BEFORE THE CENTRAL ELECTRICITY REGULATORY COMMISSION
3RD AND 4TH FLOOR, CHANDRALOK BUILDING,
36, JANPATH, NEW DELHI – 110 001

IN THE MATTER OF:

Comments/suggestions on "Draft Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2019 for the tariff period from 1.4.2019 to 31.3.2024".

SUBMISSIONS OF PRAYAS (ENERGY GROUP), Pune

1. The CERC vide public notice dated 15.1.2019 and 14.12.2018 has invited comments and suggestions from all stakeholders on the "Draft Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2019 for the tariff period from 1.4.2019 to 31.3.2024".

2. The present submission is in response to the said notice and the draft regulations published thereunder. We request the Commission to accept this submission on record and to provide us an opportunity to present our submission in person on the date of the hearing, i.e. on 1st February 2019.

Approach and perspective:

3. The multi-year tariff (MYT) regulations are an important aspect of sector regulation. Out of the 220 GW of thermal capacity, close to a third is regulated by the CERC. Similarly, more than a quarter of the installed hydro capacity falls under the CERC's jurisdiction for tariff determination. Thus, the MYT regulations framed by the CERC not only decide the tariff of this huge amount of installed capacity, but also act as model regulations for many state commissions. Therefore, the present exercise needs to be seen in context of this gravity and impact that it is likely to have on consumer tariffs and the sector's governance.

4. Further, the MYT exercise is also an opportunity to evaluate performance and efficacy of the existing norms as well as to design and develop new frameworks and mechanisms that can help the sector to adapt to the changing environment. In this context, it becomes crucial to reflect on both past performance as well as upcoming challenges and opportunities.

5. Considering these points, it is our submission that the MYT regulations should aim at the following:

(a) Simplicity in tariff determination, applicability and implementation as the criteria for introducing any new and innovative changes;

(b) Incentive structures for generators should lead to increase operational and cost efficiency, within a “cost-plus” regulatory framework;

(c) Responsible plant operation must entail due compliance with environmental norms and regulations;

(d) Considering the flux in the sector, facilitate sound planning practices and processes that would avoid or limit creation of stranded assets.

This submission by Prayas (Energy Group) is based on an approach that factors in the points listed above.

Three-part tariff structure:

6. The Commission has proposed a three-part tariff structure, with two components for capacity charge based on peak and off-peak availability and variable charge component concerning generation related costs. The Capacity Charge rate for Peak hours is proposed to be 25% more than that of Off-Peak hours. Normative Plant Availability Factor for peak and off-peak periods is specified in Regulation 59 (A). No of hours of peak and off-peak periods in a region is proposed to be declared on monthly basis in advance, by the concerned RLDC and the peak period in a day is to be not less than 4 hours.

7. According to the explanatory memorandum, the main objective of this pricing framework is to encourage generators to plan and adjust their generation resources to cater to diurnal variation/seasonal variation in demand of its beneficiary and also to facilitate power system operations to achieve load-generation balance in most optimal and efficient manner.

8. It is our submission that the primary issue here is of accountability of the generators. Often generators do not take sufficient efforts to be fully available during the peak demand periods/season(s).[1] However, since normative availability is computed on annual basis, they are able to recover their fixed costs, but the distribution companies i.e. their procurers are forced to buy power from short-term markets at high prices during peak demand periods. It is indeed important to address this issue and the CERC is right in introducing a pricing framework that is sensitive to availability during peak demand. However, we feel that the approach proposed in the draft regulations is not the most optimum for the following reasons:

(a) Normative Quarterly Plant Availability Factor (NQPAF) is proposed to be computed excluding annual scheduled plant maintenance. This lowers the effective availability of the plant, thus unduly benefiting the generator. It also does not help in addressing the accountability concerns raised above.

(b) No guidelines have been specified for RLDC for determining peak and off-peak hours for each month, which can be a cumbersome and tedious task.

(c) The implementation is unnecessarily complicated, as most of the capacity regulated by the CERC is coal based, and hence unlikely to be very responsive to hourly changes in demand.

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[1] For example, see the details submitted by MSEDCL in case of generating companies operating in the state of Maharashtra. Please refer to para 9 onwards starting on page 6 of 46 http://mercindia.org.in/pdf/Order%2058%2042/Order-111%20of%202017-02052018.pdf

9. Considering the above mentioned shortcomings, we feel that the objective of ensuring availability of contracted generation capacity during peak demand periods can be achieved in a much simpler manner by adopting the following approach:

(a) RLDCs should prescribe such monthly target availability based on consultation with the concerned state beneficiaries and observed load patterns and generation patterns for that month. These target availability requirements should fall in three brackets: a) availability for peak load months, b) availability during off-peak load months when a plant does not have scheduled maintenance, and c) availability during off-peak load months when a plant is scheduled for maintenance.

(b) Such monthly normative target availability would naturally be inclusive of planned outages and should translate into net normative availability of a given station or unit for at least 85% over a year.

(c) Generators should be required to adhere to these monthly availability targets. Since capacity charge payments are made on a monthly basis, the generator should be required to announce its planned outages in a year in advance to enable planning and bring clarity about the target availability of each plant in each month. Such outages shall not be during peak months.

(d) Capacity charge payments would be made monthly subject to achievement of the target availability. Underachievement of availability would result in pro-rata reduction of capacity charge payable. There should be no provision to offset the under-achievement of availability in peak months.

(e) For under-achievement in non-peak months, the generator can make-up for loss of availability by declaring proportionately higher availability in the months preceding or following the month of low availability. Such decision of the generator should be based on consent of the procurer and the outages should be planned accordingly.

(f) A uniform incentive (independent of peak or off-peak period) of Rs. 0.50 /kWh should be applicable for all scheduled generation in excess of ex-bus energy corresponding to the normative target plant load factor for any given month.

10. We feel that the above proposed approach is simpler to implement and will achieve the same objectives of ensuring accountability of generators for ensuring availability during peak demand periods, while also incentivising generation beyond than the monthly normative target plant load factor.

Computation of Energy Charge for Thermal Generating Stations:

11. Clause 52 (3) of the proposed regulations allows use of alternative fuel supply by coal based thermal generating stations from sources other than those agreed by the generating company and beneficiaries in their power purchase agreement (PPA) for supply from the contracted capacity. Such use is permitted on account of shortage of fuel or optimization of economical operation through blending, without any prior consent of the beneficiary, unless the PPA explicitly requires the generator to seek such consent. The provision allows coal based generating companies to use fuel from such alternative sources up to a price in excess of 30% of the approved base energy charge for that year, without any prior approval from the beneficiaries or the Commission. Only when the price of alternative source of fuel exceeds 30% of base energy charge or the average fuel price, including alternative sources of fuel, exceeds 20% of energy charge for the previous month, whichever is lower, that prior consultation with beneficiary is required.

12. We submit that the proposed provision is highly inappropriate and would lead to dilution of the commercial responsibility of the coal suppliers to ensure coal supply as per their contract terms and conditions, for the following reasons:

(a) First of all, as per the amendment to the New Coal Distribution Policy (NCDP) dated July 2013, the government has already specified the quantum of coal that would be supplied from domestic coal and the extent to which coal can be imported in case of shortages, if any. Since the government has brought about such amendments considering coal availability and likely shortages, there is clearly no reason for the Commission to allow sourcing of coal from alternate sources beyond those identified under the existing laws and coal supply contracts.

(b) Further, the said 2013 amendment to the NCDP has already been declared as a change in law event by the CERC and mechanisms are in place to allow recovery of cost of sourcing imported coal on account of any shortages in domestic coal supply due to this reason. The government has also issued explicit directions to the CERC in this regard. Thus, in case of shortage in domestic coal, the interests of the generator are well protected.

(c) The 2013 NCDP amendment assures coal supply of up to 65% to 75% (depending upon the contract year) of the Annual Contracted Quantity (ACQ). Given this fact, such a blanket provision relaxes accountability of the generator in terms of sourcing least cost fuel i.e. domestic coal by allowing use of alternate fuel that can lead up to 30% increase in energy charge. Therefore, such provision is absolutely inappropriate and unmerited and should not be allowed.

(d) The draft provision ignores the fact that even if the generator is operating at a plant load factor below the level of generation that can be supported by the minimum supply assured under NCDP 2013, it can still choose to source coal from alternate sources (such as imports or e-auctions). This would increase energy charge by up to 30% of the base rate without any regulatory approval or prior consent from its buyer. This can lead to scenarios where the generator is spending excess amount on fuel procurement as against what is allowed as per the existing FSA and fuel policy. In this regard, see the illustration below:

Table 1: Assumptions used for arriving at the illustrative calculation demonstrated in Table 2

Assumptions	Unit	Value
Capacity	MW	500
Generation at normative PLF of say, 80%	MU	3504
Domestic coal GCV	(kcal / kg)	3500
Imported coal GCV	(kcal / kg)	5500
Domestic coal price	(Rs / ton)	1500
Imported coal price	($ / ton)	70
Exchange rate	Rs - $	70
Min expectation as per amended NCDP	%	65%
SHR	(kcal / kWh)	2500
Domestic coal allocation	(MT/year)	2.5
Max increase in energy charge allowed under the proposed Clause 52 (3)	%	30%
Approved base energy charge	Rs / kWh	2
Allowed increase in base energy charge	Rs / kWh	0.6

Table 2: Illustrative calculation to demonstrate excess expenditure on fuel under the proposed provision

Particulars	Scenario 1	Scenario 2	Scenario 3	Scenario 3
Plant load factor (%)	55%	55%	50%	50%
Generation (MU)	2409	2409	2190	2190
Amount that can be spent on imported coal using the proposed Clause 52 (3) i.e. upto 30% of base energy charge (Rs cr)	145	145	131	131
Imported coal that can be procured with this additional amount (MT /year)	0.29	0.29	0.27	0.27
Generation that can be supported by importing coal using Clause 52 (3) (MU)	649	649	590	590
Balance gen from domestic coal (MU)	1760	1760	1600	1600
Domestic coal required for this gen (MT / year)	0.8	0.8	0.7	0.7
Total fuel cost in this case (Rs cr)	225	225	204	204
Min domestic coal allocation permitted under the FSA (%)	65%	75%	65%	75%

Min quantum of domestic coal that can be sourced from CIL as per FSA provisions (MT / year)	1.63	1.88	1.63	1.88
Electricity that can be generated from minimum domestic coal realization (MU)	2275	2625	2275	2625
Electricity that needs to be generated from imports if minimum domestic coal realized (MU)	134	0	0	0
Imported coal required in this case (MT / year)	0.06	0.00	0.00	0.00
Total fuel cost if minimum coal realized from domestic sources (Rs cr)	192	163	163	156
Extra fuel cost because of excess coal imports (Rs cr)	32	62	42	48

(e) As the illustration highlights, the provision makes it possible for the generator to not make an attempt to source domestic coal from CIL to the maximum extent possible. Instead, the generator may simply procure coal from alternate sources such as imports or e-auction (both of which are far more expensive than coal supplied by CIL under linkage FSA). Since no prior approval is required for such high cost fuel purchase, it would be difficult to monitor such transactions of the generator and/or to evaluate whether such alternate high cost fuel procurement was indeed merited. The beneficiary would have no say in it, although it would be forced to bear the excess price of such alternate fuel procurement.

(f) Another worrisome aspect of this provision is that it will dilute CIL's responsibility of ensuring minimum coal supply that it is mandated to provide as per the 2013 amendment to the NCDP. Given the lack of transparency in coal requisitioning, supply, and allocation of coal shortage amongst the various coal consumers, such a provision creates various gaming possibilities and a potential neglect of coal requirements of plants regulated under Section 62 by the coal suppliers.

13. Therefore, considering the serious issues highlighted above, we submit that the proposed provisions under Clause 52 (3) allowing sourcing of alternate fuel upto 30% of approved base energy charge should be removed. The existing provisions of the NCDP 2013 and SHAKTI policy are sufficient to manage coal shortage related issues, if any. The Commission must respect such existing fuel policies and fuel supply agreements and not create any parallel channels that are likely to dilute accountability of the coal supplier at the cost of the electricity consumers.

14. Regulation 49(2) which deals with computation of Gross Calorific Value (GCV) requires the generators to provide the beneficiaries with all details regarding various sources of fuel. This is a good suggestion by the Commission as these costs are eventually passed on to consumers through the beneficiaries, generators should be asked to publish such information on their websites for the benefit of informing consumers. The generator should publish information regarding its sources of coal including, captive coal mines in addition to those listed in the regulation. More importantly, such information should be made available in Microsoft excel files, thus allowing further analysis and use of such data. The data should also be properly achieved and should be easily available in the public domain.

Thermal stations completing 25 years of operation:

15. The proposed regulations have three different provisions to deal with capacity that is about to complete its useful life. Regulation 26, 27, and 28 deal with this issue. The Commission has rightly proposed optimum utilization of these assets by letting the generator and procurer decide the course of action post the useful life of the asset. As matter of principle, the sector must make best efforts to utilize such depreciated assets to meet seasonal and/or peak requirements instead of commissioning new units for such purposes. The commission should ensure that no new capacity addition is permitted until and unless all such existing and functional assets are fully utilised.

16. Having said the above, the regulations also need to clearly mention that the existing PPA will not be valid after a unit completes 25 years of its operation. In case the existing beneficiary wishes to continue procurement from such capacity post the 25-year period, the procurer and generator should be required to approach the Commission for entering into a fresh contract. The terms and conditions for such contract and its term should be evaluated by the Commission considering the beneficiary's demand and alternative lower cost sources. This requirement of should be explicitly stated in the regulations.

Compliance with environmental norms and regulations:

17. MOEFCC vide Notification dated 7.12.2015 has notified the Environment (Protection) Amendment Rules, 2015 amending the Environment (Protection) Act, 1986. Through the amendment, the existing/applicable environmental norms for all existing as well as future Thermal Power Projects stand amended. Under the amended norms prescribed by the MOEFCC Notification for compliance, all Thermal Power Plants have been categorised as (i) Units installed before 31.12.2003 (ii) Units installed between 1.1.2004 and 31.12.2016 and (iii) Units which are commissioned after January, 2017. However, it is understood that even a year after the timeline that was specified for compliance, most plants have not taken steps necessary for ensuring compliance.

18. This is a serious issue concerning thermal generation sector as it adversely affects not just the environment but also the broader public interest. Section 61 of the Electricity Act 2003 mandates the Commission to formulate regulations considering "*the factors which would encourage competition, efficiency, economical use of the resources, good performance and optimum investments*". Thus, it is the responsibility of the Commission to ensure optimal utilisation of scarce natural resources such as coal and water.

19. It is understood that in order to comply with the MOEFCC norms, most thermal power plants would need to install some pollution control equipment (PCE) and/or undertake some retrofits to the existing plant machinery. Thus, it implies that ensuring compliance would entail incurring of some capital expenditure by the power plants. Learning from the past experience of non-compliance and monitoring failure, it seems necessary to have intermediate milestones to ensure timely execution of proposed capital expenditure projects. Also, commissioning of some of the PCE may require the plant to be shut down which further underscores the need for tracking of progress and ensuring that such outages are well planned and coordinated across regions.

20. We therefore propose that while approving any capital expenditure for such compliance, the CERC should mandate the power plants to submit detailed information that would enable it undertake due scrutiny of the proposed expenditure. Additionally, the Commission should establish a web-based transparent mechanism for tracking of progress and achievement of the milestones. The onus of compliance should be entirely on the power plant and non-compliance should be assumed unless the power plant in question reports compliance status to the Commission and submits all the necessary documents.

21. If the project delays construction or commissioning of any PCE beyond the final milestone, no interest during construction (i.e. IDC) should be allowed on account of such delay, i.e. in such case no increase in IDC beyond the normative value approved by the Commission in the original DPR should be allowed to be passed on to the electricity consumers.

22. Clause 29 of the proposed regulations deals with additional capitalization on account of revised emission standards. The said clause defines the procedure for claiming recovery of the capital expenditure necessary for ensuring compliance with the revised norms. In this regard it is essential for the regulations to expressly state that any cost disallowance and/or delay in terms of securing cost approval cannot be the ground for non-compliance with the revised emission standards. The said emission standards being a statutory requirement, compliance with the same cannot be subject to any cost approval.

23. Clause 35 deals with operation and maintenance related expenses. The sub-clause 6 under this deals with provisions pertaining to water charges for thermal power stations. It is important to note that the revised emission standards also prescribe water usage for thermal plants. Therefore, the regulations should include a proviso that explicitly disallows any expenditure on water charges that is over and above the norm prescribed under the revised emissions standards.

24. Under the Clause 11, the Commission has created provision for granting in-principle approval to generating companies for undertaking any additional capitalization on account of change in law events or force majeure conditions. In order to avoid confusion or misuse of the provision it is important to make it explicitly clear that such in-principle approval should not be construed as final approval and the scheme or the said expenditure would be open to scrutiny during the subsequent regulatory process/ review, particularly in the context of actual cost incurred, scope and objective achieved, etc., ex-post after implementation of the Scheme. Such explicit provision is crucial to avoid any post implementation disputes regarding appropriateness of investment decisions or its prudence. It is important to note that the Maharashtra Electricity Regulatory Commission has notified guidelines for such in-principle approval of capital expenditure schemes and has data formats that the entity seeking such approval needs to duly fill and submit. The CERC should also notify such guidelines and data formats to enable smooth and meaningful implementation of the said provision.

Coal plants using coal from captive mines:

25. As per the Coal Mines (Special Provisions) Act 2015 and associated amendments to the Mines and Minerals (Development and Regulations) Act

1957, coal mines shall be allocated to private sector companies only through auction. As per paragraph 3.2(a) of the directive no 23/9/2015-R&R issued by the Ministry of Power to the Central Electricity Regulatory Commission dated 16th April 2015, the energy or variable charges for coal mines awarded through the auction route, i.e. to private sector companies for the end use of power generation, should be calculated based on the per-tonne amount quoted as part of the bid plus Rs. 100 per tonne. According to the same directive issued to the Commission, the energy charge applicable to public sector entities is to be estimated based on the cost of mining plus Rs. 100 per tonne. Therefore, the regulations in Chapter 9 of the proposed regulations to compute variable charges based on computation of capital cost of the integrated coal mine should be revised to make this difference between treatment of public and private sector coal mine owning generators explicit.

26. Regulation 37:

(a) According to the Coal Mine Development and Production Agreement (CMDPA) signed by the generator upon being allocated the coal mine, there are specific timelines as defined by "Efficiency Parameters" by when the coal mine has to be developed and operational. Therefore, Regulation 37 must ensure that the date of commercial operation of the mine is consistent with the CMDPA and not delayed beyond such timelines. Costs associated with using alternative sources of fuel and any increased interest burden should not be allowed if these timelines are breached.

(b) It is not clear how the "value of production" mentioned in Regulation 37(b) is determined. For example, would it be based on CIL notified prices for a similar grade? This should be made explicit in the regulation to avoid confusion and litigation in future.

(c) The term “touching coal or lignite” is not clear in Regulation 37(b). This needs to be explained further.

27. Regulation 39(5): Any such report vetting the capital expenditure and additional capital expenditure from CMPDIL or any other agency would be critical to determine tariffs from such plants. Therefore, such reports should be made available as part of the public process for tariff finalization.

28. Regulations 40(1) and 41: In addition to prudence check, any additional capital expenditure on the coal mine either before date of target capacity or after such date should be accompanied by a cost-benefit analysis to justify the additional capital expenditure and such expenditure should be subject to approval from beneficiaries and be part of the public process for tariff finalization.

29. Regulation 42(A) should clearly describe the method considered for calculation of depreciation and the rate of depreciation to be considered.

30. Regulation 45

(a) It should be noted that coal from a captive mine may be used in multiple units of multiple stations of the generator. Therefore, these regulations should be applied for determining tariff of all such stations where coal from the captive mine is used.

(b) The Commission should, as part of these regulations, outline the method by which it would determine the input price (Rs / MT) based on the inputs provided in Annexure V. It is currently left unspecified.

(c) Since one of the purposes of providing captive mines to end users was to lower the price of electricity, the input price determined (inclusive of the Rs 100 / tonne allowed) should be capped by the CIL notified price for the power sector for an equivalent grade of coal.

(d) Moreover, in case the generator produces more coal from the mine than required for its unit(s), it is expected to transfer the excess coal to CIL. Revenues from such transfer, if any, should be factored in while computing the input price. Commission should expand Annexure V to include grade-wise information regarding items such as opening coal stocks at the mine, coal production, coal use in various generation unit(s), disposal through other means and revenue generated from it, and closing coal stocks at the mine, to be able to compute the input price by factoring in such elements.

31. Appendix V (a): The Detailed Project Report and/or the Mine Plan should include information about expected coal quality in each seam (GCV, ash and moisture content etc.) to enable effective cost estimation. If they do not, such information also should be asked for.

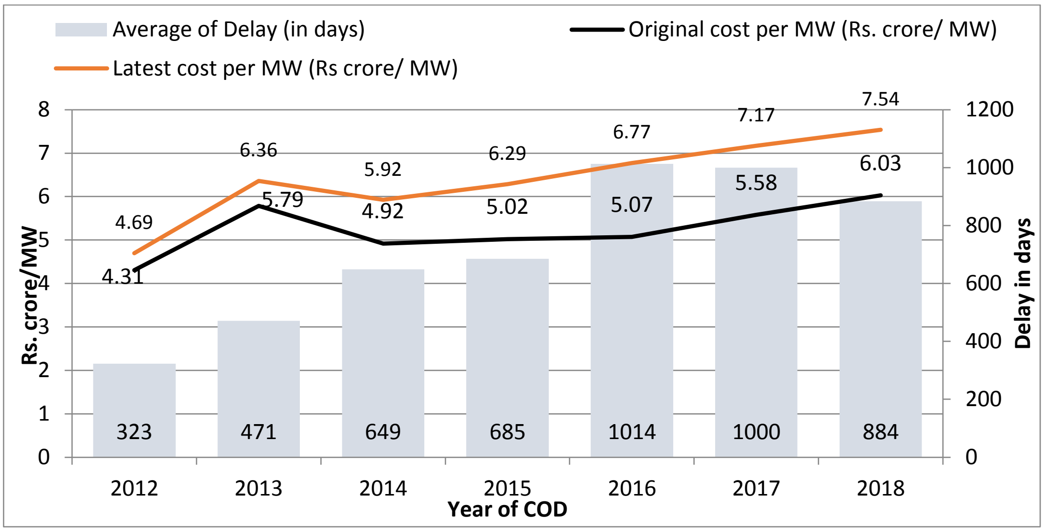
Benchmarking of capital costs and treatment of IDC:

32. The consultation paper discussed a few options for controlling capital cost, including investment approval based on benchmark/reference cost. The explanatory memorandum states that the challenge is absence of credible benchmarking of technology and capital cost. It also lists various objections to any move towards benchmark based pricing for capital cost determination of new projects.

33. It is indeed peculiar that in spite of the installed coal based generation capacity having more than doubled in the last decade, generators and promotors are still claiming that each project is unique and that it is not possible to use benchmark pricing for cost determination. This is in spite of the fact that only a few players dominate the EPC area of project construction. The situation becomes even more curious when one looks at the performance data of projects that have been commissioned in the 12th Plan period.

34. As per CEA data 86% of the capacity addition in the 12th Plan came from coal, while at the same time 64% of the capacity that slipped from the 12th Plan was also coal based. Delays are not new for coal based generation capacity, but as Figure 1 indicates, they have been steadily rising since 2012 and almost all coal based capacity in the 11th Plan and 12th Plan has been delayed. In addition, the capacity currently in the pipeline is already staring at a delay of 22 months on an average.

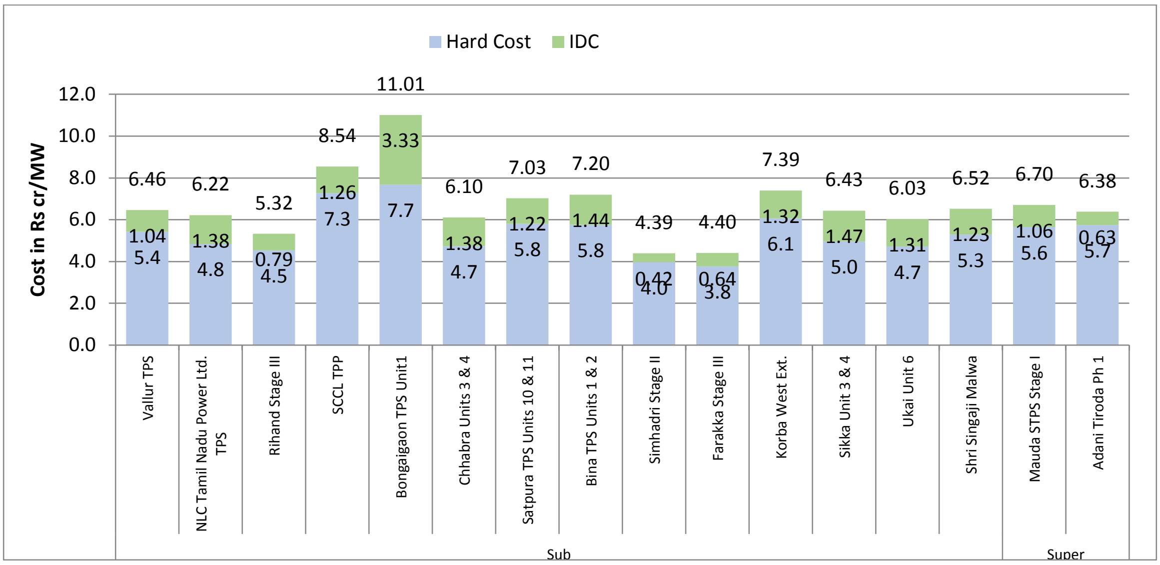
Figure 1: Increasing costs and delays in commissioning of coal based thermal projects



Source: Prayas compilation from CEA Broad Status Monitoring Report for various months

35. Now if we look at the capital costs of some of these projects (for which data was easily available in public domain), again a very disturbing image appears. Figure 2 shows break-up of the capital cost of newly commissioned projects into hard costs and IDC. As can be seen, the hard costs have remained more or less constant with the entire increase in capital cost being by IDC. This clearly indicates that there is a huge room for efficiency improvement and it is not the equipment cost that is making coal based generation costlier. Indeed, it is the issue of project management and commissioning that needs urgent attention and hence benchmark pricing can be a useful tool to ensure timely project completion.

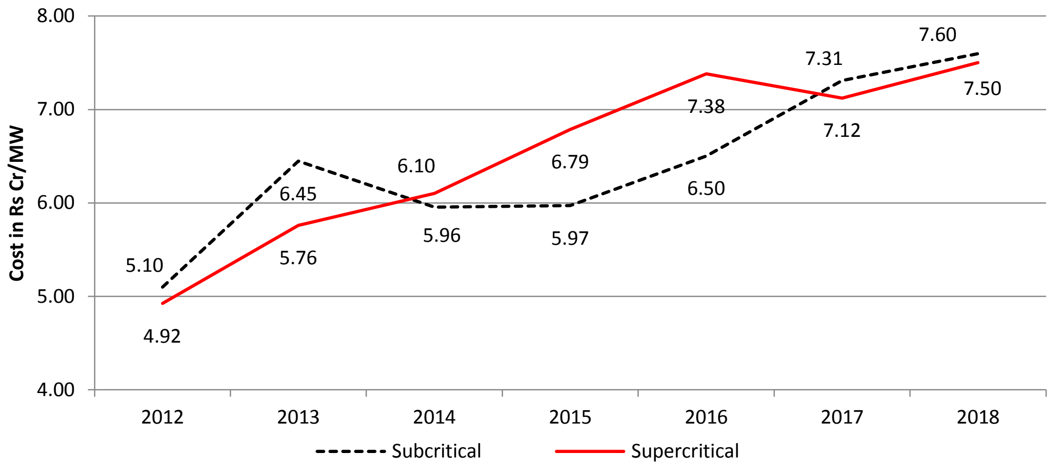
Figure 2: Hard cost and IDC (Rs Cr per MW) for 12th Plan power projects (2012-2017)



Source: Prayas compilation from various regulatory orders

36. It has been argued that newer power plants may be super-critical plants and hence costlier. However, this is belied by Figure 3, which shows that the capital cost for both sub-critical and super-critical plants have increased significantly in the past few years, with sub-critical plants surprisingly costing more than super-critical plants on average in some years. For example, as per CEA data for NTPC plants under construction, the average cost of subcritical units is Rs. 7.79 crore per MW versus Rs. 7.28 crore per MW for supercritical units. Therefore, change in plant technology does not seem to be the reason for the cost increase over time. Also, significant capacity that came up during the 12th Plan was brown field which implies that land acquisition and/or clearances played a little role in project delays.

Figure 3: Average capital costs (Rs crore / MW) of coal-based plants commissioned



Source: Prayas compilation from CEA broad status monitoring reports and CEA executive summaries

37. The above data indicates that much of the increase in capital cost of newly commissioned capacity is on account of avoidable reasons, namely, poor project management and execution. Considering this and taking into account the fact that with increasing cost competitiveness of renewable energy sources, thermal capacity utilization is going to reduce, and such high costs are bound to be a major drain for the distribution companies and are likely to be the major reason for worsening their finances.

38. In light of the data and the findings mentioned above, we submit as follows:

(a) Under Clause 21 which deals with controllable and uncontrollable factors, the Commission has treated time and cost over-runs on account of land acquisition, except where the delay is attributable to the generating company or the transmission licensee, as uncontrollable factor. We submit this is absolutely unnecessary and will lead to dilution of the project developer’s accountability leading to avoidable disputes over which delay can be attributable to the generator and hence should be removed.

(b) It is important to understand that land is like any other input for the project which the project developer should procure as per the extant legal provisions and market rates. Failure to do so should be deemed to be risk that the project developer should bear entirely. In fact, as has been implemented by the Government in case of national highways, in electricity generation and transmission also, no projects should be awarded until 90% of the land is in possession for the EPC (engineering, procurement and construction) projects. Such a provision can be far more useful in terms of avoiding project delays on account of land acquisition issues, if any.

(c) Presently, there is no real threat for the project developer in case of delays in commissioning of Section 62 projects. As against this, the model PPA for Section 63 projects allows extension of the scheduled date of delivery only up to a maximum period of one year beyond which force majeure provisions kick-in and the procurer is entitled to terminate the contract if delay seems unavoidable. Such stringent provisions are absolutely missing in Section 62 projects, which perhaps the reason why most of the delayed capacity is regulated capacity with cost-plus tariffs. This important lacuna in Section 62 project approval has not been addressed. The CERC while approving any new project should impose this condition and give the procurer opportunity to decide whether it wishes to continue the contract if the project gets delayed for more than a year. Since all the Section 63 projects could easily secure funding and many have been commissioned on time, there is no reason to believe that such provision will affect the project's ability to raise funds.

(d) Given the fact that there has not been much change in hard costs over time and/or technology, there is an urgent need to introduce benchmark pricing for approval of capital costs. With the data for most of the capacity commissioned during 12th Plan period being available in public domain, it is not clear what data challenges the explanatory memorandum is referring to. In any case, the CERC has authority to solicit any data and information that it may deem necessary for evaluating and defining benchmarks, such an important exercise should not remain stalled.

(e) Clause 6 of the proposed regulations deals with treatment of mismatch in date of commercial operation of a generating station and the transmission system. In such an event, in order to ensure accountability of the implanting agency, the costs or penalties that the generator (or Transco) pays to the other party should not be allowed to be passed on to the consumers.

Reporting of costs claimed under change in law events

39. In the last MYT control period, the Commission has issued numerous orders dealing with issues concerning change in law events. The said orders have resulted in significant increase in variable cost of the generating stations, which is borne by electricity consumers. However, there is no clarity in the extent of claims made by the generators and costs allowed by the Commission. In this regard, it can very useful to have a separate data reporting formats for annual costs claimed under various change in law events. The generating companies should be required to submit this data at the time of their tariff revision process and also maintain this data on their website in easily downloadable formats. The requirement of such data reporting should not be limited to Section 62 projects alone, but should also be applicable to Section 63 projects. Such provision can bring about significant clarity in the costs claimed by the generators and actual payments made by the beneficiaries.

40. We once again request the Commission to accept this submission on record and to allow us to make further submissions in this matter, if any. We also request the Commission to allow us an opportunity to present our submission in person during the public hearing scheduled in this regard on 1st February 2019.

Ashok Sreenivas and Ashwini Chitnis
PRAYAS (ENERGY GROUP), Pune

PLACE: Pune
DATE: 28th January 2019