5785/2018/CRU. CERC (14)

BSES

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Ref: RA/2018-19/01/A/273

Date: 13-Jul-2018

To,
The Secretary
Central Electricity Regulatory Commission
3rd & 4th Floor,Chandralok Building,
36, Janpath,
New Delhi -110 001

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

Ref.: Public Notice No. L-1/236/2018/CERC dated 24.05.2018 for submission of comments on the Consultation paper on Terms and Conditions of Tariff for the tariff period commencing from 1st April, 2019

Dear Sir,

We refer to the aforesaid notice. We are providing our comments and suggestions on consultation paper on Terms and Conditions of Tariff for the tariff period commencing from 1st April, 2019 enclosed as **Annex-I**.

We hope that the same shall be considered by the Hon'ble Commission while finalizing the Terms and Conditions of Tariff for the tariff period commencing from 1st April, 2019.

Thanking You,
Yours faithfully

For BSES Rajdhani Power Limited

Rajeev Chowdhury
Head- Regulatory Affairs

Encl: As above
- 03 Nos. Hard Copies
- 01 No. Soft Copy (C.D.)

CERC Consultation Paper on Terms and Conditions of Tariff Regulations:

S. No	Particulars	Existing	Proposed	Rationale	Comments
1	**TARIFF**				
A	Thermal Gencos (7.2)	**Two Part Tariff:** • Fixed Charges (FC): Recovery of entire fixed charges including O&M Expenses and Incentive; • Variable Charges (VC): Recovery of cost, Taxes and duties and transportation charges of fuel	**Three Part tariff:** • Fixed Charges (FC): Recovery of capex, interest on loan, ROE, Partial O&M Expenses; • Variable Charges (VC): Incremental return over guaranteed return and rest O&M expenses; • Energy Charges (EC): Cost, Transportation, taxes and duties of fuel	• Thermal Generating Stations are running at PLF of 60% due to high cost of power; • In 3 Part Tariff: a) FC shall be linked to target availability; b) VC shall be linked to difference between dispatch and availability; c) EC: Dispatch of energy	• The Tariff policy dated 28.01.2016 states that "ä two part tariff should be adopted for all long term and medium term contract to facilitate merit order dispatch….." [6.2(1)]. Recently, the Central Govt has issued the draft amendment to the Tariff policy which proposes to replace the word "should be adopted" to "shall be adopted". Applying the doctrine of *contemporaneaexposito* meaning the construction to a statue given by those who are charged with the execution namely Ministry of Power of Govt. of India understands that a two part tariff is a mandatory feature of the EA 2003.Therefore, a 3 part tariff as proposed would be contrary to the Tariff policy existing as well as proposed by the draft amendments. • Subject to the above, and in order to secure the objectives under Sec-61 of EA 2003 as well as to promote competition as enshrined in the preamble and the SOR of the EA 2003, the following safeguards are proposed: a) It should be ceiling tariff i.e. a generator can charge less from Discoms to promote competition.

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					b) IOWC should be a part of VC. c) As regards guaranteed return to the extent of risk free return, it is to be fixed at weighted average rate of loan/G-Sec of the Genco/Transco. d) However, keeping the incremental return above risk free return as part of variable charges would be appropriate and result in substantial saving of fixed costs if no power is being scheduled. e) O&M components should be equally divided between FC and VC. f) In any case the Total cost recovery should not increase by changing the Tariff structure. g) Further, clarification and actual deliberation is required on various components of FC and VC including as to whether it would be both VC and EC that would be factor for deciding the MOD or whether it would only be the EC. • With respect to Integrated Power projects with coal mines the cost of coal should be derived from bids for acquiring the mine and further request for addition in Form-15 details: 1) Name of mine from which the coal is sourced. 2) Distance between mine & plants 3) Mode of each type of transportation

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					and their individual distance. The Tariff fixed by CERC should be the ceiling tariff at which the generator can charge to Discoms. However, option should be given to generator to charge tariff (Fix + Variable) at a lower rate so as to schedule its power under MOD and or built in competitiveness.
	Thermal Gencos above 25 years of age (7.3)	• Stations crossed 25 years of age attract higher O&M Expenses due to lesser efficiency in terms of higher SHR etc.	• Possible options are: (i) Replacement of inefficient sub-critical units by super critical units; (ii) Renovation of old plants; (iii) Extension of Useful life etc.	• Older thermal plants are resulting in high cost to DISCOMs and hence falling last on MOD.	• Firstly the approval for such power plants where additional capex is required for the following: a. Replacement of inefficient sub-critical units by super critical units; b. Renovation of old plants; c. Extension of Useful life etc. Such an approval process ought to be on case to case basis with adequate opportunity of representation to the beneficiaries and stakeholders being provided: • Secondly DISCOM who do not want to extend the PPA should be entitled to relinquish their shares in favour of those DISCOMs who want to continue the PPA. The relinquished share would be proportionately reallocated to the willing DISCOM. • In case of extension of the useful life of the plant by CERC, a specific directions/clarification should be given by CERC that in such cases no further approval of PPAs are required from SERCs

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					by Discoms. • MOD is fixed by DISCOMs in accordance with the least cost principle depending upon variable cost of Generating Stations. Before approving the replacement of inefficient sub-critical units, renovation or extension of useful life, the Central Commission may examine the reasons as to why the variable cost of plant is higher. In case, it is found that the variable cost is higher mainly due to higher fuel cost, the proposed options may not be exercised as the same will result in increase in fixed cost without any reduction in variable cost. • Even if it is found that the variable cost is higher due to other reasons, the same should be subject to mandatory cost benefit analysis to be submitted by Genco and examine by the CERC by way of an Order. If the result is negative then there should be a proposal of phasing out the plant. • Further in cases where the approval for bringing efficiency in operation of such plants is accorded by Central Commission, the norms should not be relaxed for such power plants.

S. No	Particulars	Existing	Proposed	Rationale	Comments
B	Hydro Generating Stations (7.4)	**Two Part Tariff:** • Entire expenses ,i.e., Capital Cost, O&M Expenses, Incentive, ROE etc. being recovered 50% through Fixed Charges and 50% through Variable Charges	**Two Part tariff:** • Fixed Charges (FC): Recovery of capex, interest on long term loan, ROE • Variable Charges (VC): Incremental return over guaranteed return, interest on working capital and entire O&M expenses;	• Hydro Stations having higher capital cost are not being scheduled and hence, not able to recover even the capital cost. • Capital cost should be recovered entirely through fixed charges.	• It is suggested that instead of reduction of variable cost which ensure dispatch under MOD, ways and means of reduction in hydro tariff like longer loan duration, lower free energy for delayed projects, etc. may be explored. • Grants/ Subsidy should be provided to such hydro generating stations from PSDF (If required PSDF Regulations may be amended) for their revival. • Tenure of Hydro generating station and extension of useful life may be considered. • DISCOM who do not want to extend the PPA should be entitled to relinquish their shares in favour of those DISCOMs who want to continue the PPA. The relinquished share would be proportionately reallocated to the willing DISCOM. • For Pump Storage stations can be used as Grid support stations at National level and accordingly total cost should be shared nationally.
C	Transmission (7.5)	**Single Part Tariff:** • Recovery of annual Fixed Charges with incentive and disincentive linked to Transmission System Availability	**Two Part tariff:** • Fixed Charges (FC): Annual Fixed Cost of some of fixed transmission system designated for access and immediate evacuation, Annual Fixed Cost of evacuation transmission	• Existing transmission tariff do not provide distinction between transmission capacity booked and transmission capacity actually utilized. • In two part tariff, fixed charges to be linked to	• Most of the transmission lines are being reserved but not being utilized and entire cost is being put on DISCOMs which ultimately burdens the consumers. Therefore there is an urgent requirement to introduce two part tariff in Transmission system. • For implementation of 2 Part Tariff in

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			system, Part of annual fixed cost consisting of debt service obligations, interest on loans, guaranteed returns • Variable Charges (VC): Common transmission system excluding evacuation transmission system; Sum of incremental return, O&M Expenses, Interest on working capital	booked transmission capacity and Variable Charges to be recovered in proportion of actual energy flow into the system.	Transmission system, it is mandatory that NLC shall identify the transmission lines which are allocated and utilized by the beneficiaries (with a valid MTA/ LTA) so that the fixed charges and variable charges towards the energy flown through respective lines can be charged from the beneficiaries. • Incentive / disincentive mechanism should be there in case of delay in commissioning of Transmission elements.
D	Renewable (7.6) and (34)	**Single Part Tariff:** • Feed-in Tariff Structure comprising of fixed charges of RE Generation Project	**Two Part tariff:** • Fixed Charges (FC): Debt Service Obligation and Depreciation • Variable Charges (VC): O&M Expenses and ROE	• In event of regulation of power, RE generators do not get compensated with minimum charges; • For MOD, entire tariff of RE generation plants is compared with variable cost of other generation; • In case of bundling with conventional power stations, it may be difficult to combine the tariff with conventional power stations as RE generation currently has only single part tariff.	• In case there is a two part tariff in case of bundling RE power with conventional power stations, and the RE power plant is not able to generate due to environmental constraints, then energy received through conventional power to the extent of RE power scheduled by DISCOM should be considered towards RPO of DISCOM. For example: a DISCOM schedules 400 MU from Conventional power to be generated by Anta Gas Station and 20 MU from RE power to be generated by Anta Gas Station and DISCOM actually received 410 MU only from conventional power of Anta Gas Station and 0 MU from RE power of Anta Gas Station then, 20 MU out of 410 MU should be considered as RE power received by DISCOM for meeting RPO and rest 390 MU towards conventional power of Anta Gas Station. Such a mechanism would

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					ensure certainity. • Further in case of IPPs generating RE power only (not bundled with conventional sources), single part tariff should be continued so as to insulate DISCOM towards undue burdening of fixed charges when the DISCOM is actually not receiving any power or lesser power than scheduled power. • Further in case of bundled power, if RE power is scheduled by DISCOM but is actually not dispatched due to environmental constraints and DISCOM receives energy through conventional power in lieu of scheduled RE power, DISCOM must be liable to pay cost corresponding to RE power only and not conventional power. • Separate tariff for renewable and coal will ensure that any inefficiency, be it in coal plant or in RE generation is not passed on to beneficiaries. • In case of bundling the cost of common infrastructure and other facilities should not be overburdened to beneficiaries who have not opted the bundled power.
2	**Deviation from Norms**				

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A	Performance linked to Dispatch -(8.4)	• No such mechanism	• Incentive-Disincentive mechanism for different levels of dispatch.	• This will encourage competition and incentive to perform better thus leading to optimum utilization of capacity	• Incentive-disincentive mechanism linked to MOD will actually bring discipline towards declaring proper availability and schedule among Generators and shall motivate them to optimize their cost. • One possible option is generators may be allowed to give discount in AFC on annual basis which can adjusted in energy rate while scheduling dispatch as per MOD
3	**Multiple ways of selling power for same generator**				
A	Tariff for selling power(9.3)	• Currently tariff is determined either under Section-62 or 63 of Electricity Act 2003 in case of PPAs. • Generator having PPAs get their entire capacity tied-up irrespective of whether utilized or not.	• Gencos may have some capacity tied under Section-62 or 63 of Act. Balance power to be sold under Merchant Capacity. • Tariff may be determined for entire capacity but recovery of tariff may be restricted to extent of PPA on pro-rata basis and balance shall be merchant capacity or to be tied-up under Section-63.	• This will encourage DISCOMs to tie-up capacity as per their requirement. • This shall also lead to optimum utilization of capacity.	• The recovery of tariff to the extent of PPA on pro-rata basis and selling the balance on merchant capacity or under Section-63 shall contribute towards optimization of cost. However the same should be implemented on quarterly basis or monthly basis so as to provide flexibility to DISCOMs to block capacity and schedule power by factoring in seasonal variations.
4	**Optimum utilization of capacity**				

S. No	Particulars	Existing	Proposed	Rationale	Comments
A	Thermal Gencos-(10.3)	• Currently allocation of power is done on a state-wise basis by Ministry of Power, GOI. • The State share is then re-allocated among the DISCOMs operating in the state by the State Government. • DISCOMs have to bear the fixed charges corresponding to their share irrespective of the utilized capacity.	• Flexibility to be provided to DISCOMs and generating company to re-define Annual Contracted Capacity based on anticipated reduction of utilization. DISCOM shall also be given a right to recall the unutilized capacity during next year by paying 10-20% of fixed cost during current year. • Remaining unutilized capacity may be aggregated and bidded out to discover the market price of surplus capacity.	• This will encourage DISCOMs to tie-up capacity as per their requirement. • This shall also lead to optimum utilization of capacity.	• This should not be conditioned upon finding of an alternate off-taker. • Flexibility in scheduling as per requirement at DISCOM level is required. However, Thermal Gencos are getting compensation in lieu of "Central Electricity Regulatory Commission (Indian Electricity Grid Code) Regulations". Therefore in case of re-definition of ACC, the DISCOM should not be liable to pay any compensation charges. • Hence, we request the Hon'ble Commission not to overburden the consumers by levying 10-20% of additional fixed Cost.
B	Hydro Gencos-(10.5)	• Present useful life of hydro stations: 35 years; • Higher tariff resulting in higher cost and thus less scheduling; • Generally considered as peaking power stations. • Scheduling problem with pumped mode operations.	• Extend useful life to 50 years and loan repayment period to 18-20 years; • Assign responsibility of operation of hydro power stations at regional level by delinking the scheduling by designated beneficiaries. • Power scheduled can be dispatched to designated beneficiaries through banking facility	• Will contribute in economical operation of hydro stations; • Resolve the issue of scheduling with pumped mode hydro operations	• Extension of life to 50 years shall ensure reduction in both fixed charges and variable charges of Hydro Generating Stattions, provided no further additional cost Is added. • DISCOM who do not want to extend the PPA should be entitled to relinquish their shares in favour of those DISCOMs who want to continue the PPA. The relinquished share would be proportionately reallocated to the willing DISCOM. • Fixed charges ought to be allocated on proportionate basis among the beneficiaries depending upon energy

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					scheduled at regional level.
C	Gas based generation -(10.7)	• Scheduling controlled by SLDCs based on the MOD provided by DISCOMs	• Scheduling to be shifted to regional level; • All gas based capacities to be pooled together and after meeting the requirement of designated beneficiaries, the balance generation may be offered for balancing purpose.	• The possibility of immediately ramping up and ramping down by gas based stations may be utilized for balancing the variations of RE generation.	• In the prevailing scenario gas plants have limited APM allocation with respect to their installed capacity because of which beneficiaries are unable to utilize their complete allocation from these plants. • Hence we propose that the balance allocation be transferred to RLDC's so that they may be able to utilize these plants on RLNG & Liquid fuel for grid balancing under ancillary service. • In case of bundled power, if RE power is scheduled by DISCOM but is actually not dispatched due to environmental constraints and DISCOM receives energy through conventional power in lieu of scheduled RE power, DISCOM must be liable to pay cost corresponding to RE power only and not conventional power. Further in case DISCOM schedules power from RE Sources and receives power through gas stations, the energy has to be treated as RPO and should be adjusted against RPO targets.
5	**Capital Cost**				

S. No	Particulars	Existing	Proposed	Rationale	Comments
A	Capital Cost -(11.8-11.10)	• Original Cost is allowed • ROE is provided on equity infused corresponding to original cost of the project including additional capitalization.	• Move away from investment approval as reference cost and shift to benchmark/ reference cost for prudence check of capital cost. • 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. • 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. • Incentive for early completion and disincentive for slippage from scheduled commissioning can also be introduced.	• This will contribute towards reducing cost over-run and time over-run.	• In case, the actual equity deployed is less than normative equity envisaged in the investment approval or on benchmark cost, then actual equity ought to be considered. • Further in case the actual cost is lesser than the normative cost, the savings ought to be shared in ratio of 50:50. • In the prevailing scenario an early completion is rewarded by 0.5% in ROE, whereas the risk is only IDC which is also partially disallowed. Further the additional burden of IDC is also split between debt and equity there by increasing the ROE on account of delay. Hence we urge CERC to re-look the prevailing incentive and disincentive scheme to balance the risk to reward.
6	**Renovation &Modernization**				
A	R&M Expenses -(12.7)	• Generating Stations are given an option for special allowance in lieu of R&M for coal/ lignite based thermal stations to meet	• The R&M Expenses may be allowed for the purpose of extension of life beyond the useful life of transmission assets.	• This will address the issue of timely R&M of transmission lines.	. • DISCOM who do not want to extend the PPA should be entitled to relinquish their shares in favour of those DISCOMs who want to continue the PPA. The relinquished share

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		the requirement on completion of 25 years of useful life without seeking any resetting of capital base. • No such provision for Transmission assets.	Or • Special allowance for R&M of transmission assets to meet the required expenses including R&M on completion of 25/35 years of useful life of sub-station/ transmission system without need for resetting capital base.		would be proportionately reallocated to the willing DISCOM.
6	**Depreciation**				
A	Depreciation (14.6)	• Depreciation is allowed by considering first 12 years on a higher rate and then balance for rest of life. • Additional capex for R&M causes higher depreciation on balance life. • For hydro power plants, useful life is 35 years whereas actual life is much more than 35 years. Higher depreciation rates during first 12 years result in front loaded tariff.	• Increase the useful life of well-maintained power plants; Or • Continue the present approach of weighted average useful life in case of combination, due to gradual commissioning of units; Or • Admissibility of additional capex after R&M to be restricted to limited items/ equipment; Or • Reassess life at the start of every control period and thus depreciation also as prescribed in Ind-AS; Or	• Books of account are now required to be prepared as per Ind AS for generators whose tariff is determined by CERC	• CEA being a technical apex body should be consulted. • Further the balance depreciation after deducting recovered depreciation from 90% of GFA ought to be equally spread over the extended period so as to ensure tariffs go down. Reducing depreciation rates or extension of useful life should not lead to any additional expenses in any form as a pass through. • Developer may be allowed to opt for lower depreciation rate subject to ceiling limit

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			• Extend useful life of transmission and hydro stations to 50 years and thermal (coal) to 35 years; Or • Reduce rates which will act as a ceiling; Or • Continue with existing policy of depreciation		
7	**GFA Approach**				
A	GFA approach–(15.3)	• GFA approach is being adopted currently as it incentivizes equity investors to efficiently operate and maintain the infrastructure even after the plant has fully depreciated. • Internal resources generated by way of depreciation are reutilized for further capacity addition.	• Shift from GFA to NFA Approach; • Return to be allowed on GFA minus depreciation	• CEA has estimated that in view of present demand growth and availability of commissioned and under construction capacity, no new coal capacity may be required till 2027.	• We agree with the suggestion to shift from GFA to NFA Approach as after the recovery of loan through depreciation, the investor starts recovering the equity deployed in the project. However in GFA approach, the investor still gets ROE on gross block of equity despite of recovering equity. • In Delhi, RoCE Approach based on NFA is already in place where Gencos, Transco and DISCOMs gets return linked to the actual funds present in the business as on date basis.
8	**Debt-Equity Ratio**				
A	Debt-Equity (16.4)	• Existing debt-equity ratio is 70:30.	• For new plants where financial closure is yet to be achieved, debt-equity ratio of 80:20 to be considered.	• Financial Institutions are willing to lend upto 80% of the project. • For some old plants, Generators are employing equity of more than 30%, by routing depreciation back in	• Generation Utilites are better placed as compared to DISCOMs and therefore have lower risk. By virtue of their better position and lower risk profile, they are having an good balance sheet and thus are able to get loans upto 80% of the project. Therefore the debt-equity ratio may be considered as

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				the business, due to which they are getting ROE on 30% and normative rate of interest on equity infused above 30%.	80:20 in case of Gencos. However for Transmission companies where the risk is relatively higher, debt-equity ratio of 70:30 may be considered. • The revision of debt to equity ratio of 80:20 would help reduce the AFC burden on account of ROE, and as indicated by CERC certain old plant still maintain a 50:50 ratio. We urge CERC to rationalize debt to equity ratio to at least 30:70 for all existing plants, this would help curb the sharp rise in AFC on account of compliance of MOEF norms and help in avoiding a tariff shock.
9	**Return on Investment**				
A	ROI -(17.4)	• Fixed return on equity employed in the business is allowed to the Generation and Transmission Companies.	• Comments have been invited on ROE versus RoCE approach.		• We agree with the suggestion to shift from GFA to NFA Approach as after the recovery of loan through depreciation, the investor starts recovering the equity deployed in the project. However in GFA approach, the investor still gets ROE on gross block of equity despite of recovering equity. • In Delhi, RoCE Approach based on NFA is already in place where Gencos, Transco and DISCOMs gets return linked to the actual funds present in the business as on date basis.
10	**Rate of ROE**				

S. No	Particulars	Existing	Proposed	Rationale	Comments
A	Rate of ROE (18.7)	• ROE of 15.5% on post-tax basis is allowed. • Incentive of 0.5% is allowed for timely completion of the project. • ROE of 16.5% is allowed for storage type hydro generating stations.	• Different ROE for generation, transmission projects for existing and new projects. • Different ROE for thermal and Hydro Projects with additional incentive to storage based hydro generating projects. • In case of hydro, the ROE can be bifurcated into two components, one assured and other linked to timely completion of projects. • Continue with pre-tax ROE or switch to post-tax ROE; • Have different additional ROE for different unit size of generation and different line length of transmission system and different size of sub-station • Reduction of ROE in case of delay of project	• As per CEA report, there is enough capacity addition in generation upto 2027. • PLF of thermal power plants has come down steadily during last 4-5 years; • As per RBI database, the RBI repo rate, interbank rateand SBI base rate have also come down duringthis period. • The yield on 10 yearbenchmark Government Bond has come downto 7-7.5% during 2018 as compared to 8-8.5%during 2014.	• There should be different rates of ROE for Genco and Transco depending upon the risk profile. • Even between thermal and hydro, there should be different ROE. Plants with linked FSA (long term linkage coal/ gas) should have higher ROE. Rate of ROE should be lower for Gencos having imported coal linkage/ spot gas. ROE should be in the range of 2-3% only for plants having no coal/ gas linkage. • Further instead of two components of ROE, i.e., assured and timely completion of projects, the rate of ROE should be reduced in case of delay of project so that Generators have to ensure timely commissioning in order to even achieve the decided rate of ROE.
11	**Cost of Debt**				
A	Cost of Debt(19.4-19.5)	• Actual rate of interest based on actual loans availed by the Licensee is allowed to the Companies.	• Continue with existing approach of allowing cost of debt based on actual weighted average rate of interest and normative loan or switch only on normative	• Allowing actual rate of interest does not encourage generators to re-finance or restructure the cost of debt. • However linking cost of debt	• Incentive mechanism to Gencos and Transcos should be introduced for re-financing of loan. • The rate of debt should be allowed on normative basis by considering MCLR plus pre-defined margin. Margin should be

S. No	Particulars	Existing	Proposed	Rationale	Comments
			cost of debt and differential cost of debt for new transmission and generation projects. • Review of existing incentives for restructuring or refinancing of debt. • 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 of normative cost of debt.	with market parameters such as MCLR or G-Sec will bring a degree of unpredictability.	decided by considering actual loan portfolio during last 5 years. In case actual rate of debt is lower than MCLR plus pre-defined margin than actual should be considered, otherwise the same ought to be capped to normative rates. • Such methodology is already being adopted by Delhi Commission.
12	**Interest on Working Capital (IOWC)**				
A	Cost of Debt (Short term) (20.3)	• Working Capital is determined based on fuel stock, inventory on maintenance spares, 1 month O&M Costs and 2 Months receivables. • Tariff Regulations provide definition of Bank rate as the base rate of interest specified by SBI from time to time or any replacement thereof plus 350 basis points.	• Normative IWC can be reviewed or continued; • As stock of fuel is considered for working capital, fresh benchmark may be fixed or actual stock of fuel may be taken; • While working out requirement of working capital, maintenance spares arealso accounted for. • For old hydrostations, the higher O&M expenses due to higher number of employees alsoyield higher cost for "Maintenance	• In view of increasing renewable penetration and continued low demand, theplant load factor of thermal generating stations is expected to be low. As perthe present regulatory framework, the normative working capital has beenprovided considering target availability.	• The normative stock of fuel for the purpose of computation of working capital should be benchmarked based on actual stock of fuel held by Genco (individual basis) during last 5 years. • The Gencos get credit period for purchase of fuel from the supplier. The credit period which gencos get to make payment should be reduced while computation of working capital. • Maintenance spares ought only be linked to R&M Expenses and should be decided based on the age of the plant. Most of the new plants have OEM contracts and thus enjoy the benefit of warranty contract. The cost of warranty contract is borne by the

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			Spares" in IWC.Therefore, option couldbe to de-link "Maintenance Spares" in IWC from O&M expenses. • In case of wide variation between theplant load factor and the plant availability factor, the normative approach oflinking working capital with "target availability" can be reviewed.		Consumers. Therefore R&M of new plants ought to be lower. .
13	**Operation and Maintenance Expenses (O&M)**				
A	O&M Expenses(21.7)	• Normative O&M Expenses have been defined for thermal generating stations and transmission system based on the data available from FY 2009-10 to FY 2013-14. • Presently O&M Expenses have been specified on per MW basis for generation and per bay basis for the transmission system.	• Review the escalation factor for determining O&M Costs based on WPI and CPI Indexation as they do not capture unexpected expenditure; • Address the impact of installation of pollution control system and mandatory use of treated sewage water by thermal plant on O&M Cost. • Review of O&M Cost based on the percentage of capital expenditure for new hydro projects; • Review of O&M Expenses of plants being operated	• Variations in WPI & CPI expose challenge in specifying the fixed escalation rate for the entire tariffperiod. Further, the fixed escalation rate does not capture the variation due tounexpected expenses such as wage revision etc. • O&M expenses could vary depending on the type of plant and number of units. • O&M expense of hydro stations is given as a percentage of capital cost,which is inclusive of IDC & IEDC. Thus, projects with substantial time & costoverrun get higher O&M.	• The O&M Expenses should be strictly on normative basis (based on last 5 years actual data or best practices adopted in the system whichever is lower) except for expenditure incidental to "change in law" or statutory levies subject to prudence check by CERC. • Any expense of other nature shall be to account of Genco or Transco.

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			continuously at low level; • Rationalisation of O&M Expenses in case of addition of components like bays or transformer or transmission lines and review of multiplication factor in case of addition of units in existing stations; • Separate norms for O&M Expenses in case of vintage of generating station and transmission system; • Treatment of income from other business while arriving at O&M Costs.	• There could be overlapping of the O&M expenses and the compensationallowance, due to overlapping of items covered under these two.	
14	**Fuel- Gross Calorific Value (GCV)**				
A	Fuel-Gross Calorific Value-(22.8) and (26.3.18)	• GCV is currently measured on "GCV asreceived " basis.	• Specify normative GCV lossbetween "As Billed" and "As Received" at the generating station end andidentify losses to be booked to Coal supplier or Railways. • Similarly, specify normative GCV loss between As received and as fired in the generating stations." • Standardise GCV computation method on "As Received" and "Air-Dry	• There is transit loss, storage loss, grade slippage at mine end on which generating station has no control.	• DISCOMs pay the Gencos based on the invoices raised by CIL which contains the GCV "äs billed"and quantity of the coal. The GCV used for computation of energy charges should be based on "as billed" basis. Therefore the DISCOMs actually pay for the transit loss, storage loss and handling loss also as the amount is billed for the coal on GCV "as billed" basis. • Therefore transit loss, storage loss, grade slippage loss and coal handling loss has to be defined on normative basis. Such norm ought to fixed based on CAG report of Gencos.

S. No	Particulars	Existing	Proposed	Rationale	Comments
			Basis" for procurement of coal both from domestic and international suppliers.		
15	**Fuel- Blending of Imported Coal**				
A	Fuel-Blending of Imported Coal-(23.6)	• In case of blending of imported coal, the GCV is considered on "As Received" basis.	• Normative blending ratio may be specified for existing plant as well as newplants separately in consultation with the beneficiaries.	• There is difficulty in verification of GCV of blended coal, due to unavailability ofseparate value of GCV of domestic and imported coal on "As Fired Basis".	• In case of imported coal, the DISCOMs pay the Gencos based on the invoices raised by the Gencos corresponding to the quality and quantity of the coal. The GCV used for computation of energy charges should be based on "as billed" basis. However normative blending ratio may be defined in case of usage of imported coal. • Normative blending ratio may be specified for existing and new plants separately in consultation with the beneficiaries. Further, the generator should declare blending ratio to the beneficiaries in advance. • In order to increase transparency in billing system, a common methodology of measuring GCV should be used across the value chain. i.e. from loading point, un-loading point etc.
16	**Fuel- Landed Cost**				
A	Fuel-Landed Cost(24.5)	• Landed cost of fuel is included in energy charges by Generating Company.	• Specify the list of standard cost components; • Source of coal, distance (rail and road transportation) and quality of coal may be fixed for a minimum period.	• Distribution Company should have reasonable predictability over variation of energy charges.	• Form-15 should additionally include the following: - Monthly coal consumption by Unit - Opening coal stock - Closing coal stock - Bills and Form-15 to be provided in

S. No	Particulars	Existing	Proposed	Rationale	Comments
					MS-Excel format to Discoms As the data related to energy charges with the beneficiaries are one months old, the generators can be allowed to declare its energy rate considering its latest available data (variation in energy rate shall not be allowed more than 10% to last available with the beneficiaries).
17	**Fuel- Alternate Source**				
A	Fuel-Alternate Source-(25.2)	• The generators resorting thealternate source of fuel, other than designated fuel supply agreement, require priorconsultation only if the energy charge rate exceeds 30% of the base energy chargerate or 20% of energy charge rate of the previous month.	• Stipulate procedure for sourcing fuel from alternate source including ceiling rate; • Rationalise the formulation keeping in view the different level of energy charges rates, as the fuel cost has increased since 1.4.2014.	• Distribution Company should have reasonable predictability over variation of energy charges.	• Beneficiary should be consulted before arranging alternate source of fuel. Right to refusal of coal from alternate source should be with Discoms or subject to ceiling cost of contracted fuel.
18	**Operational Norms-Thermal Generation (Coal Based)**				
A	Station Heat Rate (26.3.6)	• 200/210/250 MW sets: 2425 kcal/ kWh • 500 MW and above: 2375 kcal/ kWh • Coal & Lignite GSHR= 1.045 X Design Heat Rate • Natural Gas & RLNG: GSHR= 1.05 X Design Heat Rate • Liquid Fuel: GSHR= 1.071 X	• Approach for determination of station heat rate may need review including thecriteria for specifying heat rate of old plants, continuation of relaxed norms forspecific stations and possible changes required in the existing	• Presently plants are working on lower PLF which puts adverse impact on operational norms. • The heat rate norms varies with the passage of useful life of theproject due to degradation and therefore, the norms specified based on	• Presently almost all thermal generating stations are running at minimum levels of PLF and it attracts the concern to the Gencos. But, Gencos are being rightly compensated by the Discoms through “Central Electricity Regulatory Commission (Indian Electricity Grid Code) Regulations”. • Different station heat rate norms for old and new plants considering scope for

S. No	Particulars	Existing	Proposed	Rationale	Comments
		Design Heat Rate • Existing Regulations provide for calculation of Gross SHR for new stations based on designed heat rate with margin of 4.5%. • Relaxed norms for certain stations have been specified.	norms given inTariff Regulation 2014-19.	therecently commissioned plants may not be attainable by older plants.	efficiency improvement should only be done if compensation allowance get scrapped. • Also, as per latest Tariff Regulations FY 2014-19 clause 8(2). Generating company shall carry out the truing-up of controllable parameters including Station Heat Rate. • Also, find attached the comparison of normative and actual parameters of various Thermal generating stations – Annex-1. • The comparison clearly shows that the Thermal Gencos has actually refunded to Discoms in event of improved controllable parameters. • It shows thehuge Margins still available with Gencos. • Hence, we request the Hon'ble Commission to tighten the norms further so that the practice efficiency should be promoted and consumers should not be burdened. • In case of any loss to the Genco might be Trued-up at the end of control period. • We would also like to submit that compensation mechanism also undermines the entire efforts made by Discoms/SLDC and RLDC to follow MOD for optimizing the power purchase cost.
B	Specific Secondary Fuel Oil consumption (26.3.7)	• 1.00 ml/KWh forlignite based CFBC technology with some exception in case of TPS-I and0.50 ml/KWh for	• Specific secondary fuel oil consumption to be changed based on change on account of nature of	• Reduction in specific secondary fuel oil consumption norms may adversely affect the boiler	• -do-

S. No	Particulars	Existing	Proposed	Rationale	Comments
		Coal based project with the provision for sharing of savingswith the beneficiaries.	operations keeping in view lower PLF of thermal stations.	operations under different operating conditions including partial loading of units due to fuel shortage conditions. • With contribution from renewable generation increasing in the grid, thermal power plants are facing frequent regulations of supply and operations at lower PLF up to technical minimum.	
C	Auxiliary Energy Consumption(26.3.10)	• Gas based generating station varies from 1.0-2.5%depending on open or combined cycle operation; • Thermal based generating station varies from 5.25% for Unit Size for 500 MW and above to 8.5% for 200 MW series units; • For lignite stations, 0.5% more than coal based generating station with electrically driven feeder pump and 1.5% more than coal based generating station in case of CFBC Technology.	• Methodology of declaring availability after reduction of normative auxiliary consumption and colony consumption need Elaboration.	• Presently, the auxiliary consumption of 800 MW is fixed based on 500MWsets. The auxiliary consumption of 800 MW sets may vary depending on thesize of the unit and economies of scale • Generating stations which have less auxiliary consumption than the norms, declare higher availability by making adjustment of difference between actual (lower) and normative auxiliary consumption.	• -do-
D	Normative Annual Plant Availability (26.3.15)	• Recovery of annual fixed charges is based on cumulative availability during the year	• Existing norms of annual plant availability may need review by considering fuel availability, procurement of	• Shortage of domestic fuel affects availability of plants and their scheduling. • There are changes of	• The fixed cost recovery should be shifted from annual cumulative availability basis to monthly plant availability.

S. No	Particulars	Existing	Proposed	Rationale	Comments
			coal from alternative source, other than designated fuel supply agreement, shifting of fixed cost recovery from annual cumulative availability basis to a lower periodicity, such as monthly or quarterly or half yearly.	declaring lower availability during off-peak period and higher availability during peak period. • In case of partly tied up capacity, the plant availability factor for whole plant may not be relevant.	
E	Transit & Handling losses	• 0.2% for pit head station and 0.8% for non-pit head stations	• Generating station shall only pay for coal "As Received" at the plant plus normative transmission loss of GCV and quantity as per CERC norms.	• There is often grade slippage of coal from coal mines and loss in quantity of coal to generating stations.	• -do-
19	**Operational Norms-Thermal Generation (Coal washery rejects based)**				
A	Coal washery rejects based	• Tariff Regulations, 2014 provide operational norms for thermal power plant based on coal washery projects.	• Same is required to be reviewed.	• Coal rejects exhibit distinguished characteristics. Coal rejects cannot be stacked as it would require a substantial amount of land at the mine site and storing of rejects for prolonged period is hazardous as it may lead to combustion.	• -do-
20	**Transmission System**				
A	Transmission availability factor(26.5.5)	• As per 2009-14Regulations, computation of availability of transmission system, TransmissionSystem Availability Factor for a	• Existing approach for computation of Transmission system availabilityand weightage factors to be applied for	• Availability of Transmission System/ elements is expected to increase withintroduction of new technology like polymer insulators etc. Thus,	• In order to maintain N-1 reliability, there are various transmission assets which have already commissioned. However, their utilization is not commensurate with their commissioned capacity. This leads to

S. No	Particulars	Existing	Proposed	Rationale	Comments
		month (TAFM) was computed as (100-100XNAFM), where NAFM is the non-availability factor in per unit for the month. Theprocedure of computation of transmission system factor for a month wasprovided in Appendix-IV of Tariff Regulation, 2009. This methodology ofavailability factor(TAFM) was again revised in Tariff Regulations,2014 whereinthe weightage factor was considered based on the individual group such astransmission line, ICTs and Reactors etc. • Maximum incentive for AC system isaround 1.27% (99.75/98.5) while for HVDC, it is around 3.91% (99.76/96). • In case of inter-regional links, the present framework requirescertification as to whether it is export region or import region.	outage hours for transformer andreactors; • Review of the incentive formula for HVDC bi-pole and HVDC back-to-backstations at par with AC system; • Specify appropriate region (import or export) for certifying the availability of • Inter-regional links (AC and HVDC line) for the purpose of incentive and • recovery of annual fixed charges; and • d) Review of the existing methodology or procedure for computation of • availability, monthly availability and cumulative availability;	themechanism of payment of transmission tariff based on availability oftransmission system may need review.	Increase the cost of Transmission network • Hence, as in case of HVDC Transmission system there is separate head for reliability. • There should be separate cost for N-1 which shows the reliability part in our system. • Approach may be reviewed in such a way that incentive/dis-incentive for availability shall be different for peak and off-peak seasons. It is also important to also specify standards of performance for transmission utilities like it is specified for distribution utilities. Timeframe should be prescribed to resolve outages and penalties should be levied if the prescribed timelines are not met. • Now when HVDC system is in comparable to AC system, transmission availability factor should also be at par. • Further, base transmission availability on which incentive is computed should also be revised considering improved performance of the transmission licensees.

S. No	Particulars	Existing	Proposed	Rationale	Comments
B	Transmission losses - (26.5.9)	• No Regulatory Framework on specifying the norms for transmission losses.	• To introduce the norms for inter-state transmission losses based on factors within control and international benchmarks	• The transmission losses considered in the present scheduling framework is about 4.5-5% for inter-state transmission system and 4-4.5% for intra-state transmission system. As a result, the net power delivered to the distribution periphery is reduced by about 9-10%, which has an impact on the cost of supply.	• Normative losses should be introduced by benchmarking various Transmission element of respective Region.
21	**Hydro Generation**				
A	Hydro Generation (26.6)	• NAPAF has been defined for hydro stations based on past data.	• Based on last 5 years data, NAPAF may be required to be revised.		• Actual PAF should be considered based on past data. • There is no ceiling for recovery of AFC for Hydro plants. Also, based on past data it is seen that the norms are very relaxed and Hydro plants are achieving more than 85% of PAF against the normative 77%. • Hydro plants also given incentive for excess generation Rs.90/kwh. It is proposed there should be capping of Fixed Charges (up to 50% of AFC). • Hydrology risk should not fall on the beneficiary. It is for the Genco to undertake the proper due diligence in so far as hydrology/availability of water is concerned. • Shortfall in generation for non-availability of water/hydrology should not entail any charge on the beneficiaries on the simple

S. No	Particulars	Existing	Proposed	Rationale	Comments
					logic that the Genco would have taken measures to maintain its generation.
22	**Incentive**				
A	Incentive(27)	• Presently incentive is allowed @ 50 paise based on generation above normative PLF of 85%. • In case of hydro, generation beyond the design energy is paid at 80Paise/kWh. • In case of Transmission, incentive is being recovered only throughmonthly formula of billing and collection of transmission charges	• Review linking incentive to fixed charges in view of variation of fixed chargesover the useful life and on vintage of asset - Need for different incentives fornew and old stations; • Different incentive may be provided for off peak and peak period for thermaland hydro generating stations. • Differential incentive mechanism for storageand pondage type hydro generating stations may also be considered. • Review the incentive and disincentive mechanism in view of the introductionof compensation for operating plant below norms. • Review the norms for availability of transmission system.	• At present there is same incentive for availability during peak and off peak period. • There is a need for higher incentive for the storage and pondage type hydro generating station providing peaking support. • In the absence of clear provision regarding reconciliation of annual transmission charges and incentivewith monthly billing, the concept of NATAF specified by the Commission in TariffRegulations, 2014 requires review. • Plants operating below 83-85%, there is a need to review the incentive and disincentive mechanism with reference to operational norms.	• Incentive and disincentive should be linked to the Peak and off-Peak season. • Sharing of gain between the Genco and Discoms should be increased from 60:40 to 40:60.
23	**Implementation of Operational Norms**				
A	Implementation (28)	• Presently the operational	• Whether the operational	• The new tariff regulations	• The operational norms of the new tariff

S. No	Particulars	Existing	Proposed	Rationale	Comments
		norms notified by the Commission in new tariff regulations take effect much after the date of coming into force of new tariff regulations once the order is issued by CERC. • Till the issuance of final order, the generating company or the transmission licenses keep charging the tariff based on previous tariff order including operational norms. • Consequently, the benefits of the improved operational norms are passed to beneficiaries only after time lag of few months.	norms of the new tariff period should be implemented from the effective date of control period irrespective of issuance of the tariff order for new tariff period	take effect from 1st April of the tariff period. The Tariff Regulations require the generating company or transmission licensee to file the petitions within 180 days from the date of notification of the regulations. • Since the tariff determination is quasi-judicial function, there is a time lag between filing the petition and finalization/ issuance of tariff order.	period should be implemented from the effective date of control period irrespective of issuance of the tariff order for new tariff period. • This will take care of delays in the issues of Tariff Orders owing to delay in filling petitions etc.
24	**Sharing of gains in Controllable Parameters**				
A	Incentive	• Sharing of gains and losses in ratio of 60:40 between generating company and beneficiaries on account of improvement in controllable factors.	• Whether the ratio of sharing of benefit may be reviewed. • Further procedure for the monthly reconciliation orannual reconciliation mechanism may need to be prescribed	• The compensation mechanism introduced through IEGC entails the hedging of the risk of operating at low PLF. The compensation coupled with normative controllable parameters creates a buffer for generating companies. • In view of this, the merit order operation can be linked	• As per past data it is indicative that Gencos are adequately sharing the gains and instead retaining huge profits and margins. • Therefore, Sharing of gain should be proportionate on equal basis

S. No	Particulars	Existing	Proposed	Rationale	Comments
				with the PLF in such a way that the plants under Section 62 may be encouraged to compete for maximum PLF.	
25	**Late payment surcharge & Rebate**				
A	LPSC(30)	• 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. • Rebate is provided if payment is made within 2 days of presentation of bills.	• In view of the introduction of MCLR, the rate of late payment surcharge may need to be reviewed. • Clause of rebate is required to be reviewed.	• The compensation mechanism introduced through IEGC entails the hedging of the risk of operating at low. • Valid mode of presentation of bill,(email, physical copy etc.), authorised signatory, and definition of two days (working days or including holidays) may need elaboration.	• The rebate should be provided if payment is made within 2 "working days" of "receipt "of the bill instead of "presentation "of the bill. • Since the beneficiaries are largely Govt undertakings and PPP, it would be necessary to define "working days" with reference to Govt and public holidays. • The proposed positioning of LPSC rate with the MCLR + Margins may be implemented. • The LPSC ought to be treated as a Non-Tariff income of the Genco, accordingly the ARR of the Genco ought to be reduced by the NTI. • The rate of LPSC ought to be in sync with the base rate and the MCLR regime.
26	**Non-Tariff Income**				
A	Non-Tariff Income(31)	• Present regulatory framework does not account for other income for reduction of operation &maintenance expenses in case of generation and transmission	• The principle of treatment of other income as applicable in case of transmission can be extended for the generation business. • Review of rate of sharing revenue from telecom business in case of		• Gencos should be allowed to retain only 1/3rd of their other business net income from activities like consultancy; fly ash disposal etc. (after deducting expenses towards income from other business from gross income from other business) and 2/3rd should be passed to the beneficiaries in proportion of their allocation. Similar principle is adopted by SERC in case of

S. No	Particulars	Existing	Proposed	Rationale	Comments
		companies. • Presently, the revenue from telecom business in case of transmission business is adjusted at the rate of Rs3000/- per KM, which was fixed in 2007.	transmission business requires to be reviewed.		DISCOMs where DISCOMs share their other business income with consumers as per pre-defined ratio. • Further entire Non-Tariff Income (Income incidental to electricity generation business like sale of scrap, Income from LPSC after deducting financing cost of LPSC, Income from investment of security deposits etc.) beneficiaries .DISCOMs also pass their entire non-tariff income from advertisement, sale of scrap, income from LPSC, interest on CSD etc. to the consumers. • The revenue earned from telecom business should be reviewed as the telecom sector itself has gone under numerous changes and Digital India push to be explored to minimize the transmission cost of Discoms. • All profits earned from telecom business should be shared with Discoms in ratio of 2/3:1/3 where 1/3rd should be allowed to be retained by Transmission Companies and 2/3rd should be passed on the Licensees. This will be in line with Section 41 of the Electricity Act, 2003. •
27	**Standardization of Billing Process**				
A	Standardization of Billing Process(32)	• Presently, generating companies and the transmission licensees are followingdifferent practice	• In order to avoid possibledisputes in billing, it need to be consider as to whether standardization of		• Standardization of billing process by Gencos and Transcos should be implemented in order to increase transparency and reducing complexities.

S. No	Particulars	Existing	Proposed	Rationale	Comments
		for raising bills on the basis of tariff order. • Some of the States are imposing electricity duty on the actual auxiliaryconsumption and passing to the beneficiaries along with monthly bill.	billingprocess including formats, verification and timeline etc. may be done. • Review of rate of sharing revenue from telecom business in case of transmission business requires to be reviewed. • Whether electricity duty is to be linked with actual auxiliary consumption or normativeconsumption or lower of the two, may need to be specified.		• Form-15 should additionally include the following: - Monthly coal consumption by Unit - Opening coal stock - Closing coal stock • Bills and Form-15 to be provided in MS-Excel format to Discoms
28	**Tariff Mechanism for Pollution Control System (New Norms for Thermal Power Plants)**				
A	Tariff Mechanism for Pollution Control System (33.3)	• No provision currently. • Several generating companies have filed petition for approval of additionalcapitalexpenditure under "change in law" for complying the revised standards ofemission for thermal power projects.	• The principle of bringing the generator to the same economic condition ifit is considered as change in Law. • Technical specifications based on the difference in actual emission andrevised emission, proposed technology, construction period, phasingplan for shutdown during the construction period; • Feasibility of undertaking implementation of new	• As per the new Environment norms notified by Ministry of Environment, Forestand Climate Change, the TPPs would be required to install or upgrade variousemission control systems like Flue-Gas desulfurization ("FGD") system, electrostaticprecipitators ("ESP") system etc. to meet the revised standards. • Recovery of theinvestment made during operation period in the form of additional	• The principle laid down by the Hon'ble Supreme Court that "Polluter Pays" should be implemented. • The impact on Tariff is very significant. As per industries speculations the impact for implementation of norms is Rs. 0.30/kwh to Rs. 0.60/kwh depending upon the plant specifications. • Also, there is constraints on timely implementation of retrofitting on the same. As per CEA it is 2022 by which the retro-fitting is done whereas few generating stations also require more time to implement the same. • Considering the fact that most of the

S. No	Particulars	Existing	Proposed	Rationale	Comments
			norms with R&Mproposal for plants having low residual life, say, less than 10 years. • Change in Auxiliary Consumption and operation and maintenanceexpenses due to implementation of pollution control equipments.	capitalizationthrough redesigning or retrofitting of plant and related operational costs require amechanism in the tariff regulations.	generating companies have a number of thermal power plants in their portfolio, we urge CERC that generating companies be compelled to go for consolidated global tender for all their plants in one go to realize the benefit of economies to scale. • It is pre-mature to consider such a huge impact on the consumers' tariffs. Hence, as the implementation of the notification takes time the control period FY 2019-24 is complete. • Therefore, we request the Commission to consider the impact of such cost while Truing-up only. • Also, Gencos are having huge cash surplus which can easily manage to fund interim funds if required. • If at all in case of limited fund availability, then the Long term loan can be arranged and only interest cost (debt only not equity) can be recovered from Discoms/consumers. In the form of a separate annuity. • In addition to that we would urge CERC that going forward the rate of interest on loan should be considered either wt avg rate of entire loan portfolio of the plant or rate of loan for this specific loan with ever is lower. • Alternatively, being a responsible and most important link in the value chain of cost of supply to the consumers. Thermal

S. No	Particulars	Existing	Proposed	Rationale	Comments
					generating stations should meet the Environment norms from its profits. • Without prejudice to the above, If at all the sharing is to be done then it should be in ratio of 50:50 between Gencos and consumers. • The plants age, different state pollution norms and its unique design would lead to different upgradation requirements for complying to new MOEF norms. Hence standardization of work could lead to over engineering and thereby over investment. • Alternatively we propose that an independent engineer be appointed for each plant with the following scope of work. 1) To check if the plant is complying to prevailing state and central pollution norms. 2) Based on the prevailing design of the plant, recommended design to enable plant to adhere to new pollution norms. • All the beneficiaries of a plant would together appoint the independent engineer and also pay for it based on their entitlement from that plant. • Also, Thermal generating stations whose ECR is more than Rs. 2.50/unit should not be implemented, instead should be shut down/phased out. • In line with exemption of excise duty waiver for Ultra Mega & Mega Power

S. No	Particulars	Existing	Proposed	Rationale	Comments
					plants, we urge CERC to seek exceptions from state and center levied taxes on equipment being procured for compliance of new MOEF norms (FGD & ESP upgradation). The Primary reason for seeking this exemption is that beneficiaries would not gain any efficiency gains are investment of this capital, on the contrary auxiliary consumption is expected to increase thereby not only increasing FC but VC as well. • Hence these exemption would help in rationalizing the tariff increase.
29	**Renewable Generation by existing Thermal Generation Stations**				
A	RE Generation by existing Thermal Genco	• No provision currently	• Install RE project at the same location using common facilities and land and bundle RE power with the conventional power prior to delivery point • Other option is to establish the renewable project at different location and pool the generation capacity on external basis beyond the delivery point. • However in both the cases, the annual fixed charges for thermal project and renewable project may be determined separately, based on separate set of	• The Revised Tariff Policy dated 28th January,2016 provides for setting up of renewable energy generation capacity by existing coal based thermal power generating station. • The policy provides that in case any existing coal and lignite based thermal power generating station chooses to set up additional renewable energy generating capacity with the concurrence of power procurers under the existing Power • Purchase Agreements, the	• In case there is a two part tariff in case of bundling RE power with conventional power stations, and the RE power plant is not able to generate due to environmental constraints, then energy received through conventional power to the extent of RE power scheduled by DISCOM should be considered towards RPO of DISCOM. For example: a DISCOM schedules 400 MU from Conventional power to be generated by Anta Gas Station and 20 MU from RE power to be generated by Anta Gas Station and DISCOM actually received 410 MU only from conventional power of Anta Gas Station and 0 MU from RE power of Anta Gas Station then, 20 MU out of 410 MU should be considered as RE power received by DISCOM for meeting RPO and rest 390

S. No	Particulars	Existing	Proposed	Rationale	Comments
			tariff principles. • The scheduling and dispatch mechanism of renewable generation can be as per the thermal power generation. The target availability and dispatch level, in this case, maybe pre-specified which may be 2% higher for every 10% renewable capacity addition and the annual fixed charges for the thermal project and renewable project maybe combined for deciding the tariff.	power from such plant shall be allowed to be bundled and tariff of such renewable energy shall be allowed as pass through by the Appropriate Commission. • The Obligated Entities who finally buy such power would account this power towards their renewable purchase obligations (RPOs). Scheduling and dispatch of such conventional and renewable generating plants shall be done separately.	MU towards conventional power of Anta Gas Station. Such a mechanism would ensure certainty. • The Tariff of renewable and Thermal should not be bundled as this case increase complexity and litigations further. • Tariff should be separate and it should be through TBCB route for renewable generation.
30	Energy Storage System				
A	Energy Storage System (36)	h) No provision currently i) In a Nascent stage	• Staff Paper was circulated on 4.01.2017 highlighting two options: • Generation storage system wherein Generation Company can store energy as per the consent for storage facilities. The Generator may use it for optimization of generation dispatch specific to their designated beneficiaries within the power purchase agreement.	•	• No Separate tariff is required for Energy storage for flexible operation in Thermal generating stations as its components already included in Capital Cost. • We would need clarity on, how would Transmission Company schedule power to beneficiary. • We would need clarity on type of generators being referred to here, whether its solar/wind farms or generators providing bundled power.

S. No	Particulars	Existing	Proposed	Rationale	Comments
			• Storage facility as part of Inter-State Transmission system so as to ensure overall optimization power from the grid, irrespective of the owner of storage capacity and may be dispatched when needed. Such dispatch can be added in the drawl schedule of all beneficiaries of the region on ex-post basis. • Annual fixed charges of the storage facility can be determined based on ramping rate, auxiliary consumption, Return on Equity, Interest on Loan, Depreciation, O&M Cost and Interest on Working Capital.		
31	**Alternative approach to Tariff Design**				
A	Normative tariff by benchmarking of capital cost (37.6)		• Capital cost per MW of sample plants varied from Rs. 3.87 Cr/ MW to Rs. 8.74 Cr./ MW		• Benchmarking of capital cost of similarly placed plants should be done. This will keep the Tariff in check.
B	Principle of Cost Recovery – Approach towards Multi Part Tariff (37.20)	• AFC is recovered based on normative NAPAF throughout the year	• AFC component is split into Off-Peak and Peak durations and charge on different availability	• Once the generator declares plant availability at the normative level of 85%, the distribution utilities are	• With regard to the proposed recovery ratio of AFC 20:80 between peak and off peak months of a year with four months being considered as peak, we are concerned that

S. No	Particulars	Existing	Proposed	Rationale	Comments
			factors for Peak and off-peak period.	required to pay the AFC in full irrespective of scheduling of energy. • The failure to achieve the Plant availability factor will lead to dis-incentive in terms of reduction of Fixed Charges during Peak and off-peak periods	during peak months a beneficiaries FC burden would be substantially low in comparison to off peak months, which would lead to cash flow concerns for Discoms. • Hence we propose that the recovery of FC be spread equally throughout the year with different normative plant availability factors for peak and off peak period.
C	Normative Tariff by fixing AFC as a percentage of capital cost (37.9)		• Correlation coefficient between AFC approved for first year of Operation and approved capital cost was around 0.84. Similarly correlation coefficient between average AFC per year and capital cost was 0.95.		• Normative fixation of AFC of similarly placed plants should be done. This will keep the Tariff in check.
32	**Transparency in Billing and Accounting of fuel**				
A	Transparency in billing and accounting of fuel	• The regulatory approach of pass through of coal cost to the procurer directly on the basis of certification has been well adopted.			• Form-15 should include the following: - Monthly coal consumption by Unit - Opening coal stock - Closing coal stock Bills and Form-15 to be provided in MS-Excel format to Discoms
33	**Relaxation of Norms**				
A	Norms(39)	• The present regulatory framework provides for			• Norms can be relaxed or tightened depending upon the specific site and its feature. Provided that the

S. No	Particulars	Existing	Proposed	Rationale	Comments
		specifying normative operational parameters. • However there is provision for relaxation of norms in case of situation beyond control of Generating stations such as such as FGD, Desalination plant, increase in length ofwater conductor system etc may lead to power consumption in excess of the norms			Stakeholders/beneficiaries should be granted full opportunity of presenting their say in the matter.
34	**Merit Order Despatch**				
A	MOD(40)	• Presently merit order is based on the fuelcost of the past data, with time lag of up to two-three months in billing cycle.	• The merit order operation is important for economic operation of the plants andoptimum despatch of economic resources. The consideration of other factors such asdistance of transportation, secondary fuel oil consumption may provide the option todistribution utility to optimize the despatch.	• In respect of certain old plants having lowfixed costs, their power may not get dispatched as the merit order is based onvariable cost, which may be high.	• Total cost per unit should be used for scheduling power as consumers have to bear both fixed and variable charges. In existing scenario, the Gencos get higher fixed cost, higher ROE etc. through recovery of fixed charges and also incentive by maintaining lower variable cost so that they fall in MOD. • MOD based on total cost per unit shall avoid any gaming by Gencos. • The generators may be allowed to give discount in AFC on annual basis which shall be adjusted in energy rate while scheduling dispatch as per MOD may also be explored.
35	**Application for Tariff determination**				

S. No	Particulars	Existing	Proposed	Rationale	Comments
A	Application for Tariff determination	• Presently the determination of capital cost of transmission system is distinguished ontwo counts – existing assets i.e. those commissioned prior to commencement ofrelevant tariff period and new assets commissioned during tariff period. Presently, thecapital cost of the existing assets is determined on projected basis at the beginning ofthe tariff period and trued up on completion of the tariff period i.e. twice during tariffperiod.	• One alternative to simplify the process is to determine the tariff of existingassets based on actual capital expenditure instead of projected capital expenditure,so that two applications of existing assets can be reduced to one in each tariff period. • Further, the tariff of new assets can be determined during tariff period after commissioning of the new assets. In case of new assets of transmission system, single petition may beadmitted for all the individual elements of the project which have been commissionedwithin a year. Then annual fixed charges may be determined on consolidated basisandapportioned on proportion to the capital cost of individual elements. The true upmaybe carried out on completion of the project based on balance sheet of	• Unlike the case of generating stations, the transmission system involves alarge number of individual transmission elements which are commissioned at differentpoint of time over the span of 1-2 years. Sometimes, commissioning of individualelements takes more time due to ROW issues, forest clearance and matching withupstream/ downstream system. Therefore, the number of tariff petitions intransmission projects is high and spread over a period of time as they depend uponthe commissioning of different elements. The finalization of tariff for an individualelement also involves judicial processes which is same for the whole project.	•

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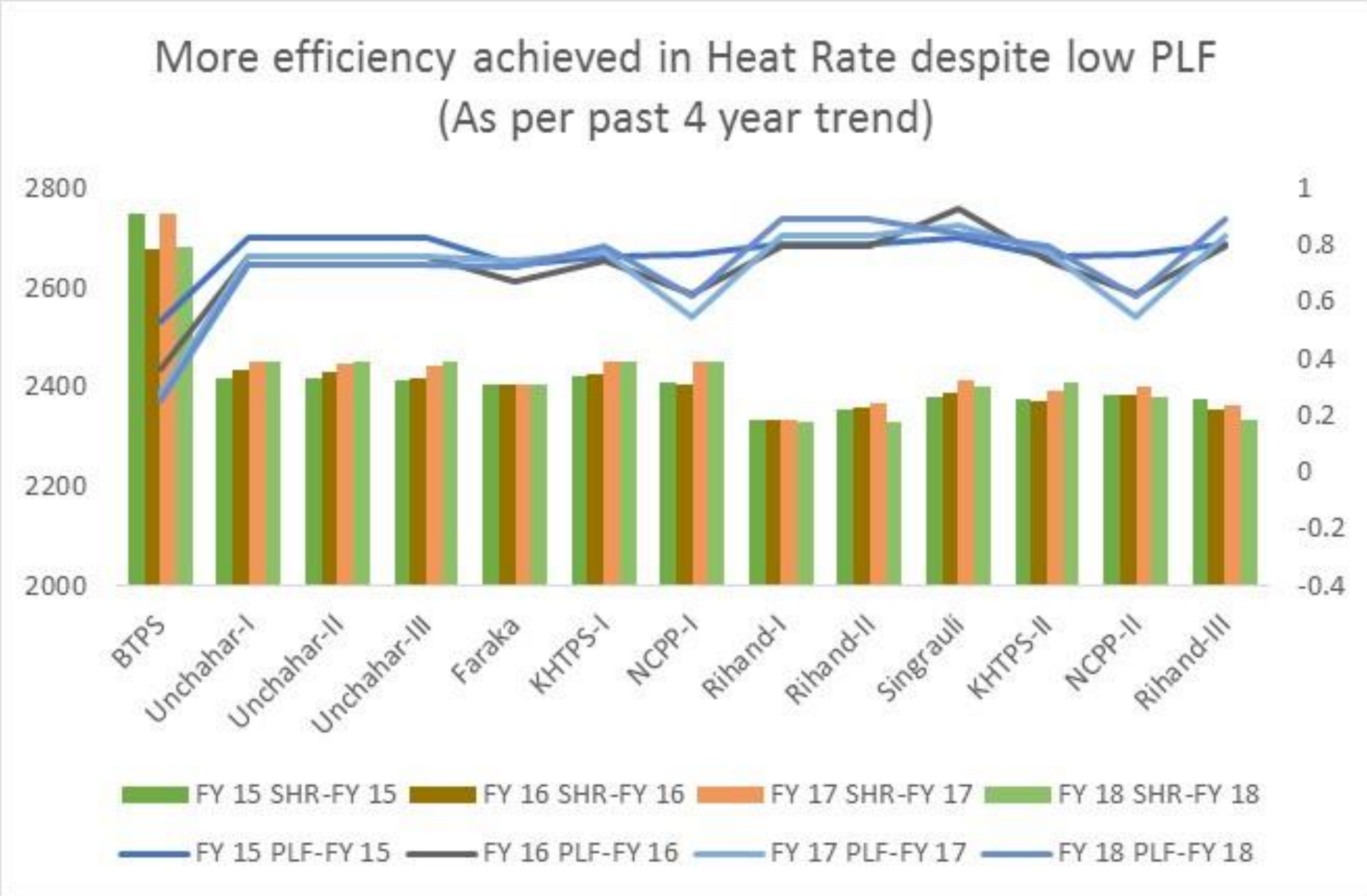
<tr><th>S. No</th><th>Particulars</th><th>Existing</th><th>Proposed</th><th>Rationale</th><th>Comments</th></tr>
<tr><td></td><td></td><td></td><td>individualproject.</td><td></td><td></td></tr>
<tr><td>36</td><td colspan="4">Goods and Service Tax (GST)</td><td></td></tr>
<tr><td>A</td><td>GST</td><td>No prudence check of taxes since GST was not in existence at the time of CERC Tariff Regulations, 2014.</td><td>Prudence check of impact of pre-GST and post-GST taxation regime on the costs may be required for determination oftariff in the next control period.</td><td>Goods and Services Tax (GST) has been introduced which has replacedvarious Central and State level taxes</td><td>GST should not be applicable in case of Transmission Companies because Transmission services are naturally bundled with the supply of electrons where the latter already enjoys exemption under the GST acts. Hence there should be no question of reimbursement of GST on transmission services.
Insofar as Genco is concerned, the electrons are exempted from GST and hence, there is no question of reimbursement of GST on the quantum of electrons.
Currently Genco are charging no GST from Discom separately as there is no specific service involved.
However, Coal cost has been effected by implementation of GST which eventually is pass through via ECR billing to Discoms.
There is marginally no impact on Genco’s operation and Fixed cost under various heads:
<table><tr><th>Components of AFC</th><th>Impact</th><th>Remarks</th></tr><tr><td>Depreciation</td><td>NO</td><td>As the cost has already been incurred and passed through in capital cost.</td></tr></table></td></tr>
</table>

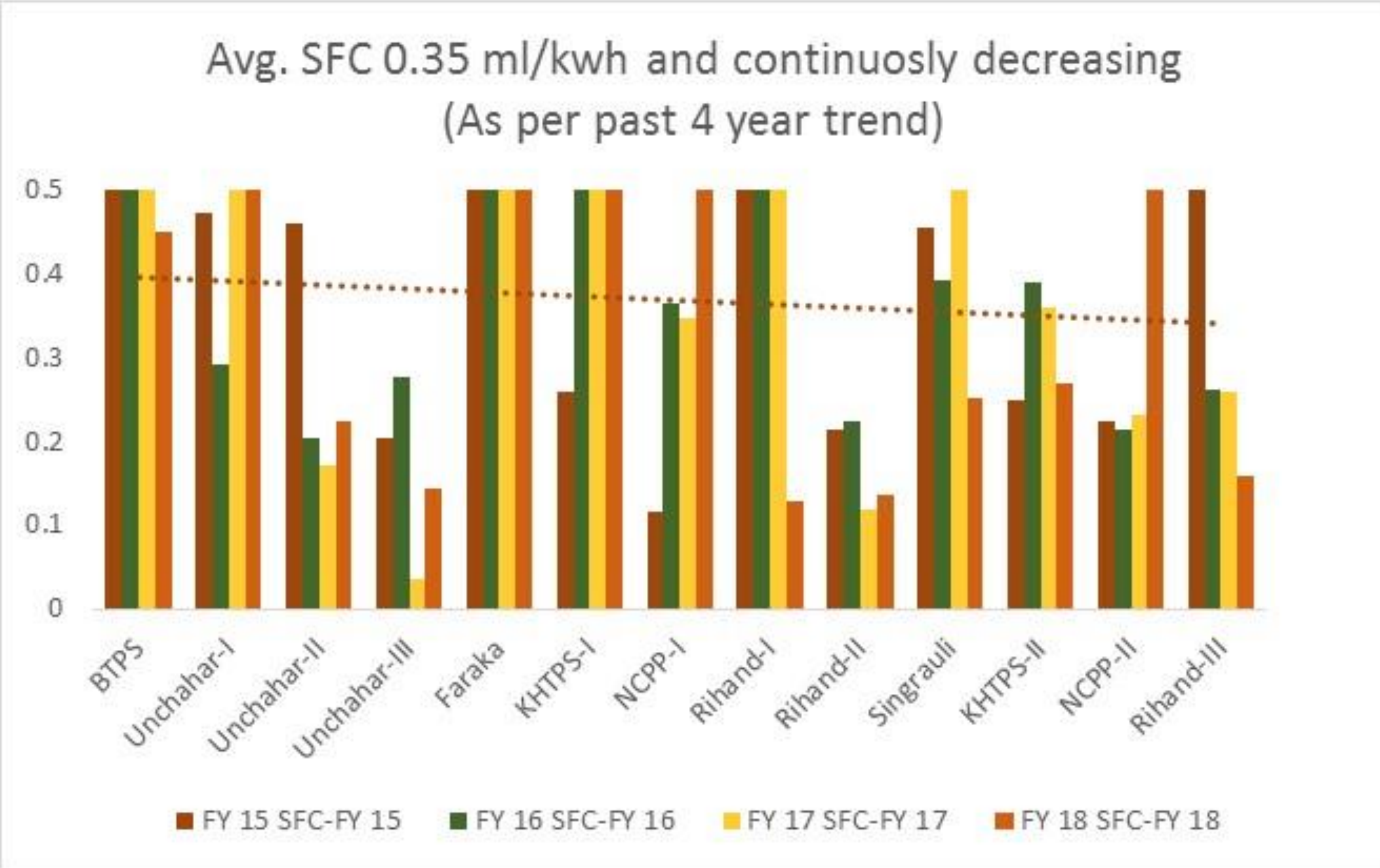
<table>
<tr><th>S. No</th><th>Particulars</th><th>Existing</th><th>Proposed</th><th>Rationale</th><th>Comments</th></tr>
<tr><td></td><td></td><td></td><td></td><td></td><td>
<table>
<tr><td>Interest on loan</td><td>NO</td><td>No statutory Tax is there in Interest cost</td></tr>
<tr><td>O&M :</td><td></td><td></td></tr>
<tr><td>Employee Cost</td><td>NO</td><td>The Salary is a part of Direct Taxation</td></tr>
<tr><td>R&M</td><td>Marginal</td><td>Only in case of outsourcing services</td></tr>
<tr><td>A&G</td><td>Marginal</td><td>Only in case of outsourcing services</td></tr>
<tr><td>IOWC</td><td>NO</td><td>No statutory Tax is there in Interest cost</td></tr>
<tr><td>ROE</td><td>NO</td><td>It has Dividend Tax. Hence, it comes under direct taxation.</td></tr>
</table>
</td></tr>
</table>

ANNEX-1

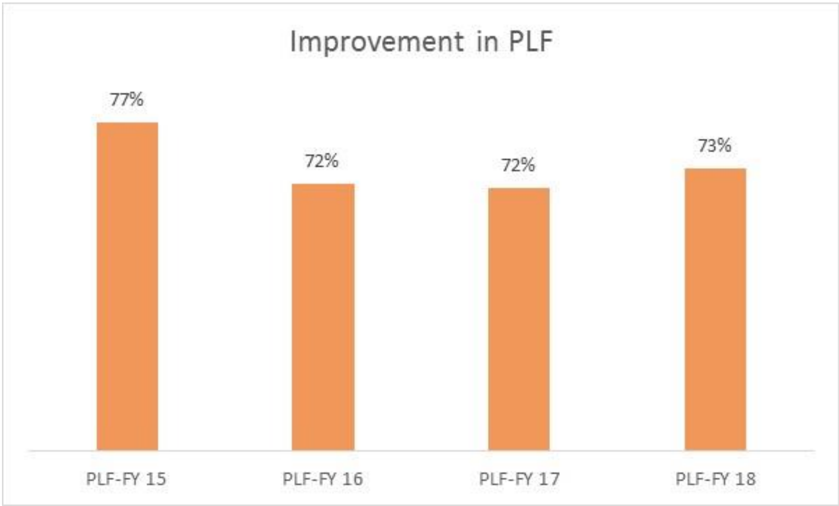
Comparison of Heat Rate and PLF:



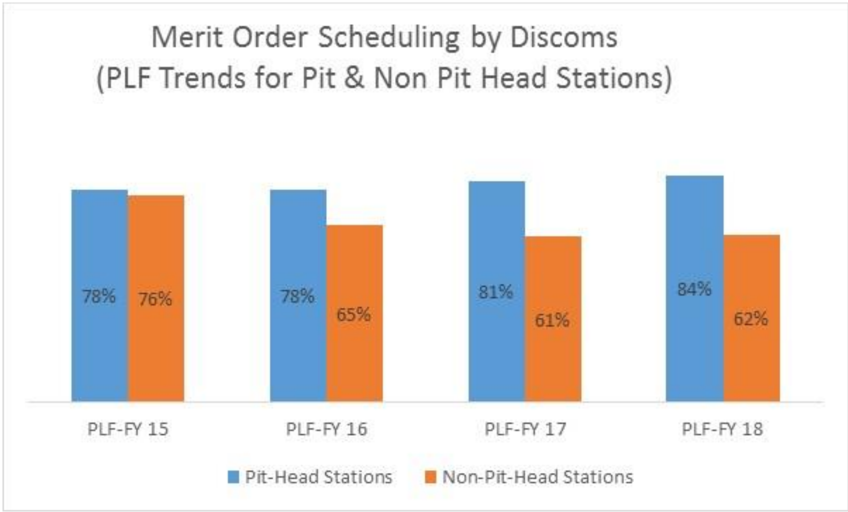
Consumption pattern of SFC:



<u>Significant improvement in PLF of Thermal Generating Stations:</u>



<u>Comparison of Pit-head and Non-Pit head PLF:</u>



Plants	FY 15				FY 16				FY 17				FY 18			
	PLF	SHR	Aux	SFC	PLF	SHR	Aux	SFC	PLF	SHR	Aux	SFC	PLF	SHR	Aux	SFC
BTPS	53%	2750	8.50	0.50	36%	2676	9.87	0.63	28%	2750	8.50	0.50	25%	2683	10.05	0.45
Unch-I	83%	2417	8.59	0.47	76%	2435	8.86	0.29	76%	2450	9.00	0.50	73%	2450	9.00	0.50
Unch-II	83%	2416	9.24	0.46	76%	2431	9.42	0.21	76%	2447	9.00	0.17	73%	2452	9.24	0.22
Unch-III	83%	2412	8.55	0.20	76%	2417	8.65	0.28	76%	2442	8.83	0.04	73%	2449	9.11	0.15
Faraka	73%	2403	6.47	0.50	67%	2403	6.47	0.50	75%	2403	6.47	0.50	73%	2403	6.47	0.50
KHTPS-I	76%	2420	9.57	0.26	74%	2425	9.53	0.54	78%	2450	9.00	0.50	80%	2450	9.00	0.50
NCPP-I	77%	2407	7.97	0.12	63%	2404	8.17	0.37	55%	2449	8.53	0.35	62%	2450	8.50	0.50
Rihand-I	80%	2335	7.75	0.50	80%	2335	7.75	0.50	84%	2335	7.75	0.50	90%	2328	7.77	0.13
Rihand-II	80%	2356	6.71	0.22	80%	2358	6.45	0.22	84%	2368	6.22	0.12	90%	2330	5.84	0.14
Singrauli	83%	2382	7.29	0.46	93%	2388	7.48	0.39	87%	2413	6.88	0.50	84%	2402	7.71	0.25
KHTPS-II	76%	2374	5.78	0.25	74%	2372	5.51	0.39	78%	2393	5.16	0.36	80%	2409	5.54	0.27
NCPP-II	77%	2384	5.03	0.23	63%	2385	4.96	0.21	55%	2401	4.95	0.23	62%	2380	5.25	0.50
Rihand-III	80%	2377	5.95	0.63	80%	2354	5.46	0.26	84%	2365	5.55	0.26	90%	2334	5.40	0.16
Average	**77%**	**2418**	**7.49**	**0.37**	**72%**	**2414**	**7.58**	**0.37**	**72%**	**2436**	**7.37**	**0.35**	**73%**	**2425**	**7.61**	**0.33**

N on – Highlighted Portion indicate improvement in Operational efficiency.