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RInfra/CERC/01/2018

July 31, 2018

By Email/Post
(secy@cercind.gov.in)

To,
Sh Sanoj Kumar Jha,
Secretary,
Central Electricity Regulatory Commission,
New Delhi- 110001

Dear Sir,

Sub: Submission of comments/suggestions on Consultation Paper - Terms and Conditions of Tariff for the tariff period commencing from 1st April, 2019

Ref: Notification on No. L-1/236/2018/CERC posted on CERC website inviting stakeholder's comment

With reference to the proposed Consultation Paper - Terms and Conditions of Tariff for the tariff period commencing from 1st April, 2019 hosted on CERC website, we hereby submitting our comments on the same attached as **Annexure**.

Our submissions may kindly be considered while finalisation of Terms and Conditions of Tariff for the tariff period commencing from 1st April, 2019.

Thanking You,

Yours faithfully,
For Reliance Infrastructure Ltd.

Kishor Patil
Regulatory Affairs

Encl: As above.

RInfra Comments on CERC Approach Paper on Terms and Conditions of Tariff, 2019-24

Ref.	Subject / Options proposed		RInfra Comments
7.	**Tariff Design Generation & Transmission**		
a)	*7.2.5 The tariff for supply of electricity from a thermal generating station could comprise of three parts, namely, fixed charge (for recovery of fixed cost consisting of the components of debt service obligations allowing depreciation or repayment, interest on loan and guaranteed return to the extent of risk free return and part of operation and maintenance expenses), variable charge (incremental return above guaranteed return and balance operation and maintenance expenses) and energy charges (fuel cost, transportation cost and taxes, duties of fuel).* *7.2.6 The recovery of fixed component could be linked to target availability, whereas variable component could be linked to the difference between availability and dispatch. Fuel charges could be linked with dispatch.*		• The basic premise of segregating the costs under 3 categories that there are certain cost which are variable in nature are also part of the fixed costs. However, it us humbly submitted that there is hardly any cost which can be treated as variable in nature. The only component which can be variable might be working capital, which also practically is not that variable per se. Various factors govern the storage of coal as compared to actual dispatch e.g., DTPS has to maintain a higher coal stock because of its distance of 1400 km from the mines and also the fact that it does not have an all-weather port, because of which imported coal required for entire year arrives in a period of 6 months only. • Moreover Para 6.2 of the Tariff Policy including the Amendment to Tariff Policy envisages a two-part tariff structure should be adopted for all long-term and medium-term contracts to facilitate Merit Order dispatch. • Segregating RoE into guaranteed return to the extent of risk free return and incremental return above guaranteed return linking to dispatch may lead to under recovery of guaranteed return, for no fault of the Generator. Further, such provisions will be viewed negative by the Lenders as it would take away the certainty of RoE and would impact the ratings of the Generating Company which most of them are already stressed. Any adverse change in the rating would increase the cost of the debt leading further increase in the cost of operations. • In view of above, it is requested to continue the existing mechanism of 2 part tariff may be continued.
8.	**Deviation from Norms**		
a)	*8.2 Section 61 of the Act provides that the Commission shall be guided by the factors which would encourage competition and recovery of the cost of electricity in a reasonable manner. The present market framework involves the competition for power procurement for securing power purchase agreement. Once the power*		• It's a welcome step to develop Incentive & disincentive targets mechanism for different levels of dispatch and specifying the target dispatch, however, it should be ensured that for generator is achieving dispatch more than the target availability no dis-incentive should be levied. • Moreover, if a particular plant is facing the issue of coal shortage then in such cases dispatch targets shall be adjusted accordingly.

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	purchase agreement is secured, there is no framework for competition of dispatch. The distribution licensees follow merit order based on the tariff agreed under PPA under Section 63 of the Act or the tariff determined by the Commission under section 62 of the Act. *8.3 For various reasons, out of tied up capacity by the distribution licensee, some of the capacity often remains undispatched over large part of the year. Since the tariff determined by the Commission acts as ceiling, there is no embargo on the generating stations or the transmission licensee to charge lower tariff. This provides a scope for creating some competition.* *8.4 Possible option could be to develop for incentive and disincentive mechanism for different levels of dispatch and specifying the target dispatch expanding the scope of Regulation 48 above.*		
10.	**Optimum Utilisation of Capacity (Coal based Thermal Stations)**		
a)	*10.2 If the unutilized capacity of the generating station is allowed to be utilized by other distribution companies or through open market, the obligations of the distribution companies may reduce to the extent of utilization.* *10.3 (a) Flexibility may be provided to the generating company and the distribution licensee to redefine the Annual Contracted Capacity (ACC) on yearly basis out of total Contracted Capacity (CC), which may be based on the anticipated reduction of utilization. Annual Contracted Capacity (ACC) may be treated as guaranteed contracted capacity during the year for the generating company and the distribution licensee*		• This is to submit that current PPAs already have the provision of selling the un-utilised capacity in the market and in case of realisation of revenue over and above the approved energy charges, such additional revenue earned (beyond normative allowed cost) is shared among generator and beneficiary resulting into reduction in the fixed cost liability for beneficiary. • The proposed mechanism is a welcome step however, it should be ensured that in the event of non dispatch of the un-utilised capacity to any other licensee, there shall be no loss to the Generator. In such event the liability to pay un-recovered fixed charges at the end of the year shall be to the original beneficiary. Such provision will provide both protections of the returns to the Generators as well as enough incentive for them to identify a buyer for such un-utilised capacity for the full year or participate in the bidding process to realise price at market discovered price. • It is to be noted that the long-term contracts / counter-party profile are the key elements for securing finance for the investments. Any un-certainty for contracting / dispatching of unutilised

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	and the capacity beyond the ACC may be treated as Unutilized Capacity (UC). The distribution licensee will have a right to recall Unutilized Capacity during next year and for securing such rights, some part of fixed cost, say 10-20% or to the extent of debt service obligations, may be paid; *(b) Such unutilized Capacity may be aggregated and bidded out to discover the market price of surplus capacity. The surplus capacity may be reallocated to the distribution licensee at market discovered price.*		capacity will again assessed by Lenders negatively and may impact the rates of lending adversely. • Such changes would require an elaborate procedure and timelines for conducting the bidding process (preferably by a central agency) with adequate administrative authority to ensure commercial discipline. Hence, it is suggested the Hon'ble commission may examine this proposal separately through public consultation.
11.	**Capital Cost**		
a)	*11.8 One of the options is to move away from investment approval as reference cost and shift to benchmark/reference cost for prudence check of capital cost. However, the challenge is absence of credible benchmarking of technology and capital cost.* *11.9 Higher capital cost allows the developer return on higher base of equity deployed. In the cost plus pricing regime, the developer envisages return on equity as per the original project cost estimation. The regulations allow compensation towards increase in cost due to uncontrollable factor so as to place the developer to the same economic position had this uncontrollable event not occurred. Therefore, in new projects, the fixed rate of return may be restricted to the base corresponding to the normative equity as envisaged in the investment approval or on benchmark cost. The return on additional equity may be restricted to the extent of weighted average of interest rate of loan portfolio or rate of risk free return. Further, incentive for early completion and disincentive for*		• We suggest that actual capital cost on project completion should be considered, with the following riders: i. Make International Competitive Bidding (ICB) mandatory for the procurement of main plant packages/major packages and competitive bidding for the other packages to ensure competitiveness of prices. However, the developer should have the freedom to go for negotiated procurement, if ICB fails or if the developer can demonstrate that the price discovered through ICB is not competitive. Alternatively, the mandate could be to carry out ICB once and if there is insufficient response, the developer could go in for negotiated procurement. ii. Specify Normative time period (construction period) for completion of the project, in consultation with the CEA and such time period could be permitted for the computation of Interest During Construction (IDC) i.e. even if the actual time for completion is more, IDC to be permitted for normative period only, unless it is expressly proven by the developer that the delays were due to force majeure conditions. iii. The Equity corresponding to capital cost allowable based on normative time period for construction should be considered for RoE. Balance equity should be treated at par with debt and cost of debt should be considered for such additional equity, for the purpose of tariff determination, as against Risk Free RoR proposed.

Ref.	Subject / Options proposed		RInfra Comments
	slippage from scheduled commissioning can also be introduced.		
14.	***Depreciation***		
a)	*Increase the useful life of well-maintained plants for the purpose of determination of depreciation for tariff;* *b) Continue the present approach of weighted average useful life in case of combination, due to gradual commissioning of units;* *c) Consider additional expenditure during the end of life with or without reassessment of useful life. Admissibility of additional expenditure after renovation and modernization (or special allowance) to be restricted to limited items/equipment;* *d) Reassess life at the start of every tariff period or every additional capital expenditure through a provision in the same way as is prescribed in Ind AS and corresponding treatment of depreciation thereof;* *e) Extend useful life of the transmission assets and hydro station to 50 years and that of thermal (coal) assets to 35 years and bring in corresponding changes in treatment of depreciation.* *f) Reduce rates which will act as a ceiling.* *g) Continue with the existing policy of charging depreciation. However, the Tariff Policy allows developer to opt for lower depreciation rate subject to ceiling limit as set by notified Regulation which causes difficulty in setting floor rate, including zero rate as depreciation in some of the year(s).*		• RInfra submits that the only option available to address the issue with respect to depreciation on units having gradual commissioning is to determine tariff for individual units. However, such option comes with even higher level of difficulty in segregating the sharing of common assets built for all units. Apart from this, segregating cost on unit wise basis poses accounting issues for booking of common expenses, which may require adhoc assumptions. Therefore, RInfra submits that the present method of weighted average useful life may be continued. • RInfra agrees with the provision of re-assessment of useful life of the project in case of additional capex infusion during fag end of the project. For this purpose, a third party assessment of useful life post capex intervention beyond 20 years of the project may be considered from independent valuation agencies. • Depreciation is a major component of tariff and assures the cash flow for the project. Frequent revision in depreciation will result in uncertain cash flows and this will create problem in arranging finance for the project. Therefore, it is not desirable to reassess life and re-compute depreciation at start of every tariff period. However, in case of useful life is extended, then it should also be ensured that the PPA with the existing beneficiaries should also be extended to useful life, other-wise Generator will not be able to recover depreciation beyond original useful life which generally coincide with PPA terms. • Moreover, it is difficult to get financing for projects beyond 12 years, hence, depreciation rates for first 12 years should be retained at 5.28% (majorly for P&M items) so that it convenient for Projects to secure financing and also does not face problems of cashflow pertaining to repayment of loan. • Regulations should also provide that all invested capital, including additional capitalisation during the tenure of operation, except the salvage value of 10%, be recovered by way of

Ref.	Subject / Options proposed		RInfra Comments
			depreciation over the Useful Life of the project. That is, the additional capitalisation should be added to the original cost and the balance depreciable value, after subtracting accumulated depreciation, should be depreciated over the balance useful life of the asset as worked out through re-assessment of useful life. However, in case of depreciable value left-over at the time of de-commissioning of power plant, the same should be considered "Residual Value" and passed on to the beneficiaries.
15.	**Gross Fixed Asset Approach**		
a)	*An option could be to base the returns on the modified gross fixed assets arrived at by reducing the balance depreciation after repayment of loan in respect of original project cost.*		• RInfra submits that the issue of reduction in the Return on Equity has also been set aside by Appellate Tribunal for Electricity (ATE) in its judgment dated 16.05.2006 in Appeal No. 121 of 2005, POWERGRID Vs CERC, wherein it has held that depletion of equity is against all fundamentals of tariff fixation and commonly followed principles of operating an enterprise on commercial basis. The relevant extract of the said judgment is reproduced herein below: *"25. It may be noted that tariff determination is a periodic exercise followed at specified regular interval. The error made in the preceding tariff fixation exercise could always be corrected in the following block year 12 with or without adjustment.* ***Denial of a large size of equity invested in projects for ROE, not only for one block period but for the entire technical life of the projects, is neither fair nor judicious. This is against all fundamentals of tariff fixation and commonly followed principles of operating an enterprise on commercial basis.*** *The said anomaly ought to have been corrected at the first available opportunity by the Regulator."*(Emphasis Added) • The issue of GFA approach vs NFA Approach hinges on which approach should be adopted so as to provide regulatory certainty to the investors who have made investments in the sector on the assumption that they will continue to get Return on Equity till the life of the asset. Accordingly, CERC adopted RoE principle linked to Gross Fixed Assets. • As per the Tariff Policy and Section 61 of the Electricity Act 2003, every Commission has clear mandate to fix a rate of return that will not only attract investment but will also allow generation of reasonable surplus for further growth in the sector and encourage efficient, economical use of the resources, good performance and optimization of investment.

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			• RInfra submits that the assets remain in service till their operational life, which itself is determined by how well the asset has been maintained by the developer. Operational life, in case of well maintained assets, is almost always greater than accounting (economic) life. Till the time, the asset remains in service, the corresponding Regulatory Equity, which remains invested in the business, is eligible for RoE. It is further submitted that if lower RoE is given for the depreciated asset, the investor would be tempted to remove the depreciated asset from service and replace the same with new asset to earn higher RoE. Such action would involve replacement of asset with lower capital cost with present cost which would be much higher thereby burdening the consumers with higher capital cost. • As such, the sector is passing through a difficult period with hardly any investor interest for fresh investments and hence this is not the appropriate time for such a transition, the same may be reviewed at later stage.
16.	**Debt/Equity Ratio**		
a)	*For future investments, modify the normative debt-equity ratio of 80:20 in respect of new plants, where financial closure is yet to be achieved.*		RInfra submits that as per the accepted financial principles, in case there is a higher reliance on debt or availability of lower cost debt to Corporates, the same will not happen in isolation, but shall have its effect on the cost of equity as well. This is because shareholders perceive a higher debt company to be riskier and therefore the cost of equity (return expected by shareholder) will rise to be commensurate with such higher risk. Hence, if the debt/equity ratio is altered, the return on equity permitted will also have to be changed. It may further be noted that if more equity is invested then share holders shall have higher commitment for operating the business in good condition. In view that this is a self balancing mechanism, there is no need to revisit the debt/equity ratio, as the overall cost of capital is likely to remain unchanged. Moreover, the Country has shifted focus in encouraging the RE in a grand way by specifying the aggressive targets which also requires investment in the substantial investment in the Transmission segment. Such changes in the debt:equity ration might create gap in Transmission requirement as investors might view low returns on the equity invested.

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17.	**Return on Investment**		
a)	*Whether the Return on Equity approach may be continued or ROCE approach be adopted.*		The issue is basically covered in our response to the issue of whether GFA or NFA based approach should be considered. We have suggested that GFA based approach should continue and equity should be considered invested in the business, till the time asset remain in service. Therefore, ROE approach should continue as well. Tariff is determined on multiyear principles, it is important to maintain certainty in approach over each control period to maintain the confidence of investors and regulated entities. In view of the fluctuating interest rate, shallow debt market and considering the financial health of Utilities and the other serious issues faced by Generators in sector such as fuel shortages, offtake issues etc., it is not desirable to switch to ROCE approach.

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18.	**Return on Equity**		
a)	*Review the rate of return on equity considering the present market expectations and risk perception of power sector for new projects*		RInfra submits that while an exercise for determining the cost of equity can be carried out for generating and transmission companies, the same would require an assessment of Equity Risk Premium (ERP). Determination of ERP is often subjective and in order to quantify the same, the index returns for individual companies would be required (i.e. the stock returns plus the dividend yield). Estimation of index returns is a very difficult proposition, since majority of listed power companies operate in more than one business area (thus distorting the risk profile). Similarly, Govt. owned companies such as NTPC etc. operate a large number of projects located all across India and carrying different risk profile, but not listed on the stock market as independent companies. In addition to this, the time horizon of data availability is short (for instance, NTPC was listed on the Stock Exchange only in Nov. 2004, hence has a historical returns data of only about 9 years). Due to these issues, it is very difficult to carry out an assessment of equity risk premium for generating and transmission businesses, at least, with the present data availability. We therefore submit that the present RoE as specified may be continued for the Tariff Period 2019-2024. The same could be reviewed at the end of the Tariff Period for the subsequent period. Further, the Hon'ble Commission may consider that the accounting returns allowed yield in reality much lower economic returns due to effect of idling of equity during the construction period. In case of debt, the return during the construction period is accumulated as IDC (interest during construction) and is paid for by the beneficiaries as part of capital cost. However, no such compensation is allowed for the equity deployed in the regulated assets during the construction period. It is therefore imperative that ROE for the tariff period beyond 2019 is commensurate with expected market return duly considering the impact of gestation period and regulatory delays.
b)	*Have different rates of return for generation and transmission sector and within the generation and transmission segment, have different rates of return for existing and new projects*		ROE should be different for different businesses (like hydro, thermal, Gas, transmission) as each one of them presents different risk profile. Factors like construction period, risks and the need to incentivize new projects should determine project returns. The risks in the sector have gone up significantly in past few years on account of reasons like demand uncertainty, coal shortage and regulatory / policy uncertainty in a supply surplus situation. Therefore, existing rate of RoE shall be continued during the next control period also for existing plants.
c)	*Have different rates of return for thermal and hydro projects with additional incentives to storage based hydro generating projects*		

Ref.	Subject / Options proposed		RInfra Comments
d)	*In respect of Hydro sector, as it experiences geological surprises leading to delays, the rate of return can be bifurcated into two parts. The first component can be assured whereas the second component is linked to timely completion of the project*		Investments made based on equity committed and expected return over useful life of assets. Sosame return should continue.
e)	*Continue with pre-tax return on equity or switch to post tax Return on equity*		In case of common accounts of the Company, it would not be possible to distinguish the income tax paid on a particular project's return vis-à-vis rest of the business. This was one reason why pre-tax approach was instituted by the Commission, so that Income Tax liability borne by the beneficiaries is limited to the regulated return of the project considered for tariff purposes and not on other incomes.
f)	*Have differential additional return on equity for different unit size for generating station, different line length in case of the transmission system and different size of substation*		RInfra submits that factors such as unit capacity, line length, etc. do not reduce or increase the perceived "riskiness" of the project and therefore there is no rationale in specifying a separate RoE on these grounds.
g)	*Reduction of return on equity in case of delay of the project*		The reasons for delay in project commissioning can be ascertained at the time of capital cost approval and only uncontrollable delays may be allowed. Therefore, the permitted capital cost itself factors in the delay in the sense that the cost overruns in the form of basic cost as well as IDC on account of delays attributable to the developer will not be considered in admitted capital cost. Hence, there is no further rationale for reducing the RoE due to project delay. In any event, a project's financial closure is based on its revenue stream, which factors in the RoE at the regulated rate. A subsequent reduction in RoE makes the project riskier by reducing its cash flows and this, in turn, is likely to increase the cost of debt to the project.
19.	***Cost of Debt***		
a)	*Continue with existing approach of allowing cost of debt based on actual weighted average rate of interest and normative loan, or to switch to normative cost of debt and differential cost of debt for the new transmission and generation projects*		In this regard, cases of project financing vs. balance sheet financing could be examined. The credit rating of the company would usually affect the cost of debt in case of balance sheet financing, whereas project financing would normally concern itself solely with the projected cash flows of the project, without looking at the parent company's credit rating or its balance sheet. At this stage, it would perhaps be advisable to carry out a study of historical variation in interest rates on debt already admitted by the Commission in the past. The standard deviation of actual

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			variation of rates for such loans over the past few years could be used as a pointer for deciding whether time is right for prescribing a normative cost of debt and that too, perhaps, only for project based financing for similarly placed projects. Support. To arrive norm a study to be commission to carry out the average of the industry.
b)	*Review of the existing incentives for restructuring or refinancing of debt*		Regulations should specify as to how such gains will actually be measured i.e. (1) over what period of time will such gains be considered – whether for the Control Period duration or the entire tenure of the loan itself? (2) How will the regulation distinguish between a genuine market correction and a gain due to refinance, that is, a genuine market correction could be masked as refinance in order to earn incentive as well as pass through the cost of refinancing?
c)	*Link reasonableness of cost of debt with reference to certain benchmark viz. RBI policy repo rate or 10 year Government Bond yield and have frequency of resetting normative cost of debt*		As submitted above, an external rate is no yardstick for determining normative cost of debt in project financing. The normative rate, if at all to be set, should be determined by analysing the actual cost of debt for project financing cases, with similar risk profiles.
20.	***Interest on Working Capital***		
a)	*As stock of fuel is considered for working capital, a fresh benchmark may be fixed or actual stock of fuel may be taken*		RInfra submits that actual fuel stock should be considered for determining Working Capital. Coal stock with a particular plant depends on fuel supply conditions of its FSA, the dispatch by beneficiaries, the coal availability issues of CIL or imported coal, availability issues due to logistical constraints, and the peculiarities of the plant, such as not having an all-weather port and hence needing to import yearly requirement only during non-monsoon window of 6 months and thereby ending up with a higher stock in the yard. RInfra submits that none of the above aspects can be tied with efficiency of a power plant in managing its coal stock. Coal stock amount is therefore largely a default than design. Hence, it is advisable to allow Working Capital on actual coal stock and not to create any artificial incentive by considering a norm for the same.
b)	*While working out requirement of working capital, maintenance spares are also accounted for. Since O&M expenses also cover a part of maintenance spares expenditure, a view may be taken as regards some percentage, say, 15% maintenance spares being*		Maintenance Spares to the extent included in O&M expenses could be excluded.

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	made part of working capital or O&M expenses.		
c)	*Maintenance spares in IWC which is also a part of O&M expenses results in higher IWC for new hydro plants with time and cost overrun. For old hydro stations, the higher O&M expenses due to higher number of employees also yield higher cost for "Maintenance Spares" in IWC. Therefore, option could be to de-link "Maintenance Spares" in IWC from O&M expenses.*		
d)	*In view of increasing renewable penetration and continued low demand, the plant load factor of thermal generating stations is expected to be low. As per the present regulatory framework, the normative working capital has been provided considering target availability. In case of wide variation between the plant load factor and the plant availability factor, the normative approach of linking working capital with "target availability" can be reviewed.*		Though the Commission may consider linking working capital requirement based on PLF, however in such cases where PLF achieved by Generator is above NAPAF should also be considered while computing working capital requirement. Fuel cost is linked to actual generation which is also linked to loading factor. Hence, if generation is considered for allowing working capital then the same should be considered on actual without limiting to any targets. Another aspect should also be considered that typically all generators are required to pay in advance to coal companies, therefore certain days of working capital shall also be added to in addition to 1 month of fuel cost for storage and generation.
21.	**Operation and Maintenance Cost**		
a)	*Review the escalation factor for determining O&M cost based on WPI & CPI indexation as they do not capture unexpected expenditure*		Employee cost may be escalated by CPI alone, while R&M by WPI alone and A&G expenses by a combination of CPI and WPI (say 60:40). All three can then be combined to produce a combined escalation factor as: CPI*X% + WPI*Y% + (60%CPI+40%WPI)*Z%, where X, Y and Z are % of employee, R&M and A&G expenses in the total O&M. Weightage should be given to plant vintage, as well. Inflation factors CPI and WPI should be considered by taking 5 year average and abnormal expenses, if any, should be removed. Further, uncontrollable expenditure such as periodic Wage Revision, License fees, changes in taxes, etc. should be permitted in addition to normative allowance.

Ref.	Subject / Options proposed		RInfra Comments
b)	*Address the impact of installation of pollution control system and mandatory use of treated sewage water by thermal plant on O&M cost.*		Normative O&M allowance should accommodate anticipated expenditure on account of new pollution control equipment and cooling towers, etc. As there may not be sufficient history of O&M expenses pertaining to these additional equipment / assets, initially a separate allowance could be provided taking OEM input with regard to maintenance expenditure into consideration. Also, due consideration should be given to the fact that OEM could itself be carrying out the maintenance for few initial years, with no cost to the generating station.
c)	*Review of O&M cost based on the percentage of Capital Expenditure (CC) for new hydro projects*		Generalised norms for hydro project based on their capacity (as thermal plants) may not be practically possible owing to different size/ design of project components for projects having similar capacity (tunnel, dam etc.). Variation in capital expenditure reflects the impact of variation in size/ design of project components and O&M based on capital expenditure should continue.
e)	*Rationalization of O&M expenses in case of the addition of components like the bays or transformer or transmission lines of transmission system and review of the multiplying factor in case of addition of units in existing stations*		If O&M norms of each Control Period are derived using the actual O&M expenses (subject to prudence checks and after removal of outliers) of previous period and the actual addition of lines, bays, units, etc. then the actual correlation between the operational factors and expenses is established anyway and multiplying factors to reflect economies of scale are not required. Economies of scale would be accounted for in the trend of actual O&M expenses.
f)	*Have separate norms for O&M expenses on the basis of vintage of generating station and the transmission system*		Whether and to what extent vintage affects O&M expenses can also be analysed using actual cost and operational data of the previous Control Period from different vintage power plants and transmission assets and accordingly age-premium, if any required, in O&M expenses can be worked out.
f)	*Treatment of income from other business (e.g. telecom business) while arriving at the O&M cost*		Revenue from Telecom activity increased from Rs. 78 Cr in FY07 (20,000 km) to Rs. 504 Cr in FY17 (41,988 km). Income shared with beneficiaries increased from Rs.6 Cr (FY07) to Rs.12.6 Cr (FY17). Income shared in FY07 ~8% of total such revenue compared with ~2% in FY17. In view, Income from other Business (Transco) considered @ Rs. 3000/km/year as per CERC (sharing of revenue derived from utilisation of Tx. Assets for other business) Regulations, 2007, needs review.

Ref.	Subject / Options proposed		RInfra Comments
23.	**Fuel – Blending of Imported Coal**		
a)	*Take actual GCV and quantity at the generating station end and add normative transportation losses for GCV and quantity for each mode of transport and distance between the mine and plant for payment purpose by the generating companies. In other words, specify normative GCV loss between "As Billed" and "As Received" at the generating station end and identify losses to be booked to Coal supplier or Railways.*		It is submitted that the Generator does not have any control in loss of GCV "As Billed" and "As Received" hence the generator can't be held accountable for such losses. Though the intent of the proposal is good to book the losses to coal supplier but practically such process will lead to dispute where in coal companies may reject such claims and generators need to pay for such losses without getting being reimbursed from the beneficiaries leading to losses. It may be noted that 3rd party coal sampling has already been initiated and implemented in most of the places which automatically will take care of losses due to difference in GCV billed at the loading point, however, if still there are losses from loading point to receiving point then in such case normative loss values may be defined. However, it should be ensured that impact of such loss beyond normative values shall not be to account of Generator and beneficiary should pay first and adjustments based on settlement done by the coal company should be done later.
b)	*Similarly, specify normative GCV loss between "As Received" and "As Fired" in the generating stations*		RInfra operate thermal power plant (Dahanu Thermal Power Station), where coal stocking period for Domestic Coal is about 30 days for Imported Coal, it is about Six (6) months. The Hon'ble Commission must appreciate that DTPS is located 1400 kms from its mine and therefore faces the risk of coal unavailability due to various freight related issues, possible wagon accidents, etc. This is because DTPS has to necessarily maintain a domestic coal stock of about 30 days. Further, in case of Imported Coal, because DTPS does not have an all weather port, the Imported Coal can only be received for six months in a year (i.e. not during Monsoon Period – May to October) and therefore coal quantity of entire year is received in the six month window, leading to average coal stock of imported of about 6 months. Such high Inventory period of coal would naturally lead to higher heat loss and hence the considerations on which CERC Tariff Regulations, 2014 are based do not hold true in case of DTPS. It is submitted that the heat loss due to coal handling, stacking, storing for longer periods, etc. is a

Ref.	Subject / Options proposed		RInfra Comments
			natural business occurrence and it actually depends upon the conditions in which the plant is operating. It is possible for pit-head stations to have little or no coal inventory and therefore for them, the GCV of coal received is as good as GCV of coal fired, but for non-pit-head and distantly located stations such as DTPS, where coal stocking period is one month for domestic coal and 6 months for Imported Coal, there is significant risk of heat loss due to coal spontaneous fire, oxidation, moisture, evaporation, windage and coal fines washed away during monsoon, etc. The Hon'ble Commission would appreciate that the generating station has very limited, if at all any, control on such occurrences and heat loss on account of the above. It is like saying that a certain level of heat loss is built in the system and is unavoidable. However, in previous Regulations had transferred the entire risk of heat loss onto the generating company assuming as if the heat loss is in their control. Hence, in case the Hon'ble Commission is requested, therefore, to provide for a target level of heat loss for pit-head and non-pit-head (and any other classification, particularly, for Imported Coal as the Hon'ble Commission deems fit), which can be used to increase the heat loss of received coal, so that upto the target level of such loss is passed through in variable cost and only the risk beyond that is then shared between the Generating Company and its Beneficiary, in accordance with the risk sharing mechanism. The target level shall be specified as 150 kCal/kg.
23.	**Fuel – Blending of Imported Coal**		
a)	*Normative blending ratio may be specified for existing plant as well as new plants separately in consultation with the beneficiaries.*		RInfra submits that the blending ratio of coal is dependent on various internal and external factors. On one hand the quality of fuel supply is an important factor deciding the blending ratio to meet the boiler requirement and on the other hand, it is not necessary for the normative blending ratio to match the design boiler GCV conditions of various 200/220/250 MW sets or 300 MW sets or 500 and above MW sets. Further, the quality of domestic fuel is not within the control of the generating station. We submit that the decisions with respect to blending may be left to the discretion of the generating station and beneficiary consent should not be required for the same. As long as the station is bound by performance parameters, including heat rate and availability, the interests of the beneficiaries are protected. Fuel blending is an input to manage heat requirement of the boiler

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			in order to achieve boiler efficiency and heat rate and hence when these output performance parameters are regulated, regulation of inputs through conditions such as beneficiary consent is not desirable. Hence, RInfra submits that the generating station should not be bound by any normative blending ratio and flexibility should be left in the hands of the generating station to decide the blending ratio, depending upon of quality of domestic fuel, quality of imported fuel, import restrictions, if any, etc. and corresponding to boiler heat requirement.
24.	**Fuel- Landed Cost**		
	a. All cost components of the landed fuel cost may be allowed as part of tariff, else, specify the list of standard cost components *b. The source of coal, distance (rail and road transportation) and quality of coal may be fixed for a minimum period, so that the distribution company will have reasonable predictability over variation of the energy charges*		It is requested that all the cost component of landed fuel cost shall be allowed since none of the cost is direct control of the Generators. Various cost elements vary from state to state also, hence in such cases there can't be any standard cost components. Once standard costs are defined and in case some costs does not get covered then in such scenario beneficiary is not going to pay such charges resulting in to losses to Generators. With regard to specify source & quality of coal for a minimum period, it is submitted that though it will provide certainty to beneficiaries but will also lead to disputes since many a times coal is procured from the market on account of short supply of coal by coal companies.
27.	**Incentive**		
a)	*Review linking incentive to fixed charges in view of variation of fixed charges over the useful life and on vintage of asset - Need for different incentives for new and old stations*		The incentive rate for old sets should be more compared to new ones. It is difficult to maintain availability as sets become old due to wear and tear. Also O&M expenditure rises. Station Heat Rate also deteriorates with age. Hence, Incentive should be on age of the plant. Higher Incentive during later years will incentivise developer to keep in good operating condition.
29.	**Sharing of gains**		
a)	*The present regulatory framework provides for sharing of gains between generating company and beneficiaries in 60:40 ratio on account of improvement in controllable factors such as Station Heat Rate,*		The existing mechanism only stipulates sharing of gains and does not talk about sharing of losses. The Hon'ble Commission itself has recorded that there are various reason which are not in control of Generator, leading to non achievement of normative performance parameters. It is suggested that to be fair with both Generators & beneficiaries in addition to sharing of gains, sharing of losses

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	Auxiliary consumptions, secondary fuel oil consumption, refinancing of loan and the true up of primary fuel cost.		should also be considered so that both parties share the risk and returns. Since, risks taken by Generators are more compared to beneficiaries it is requested that sharing of gains should be increased to 2/3rd in favour of Generators.
b)	*Further, different generators adopt different methodology for sharing of gain, say on monthly or annual basis. Thus, procedure for the monthly reconciliation or annual reconciliation mechanism may need to be prescribed.*		Since monthly performance parameters depends on various factors like seasonal effect, dispatch based on beneficiary requirements, etc. Hence sharing shall be done on yearly basis only.
30.	**Late Payment Surcharge**		
a)	*The present regulatory framework provides for late payment surcharge at the rate of 1.50% per month for delay in payment beyond a period of 60 days from the date of billing. In view of the introduction of MCLR, the rate of late payment surcharge may need to be reviewed. One option is to add some premium over and above MCLR.*		Rate of interest of short-term funding has reduced considerably over the years. However, LPSC rate continues to be 1.50% p.m. or 18% p.a. While LPSC rate is also meant as a deterrent, hence carries a penal premium, it ought to reduce in line with reduction in short-term / working capital interest rates.
32.	**Standardisation of Billing Process**		
	Presently, generating companies and the transmission licensees are following different practice for raising bills on the basis of tariff order. In order to avoid possible disputes in billing, it need to be consider as to whether standardization of billing process including formats, verification and timeline etc. may be done.		Standardisation of bills will certainly reduce the numbers of disputes arising out of billing. Rather it is suggested that an online portal shall be created wherein Generator & Beneficiary will have their respective logins and online bills will be generated based on the principles specified by Commission. If such process is developed billing will be automatically be carried out as per Regulations. If any deviation is required, respective party will require issuing customised bills. This will reduce the billing cost and verification cost.

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33.	**Tariff Mechanism for Pollution Control System**		
	a) The principle of bringing the generator to the same economic condition if it is considered as change in Law. *b) Technical specifications based on the difference in actual emission and revised emission, proposed technology, construction period, phasing plan for shutdown during the construction period;* *c) Feasibility of undertaking implementation of new norms with R&M proposal for plants having low residual life, say, less than 10 years.* *d) Change in Auxiliary Consumption and operation and maintenance expenses due to implementation of pollution control equipments.*		Recovery of tariff impact due to investments to comply new environmental norms may be considered by way of separate charge for this control period and at later stage may be merged with base tariff. Moreover, impact of norms on performance parameters like auxiliary consumption, heat rate etc. Needs to be considered while setting the performance parameters on account of complying to environmental norms.
36.	**Energy Storage System**		
	The annual fixed charges of the storage facility can be determined based on ramping rate, auxiliary consumption, Return on Equity (ROE), Interest on Loan, Depreciation, Operation & Maintenance cost and Interest on Working Capital.		Energy storage is an emerging area and hence the hon'ble Commission is requested to encourage the investments by providing higher returns considering the envisaged risks.
40.	**Merit Order Operation**		
a)	*40.1 Though merit order is a dispatch issue, scheduling/ non-scheduling has its impact on purchase cost. It is seen that in respect of certain old plants having low fixed costs, their power may not get dispatched as the merit order is based on*		RInfra submits that the present mechanism of Merit Order Dispatch works on the principle of normative variable cost, which does not recognise the efficiency of a generating station. The Variable Cost at bus–bar is a function of station parameters such as SHR, Aux Consumption, Secondary Oil consumption, etc. which represent efficiency of the plant and the landed price of primary and secondary fuel, which is not determined by the generating station and is location dependent as well. For instance, in case of load centre based plants, the landed cost of coal will

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	variable cost, which may be high. *40.2 The merit order operation is important for economic operation of the plants and optimum despatch of economic resources. The consideration of other factors such as distance of transportation, secondary fuel oil consumption may provide the option to distribution utility to optimize the despatch. Present merit order is based on the fuel cost of the past data, with time lag of up to two-three months in billing cycle.* *40.3 Comments and Suggestions are invited from the stakeholders for alternative approach, if any, for economic operation of merit order.*		always be more, as generation siting is load centre, as against those plants which are located at pit-head, but much away from load centre. The former plants suffer from high variable cost arising due to longer fuel transits and corresponding freight charges, but offer a clear benefit of lower transmission losses, being located closer to load centre. The latter do not have any significant transit cost in their variable cost and hence, the variable cost is relatively much lower. However, being located away from load centres, they require longer transmission evacuation resulting in to additional transmission cost and contribute to increasing transmission losses. Further, due to locational disadvantage, a high performing plant could end up getting backed down and get substituted by other, less efficient plant, whose variable cost is lower not because of its performance but because of the fact that it is located at pit-head or much closer to its mines, which is certainly not something that can be credited to the performance of that plant. The present system of MoD is, therefore, promoting less efficient plants at the expense of more efficient ones. Ideally the MoD stack should be prepared with actual variable cost and normative factor representing value (+/-) based on siting of generators, Load centre generators will have Negative and pit head plants will have positive factors. However this can be corrected, at least partially, by switching to a MoD system based on actual variable cost, instead of normative variable cost. The actual performance parameters, such as SHR, Secondary Oil consumption, etc. of last financial year or average of last three financial years could be considered to work out the Variable Cost to be used to develop the Merit Order. In case of high performing plants, the reduction in Variable Cost due to consideration of improved operational parameters would, at least, to some extent offset the impact of transportation cost on landed fuel price.