lalitpur power generation company limited

(Bajaj Group)

Comments/Suggestions/Objections

on

Draft CERC (Terms and Conditions of Tariff) Regulations, 2019

Contents

Preamble

The Hon'ble Commission's Draft Tariff Regulations for the period 2019-24 proposes significant changes to the incumbent CERC Tariff Regulations for 2014-19. Most of these proposed changes, if implemented, shall prove detrimental to the financial health of already distressed power plants thereby affecting their long-term sustainability. Further, any major departure in the fundamental approach from established principles may lead to regulatory uncertainty and deter funding by lenders for any upcoming new plants in future.

Some of the key changes including changing the Normative Annual PAF (NAPAF) to Normative Quarterly PAF(NQPAF) for capacity charge payment purpose are fundamentally against the spirit of the Electricity Act 2003 and Tariff Policy 2016 thereby restricting recovery of capacity charge by the generating stations. It is submitted that these capacity charge are in the form of interest on loans, O&M charges, interest on working capital and depreciation (Principal repayment). which are required to be serviced even in case of lower generation from the plants. As also acknowledged by the Hon'ble Commission, dwindling supply of linkage based Coal has created an alarming situation for the thermal power generators as they are not able to declare their full potential in terms of availability. Further, owing to non-approval by the DISCOMs and lack of regulatory guidelines, the power plants are unable to proceed for procurement of alternate coal in terms of high priced imported and forward e-auction coal. This results in a straight under recovery of capacity charge and affects the financial viability of the project. Given this situation, linkage of capacity charge with higher levels of availability would only result in further under recovery for the generators and in turn would further aggravate the stress faced by the thermal generating stations.

Delay of payment by the DISCOMs (beneficiaries) also affect the generator's ability to procure coal and incur other expenses necessary for power plant operation and may result into coal shortage, availability of the station as well as debt service defaults.

In our view, the proposed changes to the existing regulations shall act as a deterrent for the growth of the thermal power generation sector and would further lead to depletion of the value of investments already made and hamper future investor confidence and flow of funds into the sector.

Some of the key observations and suggestions with respect to these draft regulations are summarized below:

i. Introduction of NQPAF in a scenario when coal availability is not ensured to the generating company could be fatal for the generating station and specially for Private Sector Power Plants which have coal availability equivalent to 45% PLF (SHAKTI) to 57% PLF (Post 2009 FSA)

ii. If NQPAF is required to be considered for recovery of capacity charge, it should be graded considering the linkage of coal available with the generating stations. Also, separate NQPAF should be introduced based on type of plant (pit-head and non-pit head) and ownership of the plants (Government Sector and Private Sector Power Plants)

iii. Provision for Non-recovery in capacity charge of the generators due to unavailability of coal for reasons not attributable to generators should be eliminated.

iv. Appropriate escalation in O&M expenses should be allowed which would adequately reflect the actual increase in the cost of O&M components. Benchmarks such as WPI – CPI indexes should be adjusted for non-related commodities and outliers.

v. Retain the allowance of 30 days of coal inventory for non-pit head plants while computing the working capital

vi. Linking of incentive for thermal plants with PLF has become irrelevant due to lower off-take. Instead, incentives should be linked to plant availability factor

vii. Recommendations of CEA for approving higher GCV Loss for non-pit head coal should be considered with additional 40-50 kCal/kg towards slippage on account of spraying of water required during coal storage and its handling.

viii. Adequate provision for payment security mechanism specifically for Private Sector Power Plants where the growing outstanding dues are a major cause of concern

ix. Large delay in payment by the distribution utilities is impairing the ability of the generating companies to service debt and make payments for coal on time. The financial stress resulting from such delays should be addressed by way of adequate payment security mechanism as also highlighted by High Level Empowered Committee.

x. Payment security mechanism should be strengthened in order to reduce the large outstanding

xi. Truing-up should not consider any revenue from non-tariff income as benchmarks and norms are already provided for all operational parameters and provisions for sharing of benefits resulting from over-achievement in technical norms is already covered.

xii. Proposal for consideration of weighted average rate of interest on additional capitalization after cut-off date would be a deterrent for essential capital expenditure on account of flexible operations, compliance to environmental norms, etc.

We are hereby providing our detailed comments and suggestions on the Draft (Terms and Conditions of Tariff) Regulations, 2019 proposed by the Hon'ble Commission. We look forward to a considerate view by the Commission on our suggestions and anticipate the inclusion of our suggestions.

1. Recovery of Capacity charges based on Normative Plant Availability Factor

The Availability Factor of a unit/generating station reflects its readiness over a period of time to meet the declared capacity as per the schedule. From a commercial aspect, Availability is a reflection of the station's ability to recover its capital cost within the stipulated time period. Considering its significance, plant operators endeavour to ensure the upkeep of all main equipments and auxiliaries and other related systems round the clock. However, it is a well-known fact that certain parameters including availability of coal, quality of coal received, water and other inputs, and similar other aspects not under the control of the station affect the Availability of the unit/station to a large extent. In the draft regulations, the Hon'ble Commission has proposed a significant change of moving from normative annual PAF to normative quarterly PAF. The draft provisions with respect to the existing norms (as per Tariff Regulations 2014-19) are provided in the table below:

Existing CERC Norms 2014-19	Proposed CERC Norms 2019-24
Normative Annual Plant Availability Factor (NAPAF)- 85% *Provided that in view of shortage of coal and uncertainty of assured coal supply on sustained basis experienced by the generating stations, the NAPAF for recovery of capacity charge shall be 83% till the same is reviewed.*	*For all thermal generating stations, except those covered under clauses (b), (c), (d), & (e) - 83%* *Provided that for the purpose of computation of Normative Quarterly Plant Availability Factor, annual scheduled plant maintenance shall not be considered.*
The fixed cost of a thermal generating station shall be computed on annual basis, based on norms specified under these regulations, and recovered on monthly basis under capacity charge. The total capacity charge payable for a generating station shall be shared by its beneficiaries as per their respective percentage share / allocation in the capacity of the generating station	*Normative Plant Availability Factor for "Peak" and "Off-Peak" periods shall be equivalent to the NQPAF specified in Regulation 59 (A) of these regulations. The number of hours of "Peak" and "Off-Peak" periods in a region shall be declared on monthly basis in advance, by the concerned RLDC and the Peak period in a day shall not be less than 4 hours.* *(4) The generating company shall be allowed to recover the monthly Peak period Capacity Charge upon achievement of PAF equivalent to the NQPAF for cumulative Peak period during the month, and the monthly Off-Peak Period Capacity Charge upon achievement of PAF equivalent to the NQPAF for cumulative Off-Peak period during the month.* *(5) Achievement of PAF less than the specified NQPAF in "Peak" or "Off-Peak" periods shall result in pro-rata reduction in recovery of Capacity Charge for the appropriate period.* *Provided that if the cumulative peak period PAF achieved during a quarter is more than the specified NQPAF for peak period and the cumulative Off-Peak period PAF achieved during the quarter is less than the specified NQPAF for Off-Peak period, the loss in recovery of Capacity Charge for Off-Peak period shall be off-set*

	against the notional gain on account of over-achievement in Peak period, subject to the ceiling of full recovery of Capacity Charge for Off-Peak period; *Provided further that if the cumulative peak period PAF achieved during the quarter is less than the specified NQPAF for peak period and the cumulative Off-Peak period PAF achieved during the quarter is more than the specified NQPAF for Off-Peak period, the loss in recovery of Capacity Charge for Peak period shall not be off-set against the notional gain on account of over-achievement in Off-Peak period;* *Provided also that carry forward of under-recovery of Capacity Charge shall not be allowed for recovery from one quarter to the subsequent quarter.*

The Hon'ble Commission has mentioned that the existing target availability norm of 85%, includes the margin required for scheduled or planned outages required for annual inspection and maintenance of the generating station. The normative target availability being proposed to be met on quarterly basis, as against annual basis, the thermal generating stations may not get sufficient time for annual inspection and maintenance within a quarter. The Commission has therefore proposed that for the purpose of computation of quarterly PAF, annual scheduled plant maintenance shall not be considered.

Comments

The existing provisions of Tariff Regulations 2014-19 provides for maintaining 85% availability on an annual basis for full recovery of the capacity charge. It is submitted that maintaining the NAPAF of 85% itself is difficult for the generators considering the limited commitment of coal from CIL and its subsidiaries with an added lower priority offered to Private Sector Power Plants for supply of coal. Under the current circumstances, the proposed shift of NAPAF to NQPAF is detrimental to financial health of the generation business. NAPAF provisions served to address the existing shortage of domestic coal affecting availability of plant NAPAF provided that the generator meets the normative requirement on an annual cumulative basis and thereby ensured recovery of the capacity charge, interest repayment, O&M expenses, depreciation, etc.

- The proposed change to NQPAF would result in non-recovery of legitimate capacity charge of the generator that would directly affect its financial health and affect long term commitments and sustainability. This is essentially due to the non-availability/shortage of requisite amount of coal to be made available under the FSA during such quarter. While there is no incentive available for the generator for maintaining a high PAF, provision for the quarterly availability would directly affect the recovery of capacity charge.

- Availability of the stations is directly impacted by the availability of coal which is currently supplied by subsidiaries of CIL. As per the Fuel Supply Agreement signed with these coal companies, the Annual Contracted Quantity (ACQ) for post 2009 Power Plants is restricted to 76% of the plant PLF (90% of normative PLF of 85%). Moreover the actual coal supplied by the coal company gets further lower due to restriction of coal supply (upto 75% of the ACQ) which is the trigger level for penalty. Ultimately power plants are getting coal equivalent to 57% PLF. Therefore, while the generator is required to commit for 85% availability of recovering its capacity charge, the coal supply is only ensured up to 57% PLF. Further, coal allocation under SHAKTI B(ii) Scheme entails an additional reduction in the availability of coal resulting in overall coal availability equivalent to 46% PLF. The actual supply is further lowered due to preference for Private Sector Power Plants in lower order of priority allocation.

- The aspect of shortage of coal affecting the availability of plants get further compounded by the fact that the long term PPAs with state distribution utilities do not provide/provide for a limited period allowing procurement of high priced e-auction/imported coal to meet the shortfall of coal to ensure plant availability.

- Non-availability of coal is not treated as a Force Majeure event in most of the long term PPAs. The generator therefore is subject to a paradoxical situation wherein domestic linkage based coal is not made available to generators in quantity as per FSA terms and the generator cannot continue to procure e-auction/imported coal amidst the uncertainty of not getting reimbursed for higher coal price.

- In the "Report of the High Level Empowered Committee" to Address the issue of Stressed Thermal Power Projects, one of the key recommendations on short supplies of coal is as under:

  "If there is a shortfall in the supply of coal and it is attributable to the Ministry of Coal or Railways; such shortfall need not lapse and be carried over to the subsequent months up to a maximum of three months"

In order to demonstrate the actual realization of capacity charges, the following three scenarios have been developed based on the coal linkage available to the generating stations under the current context.

a. **Scenario 1- Materialisation of Coal for post 2009:**

Under FSA for post-2009 power plants, Annual Contracted Quantity (ACQ) is just sufficient for 76% PLF (90% of normative PLF of 85%). Scenario 1 therefore assumes that total 100% materialization of coal shall happen under the FSA on an annual basis for the central sector generator. This may only be possible in case of Government Sector Power Plants as they have higher priority as compared with the Private Sector Power Plants.

b. **Scenario 2- Materialisation of Coal for Power Plants post 2009:**

Actual materialisation in case of Private Sector Power Plants is much lower than ACQ, due to restriction imposed on Private Sector Power Plants by coal companies and railways at trigger level which is 75% of ACQ. While the Government Sector Power Plants get above 90% materialisation which is sufficient for PLF of 70-76%, the actual coal supply in case of Private Sector Power Plants is sufficient to sustain generation at around 57% PLF. Therefore, Scenario 2 considers the actual materialization of coal for a Private Sector Power Plants and the loss resulting from under-recovery in capacity cost.

c. **Scenario 3 - Materialisation of Coal under SHAKTI B(ii) Scheme:** It is submitted that coal allocation under SHAKTI B(ii) Scheme is even lesser at around 80% of 76% PLF equivalent (Annual contracted quantity of Post 2009 Stations) i.e. equivalent to 61% PLF. However the actual supply by coal companies is normally restricted up to trigger level of 75% of allocation which is equivalent to 46% PLF. In this shortage scenario, Private Sector Power Plants are compelled to source costly coal through special forward e-auction/import to meet the generation demand which will result into higher variable cost.

The basic assumptions considered under each of the above scenarios are as under:

- Plant size- 210 MW
- Annual Capacity charge required- Rs. 148.66 Cr.
- Peak running hours- 4 hours
- Off-peak running hours- 20 hours
- Number of days in a month- 30

Based on the above assumptions, the results for each of the scenario are summarised below

a. Scenario-1: Materialisation of Coal for Government Sector Power Plants post 2009

The **Government Sector Power Plants** get 90% and above materialisation which is sufficient for PLF of 70-76%. This scenario assumes Achievable materialization of 100% coal as per FSA i.e. 76.5%. Availability aligned with the coal supply assuming that the CIL commitments as per FSA are met. Considering that the complete ACQ of coal corresponding to 76.5% of PLF is made available, this would lead to would result in NQPAF of 76.5% for the respective quarter and an under-recovery of fixed cost/capacity charges for the respective quarter. Further, in this scenario, the availability in peak hours has been taken similar to off-peak hours.

Particulars	Units	Peak hours	Off-peak hours
Quarterly Availability	%	76.5%	76.5%
Quarterly CC recovered	Rs. Cr.	6.76	27.03
Total CC recovered	Rs. Cr.	33.78	
CC at normative availability	Rs. Cr.	36.66	
Quarterly under-recovery of CC	Rs. Cr.	2.87	

In this optimistic scenario when 100% of ACQ is available to the Government Sector Power Plants, an under-recovery of 8% in annual capacity charges is envisaged.

As an additional option to Scenario-1, it is considered that the benefit of peak hours could be utilized by the generator to maximize its capacity charges. Therefore, a 90%

availability is considered during peak hours while the availability during off-peak hours would deteriorate to 73.8% in view of the limited coal availability.

Particulars	Units	Peak hours	Off-peak hours
Quarterly Availability	%	90.0%	73.8%
Quarterly CC recovered	Rs. Cr.	9.29	24.96
Total CC recovered	Rs. Cr.	34.25	
CC at normative availability	Rs. Cr.	36.66	
Quarterly under-recovery of CC	Rs. Cr.	2.41	

Even under maximization of benefits by providing higher availability (90%) during peak hours, Government Sector Power Plants will end up losing 7% of the annual capacity charges for the respective quarter.

b. Scenario-2: Materialisation of Coal for Private Sector Power Plants post 2009

In this scenario, the actual materialization of coal in case of Private Sector Power Plants (75% of ACQ = 57.4%) has been considered in view of the ground level situation. Due to absence of level playing field for Private Sector Power Plants, the materialization is significantly lower due to restriction imposed on Private Sector Power Plants by coal companies and railways at trigger level which is 75% of ACQ. It has been assumed that the PAF during peak hours and off-peak hours would be maintained at similar level.

Particulars	Units	Peak hours	Off-peak hours
Quarterly Availability	%	57.4%	57.4%
Quarterly CC recovered	Rs. Cr.	5.07	20.27
Total CC recovered	Rs. Cr.	25.337	
CC at normative availability	Rs. Cr.	36.66	
Quarterly under-recovery of CC	Rs. Cr.	11.32	

Under the existing conditions the under-recovery in any quarter could be to the tune of 31% of the capacity charge for the quarter and this would not be recoverable in the subsequent quarters.

c. Scenario 3 - Materialisation of Coal under SHAKTI B(ii) Scheme:

Private Sector Power Plants those were allocated coal under the SHAKTI B(ii) scheme, have even lower coal allocation at around 80% of the quantity i.e. equivalent to 61% PLF. Actual supply by coal companies is restricted up to trigger level of 75% of allocation which is equivalent to 45-46% PLF. Accordingly, the recovery of capacity charges under this scenario has been computed separately as below:

Particulars	Units	Peak hours	Off-peak hours
Quarterly Availability	%	46%	46%
Quarterly CC recovered	Rs. Cr.	4.05	16.22
Total CC recovered	Rs. Cr.	20.27	
CC at normative availability	Rs. Cr.	36.66	
Quarterly under-recovery of CC	Rs. Cr.	16.39	

It can be observed from the table above that in case of coal allocation under the SHAKTI B(ii) scheme, the Private Sector Power Plants could only recover 55% of the capacity charges leading to shortfall of 45% in each quarter. This shortfall would not only erode the complete RoE entitled to the Private Sector Power Plants but also make the serviceability of loan and payment of O&M expenses difficult.

Therefore, it is highlighted that the proposed quarterly based PAF would only result in under-recovery of the capacity charge due to limited commitment of coal under the present FSA and prevailing ground level conditions. This under-recovery in any quarter cannot be safeguarded in the subsequent quarters as the proposed methodology restricts the recovery of shortfall of one quarter in subsequent quarters. Further, it needs to be mentioned here that the Annual Contracted Quantity (ACQ) committed under the FSA is not same across each quarter to accommodate the seasonal effect on coal production which further restricts the generator's ability to achieve same NQPAF in each of the four quarters. As per the model FSA, the ACQ is envisaged to be met as follows:

	Apr-Jun (Q1)	Jul-Sep (Q2)	Oct-Dec (Q3)	Jan-Mar (Q4)
Proportion of ACQ	25%	22%	25%	28%

From the above table, it is inferred that the maximum quantities of coal is available during last quarter (Jan-Mar) when the demand of electricity is lowest while during the peak season (Jul-Sep) the commitment to supply coal is lowest i.e. 22% of ACQ. Therefore, the generator would receive short-supply of coal by 3% (25%-22%) during the second quarter. Considering the short-supply of coal during the Q2, the above scenarios have been used to compute the shortfall in capacity charge on account of lower availability of coal during the second quarter. The results are shown in table below:

Particulars	Normal Recovery of Capacity Charge considering similar coal supply in all quarters	Recovery of Capacity Charge considering lower allocation (22%) of coal during Q2	Difference (Loss on account of shortfall in coal supply)	Under-recovery (in %) due to coal short-supply during Q2
Scenario 1: Post 2009	33.79	29.73	4.05	12%
Scenario 2: Post 2009 (Private Sector Power Plants**)**	25.34	22.30	3.04	12%
Scenario 3: SHAKTI B(ii) allocation	20.27	17.84	2.43	12%

The above table shows that there is further under-recovery of approx. 12% during Q2. While the short-recovery is only on account of lower coal supply commitment from the CIL, the generator would be penalized for the under-performance.

Therefore, while the draft regulations have proposed availability to be constant across all four quarters, the aspect of unequal distribution of coal availability across the quarters has not been factored in. The inconsistency associated with the coal supply across the four quarters restricts the ability of the generator to supply uniform power and recover its capacity charge. It is important that the Regulations should also be aligned with the market conditions to have effective implementation. However, the proposed amendments do not consider all these aspects that are outside the control of the generator and would only act as a deterrent for the power generation sector.

As stated earlier, restrictions in case of sourcing coal from alternate sources, such as, procurement of coal through imports or forward e-auction requires prior consent from beneficiaries and is mostly not approved. In addition to the shortage of coal affecting availability, there is loss in quantity and quality of coal during coal dispatch, receipt, storage, handling and firing in the plants that require due consideration.

The issue of availability of coal is also aggravated with respect to the supply of coal from mine to the plants. The supply of coal from mine site to the generating plants gets affected due to uncontrollable parameters like curtailment of transportation, availability of wagons, Govt. Orders etc. An on-going testimony to this affect is in the state of U.P where coal transportation has been significantly affected due to increase in passenger traffic owing to the Kumbh-Mela at Allahabad during 05th Jan – 04th March 2019 at Allahabad. This has resulted in limiting the number of days of operation for coal supplied to the region. With the norms of meeting NQPAF in place, such events would put additional pressure on the generating companies to meet the norms.

As per the draft regulations, the following restrictions in recovery of capacity charge have also been proposed:

- Under-recovery in capacity charges due to under-achievement of NQPAF would not be allowed for recovery from one quarter to the subsequent quarter
- Loss in recovery of capacity charge for Peak period shall not be off-set against the notional gain on account of over-achievement in Off-peak period

It is submitted that the above restrictions in adjustment of PAF encumbers the generator with additional risk for recovery of the capacity charge. As already discussed in the previous Para, the restriction in coal availability itself is a hindrance in achievement of the NQPAF and in addition, the inflexibility in the NQPAF mechanism provides additional challenges. As highlighted earlier, the availability during peaking quarter (Jul-Sep) the coal availability ensured by CIL is lowest i.e. 22% of ACQ while the demand remains higher which is bound to result in an underachievement during the respective quarter. As per the proposed mechanism, the generator would not be entitled to recover this loss in the subsequent quarters which is completely uncontrollable in nature.

Stringent availability norms, which are on quarterly basis and introduction of mechanism for differential peak and off-peak recovery of capacity charge, are detrimental to the health of already ailing generating stations. Moreover, conditions like restriction in carrying forward of under-recovery in subsequent quarter and adjustment for under achievement in PAF during peak hours with off-peak hours availability would only result in further increasing the risk of non-recovery of capacity charge. This clearly indicates that the proposed mechanism for differential peak and off-peak recovery of capacity charge is completely against the principles of cost recovery of assets of generating companies and would surely lead to serious financial difficulties in future.

Based on the above explanation, it is submitted that the proposed introduction of NQPAF is unachievable for the generating stations and if implemented would lead to generators not being able to meet their debt servicing requirements. Also, considering that the capacity charge is not being allowed to be carried forward, the target of 83% is very steep and would lead to under recovery in capacity charge for generator. It will surely impact the generator's earnings and would not only have the negative impact on RoE but also on serviceability of debt which would eventually make Private Sector Power Plants the Non-Performing Assets (NPAs).

Coal evacuation & Railway Logistics constraints

Coal availability remains a issue due to rail logistics constraints. Coal supply to non-pit head stations is affected due to serious coal evacuation issues at mine end..

There are several mines in Central Coalfields Limited (CCL), Mahanadi Coalfields Limited (MCL) and South Eastern Coalfields Limited (SECL), where the issue of road and rail infrastructure is a serious bottleneck for evacuation of coal.

For Example, the coal from Amrapali & Magadh mines in Central Coalfields Limited (CCL) is getting bottled up due to poor road infrastructure upto siding and partial operation of Tori-Shivpur-Kathautia railway line leading to poor off-take of coal to **Non-Pit Head Power** Stations.

Further transportation of coal through congested railway network from mine to non-pit head stations is seriously hampered. This is mainly due to inadequate electrification of Railway network, non-availability of diesel locos, inadequate availability of crew members and MG-BG conversion.

It is also relevant to analyse as to why the Hon'ble Commission thought of changing the norms of Plant Availability Factor from Annual basis to Quarterly basis.

We can put forward only three reasons for declaring lower availability in peak period namely (i) Machine being on outage (ii) Coal constraints (iii) Wilful lower declaration by the generator with a view to divert the power to some other source say Power Exchange owing to better realisation.

In case of (i) Machine outage - Hon'ble Commission has itself recognized that the outage is beyond the control of the generator and hence has been exempted even under the quarterly PAF proposal.

In case of (ii) Coal constraints - In the foregoing paragraphs it has been elaborated how coal is a CIL monopoly and procurement of coal upto normative 85% has not been assured even under the FSA/SHAKTI B(ii). The actual supply is further lowered due to poor materialisation. These issues have already been elaborated in the foregoing paragraphs and not been reiterated for the sake of brevity.

In case of (iii) Wilful lower declaration by the generator - it is respectfully submitted that Power Purchase Agreements already have suitable checks and balances and appropriate penal provisions incorporated in them to tackle such aspects. In this regard, it is relevant to reproduce Article 4.4 and Article 4.5.1 of the Model Power Purchase Agreement for Procurement of Long Term Power, Standard Bidding Document - Case 1 Bidding Procedure:

"*4.4 Purchase and sale of Available Capacity and Scheduled Energy*

4.4.1 Subject to the terms and conditions of this Agreement, the Seller undertakes to sell to the Procurers, and the Procurers undertakes to pay Tariff for all of the Available Capacity up to the Contracted Capacity and corresponding Scheduled Energy.

4.4.2 Unless otherwise instructed by all the Procurers (jointly), <u>the Seller shall sell all the Available Capacity to each Procurer in proportion of each Procurer's then existing Contracted Capacity pursuant to Dispatch Instructions of such Procurer." (Emphasis supplied)</u>

"*4.5 Right to Contracted Capacity and Scheduled Energy*

4.5.1 Subject to provisions of this Agreement, <u>the entire Aggregate Contracted Capacity shall be for the exclusive benefit of the Procurers and the Procurers shall have the exclusive right to purchase the entire Aggregate Contracted Capacity from the Seller. The Seller shall not grant to any third party or allow any third party to obtain any entitlement to the Contracted Capacity and/or Scheduled Energy" (Emphasis supplied)</u>

Similarly, in case of Model Power Supply Agreement (DBFOO) framed by the Ministry of Power, Govt. of India, Article 18.2, 18.3 and 24.1.4 are relevant clauses which have been reproduced below:

"*18.2 Contracted Capacity*

*Pursuant to the provision of this Agreement, the Supplier <u>shall dedicate a generating capacity of *** MW to the Utility as the capacity contracted hereunder</u> (the "Contracted Capacity") and the <u>Contracted Capacity shall at all times be operated and utilized in accordance with the provision of this agreement</u>.*

18.3 Committed Capacity

The Parties expressly acknowledge and undertake that the <u>Contracted Capacity</u> hereunder along with similar capacity contracted between the Supplier and other Distribution Licensees and supply of electricity in accordance with the provisions of Section 63 of the Act <u>shall at all times be dedicated for production of electricity</u>

and supply thereof to the Utility and/or other Distribution Licensees with whom such agreement have been signed (the "Committed Capacity") and shall be utilized in accordance with the instructions of the Utility and/or such Distribution Licensees, save and except as provided in this agreement.

24.1 Dispatch of Contracted Capacity

24.1.4 In the event the Supplier schedules any electricity, produced from Contracted Capacity, for sale of Buyer in breach of this Agreement, the Supplier shall pay Damages equal to the higher of: (a) twice the Fixed Charge; and (b) the entire sale revenue accrued from Buyer. For the avoidance of doubt, no Fixed Charge or any amount in lieu thereof shall be due or payable to the Supplier for and in respect of any electricity sold hereunder." (Emphasis supplied)

Thus, it can be seen that under both Case-1 and DBFOO bidding guidelines and relevant PPA/PSA, suitable provisions have been built in by the Ministry of Power to tackle the issue of wilful lower declaration of availability by the generator with a view to divert the power to some other source say Power Exchange owing to better realisation.

In reference to the reasons cited above, the Hon'ble Commission is therefore humbly requested to continue with NAPAF as set-out in the FY2014-19 Tariff Regulations. Further, the splitting of Peak and Off Peak periods should be avoided.

Further to above, there should be a differentiation of NAPAF for Pit head and Non-Pit head stations due to very serious issues in coal transportation infrastructure in India where coal is transported to a longer distance. It is proposed to have two sets of NAPAF as below :

a) PIT Head Power Plants – 83%

b) Non-PIT Head Power Plants – 70-75 %

2. Operation and Maintenance Norms

In previous Tariff regulations, the Hon'ble Commission has adopted the approach of approving O&M norms on the basis of unit size in case of coal based generating stations and on the basis of actual O&M expenses for past years for hydro generating stations. The Hon'ble Commission has now made following changes in the draft regulations for thermal stations as summarised below.

Existing CERC Norms 2014-19	Proposed CERC Norms 2019-24
29. Operation and Maintenance Expenses: *(1) Normative Operation and Maintenance expenses of thermal generating stations* *shall be as follows:* *(a) Coal based and lignite fired (including those based on Circulating Fluidised Bed Combustion*	*35. Operation and Maintenance Expenses:* *(1) Thermal Generating Station: Normative Operation and Maintenance expenses of thermal generating stations shall be as follows:* *(1) Coal based and lignite fired (including those based on Circulating Fluidised Bed Combustion*

*(CFBC) technology) generating stations, other than the generating stations/units referred to in clauses (b) and (d):: **(in Rs. Lakh/MW)***

Year	200/ 210/ 250 MW Sets	300/ 330/ 350 MW Sets	500 MW Sets	600 MW Sets and above
FY2014-15	23.9	19.95	16	14.4
FY2015-16	25.4	21.21	17.01	15.31
FY2016-17	27	22.54	18.08	16.27
FY2017-18	28.7	23.96	19.22	17.3
FY2018-19	30.51	25.47	20.43	18.38

(CFBC) technology) generating stations, other than the generating stations or units referred to in clauses (b) and (d): (in Rs. Lakh/MW)

Provided that the norms shall be multiplied by the following factors for arriving at norms of O&M expenses for additional units in respective unit sizes for the units whose COD occurs on or after 1.4.2014 in the same station.

200/210/250 MW	Additional 5th& 6th units	0.90
	Additional 7th& more units	0.85
300/330/350 MW	Additional 4th& 5th units	0.90
FY 17	Additional 6th& more units	0.85
500 MW and above	Additional 3rd& 4th units	0.90
	Additional 5th& above units	0.85

The Water Charges, Security Expenses and Capital Spares for thermal generating stations shall be allowed separately prudence check

Year	200/ 210/ 250 MW Sets	300/ 330/ 350 MW Sets	500 MW Sets	600 MW Sets and above
FY2019-20	30.59	24.22	20.38	17.39
FY2020-21	31.57	24.99	21.03	17.94
FY2021-22	32.58	25.79	21.71	18.52
FY2022-23	33.62	26.62	22.4	19.11
FY2023-24	34.69	27.47	23.12	19.72

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

The Water Charges and capital spares for thermal generating stations shall be allowed separately.	*(6) The Water Charges, Security Expenses and Capital Spares for thermal generating stations shall be allowed separately prudence check:* *Provided that water charges shall be allowed based on water consumption depending upon type of plant, type of cooling water system etc., subject to prudence check. The details regarding the same shall be furnished along with the petition:* *Provided further that the generating station shall submit the assessment of the security requirement and estimated expenses;.* *Provided also that the generating station shall submit the details of year wise actual capital spares consumed at the time of truing up with appropriate justification for incurring the same and substantiating that the same is not funded through compensatory allowance or special allowance or claimed as a part of additional capitalisation or consumption of stores and spares and renovation and modernization.*

The changes proposed in O&M expenses by the Hon'ble Commissions is after examining and reviewing the actual O&M expenses incurred by the generating stations with an escalation of 3.20% to arrive at the O&M expenses for FY 2019-20 to FY 2023-24.

Comments

- There is no secular increase in the normative O&M expenses as per the draft Tariff Regulations 2019-24 for the first year of the control period i.e. FY 2019-20 vis-a-vis the terminal year of the previous control period i.e. FY 2018-19.

Series	200/210/250 MW Series	300/330/ 350 MW Series	500 MW Series	600/660 MW Series	800 MW Series and above
FY 2018-19	30.51	25.47	20.43	18.38	18.38
FY 2019-20	30.59	24.22	20.38	17.39	17.39
YoY Increase(+) / Decrease (-)	0.26%	-4.91%	-0.24%	-5.39%	-5.39%

It can be observed that while in case of 200/210/250 and 500 MW series, the year on year increase is almost nil, but in case of 660 MW units, instead of a secular yearly increase, a reduction of 5.39% has been proposed in the base year itself. This is owing to the fact that the Hon'ble Commission has considered the sample of only one station namely Sipat TPP owned and operated by NTPC. It is respectfully submitted that one station cannot be representative of the entire 660 MW units in the country and needs to be reviewed by the Hon'ble Commission.

The average annual O&M escalation rate as per the FY 2014-19 regulations was 6.3%. Further, the security expenses are around Rs. 20,000/MW. Taking the escalation rate of 6.3% as a base and reducing security expenses from the base, O&M expenses for FY 2019-20 for 660 MW units should have been Rs. 19.33 lakh/MW as depicted in the table below.

Series	200/210/ 250 MW Series	300/330/ 350 MW Series	500 MW Series	600/660 MW Series	800 MW Series and above
FY 2018-19	30.51	25.47	20.43	18.38	18.38
FY 2019-20	32.22	26.86	21.50	19.33	19.33

- The percentage share of the components of O&M expenses is as follows:
  Employee Cost: 50-55%
  R&M: 30-35%
  A&G expenses and Overheads: 15-20%

- Since Employee Cost forms the major part of the O&M expenses, correctly capturing this element is essential for fixation of prudent norms of O&M expenses. While doing so, the following factors must be considered. The wage structure of Private Sector Power Plants is higher than PSUs, however some part of it is off-set by lower number of manpower/MW. The annual increase in wages of employees in Private Sector Power Plants is around 6-10% on an average.

- Station overheads also comprise 60-70% of total overheads as salary on account of security, corporate offices etc. It is also seen that R&M expenses also comprise 50% of total cost towards the labour cost which is again linked to the manpower cost.

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

- Based on the above analysis, it can be construed that over 60% of the total O&M expenses is directly related to manpower cost engaged in O&M activity of power plants and this manpower cost is generally increasing at about 6-7% in case of PSUs and 6-10% in case of Private Sector Power Plants per annum which is beyond the control of the generating companies.

- Considering the above, it is felt that the current practice of weightage of 60% to WPI and 40% to CPI does not capture the reality in case of escalation of actual O&M expenses and it is suggested that the weightage of CPI should be at least 80% for capturing the escalation of the O&M expenses. The allowable escalation index for FY 2019-24 control period thus ought to be around 4.90% per annum as depicted in the table below:

Year	Average CPI	% Change	Average WPI	% Change
FY 2012-13	215		106.9	
FY 2013-14	236	9.77%	112.5	5.24%
FY 2014-15	251	6.36%	113.9	1.24%
FY 2015-16	265	5.58%	109.7	-3.69%
FY 2016-17	276	4.15%	111.6	1.73%
FY 2017-18	284	2.90%	114.9	2.96%
Average		5.75%		1.50%
Weights		80%		20%
Allowable Escalation Index	4.90%			

- It is pointed out that the main sub-heads of WPI indices are namely (i) Primary Articles (ii) Coal and Power (iii) Manufactured Products (iv) Food Index. The average increase in such sub-heads is provided in the tables below:

Year	Average WPI - Primary Articles	% Change	Average WPI - Coal and Power	% Change
FY 2012-13	111.4		107.1	
FY 2013-14	122.4	9.87%	114.7	7.10%
FY 2014-15	125.1	2.21%	107.7	-6.10%
FY 2015-16	124.6	-0.40%	86.5	-19.68%
FY 2016-17	128.9	3.45%	86.3	-0.23%
FY 2017-18	130.6	1.32%	93.3	8.11%
Average Increase		3.29%		-2.16%

Year	Average WPI - Manufactured Products	% Change	Average WPI - Food Index	% Change
FY 2012-13	105.3		110	
FY 2013-14	108.5	3.04%	120.6	9.64%
FY 2014-15	111.2	2.49%	125.8	4.31%
FY 2015-16	109.2	-1.80%	127.3	1.19%
FY 2016-17	110.7	1.37%	134.7	5.81%
FY 2017-18	113.8	2.80%	137.3	1.93%
Average Increase		1.58%		4.58%

Thus, it can be seen, that the WPI index has been distorted by the remarkable reduction in Power and Coal cost by around 20% in FY 2015-16. However, this was temporary phase and the effect in reduction by such a significant number never reflected in reduced salaries or reduced O&M expenses by any way. Hence, such abnormalities ought to be ignored, which otherwise would lead to fixation of below par escalation index.

- Impact of GST on the O&M contracts, etc. to be included – GST became effective from 01.07.2017 due to which the tax on O&M contracts went up from 15% to 18%. The impact due to the change in law including GST needs to be considered separately while arriving at the base O&M expenses for the next tariff period. Averaging the O&M expenses for the 5 year would not capture the impact of GST which had been effective for 6 months in FY 2017-18.

- Ash handling and disposal charges should be given over and above O&M expenses, similar to water charges, as these are incurred on account of MoEF Notification and the expenses are dependent upon various factors like availability of land for ash dyke, quality of coal burnt, distance to be travelled for disposal, covering top soil with grass etc. MOEF notification dated 25.01.2016 stipulates that the cost of transportation of ash for road construction projects or for manufacturing of ash based products or use as soil conditioner in agriculture activity within a radius of 100 Km from a coal or lignite based thermal power plant shall be borne by such coal or lignite based thermal power plant and the cost of transportation beyond the radius of 100 km and up to 300 km shall be shared equally between the user and the coal or lignite based thermal power plant. Further, the income, if any, from ash disposal has to be utilized for environment protection and hence, cannot be deducted from the cost of handling/ disposal. Present norms of O&M expenses based on NTPC's plants do not cover such expenses for most of its plants as they have ash dykes for which capitalization is allowed separately. It is respectfully pointed out that the Hon'ble Commission has already approved ash handling and disposal as Change in Law for Case-1 power projects in several cases (Example: CERC Order dated 22.6.2018 in Pet No. 171/MP/2016). The same may be uniformly applicable to all generators by provision in the Tariff Regulations for FY 2019-24.

- Further, it is respectfully submitted that the actual O&M costs are increasing due to partial and cyclical operation of the thermal power stations. The proposed lower levels of O&M expenses for FY 2019-20 and subsequent years would result in under-recovery of O&M expenses which would lead generator to compromise in maintenance cost of equipments leading to poor availability of station, unsafe operations due to non-availability of spares/services and low employee motivation due to lower compensation. It is requested that the base O&M expense for FY 2019-20 and escalation thereafter may be determined by the Hon'ble Commission after considering the aforementioned aspects.

  Considering the above submissions, Hon’ble Commission is requested that the base O&M expense for FY 2018-19 should be considered along with escalation of 4.90 % for projecting the O&M expenses for the Period FY 2019-24.

3. Incentive on PLF

For generation, the incentive prior to 2009 was linked to normative PLF and 25 paise/kWh was paid for generation beyond normative PLF in case of thermal generating station. In the CERC Tariff Regulations 2009-14, incentive was linked to normative availability and generation beyond normative availability was payable at the fixed charge rate for the stations. During the Tariff Period 2014-19, Incentive for coal based generating plants was again linked to normative PLF of 85%@ 50 paise/kWh. The Hon'ble Commission has now proposed following changes in the draft regulation as showcased below-

Existing CERC Norms 2014-19	Proposed CERC Norms 2019-24
Incentive to a generating station or unit thereof shall be payable at a flat rate of 50 paise/kWh for ex-bus scheduled energy corresponding to scheduled generation in excess of ex-bus energy corresponding to Normative Annual Plant Load Factor (NAPLF)	*In addition to the capacity charge, an incentive shall be payable to a generating station or unit thereof @ 65 paise / kWh for ex-bus scheduled energy during Peak period and @ 50 paise / kWh for ex-bus scheduled energy during Off-Peak period corresponding to scheduled generation in excess of ex-bus energy corresponding to Normative Quarterly Plant Load Factor (NQPLF)*

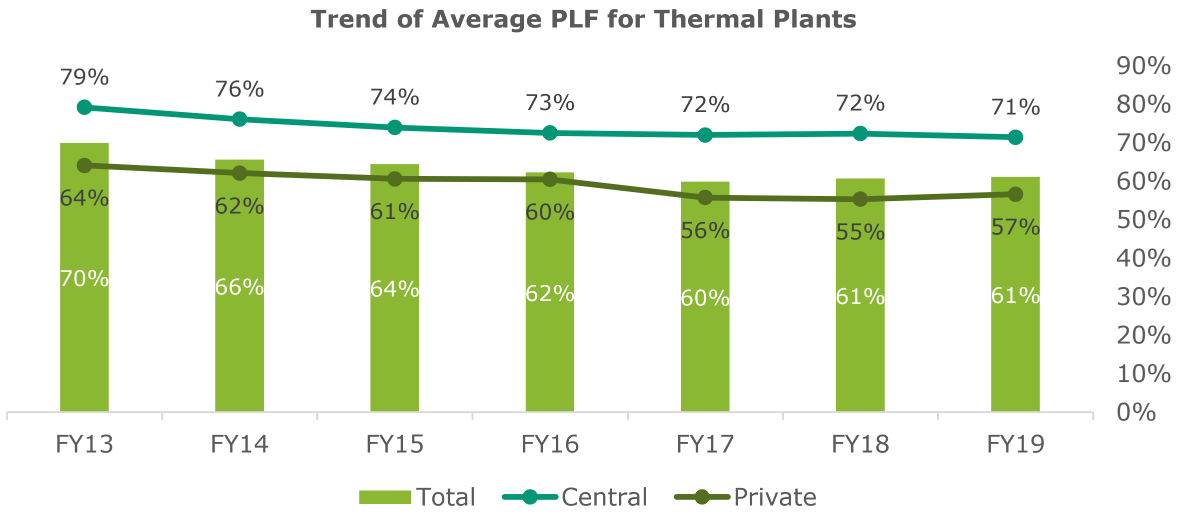
The Hon'ble Commission has stated that to promote availability and generation during the peak hours, a differential incentive for peak and off-peak hours has been proposed.

Comments

It is submitted that with increased penetration of renewable sources of energy, higher PLF of thermal generating stations has become irrelevant. There is an increasing requirement to run the thermal generating stations on part capacity during various intervals more so in case of non-pit-head generating stations which stand lower in the Merit Order Despatch (MOD). This eventuality of running non-pit head coal based stations on part loads shall become a norm of near future considering increasing RE penetration.

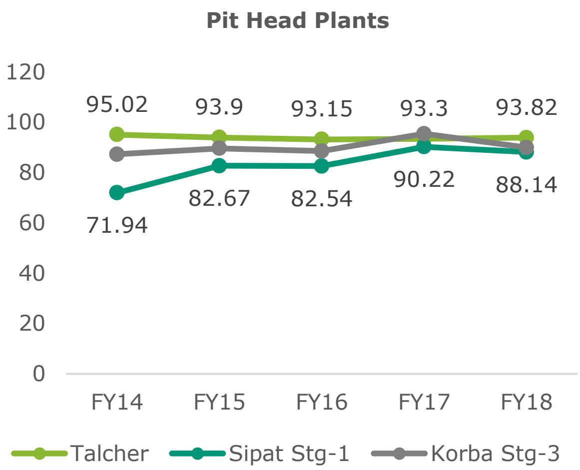
Also, considering the coal supply scenario prevailing in the country where adequate coal supply in not ensured to the power plants and coal companies tend to limit the quantities to minimum level provided in the FSA (as also discussed in the section above), the scenario of achieving PLF of 85% typically does not arise in case of non-pit head, post 2009 plants. In the proposed norms of incentive on PLF, the power plants located at Pit head and commissioned before 2009 will be benefited. This is more so in case of Private Sector Power Plants where the coal supply is further constrained due to lower preference provided by the coal companies as compared with the Government Sector Power Plants owned generating stations. The decline in PLF of thermal generating stations and particularly for Private Sector Power Plants due to reasons discussed above can be inferred from the figure below which represents the average PLF of thermal generating stations at national level and comparison with average PLF for Government Sector Power Plants and Private Sector Power Plants.

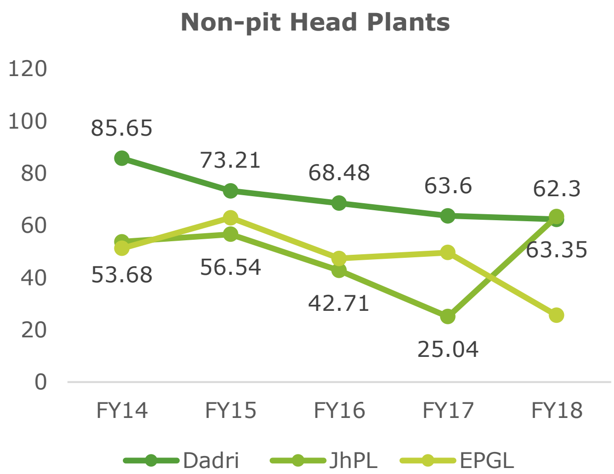
It is evident from the figure below that national average PLF of the thermal generating stations has declined in the past few years (Source: MoP and CEA). The average PLF of the Private Sector Power Plants are even lower than the national average by 4-5% on account of coal unavailability as well as lower dispatch. It is understood that the declining trend in the recent past could be attributed to the increased capacity available from renewable energy.



Also, as estimated in the National Electricity Plan of CEA, the PLF of thermal stations is likely to come down to around 56.50% by 2021-22. As per the data for last five years, it is observed that the PLF of the thermal generating stations has been declining and are operating at levels much below the normative PLF defined in the regulations for the purpose of incentive. The issue is more alarming in case of non-pit head generating stations as compared to pit-head generating stations which have lower variable cost.

A comparison of the PLF for pit-head and non-pit head generating stations for last five years is shown in the graph below:





The High Level Empowered Committee report on addressing issues on stressed thermal power projects (Nov. '18) has clearly outlined the under-utilization of thermal power assets as one of the reasons for increased stress in the power plant industry.

As per the HLEC report,
"Lower than anticipated growth in power demand coupled with a scenario of surplus supply has resulted in under-utilization of thermal power capacity. In addition to this, large quantum of untied PPAs, termination / non-operationalization of PPAs, low off-take/ difficulties in selling costlier power are also causing stress in thermal power projects"

Going forward, with increased renewable penetration, the PLF of thermal stations is going to further reduce particularly in case of non-pit head stations having lowest preference in the merit order. Therefore, it is submitted that linkage of incentives with PLF considering the current as well as the future scenario is incorrect. Linking of incentive to PLF greater than 85% when thermal generating stations are required to be more and more operationally flexible is against the various measures/ regulations, which promote flexibility in operations of generating plants (viz. the 4th amendment of IEGC's regulations require ISGS to attain a technical minimum of 55% with recommended compensation). Further, the proposed PLF of 85% is unachievable in the present scenario for non-pit-head generating station in particular.

In view of growing importance to availability, it is proposed that the incentive should be linked to plant availability factor instead of PLF as also adopted by the Commission in the Tariff Regulations 2009. As an alternate, PLF of 85% could be reduced to 60-65% in view of actual energy scheduled and unavailability of coal.

4. Gross Calorific Value (GCV)

a) Loss of GCV between "As Received and "As Fired"

The Hon'ble Commission in its earlier Tariff Regulation did not specify any norms with respect to transit and handling losses of primary fuel. In the 2014 Tariff Regulations, the Hon'ble Commission had specified that the gross calorific value for computation of energy charges shall be done in accordance with GCV on "as received" basis. However, following addition has been done by in the draft regulation wrt Normative GCV loss as pronounced below-

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

The Hon'ble Commission has taken review of suggestions provided by the stakeholders and actual data of past years and has observed that in case of non-pit head generating stations, which are located more than 1,000 km away from the mines, the actual transit and handling losses are significantly higher. Further, the Hon'ble Commission has also noted the recommendation of CEA on loss of GCV between "GCV As received" basis at generation station and have proposed weighted average GCV loss of 85 Kcal/Kg on account of variation.

Comments

Under the draft regulations, the Hon'ble Commission has specified a normative GCV loss of 85 Kcal/kg on account of variation during storage at generating station while computing the Energy Charge.

To this effect, it may be noted that there are several aspects resulting in grade slippages of the coal quality received at the power station as stated below.

- Coal quality reduction takes place during coal handling, transport and storage. A large part of which is beyond the control of the generator and therefore results in additional loss.

- The loss in GCV is a factor which is uncontrollable at the end of the generator and varies widely based on factors like seasonal aspects. The loss of heat during rainy season is significantly higher due to the moisture content in the coal received which is a direct loss to the generator. The coal company or the railways do not take any risk on the moisture content in coal at the loading end or during transportation, the entire risk is passed on to the generating company and the same is unrecoverable as per the provision of the existing regulations.

- GCV Loss in coal are attributable to three (3) key reasons viz.

    i. Storage Losses - Coal has inherent Volatile Matter that gets diffused during storage at unloading point, transportation and coal inventory in power plants.
    ii. Sampling Methodology – It is manual and taken from top of wagon while the moisture settles at the bottom of wagon. This does not reflect the real moisture content in the supplied coal. Moreover only 6 wagons are normally selected per rake (as per FSA) which is in contradiction with sampling methodology as per IS 436 (part I) according to which minimum 25 % wagons should be selected randomly i.e. about 15 wagons/rake.
    iii. Spray on coal storage for reducing coal dust reduces its GCV by approx. 50-60 kCal/kg for every 1% moisture addition.

GCV loss between "As Billed" by Coal Company and "As Received" at generating stations

- In the entire value chain from mine end to generating station end, the loss of GCV can take place on account of grade slippage at mine end and during transportation (transit with railway).

- The generating companies generally have no control over the grade/GCV of coal received at their generating stations. There are several cases of grade slippages between the mine mouth and at the site of generating stations. Further, there is loss in GCV during transport of coal through Railway. Therefore, the generator may receive coal of lower GCV than what is billed by the coal companies. These are beyond the control of the generating companies.
- In the consultation paper, the Hon'ble Commission had deliberated on the issue of grade slippage between loading point and generating station and had proposed

some sharing mechanism with the Coal Company and railways. The relevant para in the consultation paper is as below

> *Since the cost of slippage in grade of coal between the loading point and the site of generating station is ultimately passed on to the beneficiaries, this issue needs to be looked at in terms of risk allocation between the coal company, railways and the generating stations. The issue of grade slippage is significant in case of domestic coal as the GCV measurement is being done at Free on Board (FOB) through acceptable practice. This poses specific challenges with respect to the measurement point and method/ procedure for measurement of Gross Calorific Value (GCV).*

However, it is observed that no methodology or mechanism has been proposed in this regard in the draft regulations. The Commission is requested to develop an appropriate mechanism which allows sharing of such grade slippage in order to reduce the burden of increasing energy charge (50-60% of the generation cost) on the consumer when coal prices and freight charges are not regulated and have been increasing without adequate basis.

Moisture

Due to stringent environmental norms, adequate amount of spray is required for suppressing the coal dust by sprinkling & spraying of water inside plants at following locations;

a) Transfer points
b) Crusher House
c) Wagon tippler/Track Hopper.

As a result, 1.5-2.0 % increase in moisture takes place which results in loss of GCV around 90-100 kCal/kg.

In terms of actual GCV loss, CEA has enumerated in its recommendations as depicted below.

CEA's recommendation

Related to the issue of loss of GCV, CEA in its recommendations to MoP and CERC has opined

i. While taking coal sample from wagon top, GCV measurement will not be representative for the whole lot due to impact of moisture change. GCV measurement of wagon top coal will give comparatively higher GCV value due to setting of moisture at the bottom of the wagon and loss of moisture from wagon top during transportation of coal. On this account, for calculating energy charge, a GCV compensation of around 70-80 kCal/kg may be allowed to the generator.

ii. There is a loss of GCV in the coal stock where coal is stored inside the power plants. On this account, for calculating energy charge, a GCV compensation of around 35 kCal/kg (on an average 1% loss for coal of 3500 kCal/kg GCV) may be allowed to the generator for a storage of 30 days in a non-pit head station and 15 kCal/kg for pit head station.

iii. There is a minor unavoidable loss of GCV in the coal during handling inside the power plants and for that purpose a GCV compensation of around 2-3 kCal/kg may be allowed to the generator.

Further, in its inputs to MoP & CERC, CEA has suggested that above mentioned margins would vary from plant to plant, season to season and to varying coal characteristics and accordingly a margin of 85-100 kCal/kg for pit-head stations and a margin of 105-120 kCal/kg for non-pit head stations may be allowed to the generators as a loss of GCV measured at the wagon top at unloading point till the point of firing in the boiler.

Considering the facts cited above and recommendations by CEA, it is requested that the normative GCV loss should be set at least 150kCal/kg that represents the actual loss incurred by non-pit head stations.

5. Transit Loss

CERC has notified the following for transit and handling losses in the draft regulations.

"The landed cost of coal or lignite during the month shall include the transit and handling losses as per the following norms:

Category of Power Plant	Distance of Generating Station from source of coal	Proposed CERC Norms 2019-24 for Transit and Handling Loss (%) in 2019-2024
Pit Head	-	0.2%
Non-Pit Head	Up to 1000 KM	0.8%
	Above 1000 KM	1.2%

Comments:

Transit Loss in case of rail-fed stations is beyond the control of power generators due to the following reasons:

- For many Railway rakes, where the standard tare (empty wagon) weight is considered based on the design weight of empty wagon, significant loss is being observed in coal received vis-à-vis coal quantity billed by coal company.
- Coal is loaded at different sidings of the colliery and after loading, the same is weighed at weighbridges installed at or near various sidings. The Railway Receipt (RR) is generated based upon this weight. The coal rake, when reaches stations, are being weighed again. Ideally, for the determination of quantity at station end, difference in weight of loaded rake and empty rake on weighbridge should be considered. In case empty rake is not weighed in the weighbridge, difference in

loaded rake weight and stencil tare weight should be considered for quantity at station end.

- Theft and Pilferage during transit
- Weighbridge accuracy

Non-pit head based power plants procure coal from different subsidiaries of Coal India Ltd. through FSAs. Owing to the different weighing conditions at the collieries and reasons as cited above that are not under the control of the non-pit head generating station, there are significantly higher variations in the transit loss than as proposed by the Commission.

Weighment of tare weight of Railway Wagons:

Indian Railways maintain the standard tare weight of wagons when they enter into their system/network. Over the time, the tare weight of wagon increases due to repair and maintenance (welding, retrofit) work but it doesn't get reflected in the tare weight table. Study shows nearly 0.8%-1.0% shortage of coal is only on account of tare weight. This loss results into of Rs. 5 per MT in monetary terms to the Generator/DISCOMs for every 0.1 % increase in tare weight.

Railways needs to weigh every rake's tare weight before it goes to siding for loading or alternatively accept tare weight as recorded at unloading end of the power stations which has got the system for recording of loaded rakes and tare weight of rake both.

It is further requested that the transit loss for non-pit head generating station be provided in a graded manner as suggested below including the additional compensation sought on account of increase in tare weight of railway wagons:

Category of Power Plant	Distance of Generating Station from source of coal	Proposed Transit and Handling Loss (%)	Proposed Loss due to increase in tare weight	Proposed Total Transit Loss
Pit Head	-	0.2%	-	0.2%
Non-Pit Head	0-800 KM	1.2%	0.8%	2.0%
	800-1200 KM	1.5%	0.8%	2.3%
	>1200 KM	2.0%	0.8%	2.8%

6. Alternative Source of Coal

The Hon'ble Commission have permitted the alternative coal supply for generating stations subjected to the approval of rates on exceeding 30% of the base energy charge or 20% of the energy charge rate for the previous month. The relevant clause in the tariff regulation is pronounced below-

(3) In case of part or full use of alternative source of coal supply by coal based thermal generating stations other than as agreed by the generating company and beneficiaries in their power purchase agreement for supply of contracted power

on account of shortage of coal or optimization of economical operation through blending, the use of alternative source of coal supply shall be permitted to generating station:

Provided that in such case, prior permission from beneficiaries shall not be a pre-condition, unless otherwise agreed specifically in the power purchase agreement:

Provided further that the weighted average price of use of alternative source of coal shall not exceed 30% of base price of coal computed as per clause (7) of this Regulation.

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

Comments:

The Draft regulations provide for maintenance of 83% of the quarterly availability for recovery of annual capacity charge. As mentioned earlier that maintaining the normative availability is one of the biggest challenge for generator considering the shortfall and constraints in coal supply. Major reasons behind coal shortage are the limited commitment of coal from CIL and its subsidiaries. Importantly for Private Sector Power Plants where they have lower commitment as per SHAKTI B(ii) scheme (76%) as well as the lower priority of coal materialization which is significantly lower as compared with Government Sector Power Plants. Further, the constraints of rail transportation, availability of wagons, govt. orders, etc. add to the coal concerns of the Private Sector Power Plants.

The Hon'ble Commission in the Consultation paper had even recognised that the coal shortages are the major concern for the generators arising due to shortage of supply from the supplier or transportation constraints. The relevant section is pronounced below-

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

It is therefore clear from the above that the generating companies, especially the Private Sector Power Plant developers are completely dependent on Govt. controlled monopolies for the supply of coal and hold no control on coal availability. The worsening scenario of coal availability is leading to huge reliance on alternative coal by the generator to meet the normative plant availability.

However, it is observed that the tariff regulations restrict the procurement of coal from alternate sources i.e. imports or e-auction. As the procurement of coal under the alternate source are costlier and therefore provisions in the regulations restrict generating companies to freely procure coal to meet the shortfall by proposing prior consent from the beneficiaries and capping of rates by the ceiling of 30% of the base energy charge or 20% of the energy charge rate of the previous month. It is submitted that while Government Sector Power Plants are not required to go through such a process and can freely procure imported/ e-auction coal to meet the shortfall, the Private Sector Power Plants have to adhere to such procedures as the risk of non-payment by the beneficiaries is very high. Further, the approvals against procurement of such shortfall in coal is difficult to come by leaving no other option for the Private Sector Power Plants but to shut down the operations of the their plants.

The generating company, therefore is subjected to perplexing situation wherein domestic linkage based coal is not available as per the requirement and on the other hand the restriction of prior approval imposed under tariff regulations to procure e-auction/imported coal.

In such cases where the coal procurement independence is not entrusted upon the generator, the tariff regulations should not bind the generator for meeting the norms of NQPAF and linkage of NQPAF for the purpose of recovery of capacity charge due to non-achievement. It is submitted that if such NQPAF is to be approved in the final regulations, appropriate level of independence should be ensured to the generator for procuring adequate coal quantity to meet any norms in this regard. Independence in coal procurement from alternate sources should be ensured for the generator without being required to go through any approval process. Also, the regulations should clearly mandate payment of any increased energy charge to the generator resulting from such procurement with a ceiling of 30%.

In view of the shortage of coal, it is therefore requested to the Hon'ble Commission that generating companies with inadequate coal supply may be allowed to purchase coal from alternate sources and the capping of coal charges may be extended to 50% of the base charges. However, the Hon'ble Commission may introduce more transparency in the procurement of such additional coal procurement from alternate sources.

7. Working Capital

Working capital expenses are being allowed by the Hon'ble Commission in the previous regulations, which includes components like coal stock, inventory of maintenance spares, one month operation and maintenance cost and two months receivables depending on the type of thermal generating station. The changes proposed in the draft regulation with respect to the existing regulations are summarised below-

Existing CERC Norms 2014-19	Proposed CERC Norms 2019-24
Cost of coal or lignite and limestone towards stock, if applicable, for 15 days for pit-head generating stations and 30 days for non-pit-head generating stations for generation corresponding to the normative annual plant availability factor or the maximum coal/lignite stock storage capacity whichever is lower.	*Cost of coal or lignite and limestone towards stock, if applicable, for 15 days for pit-head generating stations and 20 days for non-pit-head generating stations for generation corresponding to the normative annual plant availability factor or the maximum coal/lignite stock storage capacity whichever is lower*

Receivables equivalent to two months of capacity charges and energy charges for sale of electricity calculated on the normative annual plant availability factor	*Receivables equivalent to 45 days of capacity charges and energy charges for sale of electricity calculated on the normative annual plant availability factor*
Rate of interest on working capital shall be on normative basis and shall be considered as the bank rate as on 1.4.2014 or as on 1st April of the year during the tariff period 2014-15 to 2018-19 in which the generating station	*Rate of interest on working capital shall be on normative basis and shall be considered as the bank rate as on 1.4.2019 or as on 1st April of the year during the tariff period 2019-24 in which the generating station*

The Hon'ble Commission has carried out analysis on actual annual average coal stock maintained by the generating stations and the maximum coal storage capacity of these generating stations. The Hon'ble Commission has deduced that the average stock days for non-pit head plants and pit head plants are 16.5 days and 11.3 days respectively. The Hon'ble Commission has submitted that interest rates have been revised in line with direction of Reserve Bank of India vide its Letter No. RBI/2015-16/273 dated 17 December 2015. The Hon'ble Commission has also observed that in case of a large number of entities, the number of days of receivables ranges around 40 to 50 and a majority of DISCOMs claim early payment rebates.

Comments

Receivables: It is submitted that the reduction in number of days of receivables from existing 60 days to 45 days in the calculation of working capital requirement would only lead to additional loss for generating stations specially in case of Private Sector Power Plants where the release of payment from the state owned distribution companies is generally delayed beyond the days of credit provided as per the Tariff Regulations.

The payments to Central Generating Stations are generally prompt (within the time duration provided as per the provisions of the Regulations) and also backed by LC/ State guarantee, the payments to Private Sector Power Plants are mostly delayed and it is generally difficult to exercise the alternate routes of LC / sale of power in case of non-payment of outstanding dues.

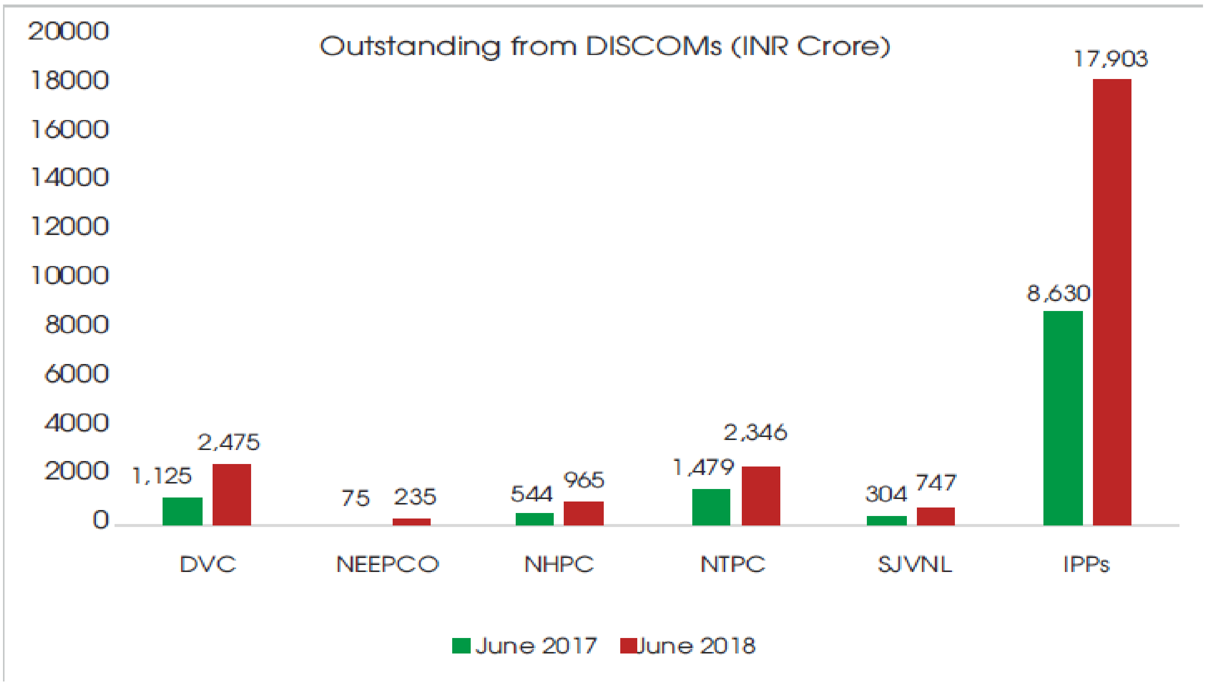
Also, it is submitted that since Government Sector Power Plants like NTPC / NHPC / etc. have PPAs with a large number of distribution utilities, the risk of non-payment by a few does not pose similar challenges as compared with Private Sector Power Plants which are reliant on select few distribution utilities. Therefore, any delay in payment to private sector power plants results in financial hurdles at every stage and they have to resort to additional borrowings for continuity of operations.

Delay in payment by distribution utilities for Private Sector Power Plants has increased considerably over the last few years as shown below. The outstanding dues towards Private Sector Power Plants has risen from Rs. 8630 Cr to 17,903 Cr in the last one year as per the High Level Empowered Committee Report to address issues on stressed thermal power projects (Nov. '18).

One of the key findings of the report outlines the aspect of receivables from the utilities. **As per the High Level Empowered Committee (HLEC) report (Nov'18),**

"Delay in realization of receivables from DISCOMs impairs the ability of project developers to service debt in a timely manner and leads to exhaustion of working

capital. In some cases, the DISCOMs have pressed for renegotiating terms of PPA. This, coupled with non-payment of penalties / Late Payment Surcharges (LPS) is causing financial stress for such projects."



Source: HLEC Report on Stressed Assets, Nov. '18

The report further states that;
"Delays in approval of working capital by lenders have adversely impacted project viability which generally happens due to exhaustion of sectoral exposure limit of individual banks. Even if the working capital is sanctioned, the limit is set based on a cover period of 2-3 months which is insufficient considering the delays involved in payment by DISCOMs. If the project is stressed, as a matter of policy, the banks do not sanction working capital loan even though the amount of working capital may be insignificant compared with advances already made."

It is worthwhile to mention that with the stress and loan defaults witnessed in the past years in this sector, the banks have become more cautious towards lending to this sector and therefore the cost of debt (interest rate) on loans to this sector has also increased significantly.
Therefore, the linkage of interest on working capital with the MCLR + 350 basis points would only result in reducing the amount of interest on working capital as opposed to the increase in the interest charged by the banks due to restriction in lending to the power sector.

It is therefore requested that the Commission may allow a higher margin (400 - 450 points) above MCLR keeping in mind the difficulties faced by Private Sector Power Plants in the current scenario.

Coal Inventory: In addition to reducing the number of days of receivable in the calculation of working capital, it is observed that the number of days of inventory has been reduced from 30 days for non-pit head stations to 20 days. The explanation in this regard has been provided as average coal stock maintained being lower than 30 days for pit-head plants. In this regard it is submitted that the reasoning for reducing the number of days of coal stock is misplaced in view of the following reasons:

- The availability and supply of coal itself is restricted by the coal companies resulting in lower inventory at the plant side
- The bottlenecks in coal transportation (availability of wagons, corridor, etc.) also aggravate the coal shortage at the plant end
- The ACQ as per the FSA does not cater to the entire requirement of the plant and in absence of alternate arrangement for balance capacity (through e-auction, imported coal, etc.), the average inventory levels do not reflect the require inventories

Above clearly provides the actual reasons for lower coal inventory levels at the plant locations that is a result of shortage of coal and transportation related hurdles. Therefore the Hon'ble Commission is requested that actual inventory level should not be considered for specifying a norm and instead it should be based on factors such as requirement for grid stability, maintaining adequate availability, etc. Reduction in days of inventory of coal stock for non-pit head stations would only increase the risk of maintaining the desired availability of the thermal generating station.

It is observed that increased thrust is being given on the availability of thermal generation plants and proposed regulations specify maintaining peak and off-peak availability separately. However, on the other hand limited resources and inventory is being allowed under the same regulations which would result in adversely affecting the ability of generating stations to be able to do so. This approach is contradictory and the Commission is requested to align the same in view of the market conditions.

Thus, it is prayed to Hon'ble Commission to continue with the existing provision of cost of coal towards 30 days of stock for non-pit head stations in the computation for working capital.

8. Payment Security Mechanisms for Private Sector Power Plants

The Draft Tariff Regulations proposes a Rebate for early payments and a Late Payment Surcharge for payments being made beyond the due date. However, as discussed in the previous section on Working Capital, the receivables due from the distribution utilities have been consistently increasing especially in the case of Private Sector Power Plants.

One of the key reasons identified by the **High Level Empowered Committee** in its report on Stressed Assets on Thermal Power Projects is the delayed payment by DISCOMs. This further reduces the limit of working capital requirement offered by the banks. One of the mandates of the terms of reference for the Committee was to suggest payment security mechanisms for Private Sector Power Plants.

The Empowered Committee, in its recommendations, has clearly brought out Payment Security Measures as a key area of consideration by the stakeholders. **The Committee has recommended as follows:**

"*DISCOMs are unable to make timely payments to the generators because of their poor financial health. At the same time, most of the generators lack liquidity to withstand the shortfall in cash-flow due to such delays. A suggestion was made by the Ministry of Power that Public Financial Institutions (PFI), such as REC & PFC, may discount the* *receivables from DISCOMs and make up front payment to the generators. The financial institutions will realize their dues from the DISCOMs in due course of time and charge interest for the period of delay in payment by the DISCOM. This is a common practice in the business world and most of the banks provide this facility. This will help the generators realize their dues in time. However, PFIs expressed that, due to poor financial health of some of the DISCOMs, there was a risk that they may not be able to recover the dues from the DISCOMs and, therefore, requested that the Public Financial Institutions providing the bill discounting facility may also be covered by the Tripartite agreement (TPA). In case of default by the DISCOMs, the RBI may recover the dues from the account of States and make payment to the PFIs. The Committee recommends that Ministry of Power may formulate the proposal for TPA coverage to PFC/REC for discounting bills of Private Sector Power Plants for consideration of the Competent Authority. Banks like SBI can also examine such discounting arrangements through existing FRAC mechanism (Fractional Reserve Banking/Lending Finance) for consideration of the Competent Authority".*

Considering the above recommendation, it is requested that the Hon'ble Commission brings in the aforementioned provision in the final regulations to ensure that aspects related to non-payment of dues by the distribution utilities are addressed thereby relieving the stressed assets in the industry.

9. Late Payment Surcharge (LPS)

The present regulatory framework provides for late payment surcharge on account of delayed payment by the DISCOMs (i.e. beneficiaries). The Hon'ble Commission has proposed the following changes in the draft regulation.

Existing CERC Norms 2014-19	Proposed CERC Norms 2019-24
In case the payment of any bill for charges payable under these regulations is delayed by a beneficiary of long term transmission customer/DICs as the case may be, beyond a period of 60 days from the date of billing, a late payment surcharge at the rate of 1.50% per month shall be levied by the generating company	*Late payment surcharge: In case the payment of any bill for charges payable under these regulations is delayed by a beneficiary or long term transmission customers as the case may be, beyond a period of 45 days from the date of billing, a late payment surcharge at the rate of 1.25% per month shall be levied by the generating company*

Comments

It is submitted that the delay in payment to generation companies is a standard practice by the distribution utilities. Further, the PPAs between Private Sector Power Plants and the State DISCOMs provide limited options for alternate mechanism to recover their legitimate receivables. Payment security is usually not backed by escrows or govt. guarantees in such PPAs. This has also lead to huge outstanding against the distribution utilities and generators have to resort to additional working capital against the same which is not compensated in case of Private Sector Power Plants.

The proposed reduction in late payment surcharge to 1.25% per month from existing 1.5% per month in draft Tariff regulations would further encourage the distribution utilities to delay the payments. Considering the liquidity crunch of these distribution utilities, reducing the LPS would only provide them an additional reason for delaying the payments of the generator as the impact would be lower.

The High Level Empowered Committee Report prepared to address issues on stressed thermal power projects (Nov. '18) has clearly recommended that the LPS is to be mandatorily paid to the generators. **The HLEC report recommends as follows**;

"It has also been pointed out that frequently the DISCOMs insist that generators should forgo the LPS on the delayed payments, despite its mention in the signed PPA. This again adversely affects the viability of generators and their ability to meet its obligation to service the debt and other operating expenses. Therefore, the Committee recommends that Ministry of Power may engage with the Regulators to ensure that LPS is mandatorily paid in the event of delay in payment by the DISCOMs"

Therefore, it is requested that LPS should be continued at the current level, if not increased, in order that it acts as a deterrent towards delay in paying the generator invoices.

Implications of Non-Payment of Charges by the beneficiaries:

Persistent and significant non-payment of dues by the DISCOMs (i.e. beneficiaries) of generating company eventually results in defaults in the debt servicing. Govt. of India has notified very severe provisions under Insolvency and Bankruptcy Code (IBC). RBI has also issued a circular dated 13.02.2018 in this regard. These developments have taken place in the backdrop of large scale loan defaults in the economy wherein many power projects also had a significant share.

Non-payment of generator's bills by the DISCOMs (beneficiaries) also affect the generator's ability to procure coal and incur other expenses necessary for power plant operation and may result into coal shortage, decreasing availability of the station as well as debt service defaults.

The Hon'ble Commission has not covered the remedies available to the generators facing this challenge under the draft regulations. PPA and tariff are composite packages and respective parties are obliged to fulfil their respective obligations wherein the beneficiaries or purchasers have obligation to make timely payment of bills and extend and maintain reliable payment security mechanism.

The terms and conditions of tariff including PAF, interest on loan, depreciation etc. under these regulations should be suitably incorporated for adjustment of various norms and methodologies to take into account consequences for payment defaults. The Hon'ble Commission is requested to specify the same in the Tariff Regulations 2019-24.

10.Return on Equity

The Hon'ble Commission had specified post-tax RoE rate of 15.5% in Tariff regulations 2009. The regulation also provided additional Return on Equity at the rate of 0.5% to the projects that are completed within the specified time. The changes proposed in return on equity are summarised below-

Existing CERC Norms 2014-19	Proposed CERC Norms 2019-24
Return on equity shall be computed at the base rate of 15.50% for thermal generating stations, transmission system including communication system and run of the river hydro generating station *in case of projects commissioned on or after 1st April, 2014, an additional return of 0.50 % shall be allowed, if such projects are completed within the timeline specified*	*Return on equity shall be computed at the base rate of 15.50% for thermal generating stations, transmission system including communication system and run of the river hydro generating station*

The Hon'ble Commission has considered the CAPM approach for determining the cost of equity and have separately computed the risk free and risk premium. The Hon'ble Commission has provided the justification that the risk profile reduces over the life of the project and have provided observation that barring few exceptions, the cost of equity for regulated entities in the power sector works out to be in the range of 12%-15%.

Comments

The current market scenario for thermal generating stations has deteriorated in the past few years due to several reasons including lower coal availability, limited power procurement by the distribution utilities, no plans for new thermal generation capacity as per CEA for the next 10 years, etc. In the last few decades, distribution companies were considered the weaker link in the entire value chain but the focus of such stress now stands shifted to generation companies. The generation sector in particular is being viewed as a high risk entity with declining PLF, increasing challenges ranging from fuel shortages, lower utilisation due to increased penetration of RE resulting into low dispatches and frequent cyclic loading of machines hence increased wear and tear of the machineries, increased outstanding payment from DISCOMs (beneficiaries), difficulties in debt servicing and payments to fuel suppliers and also additional expenditure to comply with regulatory and environmental norms etc.

The condition is more severe for the Private Sector Power Plants who have to borrow from the banks for capital as well as working capital needs. This has severely affected the financial health of the generating companies and hampers their capacity to service the debt obligations, fuel repayment, additional expenditure for changed norms and regulations, etc. It is submitted that a number of generators are already going through difficult times with the risk of becoming NPAs. Presence of large quantum of NPAs in the power sector has become a major challenge for public lending institutions as has already been recognized by the Government of India. Govt. of India constituted a High Level Empowered Committee (HLEC) on 29th July 2018 to consider issues related to Stressed Thermal Power Projects. Issues in the generation business have led to deterioration of investor's confidence and willingness to invest in the sector. Therefore, it is important that the existing generators are incentivised adequately to be able to tide through these difficult times.

In the current draft regulations, the ROE has been continued at the same level of 15.5% which does not compensate for the high level of risk associated with the generation business mentioned as above. Further, the draft regulations increases the risk on the generator with respect to recovery of capacity charge by incorporating peak and off-peak hrs availability along with respective weightages for recovery of Capacity Charge. It is suggested that the RoE for thermal generating stations be increased by 2-3% which would provide shield against the increasing cost elements for sustainability of generators and hence suggested to be a part of proposed regulation. It is also suggested to continue with additional return of 0.5% for the power projects which are completed in specific timeline.

Considering the above detailed issues, it is requested that the Hon'ble Commission in the Tariff regulations may provide for the following:

i. **Additional return on equity of 2-3% for the existing generating plants to enable them to maintain profitable operations in spite of the increasing risks and provide comfort for their long term sustainability**

ii. **Additional return of 0.5% for the power projects which are completed in specific timeline.**

iii. **In the event that the Hon'ble Commission deems it fit to modify the provision, such conditions may be imposed only on the thermal generating stations which are commissioned after 1.4.2019 and in respect of expenditure which is beyond the original scope of work.**

11. Station Heat rate

The Hon'ble Commission had introduced single norm in 2001 for old as well as new 200 MW and 500 MW units for Government Sector Power Plants and had provided relaxed norms for new thermal stations during the stabilization period. In the 2004 Tariff Regulations, the Commission specified separate norms for 200 MW and 500 MW. In 2014 Tariff Regulations, the Commission tightened the norms for both 200 MW and 500 MW followed by further reduction in SHR norms for 200/ 210/ 250 MW sets. The changes proposed by the Hon'ble Commission in the draft regulations are as summarised below.

Existing CERC Norms 2014-19	Proposed CERC Norms 2019-24
200/210/250 MW Sets- 2,450 kCal/kWh *500 MW sets- 2,375 kCal/kWh* *Note 1* *In respect of 500 MW and above units where the boiler feed pumps are electrically operated, the gross station heat rate shall be 40 kCal/kWh lower than the gross station heat rate specified above.* *Note 2*	*200/210/250 MW Sets- 2,410 kCal/kWh* *500 MW sets- 2,375 kCal/kWh* *Note 1* *In respect of 500 MW and above units where the boiler feed pumps are electrically operated, the gross station heat rate shall be 40 kCal/kWh lower than the gross station heat rate specified above.* *Note 2*

For the generating stations having combination of 200/210/250 MW sets and 500 MW and above sets, the normative gross station heat rate shall be the weighted average gross station heat rate of the combinations. *Note 3* *The normative gross station heat rate above is exclusive of the compensation specified in Regulation 6.3 B of the Grid Code. The generating company shall, based on unit loading factor, consider the compensation in addition to the normative gross heat rate above.*	*For the generating stations having combination of 200/210/250 MW sets and 500 MW and above sets, the normative gross station heat rate shall be the weighted average gross station heat rate of the combinations.*
New Thermal Generating Station achieving COD on or after 01.04.2014 *Coal-based and lignite-fired Thermal Generating Stations* *= 1.045 X Design Heat Rate (kCal/kWh)*	*New Thermal Generating Station achieving COD on or after 01.04.2014* *For Coal-based and lignite-fired Thermal Generating Stations:* *1.05 X Design Heat Rate (kCal/kWh)*

The Hon'ble Commissions has undertaken the review of actual data received from various Stakeholders especially from Government Sector Power Plants to assess actual performance vis-a-vis norms. The Hon'ble Commission has observed that actual SHR for most of the coal- based stations of NTPC are below the normative SHR. The actual SHR of almost all the coal based generating stations of NTPC is 2346 kCal/kWh for plants less than ten years old and 2351 kCal/kWh for plants more than ten years old. Therefore, the Commission proposes to retain the Heat Rate Norms for 500 MW series units to 2,375 kCal/kWh same as previous Tariff Regulation.

Comments:

- It is submitted that Station Heat rate (SHR) refers to the conversion efficiency of thermal energy into electrical energy and used for computation of energy charges. It is pertinent to mention here that the heat rate degrades with the passage of useful life of the project. Further, SHR norm is difficult to achieve due to quality of coal, cyclic demand of grid and increase RE penetration.

- The Hon'ble Commission while proposing the SHR norms for 2019-24, has referred to the Tariff Policy 2016. The relevant clause under Tariff Policy on performance norms is reproduced below-

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

- *Suitable performance norms of operations together with incentives and disincentives would need to be evolved along with appropriate arrangement for sharing the gains of efficient operations with the consumers. The operating parameters in tariffs should be at "normative levels" and not at "lower of normative and actual". This is essential to encourage better operating performance.*

- *The norms should be efficient, relatable to past performance, capable of achievement and progressively reflecting increased efficiencies and may also take into consideration the latest technological advancements, coal, vintage of equipment's, nature of operations, level of service to be provided to consumers, etc*.

  It can be noted from the above clause that Tariff Policy provides for establishment of efficient norms which should be achievable on consistent basis. However, considering the present scenario, the actual operating conditions in future is expected to deteriorate further as compared to the existing situation due to constant deterioration in coal quality, shortages in coal supply, low PLF, etc.

- Further it is submitted that operating norms should be based on the average performance of units in the country and not confined to NTPC stations alone. Operating norms should be based on past performance of the units in the country including State GENCOs / Private Sector Power Plants of relevant vintage and should factor in operating constraints like partial loading due to erratic load pattern of the DISCOMs (beneficiaries) and lower operating load factor due to shortfall of quantity and quality of coal which is expected to continue in future too.

- The normative gross heat rate in Tariff Regulations has been set by CERC considering a performance level of 85% PLF. It is evident from the figure on PLF trends illustrated in **Section 3** ***(Comments on Incentive on PLF)*** in this document that the national average PLF of the thermal generating stations has declined in the past few years and is hovering around 61%/. The average PLF of the Private Sector Power Plants are even lower than the national average by 4-5% on account of coal unavailability as well as lower dispatch. Going forward, actual operating conditions in future is likely to deteriorate further as compared to the existing situation, particularly with respect to availability / quality of coal, addition of substantial capacity of renewable energy (RE) sources, grid parameters, which is likely to reduce the PLF of thermal power stations.
- Due to deterioration in PLF there will be significant increase in number of start-ups / shutdowns, which will also result in increase in Heat rate.

- Most of the units are designed for base load operating conditions with coal close to design conditions. But in actual conditions coal quality in general vary drastically resulting in poor Heat Rate & it further deteriorates when unit are operating at technical minimum. Sometimes oil support will be required for operating unit at technical minimum which will further deteriorate Heat Rate.

- The GCV measurement of coal has been shifted from "As fired Basis" to "As received Basis" for the purpose of energy charge computation which has also resulted in significant deterioration in heat rate due to gap in GCV of as received & as fired coal.

- It is submitted that Heat Rate is a design parameter. Margin provided over Design Heat Rate depends upon variance in actual site conditions as compared to parameters considered while designing the machine. Once the margin is fixed for any machine based on COD, the same cannot vary. Therefore, Margin needs to be fixed based on COD and to be continued for entire useful life.

- It is suggested that the Hon'ble Commission should specify norms based on design parameters with appropriate operating margin to take care of lowering PLF of stations, ageing, etc. Further, there is a need to factor in degradation in Heat Rate due to vintage/ wear & tear of the machine year over year. Suitable margin may be added in the heat rate.

  CEA in its publication titled "Recommendations on Operation Norms for Thermal Power Stations for Tariff Period beginning 1.4.2009" had worked out the deviation of operating heat rate with the design heat rate for various NTPC plants for different years. The trend showed that the average deviation in heat rate was reducing over a period of years. However, considering the quantity and quality of coal being made available from CIL mines coupled with coal grade slippages and transit and handling losses, it is extremely difficult to maintain the Heat Rates as proposed by the Commission. The Salient features of the above report are as under:

  i. OEMs of Boilers specify a range of coal expected to be fired in the boilers in terms of Design coal, Best coal and Worst coal and the design efficiency of Boiler corresponds to the Design coal.
  ii. They have also recommended a set of operating conditions for efficient combustion (excess air, wind box pressure, damper positions etc.) for the design coal. But there are very large variations in coal quality especially Volatile matter & moisture at non-pit head stations. Due to continual variations in coal quality, the optimized regime of operation for boiler is disturbed frequently; thus necessitating boiler operation at higher oxygen levels, resulting in lower operating boiler efficiency.
  iii. Poor coal quality further leads to additional system losses as following:
     a) Higher firing rate in boilers leading to increase in mass flows of flue gas, higher than design velocities hence accelerated erosion of pressure parts.
     b) Frequent soot deposition in boiler internals which demands more frequent soot blower operation, increasing make up water consumption & potential steam erosion.
     c) Running of an additional mill – With deterioration in coal quality, 210 MW units designed for 4 mill operation have to be operated with 5 mills, while 500 MW units and above, designed for 6 mill operations have to run with 7 mills. An additional mill affects operating performance adversely due to increase in the boiler exit gas temperatures by 8-10 $^{\circ}$C and increased PA header pressure that result in higher air ingress in air heater & reduction in boiler efficiency
     d) Higher ash content with abrasive nature leads to erosion in flue gas path leading to higher DFG (Dry Flue Gas) losses due to leakages
- SHR depends on the quantity as well as quality/grade of coal used by the station. Both these parameters (quantity as well as quality of coal) are not under the control of the non-pit head generating station.
- The power station is therefore forced to resort to e-auction/imported coal not only to meet its obligation of supply under the PPA but also to ensure that it meets the

normative requirements of operation as per the regulations. Procurement of e-auction/imported coal proves costly to the generating station as the variable costs are usually not approved in totality by the regulator.

Heat Rate Degradation due to Partial Loading & Cyclic Operations

- In view of the proposed large-scale addition of Renewable Energy, having variable generation, Indian fossil power plants (primarily coal based) will be increasingly required to support balancing needs of the grid. With severe constraints in the availability of domestic gas for power production (and higher production costs of imported gas based stations) and limited storage based hydro potential, achieving minimum levels of flexibility for coal based power plants, thus remains the core means of balancing out the grid with high levels of RE.

- Cycling refers to the operation of generating units at varying load levels, including on/off and low load variations, in response to changes in system load. Every time a power plant is turned off and on, the boiler, steam lines, turbine, and auxiliary components go through unavoidably large thermal and pressure stresses, which cause damages. These damages are made worse by the phenomenon we call creep-fatigue interaction. When the system requirements cause utilities to cycle their power plants, one of the major decisions faced by utility power plant operators is not only how to mitigate the effects of cycling their plants, but also at what cost in terms of lost plants reliability and service life.

- Cycling costs, some of which are often latent are not clearly recognized by operators, regulators or market players. Mostly large coal units have been designed for base load operation and hence, incur significant costs on cyclic operation. Thermal stresses and strains from cycling result in early life failures compared to base load operation.

- It has been observed that there is increased partial loading and flexing of units for the last the years i.e. from 2015-16 to 2017-18. This is mainly due to increased renewable power integration, coal availability issues, low demand, etc. It is a known fact that the heat rate is more at lower loads which cannot be totally compensated by same quantity by operating at higher loads later.

- In most of the generating stations of NTPC, which is considered as one of the best operating utilities in the country, it cannot meet the operating norms on consistent basis. It is submitted that there is a need to revise the norms to make them achievable. Accordingly, it is submitted that norms may be formulated so that units/ stations could achieve the prescribed norms consistently keeping in view that there will be increased flexing of operation of units in the future.

- Unit partial loading occurs due to various reasons like equipment problem, low grid demand, coal & water shortage and as per the manufacturer's HBD Heat Balance Diagram). The heat rate of turbine (THR) varies with the loading of the unit and a 10 % change in loading between 100-80 % lead increase in THR by 27 & 25 kcal/kWh respectively for 500 & 200 MW units.

- Units are forced to run at partial loads even after meticulous planning for annual overhauls due to low domestic coal availability / shortage, low demand / schedule due to import coal blending and high energy cost, lower schedules due to addition of more capacity by Private Sector Power Plants, crash in demand during monsoon period (high frequency regime) and other problems such as water shortage etc.

- The continued trend of deterioration of coal quality for the next five years (expected to be in the range of around 10 %) would mean an additional decrease in the operating Boiler efficiency by ~0.7 % from the existing levels

- Presently the required Technical Minimum in respect of a unit (s) for CGS or ISGS is 55% of MCR loading or Installed Capacity of the units on bar as per the 4th amendment dt 6th April 2016 of IEGC-2010. The amended regulations provide for compensation of heat rate degradation, increased auxiliary usage and secondary oil consumption.

- Going forward the partial loading and cyclic operations would affect the SHR and AEC in a big way. For a 660 MW unit, variation in loading of unit from 80% to 40% would result in SHR degradation resulting in an additional energy charge in the range of 5-25p/kWh.

Under these conditions as above, the existing coal based stations are subjected to partial loading on account of coal shortage and non-despatch by the generators. This partial loading of units results in SHR degradation and increased wear & tear of equipments and reduced life of the same which is bound to further reduce the PAF of generating stations. Hon'ble Commission is requested to look into this while finalizing the NPAF levels for capacity charge recovery

12. Auxiliary Energy Consumption (AEC)

Thermal power station consumes a fraction of generated power in generating equipment, fans, motors, etc. The Hon'ble has previously specified the separate norms for 200 MW and 500 MW. In the Tariff Regulation 2014, the Hon'ble Commission has tightened the norms for 500 MW series. However, the norms have been relaxed for 300/330/350/500MW and above series in draft regulations as summarised below.

Existing CERC Norms 2014-19	Proposed CERC Norms 2019-24
300/330/350/500 MW and above *Steam driven boiler feed pumps – 5.25%* *Electrically driven boiler feed pumps – 7.75%*	*600 MW and above* *Steam driven boiler feed pumps – 5.75%* *Electrically driven boiler feed pumps – 8.00%*
Provided further that for thermal generating stations with induced draft cooling towers, the norms shall be further increased by 0.5%:	*Provided that for thermal generating stations with induced draft cooling towers and where tube type coal mill is used, the norms shall be further increased by 0.5% and 0.8% respectively.*

The Hon'ble Commissions has undertaken the review of past five year actual data and have noticed that most of the generating stations are able to achieve norms with marginal deviations. The Hon'ble Commission has also proposed that the generator should be allowed to declare higher availability if it is able to operate at lower than normative aux power. Due to this reduced AEC a generator may be able to sell extra power in exchange or to a third party.

Comments:

- The existing norms are still inadequate in the present scenario when even the NTPC coal station PLF have come down to 77.9 % (2017-18). Going forward, actual operating conditions in future will further deteriorate as compared to the existing situation, particularly with respect to availability / quality of coal, addition of substantial capacity of renewable sources, grid parameters, which is likely to reduce the PLF of thermal power stations, and above all the compliance to stringent environmental norms.

- Operating norms should be based on past performance of the units in the country including State GENCOs / Private Sector Power Plants of relevant vintage and should factor in operating constraints like partial loading due to erratic load pattern of the beneficiaries and lower operating load factor due to shortfall of quantity and quality of coal which is expected to continue in future.

- It is important to highlight that slow growth in electricity demand, large-scale capacity addition of renewables and availability of cheap power at power exchange, etc. has resulted into lower schedule of power by beneficiaries and fluctuations in generation. This has resulted in lower PLF and frequent load variation of the generating stations. It is important to mention here that presently frequent starts and stops, partial load operation and longer thermal backing down of the plants have led to significant increase in the percentage of station's AEC.

- Most of the units are designed for base load operating conditions close to design conditions. But in reality coal quality varies drastically resulting in frequent starts/ stops of standby auxiliaries leading to increase in AEC & deteriorating it further when units operate at technical minimum load.

- For older units, running of additional auxiliaries or poor performance of auxiliaries due to poor health of units results in increase in AEC (%).

- AEC norms should be increased from current norms (of Tariff cycle 2014-19) to incorporate addition of new systems (FGD/Desalination plant/ increase in ESP field Height/no of pass, increase in pumping power of Ash handling system etc)

- It is further submitted that operational norms do not capture the impact of Reserve Shut Down (RSD). During RSD, several auxiliaries would be running for equipment / system protection. Cooling water system of the Main TG Condenser, Lubricating Oil system of the Main Turbine, Turbine seal oil system, Lube oil system of Mills, Compressed air system, Control & Instrumentation system, HVAC system, Lighting system, Furnace Scanner Cooling air system etc. would be in service during RSD resulting into higher AEC. Such time bound increase in AEC cannot be made up on cumulative basis since the norms consider normal operation and not RSD. Hence, suitable compensation needs to be provided for the same.

AEC should be decided based on Normative operating level instead of actual PLF achieved by the generator with an additional margin for part load operation due to grid restrictions & coal quality / coal supply/ shortage.

13.Non-Tariff Income

The Hon'ble Commission has introduced a new provision related to sharing of Non-Tariff Income in draft Tariff Regulations. However, the sharing is governed by the Central Electricity Regulatory Commission (Sharing of revenue derived from utilization of transmission assets for other business) Regulations, 2007. The clause of Non-Tariff Income added in the regulation is pronounced below-

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

a) Income from rent of land or buildings;

b) Income from sale of scrap;

c) Income from statutory investments;

d) Interest on advances to suppliers or contractors;

e) Rental from staff quarters;

f) Rental from contractors;

g) Income from advertisements;

h) Interest on investments and bank balances;

The reason provided by the Hon'ble Commission on introduction of sharing of non-tariff income is that under Cost-plus regime each and every cost incurred in generation of power is paid by the beneficiaries. Therefore, any non-tariff income generated by generating company from regulated business should be equitably shared with such DISCOMs (beneficiaries).

Comments

In the draft regulations, sharing of non-tariff income has been introduced in the ratio of 50:50 between the generator and beneficiaries. It is submitted that the current regulations regulate and provide benchmark for all components of the capacity charge and energy charge for generating stations based on type of coal and size of plants, etc. Further, any surplus on account of better than approved SHR, AEC, and secondary oil consumption is also required to be shared with the beneficiaries as per the current tariff regulations. Therefore, all expenditure and benefits arising from the operation of the generating stations are already share with the beneficiaries. Under this circumstances the proposed change for sharing of revenue on account of conditions not attributable to operation of plants should not be considered.

As also highlighted in the previous sections, the risks associated with the generation business have been increasing and the regulated tariff does not cover all expenses relating to the various difficulties faced by Private Sector Power Plants. In such a scenario while the additional costs are not a pass through to the consumer, the proposed regulations suggest for sharing of any marginal revenue source.

Income from statutory investments , interests from other investments and interests from bank balances are not a part of project and O&M costs, Hence it should not be shared with beneficiaries.

Therefore the Hon'ble Commission is requested not to approve the same in final regulations as such amendments would only result in unviability of the generating business.

14. Return on Equity on Additional Capitalization

The Commission in the draft Tariff Regulations for FY 2019-24 has proposed to allow interest rate on the entire additional capitalization undertaken after the cut-off date. The proposed clause mentions:

Existing CERC Norms 2014-19	Proposed CERC Norms 2019-24
-	*Provided that:* *i. Return on equity in respect of additional capitalization after cut-off date within or beyond the original scope shall be computed at the weighted average rate of interest on actual loan portfolio of the generating station or the transmission system;*

The rationale for the proposed inclusion has not been provided in the explanatory memorandum, which states:

"The Commission has also proposed to clearly segregate the a) additional capitalisation within the original scope and upto cut-off date, b) additional capitalisation within original scope and after cut-off date and c) additional capitalisation beyond the original scope, in terms of treatment of these w.r.t rate of return on equity. ***It has been proposed that equity component up to 30% of the additional capital expenditure incurred after the cut-off date, whether within the original scope or not, shall be serviced at the weighted average rate of interest.****"*

Comments

It is submitted that the all capital costs are approved by the Hon'ble Commission. Even the cost incurred after the cut-off date is approved by the Hon'ble Commission after adequate prudence check. Therefore, the current provision of denying equity portion towards such additional capitalization is arbitrary and defies all financial reasoning.

It is also important to review the nature of works defined in the draft Tariff which is as indicated below

"24. Additional Capitalisation within the original scope and after the cut-off date:

(1) The additional capital expenditure incurred or projected to be incurred in respect of an existing project or a new project on the following counts within the original scope of work and after the cut-off date may be admitted by the Commission, subject to prudence check:

(a) Liabilities to meet award of arbitration or for compliance of the directions or order of any statutory authority, or order or decree of any court of law;

(b) Change in law or compliance of any existing law;

(c) Deferred works relating to ash pond or ash handling system in the original scope of work;

(d) Liability for works executed prior to the cut-off date;

(e) Works covered under original scope but executed after the cut-off date ;

(f) Liability for works admitted by the Commission after the cut-off date to the extent of discharge of such liabilities by actual payments; and

(g) Additional capitalization on account of rising of ash dyke as a part of ash disposal system.

…………………………..

25. Additional Capitalisation beyond the original scope:

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

(a) Liabilities to meet award of arbitration or for compliance of the order or directions in the order of any statutory authority, or order or decree of any court of law;

(b) Change in law or compliance of any existing law;

(c) Force Majeure Events;

(d) Any capital expenditure to be incurred on account of need for higher security and safety of the plant as advised or directed by appropriate Indian Government Instrumentality or statutory authorities responsible for national or internal security;

(e) Deferred works relating to ash pond or ash handling system in additional to the original scope of work, on case to case basis;

Provided also that if any expenditure has been claimed under Renovation and Modernisation (R&M) or repairs and maintenance under O&M expenses, same expenditure cannot be claimed under this Regulation."

Under both the above cases, it is observed that the capital expenditure is legitimate and the Hon'ble Commission recognizes that such expenditure may require to be incurred by a generator even after the cut-off date. In fact, expenditure on account of change in law (resulting from revised environmental norms) or on account of force majeure events are inevitable. Return on the equity should be allowed at the same rate (i.e. 15.5%) on such additional capital expenditure after prudence check by Hon'ble commission. Allowing return at the weighted-average rate of interest to the equity holders who bear the entire construction and operation risk does not appear to be equitable/logical.

All such expenditure would require equity contribution by the generator and in many cases such equity ratio may be higher than the normative of 30% specified under the regulations. The generating company would not be in a position to undertake such expenditure if return on equity is denied on their contribution and the same would be treated as debt. The resultant loss to generating company would be higher as apart from denial on equity on such additional capital, thus leading to higher taxable liability on the generators.

The Hon'ble Commission is requested to allow return on equity at the same rate (i.e. 15.5%) for the equity portion of the capital expenditure incurred due to Force majeure/Change in law

15. Sharing of Gains

The present regulatory framework entails the sharing of gains between generating company and beneficiaries in 60:40 ratio on account of improvement in controllable factors such as Station Heat Rate, Auxiliary consumptions, secondary coal oil consumption, refinancing of loan and the true up of primary coal cost. In draft Tariff regulations, the Hon'ble Commission has proposed following changes as mentioned below-

Existing CERC Norms 2014-19	Proposed CERC Norms 2019-24
8. Truing up *(1) The Commission shall carry out truing up exercise along with the tariff petition filed for the next tariff period, with respect to the capital expenditure including additional capital expenditure incurred up to 31.3.2019, as admitted by the Commission after prudence check at the time of truing up:* *….* *(6) The financial gains by a generating company or the transmission licensee, as the case may be on account of controllable parameters shall be shared between generating company/transmission licensee and the beneficiaries on monthly basis with annual reconciliation. The financial gains computed as per the following formulae in case of generating station other than hydro generating stations on account of operational parameters*	*70. Sharing of gains due to variation in norms: (1) The generating company or the transmission licensee shall workout gains based on the actual performance of applicable Controllable parameters as under:* *i) Station Heat Rate;* *ii) Secondary Coal Oil Consumption;* *iii) Auxiliary Energy Consumption; and* *iv) Re-financing, Re-structuring of Loans or otherwise change in Interest Rate of Loan.* *(2) The financial gains by the generating company or the transmission licensee, as the case may be, on account of controllable parameters shall be shared between generating company or transmission licensee and the beneficiaries or long term transmission customers, as the case may be, on monthly basis with annual reconciliation. The financial*

as shown in Clause 2 (a) (i) to (iii) of this Regulation shall be shared in the ratio of 60:40 between the generating stations and beneficiaries] ***Net Gain = (ECR_N– ECR_A) x Scheduled Generation*** ***Where,*** ***ECR_N – Normative Energy Charge Rate computed on the basis of norms specified for Station Heat Rate, Auxiliary Consumption and Secondary Coal Oil Consumption.*** ***ECR_A – Actual Energy Charge Rate computed on the basis of actual SHR, Auxiliary Consumption and Secondary Coal Oil Consumption for the month.***	*gains computed as per the following formulae in case of generating station other than hydro generating stations on account of operational parameters as shown in Clause 1 of this Regulation shall be shared in the ratio of 50:50 between the generating stations and beneficiaries.* *Net Gain = (ECR_N– ECR_A) x Scheduled Generation* *Where,* *ECR_N = Normative Energy Charge Rate computed on the basis of norms specified for Station Heat Rate, Auxiliary Consumption and Secondary Coal Oil Consumption.* *ECR_A = Actual Energy Charge Rate computed on the basis of actual Station Heat Rate, Auxiliary Consumption and actual Secondary Oil Consumption for the month*

Comments

The Hon'ble Commission has proposed 50:50 sharing of financial gain between generating stations and DISCOMs on account of operational parameter which was 60:40 in 2014-19 regulation

In this regard, it is submitted that the norms of technical operations i.e. SHR, auxiliary consumption, secondary coal oil consumption, etc. are specified by the Hon'ble Commission based on actual performance of similar generating units in the past. Therefore, there exists limited margins for any efficiency emerging from effective operations. Also, any such improvement should be allowed to be retained by the generating company in lieu of the various operational, coal and other risks that is being undertaken in course of operations. The same would incentivise the generating company to improvise and be more effective during the period.

While the current provisions only provide for sharing of benefits, provisions should also be included for sharing of losses. It is highlighted that due to cycling and part load operations of thermal plants, there are losses / under-achievement on account of these technical parameters which are completely borne by the generating companies. While some compensation is offered as per the IEGC 4th amendment but it is inadequate to meet the total loss caused to the generating station and its performance. The loss so incurred is solely attributable to the generator on account of inefficiency. Since, any under-achievement of the above controllable parameters like SHR, AEC, and Secondary Coal Consumption etc. is not passed on to the beneficiary, the gains arising out of improvement should be allowed to be retained by the generators.

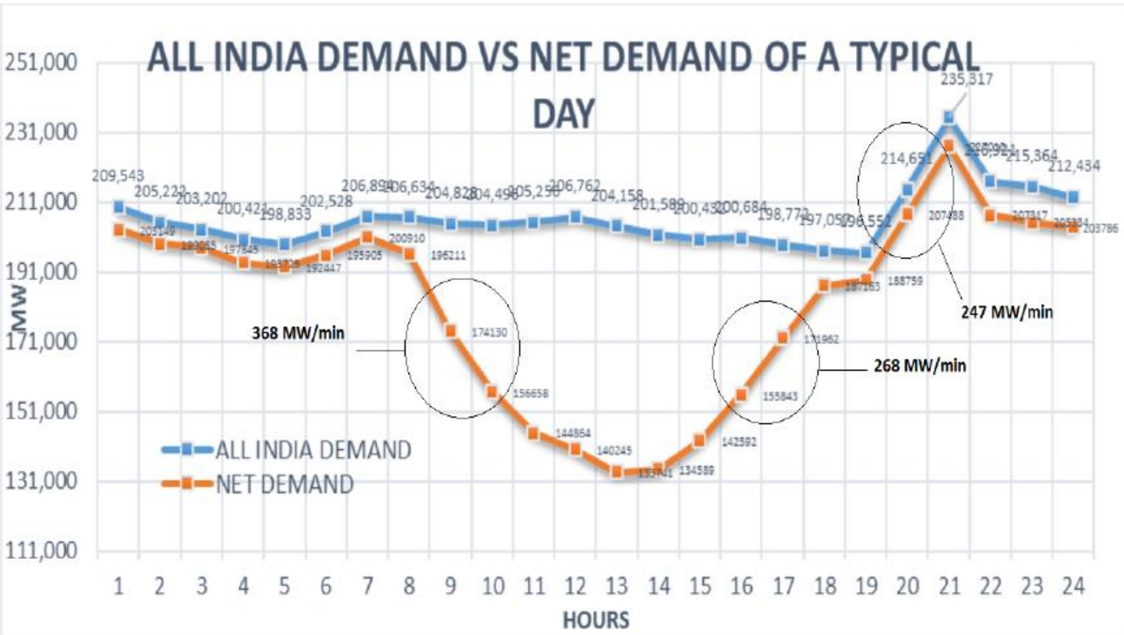
The Hon'ble Commission is requested to exclude the provisions relating to sharing of benefits or allow a suitable mechanism which also provides for sharing of losses in case of such part load operations in case of non-achievement of technical norms due to reasons attributable to such cyclical and part load operations.

16. Regulatory Compensation for Lower Technical Minimum

Emerging Scenario & Need for Flexibility

Indian coal-based power plants have been operating under deficit conditions for a long time, as base load stations. Over the twelfth five-year plan period (2012 to 2017), the operating conditions of the coal-based power plants have changed dramatically in a majority of states with the emergence of surplus power conditions and rapid penetration of Renewable capacity.

The requirement of flexibility shall be significant even with modest levels of RE penetration (175 GW of Renewable Energy capacity by 2022). A typical future net demand curve for a day India in 2021-22 (as shown below in diagram below) predicts that ramp down rate requirements (368 MW /min) and peak hour ramp up rate (247 MW/min) will lead to partial loading and two shift operation of conventional plants (mostly coal based).



Source: CEA

Hitherto, flexible generation has not been a significant priority in India under grid conditions characterized by generation deficits and outages. Coal based generation plant operators, even in newly established units in India, have thus adhered to technical minimums of 70% of Maximum Continuous Rating (MCR) and lower ramp rates than those expected under the CEA's technical standards. Existing plants configurations, firing systems, controls and instrumentation impose legitimate constraints on ramp rates and technical minimum. Thus, from a flexible generation standpoint, the Indian grid remains unprepared for the anticipated adoption of larger quantities of variable RE.

One of the key reasons contributing to the lack of preparedness for flexible operations is the absence of sound regulatory framework and compensatory mechanisms for implementing the required changes to the plant's equipment, procedures and practices.

To address the above, CERC vide 4th Amendment to IEGC Regulations 2010, have notified the Technical Minimum in respect of a unit (s) for CGS or ISGS as 55% of MCR loading or Installed Capacity of the units on bar. The amended regulation also provides for compensation of SHR degradation, increased AEC and secondary oil consumption in the event the unit(s) are required to run at or above the technical minimum.

- For unit(s) required to run below 55% in the future, there is no compensation provision. As seen from the original equipment designer's curve, below 55%, there is a sharp degradation of SHR and AEC and it is non-linear. Unit shut-down and start-up is the costliest source of flexibilization from coal-based units and the secondary oil consumption is an economic loss to the nation, dependent on coal import.

- In order to avoid/reduce frequent starts/stops, units have to run on a reduced minimum load and develop the capabilities for the same through options available. For Indian coal, reducing unit load below 55% will require additional investments, which may be reimbursed to the generator after due diligence by CEA or other authority.

In order to ensure proactive participation of coal fired power plants and to unlock the existing flexibility in the system, such plants need to be incentivised on economic principles. Failure to do will lead to increased RE curtailment and will restrict investment in RE. Already, variable renewable energy output is becoming noticeable to system operators and there is curtailment of RE on a regular basis. To start the ball rolling, regulatory interventions are imperative.

In consideration to the above, the regulator may consider bringing in separate norms and compensation for technical minimums below 55%. Further, it is requested that the existing IEGC Regulations 2010 (4th Amendment) should be made a part of the proposed Tariff Regulations 2019-24.