further, CEA recommended that tightening SHR Norms for such stations would not be prudent in view of the degraded efficiency of such units on account of frequent backing down and the fact that the rated efficiency parameters of such units was specified based on older regulatory regime wherein the SHR Norms were relaxed. In view of the facts stated above and recommendations of CEA, the Commission is of the view that prevailing SHR Norms shall remain applicable for such generating stations or units thereof for the remaining operational life of the respective generating stations or units thereof. Furthermore, since new generating stations and units thereof achieving COD after 31.03.2024 will be more efficient in operations as such units are being designed keeping in

view the current regulations. Therefore, tightened norms as proposed above shall be applicable for units achieving COD after 31.03.2024."

c) From the plain reading of the Explanatory memorandum quoted above, it is clearly stated that tightened norms as proposed in Draft Regulations 2024 shall be applicable for units achieving COD after 31.03.2024. However, as per draft CERC Regulations 2024, the norms as proposed in the Draft Regulations shall be applicable for units commissioned up to 31.03.2024. **Therefore, the Draft Regulations and the Explanatory Memorandum seem to be contradicting each other and therefore need clarification.**

d) However, it is submitted that specifying lifetime operational norms for units should be based on the parameters considered at the time of investment approval based on the prevailing operational norms as elaborated below.

e) It may be noted that since operational norms are decided at the time of awarding the project (including projects awarded during 2019-24 and to be commissioned after 31.03.2024), based on the prevalent operational norms as per extant Tariff Regulations. These parameters get frozen at the design stage itself. Since the design heat rate of these projects was based on the extant norms, they cannot meet the stringent norms as proposed by Draft Regulations for 2024-29.

f) It is submitted that gross heat rate norm as proposed in the draft CERC Tariff Regulations 2024 is stringent and many units shall be unable to achieve the same. Gross heat rate norms for units commissioned before 01.04.2009 have been tightened from 2430 to 2400 kcal per kwh for 200 MW units and tightened from 2390 to 2375 kcal per kwh for 500 MW units. Moreover, in case of coal stations commissioned on or after 01.04.2009, the operating margin have been reduced from 5.0% to 4.0%. This will result in losses in many units operating above 85% loading factor as CEA has not considered the sharing of gains in its recommendations for operating parameters for the tariff period 2024-29. The specific issues regarding gross heat rate norms proposed by the Draft Regulations are elaborated in detail in our comments on heat rate at S. No.7. of the comments **Therefore,**

adopting the heat rate norms as proposed in the draft Tariff Regulations 2024 would result in perpetual losses for these stations.

g) It is difficult for the generator to accommodate mid-course tightening of the norms, (particularly the minimum boiler efficiency and maximum turbine heat rate) in successive tariff periods. Further, there is degradation in heat rate of units with age and operation. It is not technically possible to restore the degradation entirely through annual overhauls.

h) Moreover, the project capital cost as discovered through bidding depends on the design parameters specified by the generator, which is serviced in tariff by the Discoms. Therefore, it may be mentioned that the capital cost of project vis-à-vis the operational cost / efficiency which is dependent on the design parameters gets factored in the overall tariff of electricity.

i) Since the design heat rate of these projects was based on the extant norms, they cannot meet the stringent norms as proposed by Draft Regulations for 2024-29.

j) **In view of the above, it is suggested that in order to provide regulatory certainty and simplify tariff framework, operational norms of coal-based units may be fixed for the entire life based on the norms prevailing as per the extant regulations at the time of investment approval or award of the units as against the norms proposed in the Draft Regulations 2024.**

21) **Regulation 3(45) – Definition of Integrated Coal Mines:**

a) *'Integrated Mine' means the captive mine (allocated for use in one or more identified generating stations) or basket mine (allocated to a generating company for use in any of its generating stations) or **both being developed by the generating company** for supply of coal or lignite to one or more specified end use generating stations for generation and sale of electricity to the beneficiaries;*

b) It is submitted that the requirements of Coal Mining activities are essentially different from that of the Power Generation. As a Strategic decision, a

Generating Company after obtaining the requisite approvals of the Ministry of Coal/Competent Authority as appointed by GoI, may undertake the coal mining operations through its Subsidiary Company(s). However, the end use of coal and the end use plants shall remain unaltered.

c) The aspect has also been dealt by the Hon'ble CERC nominated working group on "**Regulatory framework for Determination of Input price or Transfer Price of Coal or Lignite from Integrated Mine**". The working group in its report to Hon'ble CERC stated that *"Creation of Special Purpose Vehicle (SPV) or Company, will not alter the allotment agreements. The allottee of mine, i.e. the Generating Company shall continue to have binding obligations to comply with allotment agreement and control of such SPV or separate company will remain with the generating company. The input price of coal is to be determined by taking into account the captive nature of mine irrespective of separate creation of company or SPV.*

d) **In view of the above, definition of Integrated Coal mine may also include the mines owned/developed by Subsidiary Company(s) of a Generating Company for supplying coal to the plants of the Generating Company. Accordingly, the definition of Integrated Mine may be modified as per the following:**

'Integrated Mine' means the captive mine (allocated for use in one or more identified generating stations) or basket mine (allocated to a generating company for use in any of its generating stations) or both being developed by the generating company ***or by subsidiary(s) of Generating Company*** *for supply of coal or lignite to one or more specified end use generating stations for generation and sale of electricity to the beneficiaries.*

22) **Regulation 34 - Interest on Working Capital (IWC):**

In the Draft regulations for the period 2024-29, the interest on working capital has been proposed to be reduced by 25 basis points from 350 basis points. It is submitted that, currently when the rate of interest on IWC is SBI -MCLR +350 basis points, NTPC is not getting any Working Capital interest on the following components.

a) Generating company is bound to raise energy bill only after receipt of Regional Energy Account (REA), which is generally received on 5th or 6th day of the subsequent month. Carrying cost of around five to six days is not being serviced, however, same is being met from interest on working capital. Considering monthly billing of Rs. 12500 crores, the financial implication of carrying cost works out to around Rs. 150 crores. It is suggested that the generating company may be allowed to raise provisional energy bills on the 1st of the month before issuance of the Regional Energy Account by REA. The due date of payment of such provisional bills shall be 45 days from date of its presentation. Alternatively, the number of days of receivables may be increased from 45 to 51 days considering the date of issuance of REA on 6th of the month. Delay in billing and any reduction in interest rate on working capital shall put generator to additional financial burden.

b) FERV amount paid at the time of repayment, can be claimed from beneficiary on annual basis. Present value of money lost by the company from the payment date to realization date, is not compensated either through interest from beneficiary or working capital interest. However, carrying cost of the same is being met from normative interest on working capital. Reduction in interest rate will put additional financial burden on generator. Else, generator may be allowed to recover the FERV on quarterly basis instead of annual basis.

c) Freight Advances to Railway, CISF Deposit, Deposit with Water Authority, Pending Railway Claim Refunds, are not covered in working capital calculation of CERC.

d) Delay in receipt of credit notes from coal companies creates additional working capital lock and affects present value of money. (It takes minimum 3 months to 2 years)

e) Working Capital interest spent by companies on Capital Spares, not allowed by CERC. Capital spares are mandatorily procured by stations, (after use of mandatory spares) to maintain the availability of plant. After use of capital spares, capital spares on consumption basis is allowed but no carrying cost is allowed.

It is evident from above that any reduction in the spread of WC interest proposed in CERC Tariff Regulations, 2024, will create additional financial burden on the generating company.

In view of the above following is suggested:

i. **Therefore, existing provision of rate of interest on IWC of SBI-MCLR +350 basis points may be retained.**
ii. **Suitable provision in the regulation for enabling generating company to raise energy bills on 1st of the month may be provided. The payment period for such provisional bill shall be 45 days from presentation of the provisional bill.**
iii. **Alternatively, the number of days for receivables may be increased from 45 to 51 days considering that energy bills are raised on 6th of the month after issuance of REA by the RLDCs.**

23) **New Provisions of O&M expenses and IWC for Dedicated Transmission Line:**

a) As per the section 15 of the Explanatory Memorandum to the Draft Regulations regarding the O&M Expenses for generating station, it is understood that CERC has considered the historical data from power projects of various sizes of various entities for arriving at the admissible norms for O&M expenses for the period 2024-29.

b) It is pertinent to note that for all NTPC projects, transmission system was built, owned, and operated by ISTS Licences under coordinated transmission planning by CEA/CTU and O&M cost of the DEDICATED transmission line is not a part of the historical data on O&M cost communicated to CERC.

c) As per the CERC (Grant of Connectivity and GNA) Regulations 2022, all generators are now mandated to execute and carry out O&M of Dedicated transmission lines.

d) **In view of changed Regulatory provisions wherein Generators are required to construct and maintain the dedicated Transmission line and considering the cost-plus regulatory framework, following is suggested in regard to dedicated transmission lines:**

i. **All such generators may be allowed O&M charges for these dedicated transmission elements as per rates admissible to transmission utilities, i.e., as per Regulation 36(3) of the Draft Regulations over and above the normative O&M expenses admissible to the generating stations.**

ii. **All such generators may be allowed Interest on working capital for these dedicated transmission elements as per rates admissible to transmission utilities, i.e., as per Regulation 34 (d) of the Draft Regulations over and above the interest on working capital admissible to the generating stations.**

24) **New Provision for Auxiliary Energy Consumption (AEC) of Dedicated Transmission Lines:**

a) Under the Connectivity and LTA Regulations 2009, the transmission lines for thermal generating stations of 500 MW and above were being taken into account for coordinated transmission planning by the Central Transmission Utility and Central Electricity Authority. [Subsequently limit of 100 km was introduced].

b) However, as per the CERC Connectivity and GNA to ISTS Regulations 2022, the dedicated transmission line for connectivity up to ISTS pooling point is necessarily under the scope of the generating company.

c) The operating norms for AEC proposed in the Draft regulations are similar to those specified in Tariff Regulations, 2019. **Therefore, it is suggested to introduce the phrase "excluding dedicated transmission line" for the sake of clarity and avoid ambiguity.**

d) Further, as per the CEA Metering Regulations, Interface Meters for measurement of power injection are to be installed at ISTS periphery (i.e., remote-end substation of the dedicated transmission line).

e) The losses of the dedicated transmission line is a function of Line loading/schedule [in MW], Reactive power flow, Voltage profile, etc. Therefore, estimation of actual losses in dedicated transmission line is not possible. Further various projects shall be having different voltage levels and different conductor configurations/lengths of transmission lines, operating temperature etc. which cannot be estimated though one single normative value. This situation shall be even more complex in projects having dual connectivity to ISTS and Intra-state networks, where there could be incidental power flow through these dual connection points and the switchyard of the generating station.

f) It is therefore requested that Hon'ble Commission may kindly clarify that the actual losses of dedicated transmission lines shall be recoverable separately from the beneficiaries of the generating station or as per terms and conditions of PPA, (if any) based on the actual losses. In this regard, the Hon'ble Commission is requested to kindly direct CEA to review the Metering regulations with respect to provision of metering at the generator end of dedicated line for facilitation of measurement of actual losses of the dedicated transmission line. This shall streamline the process of DC declaration by generator and allow actual measurement and recovery of losses in dedicated transmission lines.

g) **It may be clearly specified in the Tariff Regulations that the norms for auxiliary energy consumption for the generating unit are excluding losses in dedicated transmission line for the sake of clarity and avoid ambiguity.**

h) **It may be specified that the actual losses in a dedicated transmission line shall be recoverable from the beneficiaries by the generating company separately, for which provision of metering at both ends may be introduced in the CEA Metering Regulations or may be agreed as per terms and conditions of PPA with beneficiary(ies) of the project.**

25)**Regulation 70 (D) (b) Secondary Fuel Oil Consumption Norms:**

a) Specific Fuel Oil Consumption for Wall Fired Boilers:

   i. Draft Regulations has provided norms of Secondary Fuel Oil Consumption for coal-based generating stations with front fired boilers as 1.00 ml/kwh.

ii. It is submitted that instead of the terminology front fired, the terminology "Wall fired" may be used for the sake of clarity.

iii. Secondary fuel oil consumption is higher in coal stations with wall fired boilers where the wall may be front, rear, or side wall or combination of the three. For e.g., NTPC Barh Stage-I boiler design is side wall fired and oil consumption is in line with the front fired boilers.

iv. **Therefore, in clause (b), "front fired" phrase should be replaced by "wall fired" which includes front, rear, and side wall for the sake of clarity.**

b) **Additional specific oil compensation for units operating below 55% loading:**

i. CEA vide its letter dated 19.12.2023 has recommended additional Specific Oil Consumption of 0.2 ml/kWh for units operating in the range of 40% to 55% loading.

ii. It is submitted that Specific Oil Consumption norms as recommended by CEA have been adopted by Hon'ble Commission in draft CERC Tariff Regulations 2024, but the additional Specific Oil Consumption of 0.2 ml/kWh for units operating below the 55% loading have not been included.

iii. **Hence, it is requested to include additional Specific Oil Consumption of 0.2 ml/kWh recommended by CEA in the CERC Tariff Regulations 2024.**

In addition to the above submissions, clause wise comments are being submitted as below:

CLAUSE WISE COMMENTS:

26) **Regulation 2 – Scope and Extent of application:**

a) The Draft Regulations provide as under:

"Provided that any generating station for which agreement(s) have been executed for the supply of electricity to the beneficiaries on or before 5.1.2011 and the financial closure for the said generating station has not been achieved by 31.3.2024, such projects shall not be eligible for determination of tariff under these regulations unless fresh consent of the beneficiaries is obtained and furnished."

Comments:

b) There are certain new projects of NTPC wherein the required Agreements have been duly executed with the beneficiaries. However, due to certain reasons beyond the control of NTPC, investment approval of these projects are to be accorded.

c) It is submitted that some of these projects are in the final stages of investment approval. Further, fresh consent of such projects have already been taken from the beneficiaries after 01.04.2019 as required under the 2019 Tariff Regulations. However, it is possible that investment approval of some of these projects may overshoot 31.03.2024 and be accorded on or after 01.04.2024 due to various reasons. In such cases, taking fresh consent after 01.04.2024 again shall further delay the process of investment approval.

d) **Therefore, in case of projects where consent of beneficiaries has already been sought in the 2019-24 tariff period, the Hon'ble Commission may be pleased to dispense with the requirement of seeking a fresh consent from the beneficiaries till 31.03.2026.**

27) **Regulation 3(5) ATQ in respect of Integrated Mine:**

a) **Draft Regulations provides as under:**

Regulation 3(5): *'Annual Target Quantity' or 'ATQ' in respect of an integrated mine(s) means the quantity of coal or lignite to be extracted during a year from such integrated mine(s) corresponding to* ***85% of the quantity specified in the Mining Plan****;*

b) It is a welcome step considering that the mining operations encounter various uncertainties/risks which are not captured during exploration as exploration is done on sampling basis. Such uncertainties/risks prohibit achieving 100% capacity utilization factor (thus recovery of full costs) every year.

28)**Regulation 3 (63):**

It is suggested that Integrated Energy storage system may also be added in the "Project" definition to due to increase in flexing requirements of coal power plants.

29)**Regulation 3(88) - Operational Life:**

a) It may be noted that machines have been / are being awarded considering useful life of 25 years. It may be noted that OEMs are also designing the equipment considering life of 25 years.

b) **Therefore, it is understood that specifying operational life as 35 years for coal-based stations does not call for specifying design life of power plant equipment as 35 years.**

30)**Regulation 9 (1) – Application for determination of Tariff –**

a) The Draft Regulations provide that the generating company may make an application for determination of tariff of a new generating station or unit thereof within 90 days from the actual date of commercial operation. Further, the new generating station, through a specific prayer in its application may plead for an interim tariff and the Commission shall consider granting interim tariff from the date of commercial operation during the first hearing of the application.

b) In case of determination of supplementary tariff for emission control system, generating station may file an application not later than 90 days from the date of start of operation of such emission control system.

c) It is submitted that there is need for a provisional tariff for in case of new generating station for commencement of billing after COD in the period before filing of application after COD within 90 days as proposed by the Draft

Regulations. Similarly, requirement of provisional supplementary tariff is required for billing of supplementary tariff after operation date of Emission Control System.

d) It is therefore required that in case of new projects and commissioning of Emission Control System, enabling provision for provisional tariff for billing immediately after COD or operation of ECS may be provided in the Tariff Regulations.

e) **It is suggested that to provide enabling provision for filing of tariff petition on tentative/projected figures as on anticipated COD (instead of audited figures), as provided in Tariff Regulations 2019. This is also necessary for raising provisional bill as per tariff petition filed as per terms & conditions of the PPA.**

31) **Regulation 10 (3) – Determination of Tariff:**

a) Draft Regulation provides as under:

Provided that in case the final tariff determined by the Commission is lower than the interim tariff by more than 10%, the generating company or transmission licensee shall return the excess amount recovered from the beneficiaries or long-term customers, as the case may be with simple interest at 1.20 times of the rate worked out on the basis of 1 year SBI MCLR plus 100 basis points prevailing as on 1st April of the financial year in which such excess recovery was made.

b) It is submitted that in case of new generating stations, the tariff claimed in tariff petition would be based on capital cost as on COD and Interim tariff may be granted up to 90% of the tariff claimed. However, the capital cost is disallowed by the Hon'ble Commission after prudence check shall be known only after determination of final tariff, which the generating company cannot predict or estimate upfront.

c) **Therefore, penal interest rate @ 1.2 times of SBI MCLR plus 100 bps on this excess amount recovered is not fair and therefore the above provision may be dropped. It is suggested that the excess amount**

recovered shall be refunded to the beneficiaries with simple interest at the rate of 1-year SBI MCLR plus 100 basis points.

32) **Regulation 10(7): Interest on refund or recovery of Differential Tariff:**

a) Draft Regulation provides as under:

Provided further that such interest, including that determined as per sub-clause (8) of this regulation shall be payable till the date of issuance of the Order and no interest shall be allowed or levied during the period of six-monthly instalments.

Provided further that in case where money is to be refunded and there is a delay in the raising of bills by the generating company or transmission licensees beyond 30 days from the issuance of the Order, it shall attract a late payment surcharge as applicable in accordance with these regulations.

b) The generating company takes all efforts to refund money to beneficiaries without any undue delay. It is submitted that in the existing regulatory framework, late payment surcharge (LPSC) is applicable to payments outstanding beyond 45 days. Therefore, refund may also be specified by the same stipulation to keep the provision equitable to the generating company.

c) **Therefore, it is suggested that LPSC in case of delay in refund by generating company beyond 45 days from the issuance of order.**

33) **Regulation 10 (8) – Determination of Tariff:**

a) Regulation 10 (7) of the Draft Regulations provides as under:

10(7) Subject to Sub-Clause (8) below, the difference between the tariff determined in accordance with clauses (3) and (5) above and clauses (4) and (5) above, shall be recovered from or refunded to, the beneficiaries or the long term customers, as the case may be, with simple interest at the rate equal to the 1 year SBI MCLR plus 100 basis points prevailing as on 1st April of the respective year of the tariff period, in six equal monthly instalments.

b) It may be seen that the Regulation 10 (7) of the Draft Regulations provides provision for refund or recovery of tariff for differential tariff between:

i. Final tariff determined based on projected additional capitalisation and interim tariff granted for new projects.

ii. Final tariff determined on projected add cap and existing tariff billed for existing projects.

c) The Regulation 10(7) refers to final tariff determined under clause 10(5) subject to true-up as per clause 10(8) where there is provision for interest @ 1.2 times applicable for refund in case true-up tariff determined is less than initial tariff billed on projected basis. <u>However, there is no provision in Regulation 10(8) regarding interest applicability on **under recovery** in case true-up tariff is in excess of already tariff determined and billed on projected basis.</u>

d) In respect of truing up of tariff for the period 2024-29, Regulation 13(5) provides as under:

"13(5) After truing up, if the tariff or the input price already recovered exceeds or falls short of the tariff or the input price approved by the Commission under these regulations, the generating company or the transmission licensee, shall refund to or recover from, the beneficiaries or the long term customers, as the case may be, the excess or the shortfall amount, in accordance with Regulation 10(7) and 10(8) of these regulations as may be applicable.

Provided that the generating company shall refund such excess amount or recover the shortfall amount from the beneficiaries based on scheduled energy."

e) Thus, Regulation 13(5) refers to Regulation 10 (7) and 10 (8) regarding applicability of provision for refund / recovery in respect of tariff determined by Commission after truing up. **As already submitted above there is no provision in 10(8) in case of under recovery. It is further suggested that both rate of interest for recovery and refund of differential tariff may be same i.e., 1.20 times of the rate worked out on the basis of 1-year SBI MCLR plus 100 basis points as prevalent on 1st April of the respective year. Therefore, it is suggested that following may be appended to Regulation 10(8) as below:**

"*10(8) Where the capital cost approved by the Commission …. as prevalent on 1st April of the respective year.*

Where the capital cost considered by the Commission on the basis of projected additional capital expenditure falls short of the actual additional capital expenditure incurred by more than 10% on year to year basis, the generating company or the transmission licensee shall recover from the beneficiaries or the long term customers as the case may be, the shortfall in tariff corresponding to difference in additional capital expenditure, as approved by the Commission, along with interest at 1.2 times of the rate worked out on the basis of 1 year SBI MCLR plus 100 basis points as prevalent on 1st April of the respective year."

f) The proviso under Regulation 13(5) provides that the generating company shall refund such excess amount or recover the shortfall amount from the beneficiaries based on scheduled energy. As per existing regulations, apportionment of capacity charges of a thermal generating station is done based on the percentage allocation share and not on schedule energy. **Therefore, it is suggested that in case of thermal generating stations, any refund or recovery of capacity charges needs to be based on percentage allocation share of beneficiaries for the respective period.**

34) **Regulation 10(7), 10(8) & 13 (5) – Truing up of tariff for the period 2024-29:**

a) **Regulation 10 (7), 10 (8) & 13 (5) – Recovery or refund of differential tariff for the period 2024-29:**

Draft Regulations provides as under:

10. Determination of tariff

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(7) Subject to Sub-Clause (8) below, the difference between the tariff determined in accordance with clauses (3) and (5) above and clauses (4) and (5) above, shall be recovered from or refunded to, the beneficiaries or the long term customers, as the case may be, with simple interest at the rate equal to the 1 year SBI MCLR plus 100 basis points prevailing as on 1st April of the respective year of the tariff period, in six equal monthly instalments.

Provided that the bills to recover or refund shall be raised by the generating company or the transmission licensees within 30 days from the issuance of the Order.

Provided further that such interest, including that determined as per sub-clause (8) of this regulation shall be payable till the date of issuance of the Order and no interest shall be allowed or levied during the period of six-monthly instalments.

Provided further that in case where money is to be refunded and there is a delay in the raising of bills by the generating company or transmission licensees beyond 30 days from the issuance of the Order, it shall attract a late payment surcharge as applicable in accordance with these regulations.

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(8) Where the capital cost approved by the Commission on the basis of projected additional capital expenditure exceeds the actual trued up additional capital expenditure incurred on a year to year basis by more than 10%, the generating company or the transmission licensee shall refund to the beneficiaries or the long term customers as the case may be, the tariff recovered corresponding to the additional capital expenditure not incurred, as approved by the Commission, along with simple interest at 1.20 times of the rate worked out on the basis of 1 year SBI MCLR plus 100 basis points as prevalent on 1st April of the respective year

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13(5) After truing up, if the tariff or the input price already recovered exceeds or falls short of the tariff or the input price approved by the Commission under these regulations, the generating company or the transmission licensee, shall refund to or recover from, the beneficiaries or the long term customers, as the case may be, the excess or the shortfall amount, in accordance with Regulation 10(7) and 10(8) of these regulations as may be applicable.

Provided that the generating company shall refund such excess amount or recover the shortfall amount from the beneficiaries based on scheduled energy.

NTPC Comments

a) As per draft CERC Tariff Regulations 2024, generating company is not allowed to charge any interest during the period of six-monthly instalments.

b) However, it is submitted that Interest may be allowed during the period of billing of six-monthly instalments also, as the date till which the billing is done, the funds remain undue to the generating company.

c) It is submitted that when a beneficiary chooses to pay the arrears in monthly instalments (six instalments in the present case) the same will be subject to interest because interest on arrears is nothing more than a restriction on account of the affected party's loss of funds up until the point at which the restitution is implemented.

d) It is further submitted that the EMI payment principle is always subject to interest assessments. Hence, interest on the instalments is in accordance with the well-established notion of restitution, which is to restore the affected party being deprived of its legitimate reimbursements. In this regard, reliance is also placed on the Judgment passed by the Hon'ble Appellate Tribunal in Appeal No. 308 of 2017 titled as Lanco Amarkantak Power Limited v. Haryana Electricity Regulatory Commission & Ors.

e) **Therefore, it is submitted that Interest may be allowed during the period of billing of six-monthly instalments also.**

35) **Regulations 19(2)(p) and 19(3)(g) – Enabling Flexible Operation at Lower Loads:**

a) Draft Regulations has introduced provisions in capital cost of existing and new project for enabling flexible operation of generation units at lower loads, which is a welcome step of the Hon'ble Commission.

b) It is suggested that additional implication for the following counts may also be included on account of flexible operation:

   i. Increase in maintenance costs.

   ii. Reduction in plant life due to accelerated aging.

   iii. Increase in Forced Outages.

   iv. Consequential Decrease in Plant availability.

36) **Regulation 19(5)(a) – Computation of capital cost for projects acquired through NCLT –**

a) The tariff determination based on cost-plus principle considers the historical cost data of the assets as the capital cost for tariff purposes. The capital cost considered for tariff purposes in on cash basis. The existing Tariff Regulations define the capital cost of any generating station / transmission asset as the expenditure incurred up to the date of commercial operation of the project. This basically implies that the actual cost incurred towards development / construction of the asset shall be considered for tariff determination. This approach has been followed by the Commission for the assets for which tariff is being determined based on cost-plus principles under Section 62 of Electricity Act 2003.

b) It may be seen that almost all the plants which are under NCLT are set up based on either competitive bidding under Section 63 as well as combination of Section 63, Section 62 including power at ECR etc. Even fixed charge and ECR quoted by the developer does not reflect actual fixed charge, actual ECR or heat rate etc. Assumptions of the developers at the time of bidding and tariff quoted have gone wrong and became financially unviable.

c) While bidding for stressed assets, the acquirer considers several factors including cost to be incurred for completion of the facilities, standardization of the schemes as per the industry practice, discounting the losses due to shortfall in design vs norms, etc. After consideration of above the factors and any unforeseen factors the acquisition value is arrived. Therefore, considering the acquisition value for purpose of tariff determination will deny the servicing of legitimate costs to the generator.

d) Under NCLT process of sale/ purchase, the price at which exchange of shareholding takes place is discovered through transparent process of bidding based on revenue earning potential. As the tariff offered at the time of bidding cannot be changed under the contract or the special dispensation like tariff at ECR etc., as agreed by the developer cannot be discontinued, post take over through NCLT should neither impact the tariff process, nor tariff as already agreed. CERC should ensure that there is no increase in tariff beyond the agreed contract / assumptions, while taking over station through NCLT process.

e) It may be noted that the projects which undergo NCLT process are unviable loss-making projects and therefore the recovery of tariff is inadequate to compensate for the expenses and earn the reasonable level of return. In view of the operational losses, the procurer would acquire the asset at a discount to the existing price in order to ensure that reasonable levels of returns are obtained from the stranded asset. It is highly unlikely that such an asset is acquired at any premium. Generally, it is observed the creditors take a haircut and defaulting project developers have to forego their equity.

f) Therefore, consideration of acquisition price for tariff determination process would further reduce the revenues and thereby result in continued financial stress against the acquired asset. This would therefore defeat the entire process of revival of the stranded project. It would therefore be unreasonable to consider the acquisition price for the assets acquired under the NCLT process.

g) If lower of acquisition price or historical price is to be considered for tariff determination post-acquisition, the same may be made upfront clear to prospective bidders of the project in the NCLT process. However, this is likely to reduce the takers for acquiring such assets.

h) Further, any additional investment required to make the plant operational, same also need to be considered in tariff.

i) **Therefore, Historical price may be considered for tariff purpose as consideration of acquisition price would reduce the revenues and thereby result in continued financial stress. This would add further difficulties in process of revival of the stranded project.**

37)**Regulation 22(1)(b) – Controllable and Uncontrollable Factors-**

a) Delay in execution of the new projects on account of contractor or supplier or agency of the generating company or transmission licensee. Categorization of contractual delays entirely as controllable needs to be re-examined. An additional specific provision may please be provided in the regulations in order to take care of uncontrollable contractual delays. In this regard, following may be considered for incorporation of contractual delays under uncontrollable factors.

b) It is submitted that delays due contractual issues need to be seen in the proper context of overall project execution environment in the country. In the present scenario, the execution of thermal projects is fraught with a host of risks, which are beyond the control of the generating company. The entire process of project development broadly consists of the structuring of contracts, options / mechanism for allocation of risk, and mitigation of risks with the overall objective of completing the project on schedule.

c) **Structuring of contracts -** Allocation of risks is done through the contract structuring. Contractual terms provide safeguards for compliance of timelines by Suppliers / contractors. As a safeguard to ensure that the Successful bidder(s) adheres to the contractual terms and project timelines, following safeguarding provisions are provided in the contracts such as Earnest Money Deposit (EMD), Performance Bank Guarantee (PBG), Liquidated Damages (LD) and Termination of Contract.

d) **Allocation of Risk -** To ensure timely completion of projects, there are measures like Liquidated Damages (LD) in the contract. These deterrence measures are adopted for allocating apportion of risk to the contractors. For instance, the percentage of LD is generally fixed at 5%-10% of the contract value. In case a higher consideration of LD is proposed in contract, the same will have ramifications on the prices quoted by the bidders who would load the cost of the products/services upfront by such amount. Therefore, higher loading of risks on the contractor / vendor / agency will result in higher prices which would not be overall interest of the Discoms. Disproportionate allocation of risk is not desirable. Therefore, significant risk has to be retained with the project developer. Often project delay is caused by a small contract in the entire project, whose contract value may be very small as compared to the project cost. As delays have a cascading effect, the overall impact may be significant. It is not possible for a contractor to assume unlimited liability of project delay.

e) The uncontrollable aspects of contractual delay are elaborated as under:

i. **Poor performance by agencies due to deterioration in their financial condition during course of execution of project –** In some cases, it has been observed that the performance of reputed agencies with established track record at the time of award has deteriorated mainly due to financial problems. Some of such cases have also referred to NCLT.

ii. **Shortage of contractors** - Shortage of contractors operating in certain areas of thermal power sector due to various reasons, such as NCLT, shifting of focus of some contractors from thermal to emerging and more attractive renewable energy sector, etc. Therefore, paucity of contractors often restricts the generating company to award the jobs to available contractors.

iii. **Competitive Vendor Selection process adopted by NTPC -** NTPC, with a comprehensive vendor enlistment system, follows a stringent competitive bidding process to identify and engage with suppliers and service providers. Vendors must fulfil the Qualifying Requirements such as technical competence, price competitiveness, past performance, financial stability, compliance with specifications, delivery timelines, and quality assurance measures, specified in the Notice Inviting Tender (NIT) and Special Purchase Conditions (SPC). Evidently, the contract procedures adopted by NTPC ensure highest level of transparency, robustness to ensure only technically sound and financially viable bidders participate in the tender process and rates are discovered in the most competitive manner.

iv. **Contractual Terms provides safeguards for Compliance of timelines by Suppliers -** To ensure that the successful bidders adhere to the contractual terms and project timelines, NTPC has safeguarding provisions like Earnest Money Deposit (EMD), Performance Bank Guarantee (PBG), Liquidated Damages and Termination in its contract. The contract documents provide unequivocal terms which are mutually agreed upon by the contracting parties before the start of the projects.

v. **Viability of Exercising Unilateral Termination -** Termination process is complex and involves settling of the rights and liabilities of the respective parties to the contract. If the termination is applied through mutual consensus, then dispute resolution mechanism method can be invoked. In case of absence of consensus (Unilateral Termination), Arbitration clause can be invoked. Unilateral termination of the Contract can have grave legal ramifications till the matter attains finality. Termination in itself a lengthy process and quite subjective as well. The termination essentially brings generating company again into the same position as was earlier before initiating termination process and timely completion of the works as envisaged cannot be undertaken resulting into such delay which is clearly not controllable.

vi. **Time and Complexity involved in Reappointment of Vendors is significant and is Uncontrollable -** Even after termination of the contract, it is still not possible for selecting a vendor in the current power development landscape. Reappointment of vendor is a time-consuming process. Normally the re tendering process takes up to 10-12 months, right from site evaluation to selection of new contractor. Majority of BTG and BOP suppliers are facing financial stress, pending order books, and undergoing diversification. Especially in BOP space where many companies have gone bankrupt, increasing the complexities. It needs specific mention that the replacement of BTG contractor is prohibitive owing to the very fact that establishing oneself as a BTG market player is a long-drawn process. The Boiler Turbine units being the heart of a thermal power station are designed to perform on critical operational parameters which is based on the proprietary technology developed by such manufacturer. Needless to say, that such technology is unique to each BTG (boiler or Turbine) player. Furthermore, the civil works associated around any specific BTG unit is also unique based on the Boiler and Turbine construction and design.

vii. **LD Provisions may not substitute recovery of Regulatory Disallowances -** Provisions such as levy of Liquidated Damages or encashment of Bank Guarantee act as a deterrent to ensure due performance of the Contractor in the stipulated time frame. Claims related to levy of damages on Contractor makes the determination of such matters even more complicated and subjective in absence of any specified process/formula for levy of damages. Further, the LD liability for contractors on account of delays is limited to ~5% as stated above which is also open to dispute before the arbitrator and higher courts. Therefore, the there is a limited liability on contractors on account of delays whereas, NTPC or any generating company has an unlimited liability on account of the same delay. The Regulator needs to appreciate this fact or else the generating company would not be able to operate its plants in a sustainable manner if such unlimited liability is laden on it. Courts construe the provisions of LD quite differently vis-à-vis the fixed approach adopted under Tariff Regulations which out rightly consider all contractual issues as Controllable. On the contrary, in spite of keeping appropriate contractual provisions delays on account of contractor remain essentially uncontrollable and needs to be decided on a case-to-case basis.

viii. Projects under Section 62 do not factor any plausible margin for time and cost overruns - Public sector enterprises are subject to audit by the CAG and have to ensure prudency and transparency in all its processes, planning and implementation mechanisms. An upfront consideration of cost and time overruns would essentially mean that the organization is factoring in inefficiency in cost/project timelines without passing through the test of regulatory scrutiny.

f) **It is suggested to add another clause to the uncontrollable factors i.e., regulation 22 (2) (d): “22 (2) (d). Contractual related issues not attributable to generating company or transmission licensee including but not limited to non-performance of contractor due to NCLT, supply disruptions, change in legal status of vendors, insolvency of**

contractors, termination, and retendering, etc. leading to delay in projects."

38) **Regulation 22 (2):**

It is suggested that delays on account of forest clearances may also be considered for inclusion in "uncontrollable factors" as proposed in Approach paper on Tariff Regulations for 2024-29.

39) **Regulation 23(d)(iv) – Initial Spares:**

a) The Draft Regulations has proposed initial spares for Gas insulated Sub-stations as under:

   i. Gas Insulated Sub-station (GIS) - 6.00%,

   ii. Green Field - 5.00%,

   iii. Brown Field - 7.00%.

b) **It is suggested that since initial spares in respect of Brown field and green field Gas Insulated Sub-stations are separately specified therefore initial spares of 6% mentioned against GIS in proposed Draft regulation appears to be superfluous and so may be deleted.**

40) **Regulation 26(1) - Additional Capitalisation beyond the original scope:**

a) **Additional capitalisation pertaining to installation of Carbon Capture, Utilisation & Storage (CCUS) system may also be allowed.**

b) **Works pertaining to Railway infrastructure for transportation of Limestone /Gypsum may also be allowed under Additional Capitalisation.**

41) **Regulation 28 – Special Allowance for coal / lignite fired thermal generating stations:**

a) The Draft regulations have proposed Special Allowance to a coal based generating station @ a flat rate of Rs 10.75 lakh per MW per year for the control period 2024-29.

b) In previous tariff periods 2009-14 and 2014-19, Special allowance was provided with annual escalation rate as that of O&M expenses norms.

c) It is suggested that for annual escalation in special allowance on similar lines as that of O&M expenses norms, i.e., escalation @5.9% may be provided.

42) **Regulation 30(iii)(a): RoE linked to ramp rate:** ROE shall be reduced by 0.25% in case of failure to achieve the ramp rate as specified under Regulation 45(9) of IEGC Regulations, 2023. At present ramp rate of 1% per minute ramp rate is now linked with new Grid Code Regulations. And further as per IEGC 2023 regulations, Ramp rate guidelines are linked with CEA Ramp rate guidelines which are very stringent**. It is proposed to continue the existing guidelines in case of Ramp rate assessment.**

43) **Regulation 30 (3)(i):**

a) In case of a new project, the rate of return on equity 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 Free Governor Mode Operation (FGMO), data telemetry, communication system up to load dispatch centre or protection system based on the report submitted by the respective RLDC.

b) This clause may be rephrased as follows: **"In case of a new project, the rate of return on equity 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 Free Governor Mode Operation (FGMO) or Primary Frequency Response (PFR), data telemetry, communication system up to load dispatch centre or**

protection system based on the report submitted by the respective RLDC".

44) **Regulation 30 (3)(ii):**

a) Regulation 30 (3)(ii) provides that in case of existing generating station, as and when any of the requirements under (i) above of this Regulation are found lacking based on the report submitted by the concerned RLDC, rate of return on equity shall be reduced by 1.00% for the period for which the deficiency continues.

b) **It is suggested that the requirement of FGMO or PFR may be relaxed for the older units since there would be requirement of major turbine and control system renovation) as to make them enable for FGMO/PFR.**

45) **Regulation 30 (3)(iii) - Ramp Rate of Gas Stations:**

a) **Regulation 30 (3)(iii) provides as under: "**In the case of a thermal generating station: a) rate of return on equity shall be reduced by 0.25% in case of failure to achieve the ramp rate as specified under Regulation 45(9) of IEGC Regulations, 2023……."

b) As per Regulation 45(9) of the IEGC Regulations, 2023; gas stations are required to declare ramp rate of at least 3% per minute. It is submitted that while gas stations can achieve ramp rate of 3% per minute in open cycle mode of operation (when only gas turbines are operational) but in Combined Cycle mode of operation (when coupled with Waste Heat Recovery Boiler and steam turbine), achieving the 3% ramp is not feasible without major retrofitting.

c) **It is therefore suggested that minimum ramp rate of 1% per minute should be considered for gas stations operating in combined cycle in line with the coal stations.**

46) **Regulation 34(a), 36(7) and 64(5) – Biomass Co-firing:**

a) It is submitted that MOP vide letter dated 16th June 2023 has issued following modifications to the "Revised Policy for Biomass Utilization for

Power Generation through co-firing in Pulverized Coal Fired Boilers issued on 8th Oct 2021 and its addendum issued on 3rd May 2023.

*3(i) All coal based thermal power plants of power generation utilities with **bowl mills,** shall on annual basis mandatorily use minimum 5% blend of biomass pellets made, primarily of agro residue along with coal with effect from FY 2024-25. The obligation shall increase to 7% with effect from FY 2025-26.*

*3(ii) All coal based thermal power plants of power generation utilities with **ball & race mills,** shall on annual basis mandatorily use minimum 5% blend of biomass pellets (torrefied only) made, primarily of agro residue along with coal with effect from FY 2024-25. The obligation shall increase to 7% with effect from FY 2025-26.*

*3(iii) All coal based thermal power plants of power generation utilities with **ball & tube mills,** shall on annual basis mandatorily use minimum 5% blend of torrefied biomass pellets with volatile content below 22%, primarily made of agro residue along with coal with effect from FY 2024-25.*

b) **It is suggested that considering mandatory requirement of co-firing biomass in coal-based plants, components of working capital comprising of coal may also include biomass as per the above MOP policy direction. Accordingly, Cost of biomass for 20 days and Advance payment for 30 days towards the cost of biomass corresponding to the normative annual plant availability factor may be included in the working capital.**

c) **Additional O&M on account of Biomass Handling Systems may be considered.**

d) **Degradation in gross heat rate and APC on account of biomass co-firing may be considered.**

47) **Regulation 34 (a) & 34(c) – Fuel cost in working capital for Open-cycle Gas Turbine/Combined Cycle thermal generating stations:**

a) **Requirement of Higher Inventory in coal stations:**

i. Maintenance spares requirement of coal stations shall increase due to flexing operations on account of RE integration. This will result in accelerated aging, wear and tear and therefore will require enhanced Repair & Maintenance. As a consequence, more inventory needs to be maintained at stations considering longer lead times for procurement, etc.

ii. **For calculation of IOWC for coal-based stations, it is proposed that the Maintenance Spares should be increased to 50 % of O&M expenses due fast wear & tear of parts because of frequent start & stop of the unit.**

b) **Requirement of Higher Inventory in gas stations:**

Considering the increased peaking operations and flexible operation leading to increased equivalent operation hours and higher frequency of inspections and overhauling, it is proposed that the Maintenance Spares should be increased to 100 % of O&M expenses due fast wear & tear of parts because of frequent start & stop of the unit.

c) **Fuel cost of Gas Stations for calculation of IOWC:**

Fuel cost for 15 days has been proposed. **However, it is suggested that the same to be increased to 30 days because of the following reasons:**

i. **RE penetration into to the grid will be in increasing trend. Required Ramp Rate for stability of the grid shall be provided by the Gas Stations.**

ii. **The PLF of gas stations expected to increase after implementation of Scheme for Pooling of Tariff of stations by MoP.**

48) **Regulation 35 - Regulatory Framework for Decommissioning:**

a) The existing 2019 Tariff Regulations provides a definition of decommissioning but has not dealt with associated aspects. It is suggested that Hon'ble Commission may consider establishing a comprehensive regulatory framework that encompasses all aspects of power plant decommissioning. In this regard, it is prayed to formulate specific regulations that address decommissioning, covering both "before useful life" and "after useful life" scenarios.

b) Regulation 35 of the Draft Regulations provides as under:

"*35(1) In case a generating station or unit thereof, or a transmission system including communication systems or element thereof after it is certified by CEA or CTU or any other statutory authority, that any asset cannot be operated or needs to be replaced on account of environmental concerns or safety issues or system upgradation or a combination of these factors not attributable to generating company or a transmission licensee, the unrecovered depreciable value may be allowed to be recovered on a case-to-case basis after duly adjusting the actual salvage value post disposal of such project.*

Provided that the manner of recovery, including a number of instalments in which such unrecovered depreciation will be allowed, shall be specified by the Commission on a case-to-case basis.

Provided further that no carrying cost shall be allowed on any delay associated with such recovery."

c) It is submitted that decommissioning thermal power plants (TPPs) prior to their expected useful life can have adverse financial implications for the generators. The regulatory framework needs to incorporate clear provisions to handle various challenges that may arise from forced decommissioning due to statutory orders and allow for appropriate compensation or cost recovery.

d) During Post-plant closure phase, we need to recover two types of costs:

   i. Residual capital base of 10%.

   ii. Additional decommissioning costs in the form of employee expenses and station overheads.

e) The following may be considered for decommissioning and asset disposal:

   i. The only source of income available for recovering these expenditures is through the sale of scrap. Enhancing the depreciable base from 90% to 95% (which is in line with the

Companies Act 2013) would partially alleviate this challenge, considering the significant number of capacities that will require decommissioning in the near future.

ii. Unrecovered depreciation: Decommissioning before the plant's expected life will result in the under-recovery of depreciation that was scheduled to be recovered from the tariff over the remaining useful life.

iii. Capital Spares: Capital spares stock that are not serviced should be treated separately and allowed as "deemed consumption" during decommissioning since they were originally procured for the plant's operation. It is important to address and resolve any difficulties arising from forced decommissioning which prevents future utilization of spares which have not been serviced till date. The generator will make all possible efforts to utilize the spares by transferring them to other plants. However, the residual capital spares if any, have to be serviced considering as deemed consumption. The cost of these spares becomes unrecovered during decommissioning.

f) By addressing the above aspects and incorporating them into the regulatory framework, we can ensure a fair and comprehensive approach to power plant decommissioning. This will safeguard the **financial interests of the generators and provide clarity on compensation and cost recovery, ultimately facilitating the decommissioning process in an efficient and sustainable manner.**

49) **Regulation 36(7) - Additional O&M expenses due to any change in law or Force Majeure event:**

a) Draft Regulations provides as under:

"Any additional O&M expenses incurred by the generating company or transmission licensee due to any change in law or Force Majeure event shall be considered at the time of truing up of tariff.

Provided that such impact shall be allowed only in case the overall impact of such change in law event in a year is more than 5% of normative O&M expenses allowed for the year."

b) In a cost-plus regulatory framework, all costs incurred prudently including that due to Change in Law or Force majeure needs to be allowed in the tariff of stations after prudence by Hon'ble Commission. Further, consideration of such costs at the time of true-up will lead to accumulation of carrying costs which may be avoided in the interests of the Discoms and the generating company. **It is humbly requested that the proviso mentioned above in which only more than 5% of normative O&M expenses are allowed for the year by the generating company at the time of true-up, may be omitted.**

50) **Regulation 36 (9) – O&M expenses of ECS**

a) Draft Regulations provides that income generated from the sale of gypsum or other by-products shall be reduced from the operation and maintenance expenses.

b) **In order to incentivize the generating company for sale of gypsum, it is suggested that income generated from the sale of gypsum shall be on 1:1 shared basis to utilise more gypsum.**

51) ***Regulation 37(2):***

a) *The generating company shall, after the date of commercial operation of the integrated mine(s) till the input price of coal is determined by the Commission under these regulations, **adopt the notified price of Coal India Limited commensurate with the grade of the coal from the integrated mine(s)** or the estimated price available in the investment approval, whichever is lower, as the input price of coal for the generating station: Provided that the difference between the input price of coal determined under these regulations and the input price of coal so adopted* *prior to such determination, the quantity of coal billed shall be adjusted in accordance with Clause (4) of this Regulation……*

b) It is submitted that cost of mining of coal depends upon various factors which differs from mine to mine.

c) Coal India Ltd. (CIL) is the mining giant of India and has numerous mines consisting of many old mines (mostly fully depreciated) and also certain developing mines. However, integrated mines being developed by NTPC are relatively new entrants in the power sector and still evolving. Some of the important differences between CIL Coal Mines and Integrated Coal Mines are mentioned below:

    i. CIL operates a large number of mines having combined stripping ratio of around 2 Cum/ Ton whereas stripping ratio of some of the mines allotted to NTPC is in the range of 4 – 5 Cum/Ton.

    ii. Land acquisition of CIL mines have been finalized much earlier so the capital cost of land in case of CIL mines is lower as compared to NTPC Integrated mines.

    iii. CIL mines are depreciated and many are operating at their peak rated capacities whereas the integrated mines allotted to NTPC are relatively new and are yet to achieve the peak rated capacity.

    iv. CIL notified price is pooled price commensurate with stripping ratio of around 2 Cum/Ton whereas the input price of NTPC mines is specific to the individual mine.

In view of the above-mentioned differences, the input price of higher stripping ratio NTPC mines may be higher than Coal India notified price.

d) In addition to the above, it is further submitted that there is an intrinsic difference between the input price determined as per the Draft Regulations and the notified price of Coal India Limited (CIL). The CIL notified price is the Pithead Run of Mine (RoM) price and does not include other charges like surface transportation charges, crushing charges, evacuation facility charges etc. which are levied separately by CIL.

e) CIL notified price also does not include the applicable statutory taxes, levies, cess etc. On the other hand, the input price determined as per the Draft Regulations takes into consideration all the costs, statutory taxes, levies, cess etc. incurred till the mine end loading point. Considering that all the costs, statutory taxes, levies, cess etc. are to be paid as per actual by the generating/mining company, adoption of the CIL notified price is likely to impact the cash flow of the generating/mining company negatively.

f) **In view of the above, it is submitted that the Hon'ble Commission may consider granting interim input price of up to ninety per cent (90%) of the input price claimed in case of new integrated mine from the date of filing of tariff petition (as proposed for the generating stations in the draft Regulations 10(3)).**

52) **Regulation 39(4):**

The generating company shall adhere to the Mining Plan for the extraction of coal or lignite on an annual basis and shall submit a certificate to that effect from the Coal Controller or the competent authority:

Provided that deviations from the Mining Plan shall be considered only if such deviations have been approved by the Coal Controller or the revised Mining Plan has been approved by the competent authority.

Comments of NTPC:

a) As per the Guidelines of Ministry of Coal dated 29th May 2020, any modification in Mine Plan for increasing sanctioned Peak Rated Capacity that is in excess of 150% of the sanctioned Rated Capacity requires approval of the Coal Controller.

b) It is pertinent to mention that there may be variations in the coal quantity extracted with respect to that as per the Mine Plan. Any such variation in coal extracted in excess of the quantity as per the mine plan up to 150% of Peak Rated Capacity are allowed with the approval of Board of the Company as per the above MOC guidelines.

c) It is further submitted that monthly and yearly coal production statement are being submitted to CCO/MoC for information in terms of the Allotment Agreements entered between the allottee/generating company of the mine and the Nominated Authority of MoC.

d) In consideration of the above, it is submitted that the requirement of submission of approval / certificate from the Coal Controller or the competent authority in respect of adherence to Mining Plan may be made applicable for production beyond the PRC only.

e) Accordingly, the above regulation may be revised as under:

For any deviation in coal production beyond the Sanctioned Capacity of the Mine, generating company shall submit approval / certificate from the Coal Controller or the competent authority.

53) **Regulation 50 (1): Recovery of Input Charges:**

(1) The input charges of coal or lignite shall be recovered as under:

Input Charges = [Input Price x Quantity of coal or lignite supplied] + Statutory charges, as applicable;

Provided that where the energy charge rate based on the input price of coal from integrated mine(s) exceeds 20% of the energy charge rate based on the notified price of Coal India Limited for the commensurate grade of coal in a month, prior consent of the beneficiary(ies) shall be required to be obtained by the generating company;

Provided further that where such consents of beneficiaries are not available, the input price of coal from such integrated mine(s) shall be so fixed that the energy charge rate based on the input price of coal from integrated mine(s) does not exceed by more than 20% of the energy charge rate based on the notified price of Coal India Limited for the commensurate grade of coal in a month;

Provided also that the energy charge rate based on the input price of coal does not lead to a higher energy charge rate throughout the tenure of the power purchase agreement than that which would have been obtained as per terms and conditions of the existing power purchase agreement.

(2) The generating company shall work out the comparative energy charge rate based on the input price of coal and notified price of Coal India Limited for the commensurate grade of coal for every month from the date of

commercial operation of integrated mine(s) and share the same with beneficiaries.

a) **Comments:** It is submitted that each coal mine project is unique in nature. The geo-mining conditions (stripping ratio etc.), the physical and chemical properties of coal, location, availability of basic infrastructural facilities like approach road and coal evacuation, all are site specific. Therefore, the comparison of the input prices of two different coal mine projects may not be on like-to-like basis.

b) It is submitted that some of the major differences between the CIL Coal Mines and NTPC Integrated Coal Mines having implications on the input price are mentioned below:

i. Coal India operates a large number of mines having combined stripping ratio of around 2 Cum/ Ton whereas stripping ratio of some of the mines allotted to NTPC is in the range of 4 – 5 Cum/Ton.

ii. Land acquisition of CIL mines have been finalized much earlier so the capital cost of land in case of CIL mines is lower as compared to NTPC Integrated mines.

iii. CIL mines are depreciated, and many are operating at their peak rated capacities whereas the integrated mines allotted to NTPC are relatively new and are yet to achieve the peak rated capacity. Pertinently the input price of NTPC mines is expected to reduce further as these mines achieve their peak rated capacity.

iv. CIL notified price is the Pithead Run of Mine (RoM) price and does not include some other charges like surface transportation charges, crushing charges, evacuation facility charges etc. which are levied separately by CIL. Whereas the input price determined as per the CERC Regulations takes into consideration all the costs, statutory taxes, levies, cess etc.

v. CIL notified price is pooled price commensurate with stripping ratio of around 2 Cum/Ton whereas the input price of NTPC mines is specific to the individual mine.

vi. In case of NTPC mines, the input price in some mines may be higher than CIL price in the initial years, but as the production ramps up and the mine achieves its peak rated capacity production, the input price decreases and would become lower than CIL price. It may be noted that CIL prices mostly tend go increase with time as successive price notifications are mostly for price hike. Therefore, the beneficiaries are benefitted by lower prices in case of integrated mines after production ramps up.

c) It is also submitted that the input price of coal of integrated mines are transparently determined by the Hon'ble Commission after prudence check and after considering comments of all the stakeholders. Beneficiaries also participate in this process of input price determination. Therefore, benchmarking with CIL price as ceiling may not be required.

d) In view of the above-mentioned major differences between CIL mines and integrated mines, the input price of NTPC mines may not be comparable to the Coal India notified price. In consideration of the same, it is respectfully submitted that the Hon'ble Commission may be pleased to waive off requirement of prior consent from beneficiaries in case energy charge rate based on input price of coal from integrated mine exceeds by 20% of energy charge rate based on notified price of Coal India Limited for the commensurate grade. Pertinently the requirement of fixation of the input price of coal from such integrated mine(s) based on the notified price of Coal India Limited for the commensurate grade of coal in a month may also be waived off.

54) **Regulation 55 - Quality Measurement of Coal Supplied by Integrated Mine:**

a) The Draft Regulation provides as under:

"55) *Quality Measurement - The quality of coal or lignite supplied from the integrated mine(s) shall be measured at the loading point through third party sampling as per the guidelines and procedure specified by the Ministry of Coal, Government of India and records of such measurement of quality of coal shall be made available to the beneficiaries on demand."*

b) **It is suggested that in the above regulation, the wording "Ministry of Coal" may be substituted with the wording "Central Government" as the Ministry of Power has also issued guidelines for third party sampling.**

c) **Further, Collection and preparation of coal sample for laboratory testing is carried out in accordance with the IS 436 (Part-1/ Section-1)-1964 and sample analysis is carried out in accordance with IS 1350 (Part 1 & 2). The same may be additionally mentioned in the above regulation.**

55)**Regulation 59: Transit and Handling Losses:**

a) The Draft Regulations has proposed the following:

For coal and lignite, the transit and handling losses shall be as per the following norms: -

Thermal Generating Station	***Transit and Handling Loss (%)***
Pit head	*0.20%*
Non-pit head - Rail	*0.80%*
Non pit head multi modal transportation (using two or more than two mode of transport involving multiple trans-shipments)	*1.00%*

b) It is submitted that in case of multi-mode coal transportation, quantity loss of 0.6% needs to be considered for each leg of rail transportation along with handling loss of 0.2%. In case of coal transportation through Rail-Ship-Rail (RSR) mode, coal is being transported twice through rail mode, first from the mine end coal siding to the loading port and secondly, from unloading port to the destination power plant. Accordingly, separate transportation loss of 0.6% for each leg of rail transportation needs to be considered along with handling loss of 0.2%, thus making it to 1.4%.

c) **Therefore, in the above regulation, it may be suggested to consider a Transit and Handling loss of 1.4% for coal transportation through RSR mode.**

56) **Regulation 62(1):**

a) **Draft Regulations provides as under:** *The fixed cost of a thermal generating station shall be computed on annual basis based on the norms specified under these regulations* ***and recovered on a 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.*** *The capacity charge shall be recovered in two parts, viz.,………*

b) **It is submitted that** WRPC & SRPC are providing monthly entitlement for peak and off-peak hours separately. However, NRPC & ERPC are providing single entitlement for a month. Billing is being done as per data available in REA.

c) **It is suggested that to have uniformity, it may be clearly defined in the Regulations that peak and off-peak hours entitlement to be considered for apportionment of Capacity Charges for peak period and Capacity Charges for off peak period respectively. Accordingly, all the RPC to provide entire details in REAs.**

57) **Regulation 62(5) and 65(4) - Incentive for Frequency Response Performance:**

a) Draft Regulations has introduced incentive linked to the Annual Fixed Charges of thermal and hydro generating stations for providing Frequency Response Performance as under:

62(5) In addition to the AFC entitlement as computed above, the thermal generating station shall be allowed an incentive of up to 1.00% of AFC approved for a given year, which shall be billed monthly as per the following.

Incentive = (1.00% x ß x CCy)/12, where

ß = Average Monthly Frequency Response Performance for that generating station, as certified by RPCs, which shall be computed by considering primary response as per the methodology prescribed by the NLDC and shall range between 0 to 1.

CCy= Capacity Charges for the Year.

65(4) In addition to the AFC entitlement as computed above, the hydro generating station shall be allowed an incentive of up to 4% of the Capacity Charge approved for a given year which shall be billed monthly as per the following.

Incentive = (4% x ß x CCy)/12,where,

ß = Average Monthly Frequency Response Performance for that generating station, as certified by RPCs, which shall be computed by considering primary response as per the methodology prescribed by the NLDC and shall range between 0 to 1.

CCy= Capacity Charges for the Year.

b) In regard to the above incentive mechanism following is suggested for consideration of the Hon'ble Commission:

i. **CCy can be finalised only at the end of FY after certification of availability by RPC. Therefore, it is proposed that the above formulae may be modified considering CCm (capacity charge for the month) so that billing can be done on monthly basis based on monthly ß as certified by RPC. Accordingly, Incentive=***1.00% x ß x CCm.*

ii. **Incentive should be computed by taking "up to the month Capacity charges" i.e., monthly performance evaluation with yearly reconciliation.**

iii. **Method of apportionment of incentive among customers may also be mentioned for better clarity.**

iv. **Methodology for calculating average monthly frequency response performance and capacity charges may be included**

in the Tariff regulations itself so that a uniform procedure for computation of ß may be achieved.

v. **As quantum of Primary Frequency Response (PFR) delivery depends upon the enthalpy of entrapped steam in the system before the control valve of the turbine so PFR performance above 70 % delivery needs to be considered as deemed full delivery of PFR and Beta may be considered as 1.**

58) **Regulation 62(7):**

(7) The provisions under Clauses (1) to (6) of this Regulation shall come into force with effect from 1.4.2024. Till that date, the capacity charge for a thermal generating station determined under these regulations shall be recovered in accordance with the provisions contained in Regulation 42 of the Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2019, subject to the condition that the NAPAF and NAPLF shall be taken as specified under these regulations.

Comment: The above paragraph is redundant and hence same may be removed. Similar clause was there in Tariff Regulations, 2019 which was kept for the dispensation of High Demand / Low Demand Season (HDS/LDS) were effective from 01.04.2020 instead of 01.04.2019.

59) **Regulation 64(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 an ex-power plant basis, at the energy charge rate of the month **(with fuel and limestone price adjustment)**. The total Energy charge payable to the generating company for a month shall be:*

Comment: The phrase "with fuel and limestone price adjustment" may be replaced with "with fuel and limestone price and fuel's calorific value adjustment".

60) **Regulation 64(3)(a):**

ECR 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)

Comment: Opening bracket before CVPF is leading to erroneous formulae and hence required to be removed.

61) **Regulation 70 (A)&(B) – Revision of NAPAF & NAPLF considering transition to RE & flexible operation:**

Further, it is submitted that with increasing RE penetration, thermal stations will be required to balance the intermittent RE generation resulting in flexible and low load operation. This change in operational pattern requiring operating in a cyclic manner with wide variations in load which will result in increase in forced outages. Hence plant availability will be severely impacted. Present norm of 85% for NAPAF/NAPLF has been fixed based on past data when there was not much cyclic operation of thermal stations. In view of the above, following are suggested:

A) **In this transition phase of power sector, there is a requirement to review NAPAF/NAPLF. It is proposed that NAPAF/NAPLF may be reduced to 80%.**

B) **Above 5% relaxation in NAPAF/NAPLF may be extended to gas-based stations also.**

62) **Regulation 70(C)(b)(i) - Maximum TG Cycle Heat Rate:**

a) The table provided at Regulation 70 (c) (b) (i) of the Draft Regulations specifies the maximum design unit heat rate for different pressure and temperature ratings of the units. In case of TG Cycle Heat Rate for 270 kg/cm2(abs) / 600°C/ 600°C, maximum turbine cycle heat rate norm has been reduced from 1800 kcal / kwh to 1790 kcal /kwh. Further, for steam parameters 270 kg/cm2(abs) /593 °C /593 °C, the maximum TG Cycle heat rate value is retained as 1810 kcal/kwh, aligning with CERC Tariff regulations for 2019-2024.

b) ***It is to be noted that as per OEM product design, for every 1°C change in Main Steam (MS) temperature and 1°C change in hot reheat (HRH) steam temperature, the TG Cycle heat rate changes by approximately 0.56 and 0.40 kcal/kwh respectively. Therefore, for a 7°C change in***

both MS and HRH temperatures, the HR improvement would be around 7 kcal/kwh.

c) There seems to be a technical discrepancy in the CERC draft regulations, where the difference in heat rate improvement for a 7°C change in temperatures is stated as 20 kcal/kwh which needs to be reviewed in light of technical design criteria as elaborated above. Further, in absolute term 1790 Kcal per Kwh considering the present scenario (when heat rate guarantees are to be sought both at rated load and at part load and considering the optimisation at both loads) is not practically possible for steam parameters 270 kg/cm2(abs) / 600°C / 600°C specially for upcoming projects unit capacity.

d) **In view of the above, following is suggested:**

   i. **Review Maximum turbine cycle heat rate for steam parameters 270 kg/cm2(abs) / 600°C / 600°C:** Review the specified limiting value of Turbine Cycle Heat rate at 100% load for Ultra-Supercritical parameters, else utilities may have no option but to opt for lower parameters and loose in terms of efficiency for 25 years.

   ii. Re-consult with turbine OEMs before finalizing the turbine cycle heat rate limits both at 100% load and at part load.

e) **In addition, Hon'ble Commission may kindly also consider the following:**

   i. **Optimization of plant at both 100% TMCR load and 55% TMCR load:** In addition to specifying the Turbine Cycle Heat rate at 100% load, the same may be also specified at 55% load, considering that units are likely to run at part load in future most of the time due to increasing RE penetration and as per projections made by CEA.

   ii. **Inclusion of Maximum Unit Design Heat Rate:** It is suggested to include maximum Unit design heat rate in the table. This is required for enabling utility/vendor to be able to guarantee unit heat rate without giving separate guarantee for TG and SG. Norms should be based on Unit heat rate.

iii. **Boiler Efficiency based on Coal Quality:** The Boiler efficiency depends mainly upon coal quality and does not depend upon type of technology employed, i.e., subcritical, and supercritical technology. Accordingly, it is requested that Boiler Efficiency specified in the table to be fixed based on coal quality and not based on technology.

63)**Regulation - 70(c)(b)(ii) - Heat Rate Norm for Kanti Stage-II**:

a) In the CERC Explanatory Memorandum, the past actual data reveals that the Five-Year Average Heat Rate for Kanti TPS is 2581 kcal/kwh.

b) Although Hon'ble Commission has taken into account an average station Heat Rate (SHR) of 2555 kcal/kWh for the plant's operations spanning from FY 2020-21 to FY 2022-23, norm of 2500 kcal/kWh has been proposed.

c) It is requested to review the proposed norm and provide a suitable margin of 50 kcal / kwh over the norms.

64)**Regulation 70 (E) - Auxiliary Energy Consumption (AEC):**

a) The norms for Auxiliary Energy Consumption for units with Steam driven boiler feed pumps have been reduced from 5.75% to 5.25% for unit rating more than 300 MW. Further, the AEC norm has been retained at 8% in case of units with motor driven boiler feed pumps (MDBFP).

It may be pertinent to point out that majority of the new projects developed are brownfield projects as this avoids many hassles including land acquisition and facilitates project execution.

In brownfield projects, opportunities for optimizing the system and layout are significantly restricted due to requirement the integration with existing plants. This limitation often results in longer distances and hence a requirement for higher auxiliary power consumption.

- **Therefore, it is submitted that AEC norms for brownfield projects should be increased even beyond earlier value of 5.75%. The advantage of going for steam turbine driven BFP will not be realised with this stringent revision of normative values.**

- **Further, existing APC norms of 8 % with motor driven boiler feed pumps also needs to be technically reviewed for further increase for 660/800 MW units based on real power consumption by higher rating BFP motors.**

Additional APC for units having electrically driven BFPs:

Draft Tariff Regulations 2024 provides for additional APC of 2.75% for 600 MW and above units for electrically driven boiler feed pumps (MDBFP) (APC of 8%). The same is inadequate for the following reasons as under:

i. 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 into boiler operating at a pressure of 270 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.

ii. Accordingly, the auxiliary power requirement for units having MDBFP exceeds the present provision of additional APC of 2.75% 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%).

iii. 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).

In view of above, additional APC of 2.75% for units having electrically driven BFPs is not adequate; instead, additional APC of at least 4% is required. Accordingly, it is submitted that CERC Tariff Regulations 2024 may provide APC of 9.75% (i.e., norms for MDBFP to be 4% more than that for TDBFP) for units having electrically driven BFPs.

b) **Additional APC for Talcher Stage-I having Tube and Ball Mills:**

i. Draft CERC Tariff Regulations 2024 has provided the proposed normative APC of 5.25% applicable to 500 MW and above unit size. In addition, thermal generating stations are allowed additional normative APC of 0.5% & 0.8% respectively having Induced Draft Cooling Tower (IDCT) and Ball & Tube mills.

ii. It is pertinent to mention that the actual APC of Talcher Stage-1 (2x500 MW) is about 7.3% against the proposed norms of 6.55%. One of the main reasons for higher APC is that the units are provided with Ball & Tube Mills, which is highly power intensive.

iii. The auxiliary power consumption of Ball & Tube Mills is significantly higher than the normal BHEL bowl mills. The average power consumption for each tube mill is in the range of 2300 KW as compared to the average power consumption of around 500 KW for each BHEL bowl mill.

iv. In this regard, a comparison of power consumption in these two types of coal mills are given below at normative loading conditions.

Description	**500 MW units**	
	Talcher Stage-I	**Typical for 500 MW**
Make/ Description of Mill	GE/Tube Mills (BBD 4772 SI)	BHEL/Bowl Mills (XRP 1003)
Unit Size (MW)	500	500
Name Plate Rating of Mills (kW)	2400	525

Loading of Mills at Full Load (kW)	2280	499
Number of mills required for full load	4	6
Total power consumption (kW)	9120	2993
Mill Energy consumption @ 0.85 PLF (MUs/annum)	67.91	22.28
Contribution towards APC (%)	1.82%	0.60%

v. As evident from above, the station like Talcher Stage-I with Tube and Ball mills required an APC of 1.82% towards milling system in comparison to 0.60% required by normal BHEL bowl mills.

vi. **Thus, an additional APC of 1.20% may be allowed to Talcher Stage-I Station operated with Tube and Ball mills instead of 0.80% proposed in draft CERC Tariff Regulations 2024.**

c) **Additional APC for Simhadri Station using Sea Water:**

i. Simhadri being coastal plants requires additional APC of around 0.13% due to usage of sea water in condenser. Due to usage of sea water, APC of the Simhadri Station is higher than the norms provided by the Draft CERC Tariff Regulations. The following factors contribute to increase in APC for power plants using sea water over the river water-based power plants.

a) SP. Gravity of Seawater: (around 2.5% higher than that of River water) – Requires more pumping power.

b) Cycles of Concentration (COC): 1.5 (instead of 3.0 for river water-based systems): Requires more blow down and more make up.

ii. The system wise additional pumping power (with sea water) required for a 2X500MW Station at 85 % load in comparison to river water-based stations is tabulated below:

	System	Additional Power (MW)
1	Cooling Water System	1.055
2	ASH HANDLING SYSTEM	0.0319

3	Auxiliary Cooling Water System	0.0102
	TOTAL	**1.0971**
	IMPACT ON APC (%) at 85% LF	**0.13**

- **It can be seen from the above table that the impact of using Sea water on Aux power Consumption for 1000 MW Station (2 X 500 MW) comes to 0.13% at 85% loading. Hence, additional APC of 0.13% may be provided to Simhadri Station using sea water in the CERC Tariff Regulations 2024.**
- **Also, additional APC of 0.5% may be provided for plants employing Reverse Osmosis (RO) / Desalination Technology for meeting water requirement from sea water.**

d) **<u>Additional APC for Vallur having Piped Conveyors & desalination plant:</u>**

i. Additional electrical powers are required for the operation of cross-country pipe conveyor system, Grab un-loader at Jetty installed for unloading of coal from the ship and desalination plant as there is no water source near the power plant of NTECL Vallur (3 x 500 MW) and the project is designed to use sea water which will be converted as potable water for drinking, service water for different purposes and DM water for process makeup & equipment cooling make up through RO conversion.

ii. It is submitted that 5.99 MW is required for cross country pipe conveyor, 4.44 MW for Grab unloader at Jetty (for unloading coal from the ship) and 5.26 MW electrical equipment (for desalination of sea water through RO system).

iii. **Hence, an additional load of 15.69 MW may be considered for calculating the APC for the Vallur station i.e., additional 1.04% of the APC may be provided over the proposed APC norms of 5.75% (5.25% + 0.5% (IDCT)).**

e) **<u>Additional APC for Equipment's/ systems being installed to comply with Statutory requirements:</u>**

i. To comply with many statutory directions or based on the need, many new equipment's / systems are added for smooth and reliable operation of plant which consume power, thereby increasing the APC of the stations.

ii. Following new equipment's are being installed in NTPC stations whose APC is not totally captured in the historical data.

   a) Dry ash evacuation system.

   b) Equipment's being installed for Zero Liquid Discharge.

   c) Equipment being installed to enable Biomass Cofiring.

   d) R&M of ESP: Installation of additional pass or additional fields row.

iii. **Hence, it is submitted that an additional APC on account of above may be allowed to the generating stations in APC norms applicable for the tariff period of 2024-29.**

f) **Additional APC for R&M of ESPs:**

i. To comply with statutory directions of meeting the environmental norms, retrofitting of ESPs is being carried out in many stations of NTPC, which is likely to increase the APC of the stations. However, additional APC on account of renovation & modernization of ESPs has not been proposed in the draft CERC Tariff Regulation 2024.

ii. As the Tariff Regulations is applicable for the five-year period of 2024-29, it is suggested that norms may be specified based on the requirement anticipated in the future in addition to past actual data.

iii. **It is therefore submitted that enabling provision of additional APC on account of retrofitting of ESP required for the specific unit/project in order to comply revised environmental norms may be provided in the CERC Tariff Regulations 2024 due to the following reasons:**

   a) Increase in number of Fields/Pass added for compliance of Environmental Norms. This has resulted in increase in corona power, heater power. Moreover, increase in ESP field had also caused increase in Draft Power (ID/FD Fan), due to increase in resistance due to sharp bends.

b) The system wise additional power required after R&M of ESP of Singrauli Station (2 x 500MW + 5 x 200 MW) is tabulated below.

Table 1: Additional Power after ESP R&M of Singrauli Stage-II (2 x 500 MW)			
Hopper heater Power (Stage-II)		**Insulator Heaters Power (Stage-II)**	
No of New Hoppers	64	Shaft Insulators heater/ ESP	8
Total Power for hopper heaters	6	Power Consumed per heater (kW)	1
Total Power for One ESP (KW)	**384**	Support Insulators/per ESP	32
		Power Consumed per Support Insulator (kW)	1
		Total Power of Insulator heater/per ESP	**40**
Total Additional Power consumed per 500 MW Unit (kW)			424
Guaranteed Corona Power for Each Unit (KW)			86
Total additional ESP power for 2 x 500 MW units of Singrauli Stage-II (kW)			**1020**

Table 2: Additional Power after ESP R&M of Singrauli Stage-I (5 x 200 MW)	
Shaft Insulators heater per ESP	16
Power Consumed per heater (kW)	1
Support Insulators per ESP	64
Power Consumed per Support Insulator (kW)	1
No of Hopper heater Per ESP	144
Hopper heater power rating (kW)	0.5
Total Additional Power per 200 MW Unit for St-I	**152**
Guaranteed Corona Power for Each Unit	**120**
Total additional ESP power for 5 units of St-I (5 x 200 MW)	**1360**

Table 3: Additional APC Power due to R&M of ESP of SIngrauli Station	
Additional APC power for Singrauli St-I (5 x 200 MW) after R&M of ESP (kW)	1360
Additional APC power for Singrauli St-II (2 x 500 MW) after R&M of ESP (kW)	1020
Total Additional APC Power due to R&M of ESP of Singrauli Station (5 x 200 MW + 2 X 500 MW) (kW)	**2380**

Hence, as evident from above table, an additional APC of 0.15% may be allowed in the APC norms proposed for the tariff period of 2024-29 due to R&M of ESPs.

g) **Specific Norms for special features like Biomass firing–may be incorporated in the Regulations:**

i. As per MoP notification all thermal plant is mandatorily co-fired biomass pellet of minimum 5% annually. Co-firing of biomass increases Heat rate & Auxiliary power consumption of station.

ii. **Thus, it is submitted that increase in heat rate & APC on account of biomass co firing may be taken care during formulation of tariff norms.**

iii. **Also, increase in energy charge rate due to biomass co-firing, if any, should not be considered for merit order scheduling.**

In view of the above, the submissions made from S. No 64(a) to 64(g) for additional APC may be suitably considered.

65) **Regulation 70(E)(f) – Norms of Auxiliary Energy Consumption for Emission Control System (ECS):**

Auxiliary power at part load will be higher so correction for part load to be given. auxiliary power consumption of Dry Sorbent Injection (DSI) System to be given based on actual power consumption of Dadri DSI. auxiliary power consumption for Selective Non-Catalytic Reduction System (SNCR) also to be provided.

66) **Regulation 70(F) - Norms of Consumption of Reagent for ECS:**

a) Regulation 70(F) of the Draft regulation provides as under:

The normative consumption of specific reagents for various technologies for the reduction of emission of sulphur dioxide shall be as under:

(a) For Wet Limestone based Flue Gas De-sulphurisation (FGD) system: The specific limestone consumption (g/kWh) shall be worked out by following the formula:

For wet FGD-Limestone Consumption = K x Normative heat rate (kcal/kWh) x Sulphur content of coal (%) kg/kWh / GCV of Coal (kcal/kg).

GCV = (a) Weighted Average Gross calorific value of coal in kCal per kg for coal based thermal generating stations computed in accordance with Regulation 60 of these regulations;

…

Provided that the value of K shall be equivalent to 35.2 for units to comply with the SO2 emission norm of 100/200 mg/Nm3 or 26.8 for units to comply with the SO2 emission norm of 600 mg/Nm3;

Provided further that the limestone purity shall not be less than 85%.

b) **It is submitted that the formula specified for working out normative specific consumption of limestone involves maintaining elaborate records and is a cumbersome process. It is to be noted that limestone cost difference works out to be very minor so normative Limestone consumption may be specified in line with normative consumption mentioned for other technologies. Further, Kg/Kwh to be deleted and purity correction to be indicated.**

c) **Part load consumption will be more. Correction for same may be provided.**

d) **For DSI, consumption varying when imported coal is being fired so correction for imported coal to be provided.**

67) **Regulation 70(F)(1)(a)**

For Wet Limestone based Flue Gas De-sulphurisation (FGD) system: The specific limestone consumption (g/kWh) shall be worked out by following the formula:

K x Normative heat rate (kcal/kWh) x Sulphur content of coal (%) kg/kWh/

GCV of Coal (kcal/kg)

Where,

GCV = (a) Weighted Average Gross calorific value of coal in kCal per kg for coal based thermal generating stations computed in accordance with Regulation 60 of these regulations;

(b) Weighted Average Gross calorific value of lignite as received, in kCal per kg, as applicable for lignite based thermal generating stations:

Comment:

The Draft Regulations has provided a margin in GCV of 85 kcal per kg for loss in calorific value during storage within the station for computation of ECR. However, it appears that same has been missed out in the above formula. It is therefore suggested that the margin in GCV of 85 kcal /kg which has been provided for coal towards loss of GCV on account of storage may be retained as was provided in 2019 Tariff regulations for working out supplementary ECR.

68) **Regulation 79 – Rebate:**

a) Draft Regulations provide as under:

79. 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 5 days of presentation of bills by the generating company or the transmission licensee, a rebate of 1.50% shall be allowed.

……………………….

(2) Where payments are made on any day after 5 days and within a period of 30 days of presentation of bills by the generating company or the transmission licensee, a rebate of 1% shall be allowed.

b) The Draft Regulations provide, the rebate of 1.5% for prompt payment of bills within 5 days from presentation of bills and 1% from payment done from 6th day to within a period of 30 days of presentation of bills and no rebate thereafter up to 45th day.

c) This dispensation provides for rebate of 1% for 15 days of advancement in payments from 45th day to 30th day from date of presentation. Further, 0.5% increment in rate of rebate is provided for advancement of payments from T+30 days to T+5 days, where T is date of presentation of bills. However, if same rate (i.e., 1% for 15 days) is maintained for advancement in payment from 30 days to date of presentation (i.e., by 30 days), rebate that needs to be provided on presentation would be as high as 3%.

d) In view of the above, it is submitted that rebate of 0.5% may be allowed on 30th day from date of presentation considering 1.5% on presentation. This will provide a uniform rebate without skewing the rate of rebate on 30th day of presentation. Therefore, it is suggested that the regulation 79(2) may be revised as under:

"79(2) Where payments are made on any day after 5 days and within a period of 30 days of presentation of bills by the generating company or the transmission licensee, a rebate of 0.5% shall be allowed."

69) **Regulation 84 - Sharing of non-tariff income:**

a) Draft Regulations provides as under:

"The non-tariff net income in case of generating station and transmission system from rent of land or buildings, eco-tourism, sale of scrap, and advertisements shall be shared between the generating company or the transmission licensee and the beneficiaries or the long-term customers, as the case may be, in the ratio of 1:1."

b) It is submitted that as per the present regulation, the salvage value of the asset is considered as 10% and the same is not to be recovered as part of tariff from the beneficiaries. Further, the Hon'ble Commission disallows certain part or cost of the capital cost during prudence check of capital cost or additional capital expenditure. Recovery through sale of scrap can't be segregated to such approved or disallowed portion of the capex of the plant. There are various other type of expenses such as processing of tender, transportation of scraps etc are associated pertaining to sale of scrap which are borne by the generator and the same is not recovered by the generator.

As any loss incurred from sale of scrap is not allowed to be claimed by the generator.

Therefore, it is suggested that the gain realized by selling of scrap should not be shared with the beneficiaries.

70) **Heat Rate Norm for NTPC Bongaigaon TPS (3x250MW):**

a) Heat Rate Bongaigaon (3x250MW) has boiler efficiency of 86% as per tariff regulations and normative heat rate is 2373 kcal/Kwh.

b) However, Design boiler efficiency is 84.95% and if it is calculated with design boiler efficiency HR will be 2403Kcal/Kwh.

c) It is submitted that NTPC Bongaigaon is losing on account of gross Heat Rate due to difference of 29.47 Kcal.

d) Normative heat rate should be using design boiler efficiency provided by Equipment Manufacturer.

e) Hon'ble Commission prescribed boiler efficiency & turbine heat rate first time in Tariff Regulations 2009. Bongaigaon Station was envisaged in 2006 and Cabinet approval was accorded in Feb' 07. NTPC Board approval was accorded in Jan'08 and Award of Boiler and Turbine packages to BHEL were done in Feb'08 - much earlier than issuance of Tariff Regulations 2009. At that time such limitations was not known to NTPC. Therefore, it was not possible for NTPC to envisage such stringent norms.

f) **It is therefore suggested that operational norms including boiler efficiency applicable at the time of award of projects should be retained for such units.**

71) **Operational norms for TSTPS**

a. Heat Rate: New Normative is 2375 Kcal/kwh, however the average of last 10years Heat Rate of TSTPS-I & TSTPS-II is 2403 & 2388 respectively.

	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23	**Average**
TSTPS-I	2399	2370	2378	2487	2410	2386	2420	2430	2345	2406	**2403**
TSTPS-II	2359	2352	2377	2459	2360	2376	2419	2427	2351	2403	**2388**

Considering the above, **the normative Heat Rate may be kept at 2390Kcal/kwh (instead of 2375) in line with regulation 2019-24**.

b. The normative Heat Rate may be **increased by 30Kcal/Kwh for stations completed 25 years** as on 31.03.2024.

c. **APC:** Allowed APC for Talcher STPS-I as per Regulation may be calculated as below.

5.25(norm)+0.5(IDCT)+0.8(Tube Mill) = 6.55%

However, actual average of last 10 years APC of Talcher STPS-I is 7.57. average PLF 84%.

TSTPS-I	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24 (till Dec)	**Average**
APC	7.18	7.30	7.80	7.99	7.89	8.21	7.49	7.50	7.18	7.19	**7.57**
PLF	85.48	89.42	87.06	87.66	80.15	68.80	84.13	82.84	86.44	88.64	**83.98**

d. Allowed APC for Talcher STPS-II as per Regulation may be calculated as below.

5.25(norm)+0.5(IDCT) = 5.75%. However, actual average of last 10 years APC of Talcher STPS-I is 5.83%. average PLF 85.31%.

TSTPS-II	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24(till Dec)	**Average**
APC	6.09	5.74	5.57	5.70	5.61	5.80	6.24	6.09	5.90	5.69	5.73	**5.83**
PLF	82.63	92.53	91.71	86.88	87.32	81.17	75.24	82.92	84.85	89.33	83.88	**85.31**

In addition to the above, additional systems for mine void filling, Dry Ash Evacuation, Biomass firing etc will increase the APC further.

Hence, Considering the above, **the normative APC may be kept at 5.75% (instead of 5.25%) in line with regulation 2019-24.**

Talcher STPS-I may be considered as a special case to allow the APC as 7.50%.

72)**Transit Losses for North Karanpura STPS**

100 % Coal is being transported through trucks at North Karanpura. It is requested that separate norm for “Transit and handling loss” for coal transportation through

truck mode may be considered by Hon'ble Commission. In this regard, it is submitted that in the case of pit-head stations, if coal or lignite is procured from sources other than the pit-head mines due to reasons not attributable to the generators and transported to the station through rail /road, transit and handling losses applicable for non-pit head stations may be applicable.

73)**Compensation for Synchronous Condenser, STATCOM, etc.:**

a) Addition of renewable energy is leading to reduction in inertia, short circuit power and dynamic reactive power in the grid, which are the key elements of grid stability and reliability.

b) Considering the ambitious RE integration planned in future, there is a need to install compensation devices, such as, synchronous condensers, STATCOMS, which can provide these ancillary services and help in grid stability.

c) Therefore, there is a need to have a uniform cost recovery mechanism for different compensation devices (STATCOM, synchronous condensers etc.). Also, tariff/cost recovery mechanism for these compensation devices shall promote the investment in these areas for installation of equipment for grid stability.

d) **It is therefore suggested that provision of tariff/cost recovery mechanism for compensation devices, such as, synchronous condenser, STATCOM, etc. may be included in the Tariff regulations.**

e) **It is also suggested that incentives for providing inertia in the grid, and fast dynamic reactive power may be included in the Tariff regulations.**

74)**Aspects Related to Energy Storage System (ESS):**

a) Energy Storage System (ESS) will be required for thermal generating stations for integration of upcoming RE and enhance their flexibility.

b) It is therefore suggested that Tariff Regulations may consider addition of provisions related to ESS. Provisions related to definition, and capital expenditure on account of installation of energy storage system to enhance flexibility of thermal generating stations may be included in the Tariff Regulations, 2024.

75) **Additional Capitalization for decarbonization:** To achieve GoI NDC target, decarbonisation in thermal power sector has become mandatory. Following are the option to decarbonise thermal power plant:

a) Carbon capturing, Utilisation, and storage

b) Co-firing of carbon neutral fuel like biomass, green methanol and non-carbonous fuel like ammonia etc.

However, to make the thermal units suitable for above option additional capital investment will be required. In view of above, additional capitalisation under the head of ammonia/ methanol co-firing, CCUS and integration of thermal energy storage need to be included.

76) **Flexible Operation at Lower Loads –** Capital expenditure may be required to enable flexible operation of the generating station at lower loads. It is suggested that the regulation may also clearly include the specific aspects of flexible operation (such as minimum load – 40%/ 55% & ramp rates) for such expenditure.

77) **Additional O&M expenses for Coastal projects -** Additional O&M expenses are to be provided for Coastal projects like Simhadri, Vallur etc which is using sea water for cooling system & ash disposal, as the actual water charges are less compared to other projects. (Actual Water Charges in FY 22-23: Simhadri: Rs. 17.36 Cr, Korba: Rs.101.49 Cr, Mouda: Rs. 48 Cr). It is also pertinent to mention that due to corrosive nature of sea weather, huge expenses are being incurred in maintaining structural health & integrity and also on recurrent painting.

78) **Aspects Related to Hydro:**

a) ***Regulation 3(24):*** Regulation 3(24) of the Draft Regulation has proposed design energy of hydro station as under:

"'Design Energy' *means the quantum of energy which can be generated in a 90% dependable year with 95% installed capacity of the hydro generating station."*

<u>Comments:</u>

i. It is submitted that the definition of 'Design Energy' applicable for a Pump Storage Project (PSP) may also be included. In this regard, following definition is suggested for PSPs:

ii. *"Design Energy of a Pump Storage Project (PSP) means the quantum of energy which can be generated with 95% installed capacity of the plant considering 75% cycle efficiency with a daily single cycle of operation."*

b) ***Regulation 3(32): 'Force Majeure'*** *for the purpose of these regulations means the events or circumstances or combination of events or circumstances, ……………………...:*

(a) Act of God including lightning, drought, fire and explosion, earthquake, volcanic eruption, landslide, flood, cyclone, typhoon, tornado, geological surprises, or exceptionally adverse weather conditions which are in excess of the statistical measures for the last hundred years; or……….

…………………………

Comments of NTPC:

1. It is submitted that in the definition of 'Force Majeure', pandemic may also be included. Accordingly, the proposed revised definition is as follows:

'Force Majeure' *for the purpose of these regulations means the events or circumstances or combination of events or circumstances, ……………………...:*

(a) Act of God including lightning, drought, fire and explosion, earthquake, volcanic eruption, landslide, flood, cyclone, typhoon, tornado, geological surprises, ***pandemic*** *or exceptionally adverse weather conditions which are in excess of the statistical measures for the last hundred years; or……..*

………………………

2. It is also submitted that in the definition of 'Force Majeure', a new clause (e) as per the following may also be added:

(e) State/Central Government Stop Order or Public Protest Resulting in Delay of Work due to reasons beyond Owner's control.

c) ***Regulation 21. Interest During Construction (IDC) and Incidental Expenditure during Construction (IEDC):*** *(5) If the delay in achieving the COD is attributable either in entirety or in part to the generating company or the transmission licensee or its contractor or supplier or* *agency, in such cases, IDC and IEDC due to such delay may be disallowed after prudence check either in entirety or on pro-rata basis corresponding to the period of delay not condoned vis-à-vis total implementation period and the liquidated damages, if any, recovered from the contractor or supplier or agency shall be retained by the generating company or the transmission licensee, in the same proportion of delay not condoned vis-à-vis total implementation period.*

Provided that in case of activities like obtaining forest clearance, NHAI Clearance, approval of Railways, and acquisition of government land, where delay is on account of delay in approval of concerned authority, in such cases maximum condonation shall be allowed up to 90% of the delay associated with obtaining such approvals or clearances.

…………………………

Comments of NTPC:

1. It is submitted that the generating company/project owner make all-out effort to comply with the statutory requirements for various clearances and approvals by submitting the documents/making studies/analysis etc. In this regard, generating company/project owner has also to get the data from the external agencies which is sometimes beyond its control.
2. In view of the same, it is submitted that the proviso to Regulation 21(5) may be modified as per the following:

Provided that in case of activities like obtaining forest clearance, NHAI Clearance, approval of Railways, and acquisition of government land, where delay is on account of delay in approval of concerned authority, in such cases maximum condonation shall be allowed up to ***100%*** *of the delay associated with obtaining such approvals or clearances.*

d) ***Regulation 65. Computation and Payment of Capacity Charge and Energy Charge for Hydro Generating Stations:***

……………………

(9) In case the energy charge rate (ECR) for a hydro generating station, computed as per clause (5) of this Regulation exceeds one hundred and twenty

*paise per kWh, and the actual saleable energy in a year exceeds {DE x (100-AUX) x (100 - FEHS) /10000} MWh, the energy charge for the energy in excess of the above shall be billed **at one hundred and twenty paise per kWh only**.*

……………………..

Comments of NTPC:

1. It is submitted that the energy charge rate for the excess energy in reference to net saleable design energy has been kept unchanged as "one hundred and twenty paise per kWh".
2. It is submitted that the energy charge rate for such excess energy/secondary energy may be increased to at least "**one hundred and fifty paise per kWh**" as there shall be increased wear and tear of the equipment due to extra running hours in generating the excess energy. Furthermore, the required increase is also justified considering the inflation over the period.

e) ***Regulation 66. Computation and Payment of Capacity Charge and Energy Charge for Pumped Storage Hydro Generating Stations:***

Comments of NTPC:

1. It is respectfully submitted that for clarity, the computation of Capacity charges and Energy charges in case of Pumped Storage Hydro Generating Stations may be illustrated with examples for different case scenarios.
2. It is also submitted that in case the no. of cycle of operation are greater than the single cycle of operation, the energy charge may be revised accordingly.

f) ***Regulation 71. Norms of Operation for Hydro Generating Stations: The norms of operation as given hereunder shall apply to hydro generating stations:***

(B) In the case of pumped storage hydro generating stations, the quantum of electricity required for pumping water from the down-stream reservoir to the up-stream reservoir shall be arranged by the beneficiaries duly taking into account the transmission and distribution losses up to the bus bar of the generating station………………...

……………………

Provided further that the beneficiaries may assign or surrender their share of capacity in the generating station, in part or in full, or the capacity may be reallocated by the Central Government, and in that event, the owner or assignee of the capacity share shall be responsible for arranging the equivalent energy to the generating station in off-peak hours, and be entitled to corresponding energy during peak hours in the same way as the original beneficiary was entitled.

…………………

<u>Comments of NTPC:</u>

1. It is respectfully submitted that the second proviso to Regulation 71 (B), quoted above may be modified as per the following:

   ………………...

   Provided further that the beneficiaries may assign ~~or surrender~~ their share of capacity in the generating station, in part or in full, or the capacity may be reallocated by the Central Government, and in that event~~, the owner or~~ ***new*** *assignee of the capacity share shall be responsible for arranging the equivalent energy to the generating station in off-peak hours, and be entitled to corresponding energy during peak hours in the same way as the original beneficiary was entitled.* ***However, in case original beneficiary fails to assign new assignee for the capacity or the capacity is not reallocated by the Central Government to any other assignee, suitable compensation in terms of Annual Fixed Charges (AFC) shall be paid to the owner by the original beneficiary(s).***

   ………………..

g) ***Regulation 71. Norms of Operation for Hydro Generating Stations: The norms of operation as given hereunder shall apply to hydro generating stations:***

(C) Auxiliary Energy Consumption (AEC):

Type of Station	AEC	
	Installed Capacity above 200 MW	Installed Capacity upto 200 MW

Surface		
Rotating Excitation	0.7%	0.7%
Static	1.0%	1.2%
Underground		
Rotating Excitation	0.9%	0.9%
Static	1.2%	1.3%

Comments of NTPC:

1. It is respectfully submitted that the Auxiliary Energy consumption (AEC) of a PSP shall also include the Auxiliary energy consumed during pumping operation. Accordingly, the AEC for PSP may be increased at least by 1.0%.

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ANNEXURE-1

Sl.No.	NTPC Stations	Installed Capacity (MW)	Actual heat Rate (Average of FY 21-22 & FY 22-23) (kCal/kWh)	Heat Rate norms as per Draft CERC TR 2024 (kCal/kWh)		Indicative Gain (+)/Loss (-) *	
						Before Sharing	After Sharing
COD of Stations before 01.04.2009							
	a. 200 MW Units						
1	Kahalgaon-I	840	2,422	2,400		-25	-25
2	Vindhyachal-I	1260	2,421	2,400		-8	-8
	S.TOTAL	**2100**				**-33**	**-33**
	b. 500 MW Units						
1	Vindhyachal-3	1000	2,375	2,375		2	1
2	Sipat 2	1000	2,355	2,375		11	6
3	Vindhyachal-2	1000	2,376	2,375		3	1
4	Rihand-1	1000	2,363	2,335		-11	-11
5	Rihand-2	1000	2,396	2,375		-12	-12
6	Talcher-1	1000	2,373	2,375		-10	-10
7	Talcher-II	2000	2,375	2,375		-2	-2
	S.TOTAL	**8000**				**-19**	**-27**
	c. Combination of 200 MW & 500 MW Units						
1	Singrauli	2000	2,406	2,388		-39	-39
2	Korba 1&2	2100	2,362	2,382		29	15
	S.TOTAL	**4100**				**-10**	**-24**
COD of Stations after 01.04.2009 (500 MW & Above units)							
1	Korba 3	500	2,323	2,351		8	4
2	Vindhyachal 5	500	2,345	2,336		0	0
3	SIPAT-I	1980	2,290	2,290		4	2
4	Darlipalli	1600	2,130	2,196		29	15
5	Lara	1600	2,163	2,207		53	27
6	Vindhyachal-4	1000	2,346	2,336		-2	-2
7	Kahalgaon-2	1500	2,375	2,351		-35	-35
8	Rihand-3	1000	2,406	2,336		-27	-27
9	Nabinagar	1980	2,252	2,215		-27	-27
	S.TOTAL	**11660**				**3.9**	**-43.5**
A	**G.TOTAL**	**25860**				**-58**	**-128**

** Indicative loss is on account of heat rate and APC*

ANNEXURE-2

TABLE 1: STATIONS OPERATING LESS THAN LOADING FACTOR OF 85% AND ABLE TO RECOVER LOSSES

Sl.No.	Stations	Installed Capacity (MW)	Heat Rate norms as per Draft CERC TR 2024 (kCal/kWh)	Actual Heat Rate corrected at 85% Loading Factor (Average of FY 21-22 & FY 22-23) (kCal/kWh)	APC norms as per Draft CERC TR 2024 (%)	Actual APC corrected at 85% Loading Factor (Average of FY 21-22 & FY 22-23) (%)	Indicative Impact (Rs Cr) [Due to norms or Actual whichever is lower]
1	Dadri-I*	840	2,400	2,386	8.50	8.41	0
2	Ramagundam-III*	500	2,375	2,289	5.75	6.24	0
3	Simhadri-I*	1000	2,375	2,364	5.25	5.10	0
4	Ramagundam I&II*	2100	2,382	2,315	6.68	7.23	0
5	Dadri-2	980	2,340	2,322	5.25	4.95	0
6	Simhadri-2	1000	2,337	2,329	5.25	4.81	0
7	Mouda-1	1000	2,336	2,325	5.75	4.82	0
8	SOLAPUR	1320	2,215	2,180	5.75	5.46	0
9	KHARGONE-I	1320	2,153	2,136	5.75	5.55	0
10	GADARWARA	1600	2,215	2,176	5.75	5.94	0
11	KUDGI	2400	2,200	2,021	5.75	4.59	0
12	MOUDA-II	1320	2,218	2,220	5.75	4.11	0
	S.TOTAL	**15,380**					**0**

TABLE 2: STATIONS OPERATING LESS THAN LOADING FACTOR OF 85% AND NOT ABLE TO RECOVER LOSSES FULLY

Sl.No.	Stations	Installed Capacity (MW)	Heat Rate norms as per Draft CERC TR 2024 (kCal/kWh)	Actual Heat Rate corrected at 85% Loading Factor (Average of FY 21-22 & FY 22-23) (kCal/kWh)	APC norms as per Draft CERC TR 2024 (%)	Actual APC corrected at 85% Loading Factor (Average of FY 21-22 & FY 22-23) (%)	Indicative Loss (Rs Cr) [Norms or Actual whichever is lower]
1	Unchahar-I*	210	2,400	2,477	9.00	9.64	-30
2	Unchahar-II*	420	2,400	2,446	9.80	8.95	-9
3	Unchahar-III*	420	2,400	2,439	9.00	8.26	-4
4	Farakka I&II*	1600	2,384	2,423	6.47	7.59	-98
5	Unchahar IV	500	2,336	2,351	5.75	5.71	-5
6	Farakka-3	500	2,351	2,428	5.75	5.84	-32
7	TANDA-II	1320	2,199	2,233	5.25	5.60	-55
8	BARH-I	660	2,284	2,343	5.75	7.09	-48
9	BARH-II	1320	2,223	2,259	5.75	5.21	-29
	S.TOTAL	**6,950**					**-311**

* Heat rate norms applicable for stations achiveing COD before 01.04.2009.