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(भारत सरकार का उद्यम)

NHPC Limited
(A Government of India Enterprise)

स्वच्छ भारत
एक कदम स्वच्छता की ओर

फोन/Phone :

संदर्भ सं./Ref. No. NH/Comml./Tariff/315/2018/1485

दिनांक/Date : 13.07.2018

Secretary,
Central Electricity Regulatory Commission,
3rd & 4th Floor, Chanderlok Building,
36-Janpath, New Delhi – 110 001
Fax: 011-23753923

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Sub: **Comments on consultation paper for Tariff Regulations, 2019.**

Sir,

This is in reference to CERC public notice dated 24.05.2018 vide which consultation paper for framing terms and conditions of tariff for the next control period has been issued for comments from stakeholders. The referred document has been studied by us and the detailed comments on specific clauses are enclosed. The gist of our comments is discussed hereunder:

At the outset, we would like to place our appreciation for CERC on record for highlighting the importance of hydro power projects in balancing of the national grid. It may be noted that the share of hydro power in the grid has depleted to 14% against a desired share of 40% for ideal balancing of the grid. This depletion can be attributed to the inherent characteristics of hydro projects and constraints such as location remoteness, hydrology, geology, plant layout, socio economic conditions, security and law & order issues. The hydro sector being inflicted with these issues, has not got the momentum it deserves and needs to be suitably resurrected through appropriate policy and regulatory framework.

The initial period high tariff of hydro projects seems to be a matter of primary concern in the consultation paper. However, in the process of reducing this high initial tariff, the consultation paper seems to be proposing squeezing of tariff provisions from all sides. This approach may lead to further downfall of investments in the sector and may result in further reduction of hydro power share in future. These propositions run in contradiction to the concerns expressed in the approach paper regarding need of hydro plants for grid balancing. NHPC believes that regulatory certainty and consistency is essential for confidence building of the hydro developers and the proposals made need to be relooked in light of NHPC's comments.

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The major points of concern are as under:-

1. The proposition of restricting the rate of return on equity deployed beyond original sanctioned cost i.e. the equity portion of cost overrun to rate of interest rate for loan portfolio or risk free rate, for reasons beyond the control of developer is not prudent. The equity invested carries same risk, whether for original sanctioned cost or for cost overrun. Any such move will discourage investment in hydro power sector, which is already suffering reduced effective rate of return due to uncontrollable delays.

2. In order to reduce recovery of depreciation, the useful life of project is proposed to be extended from existing 35 years to 50 year. The present estimated life of 35 years is based on established data and particularly due to life span of electro-mechanical components of the project. The benefit of longer life of civil structure is being passed on to beneficiary states in terms of NIL depreciation and reduced R&M cost of the project.

3. The proposal indicates uniform depreciation throughout the life of project, but is silent on the source of cash for repayment of loan. In case, the tenure of debt is being extended to 18-20 years then the project cost equivalent to 70% of the total cost (i.e. to the extent of debt portion) needs to be depreciated in 18-20 years so as to match the cash flows for repayment of debt. The recovery of depreciation should remain linked with debt repayment schedule. Further, the suggested long term borrowing at Clause 10.5 (a) (18-20 years) may not be feasible in all cases, especially for hydro power projects.

4. The proposal of proportionate reduction of equity base after repayment of loan will also go against the interests of developer. In such a scenario, the return on equity deployed during construction stage of the project has to be allowed to the developer.

5. The proposed debt equity ratio of project funding (80:20), when looked at with associated increase in expectation of return on equity (on account of increased leverage) will not be beneficial. If this change is effected in isolation i.e. without corresponding increase in return on equity, it would lead to reduced return for the developer and accordingly, the investment in hydro power sector will get adversely affected. Moreover, it may not be possible for long gestation period hydro projects to get 80:20 funding.

Continuation Sheet No.

6. The paper proposes determination of capital cost on benchmark basis. In case of hydro generation projects, the benchmarking of capital costs is not possible, as capital costs vary from project to project depending upon peculiarities for each project - location remoteness, hydrology, geology, plant layout, socio economic conditions. Hence, the determination of capital cost on benchmark/normative basis is not at all advisable.

7. The paper also proposes to review the methodology of allowing O&M cost as a percentage of capital cost for new hydro projects. It is pertinent to mention that currently, the applicable O&M expenses are reviewed after 3-4 years of operation on the basis of actual expenditure with certain disallowances. Normative O&M expenses approved by the Commission, whether determined based on percentage of capital cost basis or based on actual O&M expenses, fall short of actual O&M expenditure. This results in erosion of return on equity, reducing it even further below the allowed levels.

NHPC's detailed response to pertinent clauses is enclosed herewith, along with detailed Annexures explaining our comments.

Thanking you,

Yours faithfully,

(Pra4"aWKaul)
Executive Director (Comml.)
0129-2259923

COMMENTS OF NHPC LIMITED ON THE CONSULTATION PAPER ISSUED BY CERC FOR FRAMING TERMS AND CONDITIONS OF TARIFF FOR THE CONTROL PERIOD 2019-24

NHPC Limited

(A Govt, of India Enterprise)

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N.H.P.C. OFFICE COMPLEX,
SECTOR-33. FARIDABAD (HARYANAM21003

NHPC's Comments to CERC Consultation Paper 2019-24

Topic	Clause	Options Proposed bvCERC	Nil PC's Comments
	5.5.1	The share of total I installed capacity of ! hydro power is a I meagre 14% of the total installed capacity.	We agree with CERC's assessment that in the present energy scenario, due to fast-paced addition of RE projects, the requirement of hydropower will become even more pertinent for stabilisation of grid as solar and wind energy are intermittent in nature.
Some Key Challenges - Hydro Generation	5.5.2	Hydro projects are highly capital intensive and have long gestation period. With majority of the I plants located at remote and inaccessible regions, hydro projects generally get delayed due to various factors which, inter alia, include geological surprises, natural I calamities, lengthy clearance time, law & order problems and delay in implementation of [1] R&R Plans. These factors result in time and cost overrun which in turn increases the capital cost, leading to higher and, often, unviable tariff.	It is also true that due to its inherent characteristics, I hydropower projects are capital intensive in nature and have long gestation periods that vary across i projects, depending on various factors like ' remoteness of location. Uncertainties and risks associated with hydropower project development J cause frequent and uncontrollable time and cost over-runs. However, other benefits of hydropower like pollution free generation, quick start capability, etc. are well known. As explained in 5.5.3, the tariff of hydro power is low in the longer run and due to its inherent flexibility, the hydro power generation will! have a significant role in the future. It is submitted that ground realities and challenges ; associated with execution of hydropower projects j and attractiveness of the sector for investments be j taken into account while assessing any of the proposed changes in the regulatory framework. Some of the challenges placed in the hydropower sector are illustrated below:
	5.5.3	The hydro generation ! offers greater I advantages with its ! economical and environmental friendly power resource in the long	o <u>Illustration 1:</u> In case of projects developed in the state of J&K, generating companies have to pay water usage charges to the government of J&K, which is causing increase in tariff by 10% to 15%. Though the water usage charge is a pass through expenditure to beneficiaries, its addition in tariff is making hydropower prohibitive for beneficiary states. Therefore, there is a need to review the concept of free power wherever water usage charges / cess is applicable. CERC may kindly advise Central Govt, on this issue.

,,, Clause	Options Proposed bvCERC	NIMH \s Comments
	run. However, the cost of electricity of hydro power is comparatively expensive vis a vis coal based power plants in the short-run. In view of this, the hydro projects find it difficult to attract investment and many times, do not find buyers. Since the tariff of hydro power is low in the longer run and that it has inherent flexibility, the hydro power generation will have a significant role in future especially in view of large scale additions of renewable energy sources in the grid that has inherent intermittency. Therefore, there is a need to address factors that currently drive hydropower costs up.	<u>Illustration 2:</u> En case of Ix>wer Subansiri project, NHPC has invested approximately INR 10,000 crores and more than 50% of the project is complete. However, the project has been halted since 16.12.2011 due to agitation by various groups in Assam. This situation is not in control of generating company, but it has serious repercussions on financing of project and tariff. <u>Illustration?:</u> For the Hydro projects which get delayed due to law and order situation, agitation, militancy etc., there is an increase in IDC which results in increase in capital cost / tariff. Hence the Government and CERC need to formulate some mechanism so that such IDC for the delayed period (for the reasons beyond control of the developer) is separately reimbursed to the developer along with financing charges and is not made part of capital cost in order to optimize the tariff.
5-5-4	The pumped storage hydropower stations have generally been integrated as a part of the generation project. In present regulatory framework, additional return has been provided for pumped storage plants.	

Topic	Clause	Options Proposed In CIRC	NIIPC's Comments
Hydro Generating Stations -Tariff Structure	5.5.5	Flexibility of hydro power helps in the grid balancing required due to the renewable generation. The challenge is to evolve a suitable regulatory framework to make the hydro operation flexible.	
	7.4.1	The two part tariff structure of hydro generating stations seems adequate in present scenario. However, in view of large capital cost, hydro generating stations often find it difficult to get dispatched due to resultant higher energy charges. In order to address this issue, for the hydro generating stations, the fixed charges and variable charges may need to be reformulated.	Presently, the recovery of annual fixed cost of a hydropower plant is through a two-part tariff consisting of capacity charges and energy charges, These charges are determined by allocating the annual fixed cost (AFC) of the hydropower plant into capacity and energy charges in the ratio of 50:50. Though we recommend that the present two part tariff is most suitable, simple and logical, it is pertinent to note that the components translating into capacity and energy charges are essentially fixed in nature. An alternative approach to tariff determination could be to determine capacity charges based on components linked to capital cost and variable charges to operational costs. Thus, the capacity charge may be determined considering the interest on loan, depreciation and return on equity and the energy charge may be linked to O&M expenses and interest on working capital. It is categorically stated that linking of capacity charge to risk free return is not prudent, as development of hydro projects is fraught with risks and any linking to risk free return will go against the interest of hydro power development and further discourage investment in the sector. Further, linking of return on equity portion of cost overrun deployed to weighted average of interest rate on loan portfolio / risk free rate is also not desirable as this equity portion also carries the same risks as normative equity envisaged in the investment approval.
	7.4.2	The fixed component may include debt service obligations, interest on loan and risk free return while the variable component may include incremental return above guaranteed return, operation and maintenance expenses and interest on working capital. The	

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		annual fixed cost can consist of the 1 components of return on equity, interest on loan capital, , depreciation, interest on working capital; and operation and maintenance expenses.	
Deviation from Norms	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. The question is whether the annual fixed charges and energy charges are to be determined to the extent of the capacity tied up under Section 62 of the Act or for the entire capacity. One approach could be to determine the tariff of the generating station for entire capacity and restrict the tariff for recovery to the extent of power purchase agreement on prorata basis and balance capacity will be merchant capacity or	• Flexibility provided by Regulation 48, which allows a company to charge a lower tariff than that determined by the CERC, needs to be retained as it encourages competition. NHPC has already opted for this flexibility in case of tariff of Kishanganga HE Project. • It is further submitted that for operational ease, generating company may be allowed to use this option at its discretion, without prior approval from the CERC. However, the generating company may be required to notify the same on rolling basis for a specified period. • We recommend that the annual fpced charges ! should be determined for the entire capacity so that j there is no uncertainty for developers' investment and also regulatory risk. However, the recovery of annual charges may be restricted on pro-rata basis ' in case of signed power purchase agreements and balance capacity should be treated as merchant capacity for trading through energy exchange. • Additionally, in case of merchant trading, the j generating company may be allowed to sell its power at higher/lower rates depending upon the energy market scenario, without obtaining any ! consent from the regulator.
Components of Tariff	9-3		

	Oplions Proposed	Nl IPC's Comments
Optimum Utilization of Capacity	tied up under Section 63, as the case may be. 10.5 (a) Extend the useful life of the project up to 50 I years from existing 35 years and the loan repayment period up to 18-20 years from existing 10-12 years for moderating upfront loading of the tariff.	• Extension of useful life to 50 years o It is pertinent to note that life of electromechanical components is not more than 35 years whereas for civil structures the life may be longer. o After completion of 35 years, the users enjoy the benefit of lower tariff as renovation and modernization needs to be carried out for electromechanical components only and zero depreciation is enjoyed by the users for civil structures. Thus, it would not be in the interest of the stakeholders to increase the life to 50 years. o Further it is to be noted that the under water rotary components in plants of Himalayan region suffer from heavy silt, which adversely affects the life of components. o Procurement of electromechanical components designed for 50 years useful life would increase in capital cost of the plant, thereby increasing the tariff o <u>Therefore, we recommend that estimated life should be retained at 3s years</u> • Loan duration of 18-20 years o Lenders may not be willing to extend loans for 18-20 years duration, which is much higher than typical duration of 12 years. o In such a scenario, considering a debt repayment period of 18-20 years and de-aligning the depreciation rates to the same will create mismatch in cash flow of the power project and may adversely affect the debt servicing ability of 1 the borrower. o <u>Thus. NHPC recommends that the debt repayment period of 12 years should be retained and the depreciation rates should continue to be linked to loan repayment</u>

' ,,,	Options Proposed bv (l\Rl	NUPCsComnienls
10.5 (b)	Assign responsibility of operation of the hydro power stations I and pumped mode I operations at regional level with the primary objective for , balancing. For this purpose, the ! scheduling of the I hydro power operation (generation I and pumped mode l operation) may have I to be delinked from j the requirements of designated beneficiaries with whom agreement I exists. The power I scheduled to the hydro generation can I be dispatched to designated beneficiaries through banking facility so that flexibility in scheduling can be achieved for balancing purpose and to address the difficulties of cascade hydro power station. Some part of fixed charge liability to the extent of 10-20% I against the use of flexible operation and pumped operations I may be apportioned to the regional beneficiaries as reliability charges.	The scheduling of hydropower projects/pumped storage scheme are established by RLDC as per requirement of grid. The hydropower projects are meeting the balancing requirement of grid against any fluctuation caused by the utility connected to the grid or by renewable energy utility. The scheduling is done on regional basis and requirement of grid balancing is technically met. The proposed methodology will complicate the energy accounting and it will require additional power purchase agreements with new beneficiary for recovery of 10-20% AFC, which will be a cumbersome process for a generating company In our view, the present distribution of hydro energy as per allocation of power should be continued and if required, a bilateral banking system may be incorporated in REA like DSM system.

	Chaise	Options Proposed bvCGKC	NHFCs Comments
	11.8	One of the options is to move away from investment approval as reference cost and i shift to benchmark/reference cost for prudence check of capital cost. However, the challenge is absence of credible benchmarking of technology and capital cost.	It is categorically stated that in case of hydro generation projects, the benchmarking of capital costs is not possible, as capital costs vary from project to project depending upon peculiarities for each project - *location remoteness, hydrology, geology, plant layout, socio economic conditions, security and law & order issues* Statutory bodies of the state government such as pollution control board, forest divisions, sometimes levy unwarranted penalties during construction which though challenged, remain under litigation. These statutory compliances have cost implications which vary from state to state Therefore, econometric analysis or benchmarking for determination of capital cost is not advisable, especially for the hydro sector
Capital Cost	11-9	[1] Higher capital cost allows the developer I return on higher base | of equity deployed. In i the cost plus pricing 1 regime, the developer J envisages return on ! equity as per the i 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	The approach paper proposes to restrict the return on equity on equity deployed beyond original sanctioned cost, Under this concept, generating company will get return on equity portion of cost overrun (over and above that envisaged in the investment approval) at rate of interest rate for loan portfolio or risk free rate. a. *Interest rate of loan portfolio* - under this approach, equity portion of cost overrun deployed in the project be treated as a normative loan b. *Risk free return* - under this approach, equity portion of cost overrun deployed will be treated at par with government securities. The equity being infused by the developer, whether as per investment approval or in excess of it. is equity nevertheless and bears the same risk. This risk borne by equity holders can never be compared to risk of lenders, whose returns are guaranteed, or the government. It will therefore not be prudent to reduce the return on excess equity, infusion of which is beyond the control of generating company. It is to be noted that this approach will drastically reduce the return on total deployed equity in the

	Options Proposed bv CERC	Nil PC's Comments
	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 slippage from scheduled commissioning can also be introduced.	project and same will discourage any further investment in hydro power sector, which is already suffering reduced effective rate of return due to uncontrollable delays. As already demonstrated in comments on Clause No. 18.7, every year of delay already causes a reduction in effective rate of return by ~ 0.7%. Any further disincentive for delay will be detrimental to the interest of existing developers and potential investors. Therefore, in our view, the present concept of working out equity base should be continued.
Renovation and Modernisation	12 TheR&Mof transmission system could include Residual Life Assessment of Sub-Station and Transmission Lines, Upgradation of sub-station and transmission line, System Improvement Scheme (SIS) and replacement of equipment. The Commission may allow Renovation & Modernisation (R&M) for the purpose of extension of life beyond the useful life of transmission assets. Alternatively, the Commission may allow special	In reference to recovery of AFC when generating station or unit is under shutdown due to R&M, Regulation 30 (2) of 2014 Tariff Regulations provides as under: *"Provided that in case of generating station or unit thereof or transmission system or an element thereof as the case may be, under shutdown due to Renovation and Modernization, the generating company or the transmission licensee shall be allowed to recover part of AFC which shall include O&M expenses and interest on loan only"* As on date any special allowance is not applicable for hydropower generating stations and hence the hydropower stations are to be renovated / modernized after completion of useful life. During R&M of project, the generating stations may be in partial operation or complete shutdown for limited periods. CERC may kindly define a separate regulation for determination of tariff for the project during R&M stage. Provision should be there to encourage and incentivize Generating Company to carry out concurrent operation of units along with shutdown of unit for renovation and modernization.

I upic	('lause	Options Proposed b\ (r.KC	NIH'C'sComiiuMils
		allowance for R&M of transmission assets. Such provision will enable the transmission companies to meet the required expenses including R&M on completion of 25/35 years of useful life of sub-station/transmission line without any need j for seeking resetting of capital base.	Accordingly, the generating company may be allowed to bill the scheduled energy generated during the R&M period. This should be over and above the provisions of existing regulations 30(2) The above may be taken up for deliberation and incorporation in the new Tariff Regulations.
Financial Parameters	13.1	The performance based cost of service approach, a combination of actual cost and normative parameters has been evolved for the Tariff regulations. Components like return on equity, operation & maintenance expenses and interest on working capital have been specified on normative basis whereas cost of debt has been allowed based on actual rate of interest on normative debt. The normative parameters are expected to induce operational and financial efficiency. While continuing with the hybrid approach, more weightage may be provided for	► Out of various parameters constituting tariff of generating companies, majority of components are already normatively determined or capped. o The rate of Return on Equity is fixed for projects by CERC at the beginning of the Control Period. The equity base to be used for calculating RoE is also capped at normative levels by CERC. The rate of depreciation allowed is also applied based on norms defined by the CERC. o The working capital base is also normatively defined and the interest on it is linked to market rates specified explicitly in the regulations to promote efficiency. o For optimal operational efficiency, project wise norms of NAPAF are also decided by CERC. o As regards the Operation and Maintenance 1 expenses, our submission on O&M expenses | (comments on Clause No. 21.7) clearly 1 demonstrates that the O&M expenses vary widely depending on site-specific & project specific | requirements like location remoteness, plant layout, socio economic conditions, technology etc. Thus, it is very difficult to decide on any further | normative value for O&M expenses. o The interest on loan is based on actual weighted 1 average rate of interest on loan portfolios of the I

	Clause	Options Proposed bvCERC	Nil PC's Comments
		normative parameters to induce greater efficiency during operation as well as in development phase.	company. In view of reasons explained in comments on Clause No. 19.5 (Cost of Debt), it would not be prudent to adopt a normative approach for estimating cost of debt as it exposes beneficiaries to interest rate volatility. • Thus, the existing approach of determining tariff based on mix of normative and actual parameters provides sufficient incentive for operational and financial efficiency
	14.6 (a)	Increase the useful life j of well-maintained I plants for the purpose of determination of depreciation for tariff;	• Reassessment of the life of assets - increase or decrease in life o Any increase or decrease in life of a plant would require conducting residual life assessment studies, whose results might give rise to disputes due to disagreement and subjectivity o We suggest that present system of useful life of hydro plants should be continued
	14.6 (b)	Continue the present approach of weighted average useful life in case of combination, ! due to gradual commissioning of units;	We recommend that the present method of useful life of hydro plants should be continued
Depreciation	14.6 (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.	» Extension of useful life to 50 years o It is pertinent to note that life of electromechanical components is not more than 35 years whereas for civil structures the life may be longer. o After completion of 35 years, the users enjoy the benefit of lower tariff as renovation and modernization needs to be carried out for electromechanical components only and zero depreciation is enjoyed by the beneficiaries for civil structures. o Further it is to be noted that the under-water rotary components in plants of Himalayan region suffer from heavy silt, which adversely affects the life of these components.

I opic	(lause	Options Proposed by C IJU	NIIPC's Comments
			o Procurement of electromechanical components designed for 50 years useful life would increase in capital cost of the plant, thereby increasing the tariff. o Therefore, we recommend that estimated life ' should be retained at 35 years.
	14.6 (f)	Reduce rates which will act as a ceiling.	(Reproduced from reply to Clause No. 10.5 (a)) • We recommend that the present method of depreciation and its linking to loan repayment be continued. • Any reduction will cause serious issues with generating companies' cash flows which will adversely affect their debt servicing capability
	14-6 (g)	Continue with the existing policy of charging depreciation. However, the Tariff Policy allows 1 developer to opt for I lower depreciation rate subject to ceiling limit as set by notified Regulation which [causes difficulty in I setting floor rate, including zero rate as depreciation in some ' oftheyear(s).	Option of reduced depreciation may be left to the generating companies depending upon their actual loan repayment portfolio. Issue is linked with repayment of debt.
Gross Fixed Asset (GFA) Approach	15.2	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.	It is reiterated that no depreciation should be applied on the equity invested and return on equity should always be allpwed on 30% of project cost. which is the normative level of equity invested by the developer. The suggested approach will significantly affect the returns to a developer, which will affect the investment in the sector. Considering, the need of further augmentation in hydropower capacity with penetration of renewable energy, it is imperative that the developers are allowed to build internal accruals for future investments. Thus, the existing approach of allowing return on GFA should be

Topic	Clause	Options Proposed by CMU	NI IPC's Comments
Debt:Equity Ratio	16.4	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.	continued, otherwise, the investors will be further discouraged from investing in the hydro sector. It is pertinent to emphasize that return on equity is allowed only after the date of commercial operation of a project. For hydro power generators, the long gestation period reduces the effective rate of return significantly by ~ 0.7% for each year of uncontrollable delay. In view of above, it is submitted that before thinking of making any changes in the equity base for working ou,t return on equity during the operations period, equity deployed during construction stage of the project may be allowed for calculating the return on equity. With increased leverage, since deployment of owner's equity reduces, the project financing risk of lenders increases, which is likely to result in higher interest rates on loan being charged. It may not be possible to procure funding on 80:20 basis, especially for hydropower projects having high gestation period. Increasing the leverage in a generating company's capital mix poses a higher risk for equity holders of the firm. Whereas interest on debt is a fixed income stream for the lenders, the return to equity holders comes only after discharge of such cost of debt obligations. The impact of change in debt to equity I ratio on expectation of return on equity can be ; demonstrated by reworking the CAPM using the recommended debt to equity ratio of 80: 20 for re- (levering the Un-levered Beta. The same has been I demonstrated in **Annexure C.** The required rate of | return on equity consequent to debt to equity ratio of 80: 20 works out to be 23.74% against 18.84% with debt to equity ratio of 70:30. In such a scenario, the benefits envisaged from leverage (on account of current interest rates being lower than return on equity) would be offset by higher requirement of return on equity, leading to potential increase in annual fixed charges. In addition to the increased risk for the generating company, an increase in leverage would result in

topic	,,. (lanse	Options Proposed , ,,,,,,,	NHP(s Comments
			increasiii" the exposure of beneficiaries to the risK of excessive volatility of interest rates. • The Tariff Policy 2016 also provides for a debt:equity ratio of 70:30 for financing of future projects. The proposed draft Tariff Policy issued in May 2018 carries a similar provision, which needs to be adopted in Tariff Regulations for the upcoming control period. • <u>It is therefore recommended that normative debt to equity ratio should not be modified to 80:20.</u>
Return on Investment	17.2	Section 61 (d) of the Electricity Act, 2003 and Para 5.11 (a) of Tariff Policy 2016 have laid down broad guiding principles for determination of rate of return. These have mandated to maintain a balance between the interests of consumers and need for investments while laying down the rate of return. It is stipulated that the rate of return should be determined based on the assessment of overall risk and prevalent cost of capital. Further, it should lead to generation of reasonable surplus and attract investment for the growth of the sector. As per the Tariff Policy, the Commission may 1 adopt either Return	• Under the RoE regime, the equity invested in a project continues to generate returns till the assets are under operation (GFA). However, in the case of RoCE the return is given on base that keeps on reducing (NFA). • Across sectors like aviation, where RoCE regime is followed, the returns are allowed even on Capital Works in Progress, implying returns are being allowed on under construction assets as well. In such an annrnarh rptiirn nn prmitv has tn V»P pnmtv <u>allowed during construction phase as well</u>, if RoCE i is to be followed. Considering the need of investment in the sector, it is imperative that sufficient returns are allowed to ' investors on the invested equity capital. As observed above, <u>adopting RoCE regime would imply a</u> the <u>reduction in returns, which would hamper forecasted investments into the sector.</u>

		Options Proposed bv(IIU	Nil PC's Common IN
		on Equity (RoE) or Return on Capital Employed (RoCE) approach for providing the return to the investors.	
Rate of Return on Equity	18.7(a)	Review the rate of return on equity considering the present market expectations and risk perception of power sector for new projects;	• Currently, a regulated return at rate of 15.50% / 16.50% is allowed for hydropower projects in India. Keeping in view the addition of more renewable sources in the grid, hydro sector is required to be developed in an expeditious way. In order to achieve the above target, an attractive rate of return on equity is essential for Hydro. • It is to be noted that since hydro power projects have long gestation periods, the <u>effective rate of return reduces to .13.13% for 5 year construction</u> j <u>period and ii,.68% of 7 year construction period.</u> | The detailed calculations are demonstrated in i **Annexure A.** • Any hydro project with gestation period beyond 5 ' years would give effective rate of return lower than transmission projects (3 years construction period), despite of being fraught with much higher risks. • In order to work out the risk perception of hydro j sector and work out commensurate required rate of ' return, we have adopted three methodologies **(Annexure A).** The summary of the three ' methodologies is as below: a. <u>Hydropower Sector - India using CAPM</u> i. Expected return on equity calculated using Capital Asset Pricing Model works out to **18.83%** b. <u>Other infrastructure sectors in India - Renewable Sector</u> 1. Effective rate of return works out to 13.40% for a construction period of 1 year and useful life of 25 years. 11. Based on the effective rate of return principle, <u>in order to match the effective rate of return of Hydro sector to Renewable sector, the return on equity works out to **i6.QO%** for 5 year construction period</u> and 19.68% for 7 year

(1 ail:SO	Options Proposed In CIRC	NUPC's Comments
		construction period, which are significantly higher than the return allowed for Hydro sector. :. <u>Other infrastructure sectors in India - Aviation</u> i. Regulated return on equity works out to 16.00%. ii. For an entity like airport which involves much lesser risk and lower gestation period than the hydro power plants, the allowed return is almost at par with the hydro sector. From the thorough assessment of allowed Return on Equity by factoring in risk perception and market expectations, it can be concluded that the existing allowed rate of Return on Equity is proving to be inadequate for hydropower generation business in India. <u>It is therefore pertinent to ensure that Return on Equity should either be enhanced or at least retained at the level of 16.50% to guard the power sector utilities against business and market risks</u>.
18.7 (b)	Have different rates of return for generation and transmission ! sector and within the generation and j transmission segment, have different rates of I return for existing and new projects;	• Discussed above
18.7 (c)	Have different rates of return for thermal I and hydro projects with additional I incentives to storage based hydro generating projects;	We agree with the proposal. There should be different rates of return for thermal, transmission and hydropower projects keeping in view the high risk & long gestation period associated with the development of hydro power projects. Further pondage / storage type hydro projects should be given additional return.
18.7 (d)	In respect of Hydro sector, as it ! experiences geological surprises leading to delays, the rate of return can be bifurcated into two	It is pertinent to note that the hydropower projects are delayed, generally owing to factors beyond the control of developer such as *location remoteness, hydrology, geology, plant layout, socio economic conditions, security and law & order issues* etc.

Topic	.,, Proposed (,m,SC byCliRC	Options	N i l PCs Comments
		parts. The first component can be assured whereas the 1 second component is linked to timely completion of the project;	• New land acquisition Act provides a very high rate of compensation for acquisition of land and the cost of land would increase significantly for new projects. • Hence, the existing mechanism of rate of return should be continued, with additional return for timely completion of projects.
	18.7 (e)	Continue with pre-tax return on equity or switch to post tax Return on equity;	• Present mechanism should be continued
	18.7 (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;	• Rate of RoE should be same irrespective of unit size.
	18.7 (g)	Reduction of return on equity in case of delay of the project;	• CERC has contended that while early completion of projects is incentivized by additional 0.5% RoE, there is no reduction in RoE in case of delay. Although this provision seems attractive but practically it has not been used as there are many challenges in completion of hydro power projects. • It is pertinent to mention that in case of delay, the developer's effective rate of return is automatically • reduced. Considering that no return is allowed during the construction period, the effective rate of return works out to: - 13.13% for construction period of 5 years and , useful life of 35 years - 11.68% for construction period of 7 years and ' useful life of 35 years Detailed calculations are demonstrated **Annexure A** • For Transmission sector, the effective rate works 1 out to 13.13% for 3 year construction period and useful life of 35 years, which is significantly higher compared to hydro projects which are delayed

	Options Proposed bvClRC	NUPCs Comments
Cost of Debt	19-5 (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 I differential cost of debt for the new transmission and generation projects; 19-5 (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	beyond 5 years. The detailed calculations are demonstrated in **Annexure A.** » As explained above, the effective rates of ROE in case of hydro power projects are significantly lower than the RoE allowed. Adoption of normative approach for determining cost of debt has been put across for discussion by CERC in view of the recent trends observed which seem to point towards falling interest rates and also the increase in corporate bond market activity. A careful analysis of key cost of debt indicators discussed by CERC is given below. a. JO *year Government Securities yield (G Sec rate)* - it has been plotted in **Annexure B,** from where it can clearly be observed that G Sec rate has increased from 6.4% in Jan 2017 to 7.99% in Jun 2018. The G Sec rates are also observed to be high in terms of volatility. **(Annexure B)** b. *Repo rate* - CERC refers that RBI's policy rate (Repo rate) have fallen from 8% in 2014 to 6% in August 2017 and have stayed at those levels ever since. However, if we factor in the most recent changes in monetary policy rates by RBI, it can be seen that for the first time since 2014, Repo rate has been hiked in June 2018 and it stands at 6.25%. The tightening of monetary policy is backed up with RBI's macroeconomic reasoning, including the efforts to tame increased levels of inflation. This clearly indicates that Repo rate may have already bottomed out. **(Annexure B)** c. *D4CLR rates* - CERC has also drawn reference to the new MCLR based regime, which has been developed as a mechanism to ensure passing on of lower repo rate to consumers. It can be seen from the trend of MCLR rates of leading PSBs **(Annexure B)** that after bottoming out in 2017, the MCLR rates are on the rise indicating increase is cost of borrowing. E.g., SBI's MCLR has risen from 7.95% in Nov 2017 to 8.25% in June 2018. **(Annexure B)** From the analysis above, it can be clearly observed that the interest rate trends after having a downtrend since 2014 have already started to reverse and the outlook is upward looking. This reflects high degree

'Iopic	Ola use	Opiums Proposed bvOLRC	NIIl'Cs Comments
			of volatility in the cost of debt expectations. Therefore, linking cost of debt to benchmarks such as G Sec rate, Repo rate or MCLR rates shall expose beneficiaries to risk of interest rate volatility and hence is not recommended. In present regulations, the reduced cost of debt due to refinancing is passed on to the beneficiary and we recommend that the same practice should be continued.
	19-5 Cb)	Review of the existing incentives for restructuring or refinancing of debt;	Further, the generating companies are required to submit truing up petitions with updated data on various parameters after the control period, limiting the benefits to period between refinancing and end of control period. Thus, we also recommend that the benefit of refinancing should be allowed to the company until the repayment of entire debt is done. We also suggest that the benefits of refinancing should be shared in the ratio of 1:1
Interest on Working Capital (IOWC)	20.3 (a)	Assuming that internal resources will not be available for meeting working capital requirement and short-term funding has to be obtained from banking institutions for working capital, whose interest liability has to be borne by the regulated entity, IWC based on the cash credit was followed during previous tariff period. Same approach can be followed or change can be made.	The current methodology of allowing interest on working capital has been debated and refined over the past control periods. A working capital base consisting of O&M expenses, spares and receivables is established. The interest on the same is allowed based on normative interest rate set based on base rate, plus a margin. This allows the generating company to maintain sufficient working capital, at the same time incentivizing the company to ensure efficiency in procurement of funds. Thus, the present approach of linking interest rate to benchmarks plus sufficient margin may be continued.
	20.3 (c)	While working out requirement of working capital, maintenance spares are also accounted for.	There are two types of spares - Mandatory spares (initial spares) and O&M spares. Mandatory spares or initial spares which are procured with mother equipment and is part of the capital eost. Meanwhile, the cost of carrying unutilized spares in inventory remains unfunded. The 15% of O&M added in IWC serves the purpose of expenses aaaea in xwc serves me purpose funding this inventory carrying cost, which needs to be continued.

Topic	Clause	Options Proposed *by* CT.KC	NHTC's Comments
	20.3 (d)	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 made part of working capital or O&M expenses. 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.	
Operation and ' Maintenance (O&M) expenses	**21.2**	For new hydro stations whose COD was declared during the tariff period 2014-19, the first year normative O&M has been specified as 4% and 2.5% of original project cost (excluding cost of R&R works) for stations less than 200 MW projects and for stations more than · 200 MW respectively.	• In accordance with the CERC tariff regulations, the O&M cost for new projects is linked to the capital cost. However, at a later stage norms are fixed by CERC based on actuals. Thus, it is not correct to say that projects with cost and time overrun get higher O&M. • It is worth mentioning here that unlike thermal 1 power stations, the O&M expense in case of hydro I power projects depend upon remoteness of location, j topography and other local social conditions. • NHPC is submitting details of O&M expenses in few of its projects where the O&M expenses allowed by CERC is lower than the actual expenditure incurred - by NHPC. A comparative statement of O&M

Clause	Options Proposed h\ CIRC	NI IPC's Comments
	But 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 &cost overrun get higher O&M..	expenses allowed by CERC under Tariff Regulation 2014 and actual expenditure incurred by NHPC for few plants is provided in **Annexure-D** for reference. <u>It can be seen that there is significant shortfall in actual O&M expenses vis a vis normative O&M expenses</u>. The difference between the actual and allowed O&M is <u>eroding the return on equity</u>, which is hampering company's ability to invest in future projects. It can be seen from summary below that effective post tax ROE after adjusting for shortfall has fallen below 15.5% for many plants from 2014 - 15 to 2016 - 17. <u>Therefore we recommend that O&M expenses should be allowed on actual basis subject to prudence check.</u>
	21.7 (a) Review the escalation factor for determining O&M cost based on WPI & CPI indexation as they do not capture unexpected expenditure;	
	21.7 (c) Review of O&M cost based on the percentage of Capital Expenditure (CC) for new hydro projects;	
Operationa 1 Norms -Hydro Generation	21.7(f) Have separate norms for O&M expenses on the basis of vintage of generating station and the transmission system. The existing Operational norms of Hydro generation include norms for auxiliary consumption, transformation losses and normative annual plant availability factor. Capacity Index as a measure of plant availability was	• Existing NAPAF should be reviewed only after I sufficient availability of data on operation of plants ' i.e. at least two control periods. • In the existing regulations, maximum NAPAF has been fixed at 90% for Pondage plants and 70% for | ROR Plants. Any further increase in NAPAF is not j desirable for following reasons: i. NAPAF should be fixed so that the generating company is encouraged sufficiently to effort for higher availabilities to get incentivized for a longer period and not the other way.

Proposed lõp.e bvCERC	Options Clause	NHPCs Comments
	implemented by the Commission during tariff periods 2001-2004 and 2004-09. It was based on the concept that hydrology risk has to be borne by 1 beneficiaries all the time. After consultation, capacity index concept was modified with the new concept of Normative Annual Plant availability Factor (NAPAF) during 1 2009-14 and continued during 2014-19 based on 1 actual data. However, in case of a few hydro plants the same was revised. This is based on the premise that hydrology risk is to be J shared by the generator & the beneficiary in the ratio of 50:50. There may be need for review of existing values of NAPAF 1 based on actual PAF data for last 5 years.	ii. The commission has already considered the role of flexible hydro power in the grid balancing due to the variability in renewable generation.
26.6.2	The norms of auxiliary power consumption of hydro generating station vary from 0.7% to 1.2% based on rotational or static 1 excitation system. The transformation losses	• A study of surface power stations of NHPC (7 power stations) with static excitation with IC less than 200 MW shows that average auxiliary consumption in last 4 years have been much higher than the normative (1%) prescribed in the Regulations (see **Annexure F).** • In all hydro projects, installations are more or less similar in nature. The auxiliary equipments are similar in power stations with higher or lower MW. '

	('lau.se	Options lVoposed I)V(I.K(	NNl'C \s (ominenls
		are covered as a part of auxiliary consumption.	As such, in case of small capacity power stations, the auxiliary consumption in percentage terms is higher. Accordingly, it is proposed that a sub category in Surface hydro generating stations may be provided for IC<200 MW with normative AUX as 1.7%
	27-5 (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;	Presently, an incentive of 90 paise/unit is being allowed to hydro power generation as incentive for generation beyond design energy (i.e. secondary energy). The rate of secondary energy should be DSM rate at 50 Hz. Considering the suitability of hydropower for balancing the grid, which needs 60:40 ratio mix of thermal and hydro to be secured to avoid outages caused by other generators, a better incentive provision is required for hydropower projects.
Incentive	27-5 (b)	Different incentive may be provided for off peak and peak period for thermal and hydro generating stations. Differential incentive mechanism for storage and I pondage type hydro I generating stations may also be considered.	In existing scenario, hydropower meets the peaking requirements of the grid. Accordingly, it is recommended to differentiate the rate of incentive during peak and off peak periods also. The rate of incentive should be linked with grid frequency and may be treated in line with DSM charges.
	27.5 (c)	Review the incentive and disincentive 1 mechanism in view of the introduction of compensation for operating plant below norms.	It is suggested that the amount of peak time incentive should be in addition to allowed AFC.
Implement I ation of I Operationa 1 Norms	28.2	Comments and suggestions of stakeholders are invited whether the operational norms of-the new tariff period should be implemented from the effective date of	The applicability of operational norms approved for the new tariff period between date of effectiveness of control period & date of tariff order. It is pertinent to note that the condition is equally applicable where the tariff orders have not yet been issued for previous control periods (2009-14 / 2014-19) owing to various reasons.

Options Proposed In CIRC	NHPC's ComiiK'nls
control period irrespective of issuance of the tariff order for new tariff period.	• In case of delay in notification Of tariff orders, the operational parameters notified for the control period are honored. • On similar lines, operational norms for new tariff period should be implemented from the effective date of control period irrespective of issuance of tariff order. • We agree with the idea put forth in the consultation paper.
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.	Late Payment Surcharge (LPSC) is a penal provision imposed only in cases of delay in payment of bills beyond 60 days from the invoice date. If LPSC is to be linked to MCLR while ensuring that it remains a deterrent, o LPSC should be reflective of MCLR plus spread plus penal rate. o However this might result in varying rates of LPSC for different entities as the spread would be different for each entity whose payment becomes due. o This may encourage selective default from the payer i.e. priority of payment would be directly proportional to applicable rate of LPSC for the payee. It is suggested that the current provisions of LPSC should be retained.
Further, as per the existing regulations, the rebate is provided if payment is made within 2 days of presentation of the bill. Valid mode of presentation of bill, (email, physical copy etc.), authorised signatory, definition of two days (working	• We recommend that Commission should streamline the billing and payment procedure / schedule. • We also suggest that billing formats should be standardized.

			Options Proposed bv(I K(	NHPC's Comnu'iils
			days or including holidays) may need elaboration.	
Standardization of Billing Process	32.1		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.	NHPC has a standard billing module under ERP system, which is enclosed as **Annexure G** for CERC's reference.
Commercial Operation or Service Start date	35-5		Comments and suggestions are invited from the stakeholders on possible options for dispute-free and practical mechanism for declaring commercial operation date.	• The existing regulation for declaration of COD in case of generating station / transmission system is generally in order. • In order to avoid any dispute between generating company & transmission licensee, <u>a joint tripartite certification of COD between generating company. transmission licensee & Central Electricity Authority be made mandatory in the new tariff regulations.</u> • All the three parties will prepare a detailed report on completion of installation of all components of generating station / transmission system before declaration of COD.
Alternative Approach to Tariff Design	37-6 (a)		Would it be advisable to undertake econometric analysis to arrive at benchmark capital cost?	• It is categorically stated that in case of hydro generation projects, the benchmarking of capital costs is not possible, as capital costs vary from project to project depending upon peculiarities for each project - <u>*location remoteness, hydrology. geology, plant layout, socio economic conditions*</u> • Variance in capital cost per MW for different hydro power plants is shown in **Annexure E.**

	Clause	Options Proposed byCERC	Nl IPC's Comments
			o Capital cost per MW varies significantly for similar projects as demonstrated below: ■ Pondage / RoR with Pondage plants: Average capital cost of INR 15.24 Cr per MW with a standard deviation of 6.98 ■ RoR plants: Average capital cost of INR 14.75 Cr per MW with a standard deviation of 9.36 o There are costs associated with socio economic development of area around hydro projects and this varies from state to state. o This demonstrates that no two projects can be compared on a similar scale, like in case of thermal plants of similar capacity. » Modelling each of the parameters or peculiarities (location remoteness, hydrology, geology, plant layout, socio economic conditions) may not be possible in an objective manner, as many of these are not quantifiable. » Therefore, econometric analysis or benchmarking for determination of capital cost is not advisable. especially for the hydro sector.
	37-6 (b)	What are the variables that should be considered for the purpose of determining Capital Cost on normative basis?	» As stated above, variables like *location remoteness. hydrology, geology, plant layout, socio economic conditions* would need to be considered, which is not possible in an objective manner.
	37-6 (c)	Any other methodology for benchmarking the capital cost for generation and transmission projects?	For hydro sector, each project is different as discussed above, and hence benchmarking is not possible.
Normative Tariff by fixing each component	37.15	Hence, the generator has approximately three years duration beyond CoD for	In our view, the existing provision for allowing additional capital expenditure beyond cut-off date should be retained.

Topic	Clause	Options Proposed byCEKC	NHPC's Comments
of AFC as a percentage of total AFC		additional capitalization. Therefore, in order to provide regulatory certainty, the "Additional Capitalization" could be strictly restricted to the period between "CoD" and the "Cut-Off Date". This would imply that the "Capital Cost" as on "Cut-Off Date" would remain unaltered for the rest of the useful life of the plant. However, any reasonable expenditure in future, such as cost towards meeting new environmental norms etc. if considered uncontrollable / unavoidable may be treated as a separate stream of revenue and recovery could be allowed as a separate component on annuity basis.	
	37-17	Whether isolation of "Additional Capitalization" as a separate stream of revenue would provide for recovery of AFC on a normative basis in realistic terms?	• The methodology for calculating the separate stream of revenue is not clear and we propose that a detailed methodology may be proposed.
	37-17 (e)	Alternatively, do you suggest any other methodology to treat	

Topic	,V| Proposed byCFRC	Uai,se Options	N11PCs Comments
		"Additional Capitalization" for determination of AFC on normative basis?	
Principles of Cost Recoverv-Approach 1 towards Multi-Part 1 Tariff	37-20	The proposition is to i introduce the system of differential AFC recovery linked to peak and off-peak periods in the following manner:- a. Off-peak component of AFC: The generating station has to declare a PAF of 8o%... b. Peak component of AFC: The remaining20%... c. The peak and off-peak months... i. Recovery of 80% of AFC. upon declaration of 8o% PAF during the year and remaining 20% of AFC upon achieving 95% PAF during the peak period, say of 4 months. ii. Higher peak price (i.e. by 25% over the off-peak price)	• In case of ROR Power Plants, achieving 95% PAF in peak period and 80% PAF in off-peak period is not possible due to inherent feature of ROR as it runs continuously on the same load depending on availability of water.
	37.21 (a)	Does the proposal of differential recovery of AFC by segregating into peak and off-peak periods balance the	• Introduction of differential tariff for peak & off-peak periods should be done only if the peak period incentive is allowed over & above the determined for that period. • Further, declaration of peaking month may not be feasible in case of hydro power projects due to its

Proposed 1 opic bv C L'RC''''	'M (muse	Options	NlIPC's Comments
		need for both the buyers and sellers?	water discharge characteristics & site specific conditions. • In view of above, the implementation of differential tariff for peak & off peak period should be considered on daily basis.
Relaxation of Norms	39-1	The present regulatory framework provides for specifying normative operational parameters. However, there may be situations where the normative level due to the site specific features such as FGD, Desalination plant, increase in length of water conductor system etc. may lead to power consumption in excess of the norms. In such situations, the present regulatory framework provides for relaxation of norms.	• Relaxation of norms for operational parameters should be continued, depending upon site condition and project specific issues.
CrOOfl<5 flUfJ \JvUUO U.1J.VJ. 1 K_JV^X V Ivv J. CUV (GST)	42.1	Goods and Services Tax (GST) has been introduced which has replaced various Central and State level taxes. Accordingly, prudence check of impact of pre- GST and post-GST taxation regime on the costs may be required for determination of tariff in the next control period.	• Impact of GST on capital cost and O&M expenses should be cohsidered as pass through

Annexure A

a. Expected Rate ofRoE based on CAPM for Indian Hydro Generating Entities

Capital asset pricing model (CAPM) is the most widely used method to estimate the required rate of return. According to this method, the expected rate of return on equity can be calculated as:

Ra = Rf+[j3x(Rm-Rf)]

Where:

Ra = Expected rate of return

Rf = Risk-free rate

jB = Beta of the security

Rm = Expected return on market

For estimating the rate of return on equity using CAPM, following steps were followed:

- •Calculate historical market returns for the past 9 years (2009 <- 2017) using BSE Sensex data to determine Rm
- •Calculate risk free rate for similar period of 9 years using 10 year govt, bond yields
- •Es •Estimate the Beta for NHPC Ltd. using data of listed Indian hydro CO] generation companies]

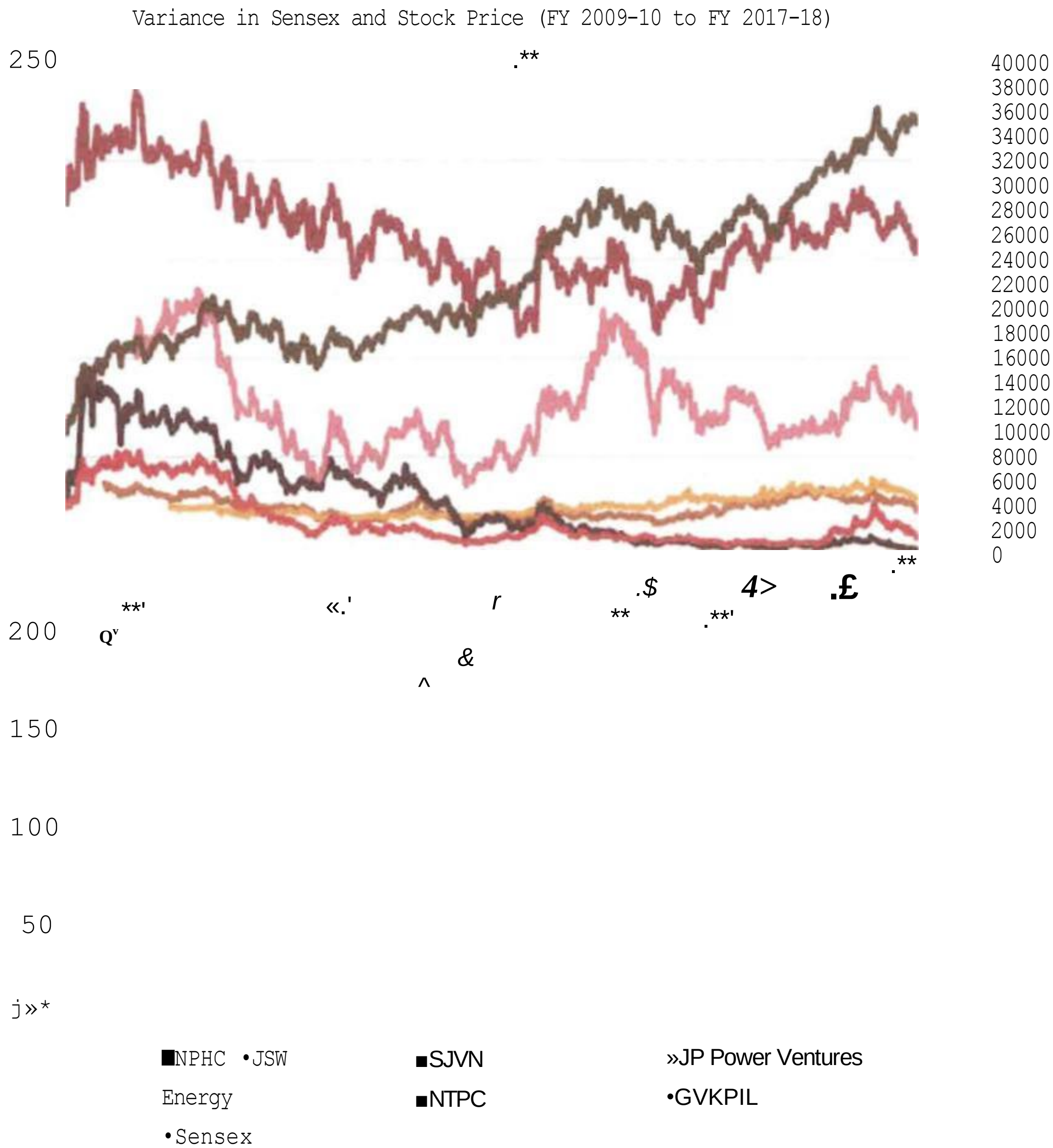
The beta for NHPC Ltd. has been estimated as depicted below:

The unlevered beta is then calculated using the following formula:

Unlevered Beta = *(Levered beta ot equity beta)/((l +* ((1 - *tax rate)x(debt/equity))}*

(i) Calculation of market return

The market return has been estimated based on historical data of returns of BSE Sensex over past 9 years from FY 2009-10 to FY 2017-18. The data has been taken for 9 years to exclude the outlier effect caused by global recession during FY 2008-09.



The market return for a period from FY 2009-10 to FY 2017-18 is 16.07%. ***(ii)***

Calculation of risk free rate based on 10-year government bond yields

The risk free rate for India has been estimated based on yield on average yield of 10-year government bond over past 9 years. The data has been taken for 9 years to exclude the outlier effect caused by global recession during FY 2008-09.

10 year bond yield (FY 2009-10 to FY 2017-18) 7.78%

10.0%
9.0%
8.0%
7.0%
6.0%
5.0%

The Risk free rate (Rf) based on 10-year Indian government bond yield for 2009-17 works out to be 7.78%.

(Hi) Estimation of expected Beta for NHPC Ltd.

The un-levered beta for transmission sector in India has been calculated as below:

*\

NHPC Ltd.	0.72	0.59	30%	0.509
SJVNLtd.	0.37	0.19	30%	0.329
Jaiprakash Power Ventures Ltd.	1-43	Q.91	30%	0.874
JSW Energy Ltd.	1-35	1.27	30%	0.718
NTPCLtd.	0.72	1.03	30%	0.417
GVK Power and Infrastructure Ltd.	1.34	8.62	30%	0.191
Overall Average				**0.506**

- For NHPC, data used from Sep 2009 - Mar 2018, since it got lusted in Sep 2009
- For SJVN, data used from May 2010 - Mar 2018, since it got listed in May 2010
- For JPPV, data used from FY 2009-10 to FY 2017-18, consistent with Rf and Rm
- For JSW Energy, data used from Jan 2010 - Mar 2018, since it got listed in Jan 2010
- For NTPC, data used from FY 2009-10 to FY 2017-18, consistent with Rf and Rm

For GVKPIL, data used from FY 2009-10 to FY 2017-18, consistent with Rf and Rm

The unlevered beta works out to be 0.506.

The average un-levered Beta for all Indian hydro generation players is levered using financial leverage for NHPC Ltd. to give expected Equity Beta.

Re-levered Beta = Un-levered Beta x (1 + ((1 - Tax Rate) x (Debt/Equity))) =
0.506 x (1 + (1-0.30) x (70/30)) = 1-33

Thus, the Beta for calculation for expected return for NHPC Ltd. is estimated at 1.33. ***(iv)***

Estimation of expected Rate of Return for NHPC Ltd,

Expected rate of return = Rf + [p x (R_m *- Rf)]

= 7.78% + [1.33 x (16.07% - 778%)]

= 18.83%

Thus, it can be observed that using the CAPM method, the expected return works out to be 18.83%. much more than the existing number of 16.50%.

b. Expected Rate ofRoE based Return on Equity Allowed in Other Infrastructure Sectors in India

(i) Aviation

Airport Economic Regulatory Authority of India (AERA) sets Fair Rate of Return (FRoR) for a control period is based on weighted average cost of capital.

- Cost of equity, for a control period is estimated by using the Capital Asset Pricing Model (CAPM) for each airport operator
- Cost of debt is based on forecast cost of existing debt and forecast cost of future debt to be raised during the control period

FRoR = (g x Rd) + ((i-g) x Re)

The return allowed to private airports in the country is listed in the table below:

s.\<>. SoLipc-		Amiiu-i	,, ,
1	Indira Gandhi International Airport., Delhi	**16.0096**	AERA's order on determination of Aeronautical Tariff for IGI Airport, Delhi for second control period (2014-19)
a	Chhatrapati Shivaji International Airport, Mumbai	**16.00%**	AERA's order on determination of Aeronautical Tariffs in respect of Chhatrapati Shivaji International Airport, Mumbai for the first Regulatory Period **(2OOQ-14)**
3	Rajiv Gandhi International Airport, Shamshabad, Hyderabad	**16.00%**	AERA's order on determination of Aeronautical Tariffs in respect of Rajiv Gandhi International Airport, Shamshabad, Hyderabad for the first control period (2011-16}
4	Kempegowda International Airport, Bengahiru	**16.00%**	AERA's order on determination of Aeronautical Tariffs in respect of Kempegowda International Airport, Bengaluru, for the first Control Period **(2011-16)**

It can be observed that for an entity like airport ivith limited geographic spread and lesser risk, the allowed return of 16% is almost par with the hydro generation business

Effective RoE

For construction of Hydropower projects in India, there is a significant delay in start of scheduled operation. Considering the prevalence of delays in mind, we have considered two scenarios for calculation of effective RoE. Scenario 1 considers a construction period of 5 years and scenario 2 considers a construction period of 7 years. Both the scenarios consider the useful life of the project as 35 years.

(i) Scenario 1

<u>Assumptions</u>

Project Construction time period - 5 years Useful Life: 35 years Equity infusion during the construction period is as follows:

In Rs Crores

1	0	10	10	5
a	10	15	25	17.5
3	25	25	50	37.5
4	50	30	80	65
5	80	20	100	90

I \ \ \ I '35

Start of construction | io years | 15 years | 20 years | 25 years | 30 years | years | 39 years

........Return @ 1650% ....

5years

Operation Period (UieAil Life)

«"No return •■•*« ....

Con»t. Period Delay

BB 18 3 -1 5 * 7 8 9 to.—17 18 19 20 It 32 23 24 25—32 33 34 35 30 37 38 39 4°

inflow/ Outflo -10 -15 -25 -30 -20 16.5.16.516.5:16.5:16.516.5 16.516.516.516.516.5:16.516.5 16.516.5 16.5 16.5:16,5 16,5 16.516.516.5 16.5

JRR IS-**

■Effective return @ 13.13%

(ii) Scenario 2: Construction period of 7 years

<u>Assumptions</u>

Project Construction time period - 7 years Useful Life: 35 years

Equity infusion during the construction period is as follows:

In Rs Crores

1	0	10	10	5
2	10	10	20	15
3	20	15	35	27.5
4	35	15	50	42.5
5	50	20	70	60
6	70	20	90	60
7	90	10	100	95

r

r loyears I5years wyears 25years 3oyears 35years

Start of construction | 7 years | 42years

« ......No return •■►«• .... Return® 16.50% ....

Const. Period | Operation Period (UsetulIJfe)

1 a 3 4 5 6 7 8 9 10.......17 18 19 20 ai 22 23 24 as........39 33 34 35 Sfi—39 *W V* 42

Inflow/ Outflow -10 -10 -15 -is -20 -20 -10 16.5 16.5 16.5 16.5 16.5 16.5 16.5 16.;j 16.5 16.5 16.5 16.6 *l6l* 16.5 16.5 16.5 16.5 16.6 16.5 16.5 1

IRK 11,68%

♦ ..... ■ Effective return @ n.6856 ....

d. *Renewable Sector*

Similar to the effective rate of return worked out above, for Renewable sector with allowed RoE of 14% during operations period works out to **13.40%,** considering useful life of 25 years.

r+

Start of construction   lyear   6 years   10 years   16 years   20 years   25 years   26 years

*"No return ■► *..Return @ 14.00%.. ►

^ºTM'j   OpenHouPeriodCUsBAaUft)

1 a 3 .1 5 11 - » o 10 11 is 15 n 13 16 IT i» 19 lu

si u £j 3.1 11 3('

^^ -100 1 4 M 1 4 > 4 1 4 1 4 1 4 1 4 1 4 1 4 » 4 M M 1 4 1 4 M 1 4 1 4 1 4 1 4 M 1 4 » 4 > 4 1 4 M 1 4

1.1.40%

•Effective return @ 13.40%

If similar effective rate of return is to be earned by Hydropqwer plants, the allowed RoE should be as follows:

1	5 years	13.40%
2	7 years	13.40%

Transmission Sector

Assumptions:
Project Construction time period - 3 years
Equity of 100 lakhs is phased in the ratio of 4o96:40%:2o96 during the period of construction
No equity addition during the project life
Useful Life: 35 years

Start of construction   3 yean   I   10 years   !   15 years   20 years   25 years   30 years   3Syears   38years

"No return ► *.........................   Return @ 15.50% ....

Const. Period I 3   Operation Period (UMhd Life)

3 * 9 4 s v in.—a id ui ai si «9 a) SM oa™js m aA M .IT as a*

Inflow/ I

Satflw , -Ja -i ~ 'ss 155 15- is-n lu;; ISJ; ts-B «y; «J; «■» >H >5-s >s« '5-s »w ^-S «-S «s "s-s 15-5 «>i i£g its

pw   13.13%

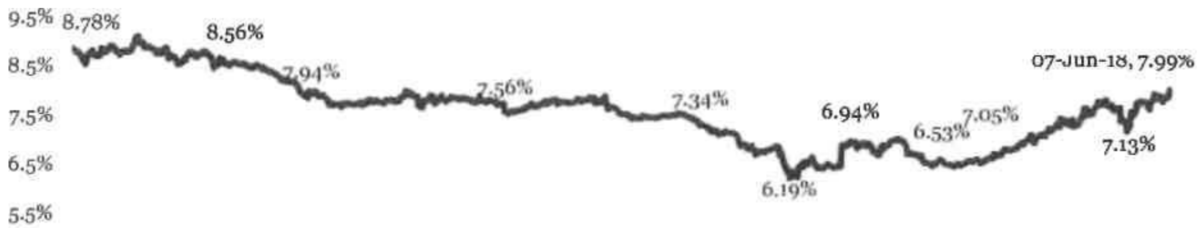
«...Effective return @ 13.13% .... *

Effective return for a transmission project comes at 13.13% considering no return during the construction period.

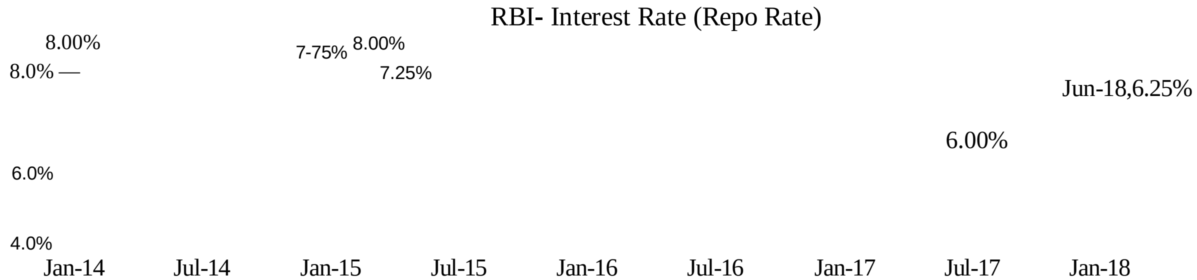
Annexure B

Key Cost of Debt benchmark indicators

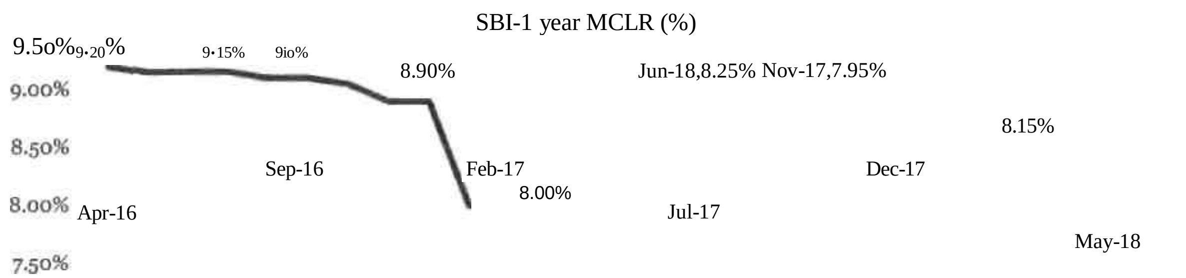
a) Historical data of India's 10 year Govt. Bond yield



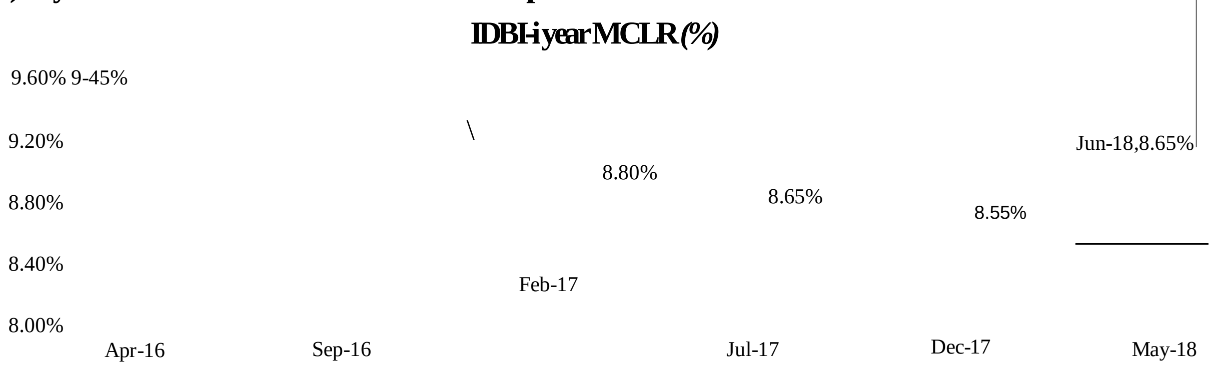
b) Historical trends of RBI determined Repurchase Rate (Repo Rate)



c) 1 year MCLR of State Bank of India since April 2016



d) 1 year MCLR. of IDBI Bank since April 2016



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Annexure C

Estimation of expected Rate of Return for NHPC with resetting of debt to equity ratio to 80: so

The expected return on equity in the Indian hydropower sector based on revised debt to equity ratio of 80: 20 is demonstrated here. The un-levered beta for hydropower sector in India, as demonstrated in Annexure A is reproduced below.

NHPC Ltd.	0.72	0.59	30%	0.509
SJVNLtd.	o.37	O.19	30%	0.329
Jaiprakash Power Ventures Ltd.	1-43	0.91	30%	O.874
JSW Energy Ltd.	1-35	1.27	30%	O.718
NTPC Ltd.	0.72	1.03	30%	0.417
GVK Power and Infrastructure Ltd.	1-34	8.62	30%	0.191
Overall Average				**0.506**

- For NHPC, data used from Sep 2009 - Mar 2018, since it got listed in Sep 2009
- For SJVN, data used from May 2010 - Mar 2018, since it got listed in May 2010
- For JPPV, data used from FY 2009-10 to FY 2017-18, consistent with Rf and Rm
- For JSW Energy, data used from Jan 2010 - Mar 2018, since it got listed in Jan 2010
- For NTPC, data used from FY 2009-10 to FY 2017-18, consistent with Rf and Rm
- For GVKPIL, data used from FY 2009-10 to FY 2017-18, consistent with Rf and Rm

Equity Beta

The overall average unlevered beta for all hydropower players works out to be 0.506, which is levered using modified proposed financial leverage f8o: 20") to give expected Equity Beta.

Re-levered Beta = Un-levered Beta x (1 + ((1 - Tax Rate) x (Debt/Equity)))

= 0.506 x (1 + (1-0.30) x (80/20))

= **1.924**

Expected Rate of Return on Equity

Expected rate of return = Rf + [p x (Rm - Rf)]

= 7.78% + [1.924 x (16.07% - 778%)] =

23.73%

Annexure D

Table-I.A Under recovery in O&M Expenses & its effect on post tax ROE in the tariff period 2014-19

Old Power Stations - FY 2014-15

Amount ? In Cr

SI No.	Power Station	Normative O&M allowed in tariff	Actual O&M Exp.	Shortfall	Normative ROE allowed in tariff	Effective ROE (after adjustment of shortfall in O&M Exp.)	
(1)	(2)	(3)	(4)	(5H4-3)	(6)	(7)=(6-5)	
1	Salal	144.30	191.73	47.44	75.64	28.21	5.78%
2	Tanakpur	71.02	97.86	26.84	15.82	-11.02	-10.80%
3	Uri-I	74.19	96.20	22.01	168.45	146.44	13.48%
4	Chamera-ll	72.57	91.24	18.66	101.25	82.57	13.46%
5	Dulhasti	137.47	195.33	57.87	327.80	269.94	13.59%
6	Sewa-ll	61.58	66.02	4.44	49.21	44.77	14.10%
	Total	**561.12**	**738.39**	**177.27**	**738.17**	**560.91**	

Table-I.B Under recovery in O&M Expenses & its effect on post tax ROE - Otd Power Stations - FY 2015-16

Amount ? In Cr

SI No.	Power Station	Normative O&M allowed in tariff	Actual O&M Exp.	Shortfall	Normative ROE allowed in tariff	Effective ROE (after adjustment of shortfall in O&M Exp.)	
(D	(2)	0)	(4)	(5W4-3)	(6)	(7H	6-5)
1	Salal	153.88	188.73	34.85	76.24	41.39	8.41%
2	Tanakpur	75.73	117.88	42.14	15.83	-26.31	-25.76%
3	Uri-I	79.12	110.76	31.64	168.72	137.08	12.59%
4	Chamera-ll	77.39	90.41	13.02	101.33	88.31	14.38%
5	Dulhasti	146.60	187.02	40.42	327.80	287.38	14.47%
6	Dhauliganga	76.59	98.76	22.17	77.90	55.73	11.80%
7	Teesta-V	88.49	119.33	30.84	186.21	155.37	13.77%
8	Sewa-ll	65.67	71.77	6.11	49.21	43.10	13.58%
	Total	**763.47**	**984.67**	**221.19**	**1003.23**	**782.04**	

Table-I.C **Under** recovery In O&M Expenses & its effect on post tax ROE-Old Power Stations - FY 2016-17

Amount fin Cr

SI No.	Power Station	Normative O&M allowed in tariff	Actual O&M Exp.	Shortfall	Normative ROE allowed in tariff	Effective ROE (after adjustment of shortfall in O&M Exp.)	
(D	(2)	(3)	(4)	(5)=(4-3)	(6)	(7)=(6-5)	
1	Salal	164.11	229.50	65.40	77.24	11.85	2.38%
2	Tanakpur	80.77	139.50	58.74	16.15	-42.59	^0.89%
3	chamera-l	121.29	139.99	18.70	107.02	88.32	13.62%
4	Uri-I	84.38	140.77	56.39	169.12	112.74	10.33%
5	Rangit	52.05	61.26	9.21	30.99	21.78	11.59%
6	Chamera-ll	82.53	119.30	36.77	101.52	64.75	10.52%
7	Dulhasti	156.34	247.01	90.67	327.80	237.14	11.94%
8	Dhauliganga	81.68	127.83	46.15	78.00	31.84	6.74%
9	Teesta-V	94.37	145.70	51.34	186.84	135.50	11.97%
10	Sewa-ll	70.03	80.77	10.74	49.21	38.47	12.12%
	Total	**987.64**	**1431.64**	**444.10**	**1143.89**	**699.79**	

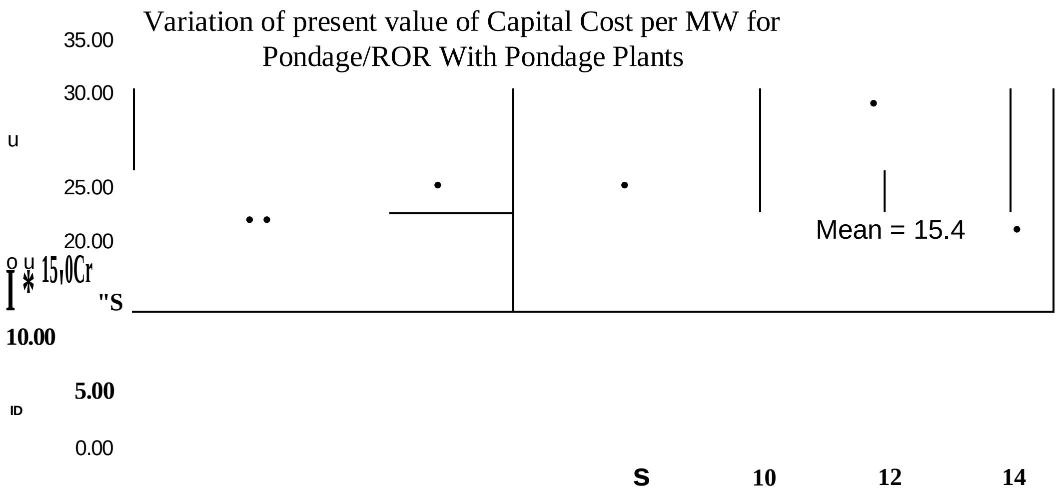
Annexure E

a. ***Variation qf present value qf Capital Cost per MWfor Pondage/ROR with Pondage Plants***

<u>Assumptions</u>

- The original capital cost of the projects is escalated at the rate of 7% per annum to arrive at 2018 values i.e. the present value of capital cost
- In cases where different units of the same plant have been commissioned at different years, year of COD of the last unit has been considered

SI. No.	Niimi' of I'ow vv SI;ilion 1 oration	Original (apilal < o s l (I N K (i-M D)	YIMI-OI' COD of liISI 1 nil	I'ri'M'iil \A Inc. of (npilal (OSl (INK (.) (\)	Installed (';i|>aril\ (V1W)' (15)	(>rigi.n;i.l CaptLal < osl (in INK(i-) per M\\ (l;= 1). D)	I'rrsi'iil \alur of (apiial (osl (iii INK O) per MVV (C= \ B)
1	BairaSiul/HP	143.2	1982	1636.02	l8o	O.80	909
2	Chamera -1 / HP	1969.8	1994	9991.35	540	3-65	18.50
3	Chamera - II/HP	1956.1	2004	5043.77	300	6.52	16.81
4	Chamera-III/ HP	1992-5	2012	2990.16	231	8.63	12.94
5	Dulhasti /J&K	5078.5	2007	10689.47	390	1302	27.41
6	Sewa - II /J&K	1079.2	1079	1854-21	120	8.99	1545
7	Dhauliganga / Uttarakhand	16314	2005	3931.42	280	5-83	14-04
8	Rangit /Sikkim	475-9	2000	1608.34	60	7-93	26.81
9	Teesta-V /Sikkim	2619.6	2008	515344	510	5-14	10.10
lO	TLDP-III/WB	1790.4	2013	2511.17	132	13.56	19.02
11	TLDP - IV/ WB	1793.2	20l6	2053.08	160	11.21	12.83
12	Nimmo Bazgo/ J&K	946.0	2013	1326.84	45	21.02	29-49
13	Parbati - III / HP	2538.6	2014	3327.64	520	4.88	6.40
14	Kishanganga	5755-2	20l8	5755-24	330	17.44	17.44
	TOTAL PONDAGE/ RORwith PONDAGE	29769.6		57871.86	3798	7.84	15.24



We can observe that present value of capital cost per MW varies significantly across plants with a, standard deviation of **INR** 6.Q8 Cr per MW, Therefore, this demonstrates that no two proiects can be compared on a similar scale, like in case of thermal plants of similar capacity.

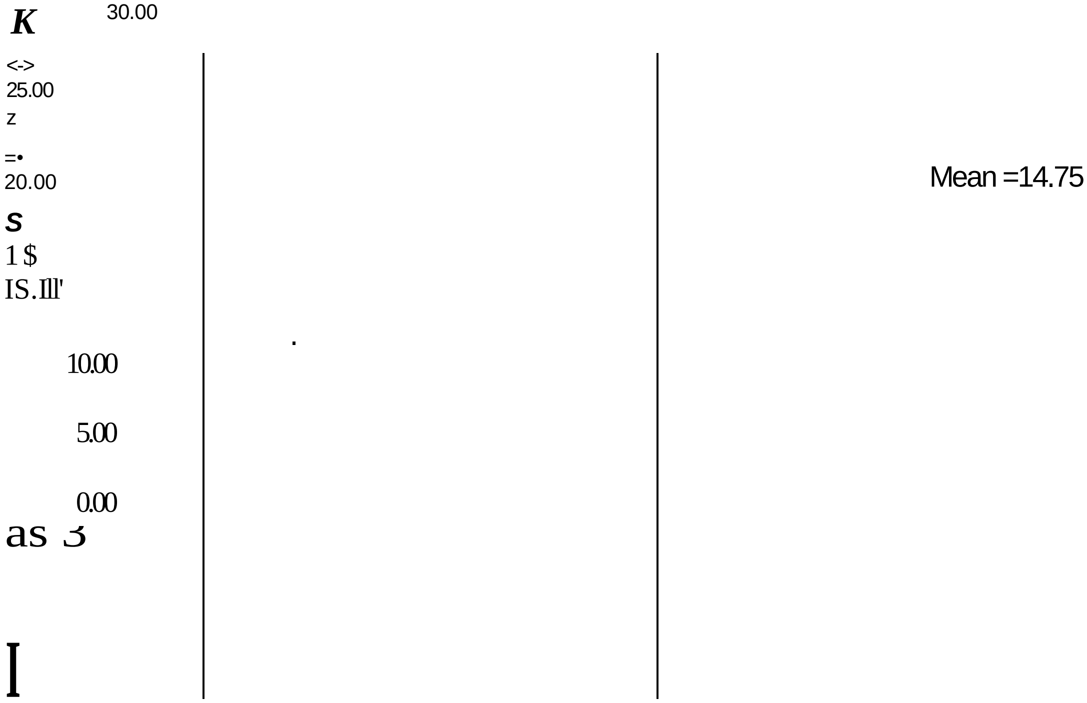
b. Variation Of present value of Capital Cost per MW for ROR Plants

Assumptions

- The original capital cost of the projects is escalated at the rate of *7%* per annum to arrive at 2018 values i.e. the present value of capital cost
- In cases where different units of the same plant have been commissioned at different years, year of COD of the last unit has been considered

SI. No *	\;IIIIC of I'lnvcr Station /1 oration	i.M'lt^llliM Capital (bsl (INK I V) (i f)	^ ear of COO<>l lasl 1 nil	lYi-sciil \aim- ol Capital (osl (INK Cr) (\)	Installed (apacil\ (MW) (1!)	Original (aptial (osl (in INK (1) per A1W (1 1)	Prcsi-nl \ aluc (il (aplial (Osl (in (NK Cr) pec MW ((\ 1?)
1	Salal/J&K	803.4	1995	3808.59	690	1.16	5.52
2	Uri -1 / J&K	3166.x	1997	13109.60	480	6.60	27.31
3	Chutak/J&K	814.0	2013	II41.69	44	18.50	2595
4	Tanakpur/ Uttarakhand	357.7	1993	1941.28	94-2	3.8o	20.6l
5	Uri -11/ J&K	2158.3	2014	2829.14	240	8.99	11.79
TOTAL ROR		7299.6		22830.31	1548.2	4.71	14.75

Variation of present value of Capital Cost per MW for ROR Plants



We can observe that present value of capital cost per MWvariRSKiflnifirantly across plants with a, standard deviation of INR Q.36 Cr per MW. Therefore, this demonstrates that no two projects can be coin pared on a sunilar scale, like in case of thermal plants of similar capacity.

Ai

Annexure F

Average auxiliary consumption in last 4 years

SI \o	Name of tin- Povv t'f Station	Installed (lap ac.it> (M \\ )	1\))(.' ()f 1'OWL'I' Station	No *n* native \u\i liars (onsumption	201.4	cilia! Auxiliar \(uiisumplio -1,"	>	('I)lIM! 2()l--l8 ('	Au\ ii|)tior, *i)*
1	Bairasiul	**180**	Surface Power Station With Static Excitation Syatem	1.0%	**2.3%**	2.0%	1.1%	1.1%	1.6%
2	Loktak	**105**		1.0%	**2.4%**	2.3%	2.5%	2.3%	2.4%
3	Tanakpur	**94-2**		1.0%	**1.8%**	2.6%	2.7%	2.2%	2.3%
4	Rangit	**60** ;		1.0%	**1.5%**	1.0%	0.8%	0.8%	1.0%
5	Sewa-II	**12Q**		1.0%	**1.3%**	1.7%	1.1%	1.0%	1.3%
6	TLDPIII	**132**		1.0%	**1.856**	2.4%	1.6%	1.6%	1.9%
7	TLDP-IV	**160**		1.0%	-	-	1.3%	1.4%	1.4%
T( )tal		**851.2**							**1.70%**

NHPC Ltd.
(A Schedule 'A' Enterprise of Govt, of India)
NHPC Office Complex, Sector 33, Faridabad - 121003

NH/Comml./FInance cell/

Speed Post/Courier

INVOICE NO.	NH/JK/1050
INVOICE DATE.	09-JUI-2018
BILL FOR :	Jun 2018
TYPE OF BILL.	PROVISIONAL

To.

THE EXECUTIVE ENGINEER,
JAMMU
LOAD & DESPATCH, METERING AND
TESTING(LDM & T DIV)GLADNI, NARWAL,
JAMMU-180001
JAMMU AND KASHMIR

Sub. :- Bill for the month of Jun 2018 In respect of power stations in the Northern Region of NHPC.

Sir,

Please find enclosed the bill for energy supplied from NHPC power stations In the Northern Region during Jun 2018 on the basis of provisional ABT based REA received from NRPC vide its letter dated OWUL-18.

This also includes RLDC charges for the Month of Jun - 2018.

Payment may be released expeditiously

S.No.	Power Stations	Bin Amount	Amount Eligible For Rebate
1 2	SALAL	123,510,368	123,510,368
3	TANAKPUR	10,460,303	10,460,303
4 5	CHAMERA-I	18,954.579	18,954,579
6 7	URI	105,134.641	105,134,641
8 9	CHAMERA-II	34,633,469	34,633.469
10	DHAUUGANGA	28,142,326	28,142,328
11	DULHASTI	151.441.433	151,441,433
12	SEWA-II	0	0
13	CHAMERA - III	0	0
	CHUTAK	0	0
	NIMOO BAZGO	0	0 81,313,174
	URI - II PARBATI-	81,313,174	37,054,284
	III	37.054.284	
TOTAL(Princlpal) Billed TOTAL(Intereat) Billed		590,644,579	590,644,579

Outstanding

Description	Previous Balance	Amount Billed	Payment Received	Rebate Allowed	Adjustment	Outstanding
Principal	7,584,575,157	(^590,644,579	60,800,000			8.094,419,736

Grand Total:

Late Pavment Surchaae	648,962,847	62,855,642				711,818,489

8,806,238,225

ज़ि.ल.
09/07/18

<tt

iMSJCOMffM aurohage amount shown above is exclusive of surcrtage on principal amount or Re. uto.^-w«W,«2|007 short received from J&K through bonds for the period from 01-OcWOOI till date
BffDMe: M.01.2012

For NHPC
v ,-"""r
) *I I* «>^0>{£

Au th orlzodSlgn atory Telefax No. -0126-2254868 Ertol. as above CC:-

Development Commissioner, Power Development Department, J&K Government, Grid Sub-Station, Janlpur, Jammu Tawl (J&K) The Chief Engineer (Survey and Commercial.) Power Development Department, Gladnl Grid Station, Narwal, Jammu(J&K) Chief Engineer, NHPC Umlted, Liaison Office, Ualsdn & Project Services Complex, Railway Siding, Near New FruH Market, Jammu Tawl -180 012.

NHPC Ltd.
(A Schedule 'A[1] Enterprise of Govt of India)
NHPC Office

Address of Beneficiary	BILL FOR	Jun2018
THE EXECUTIVE ENGINEER,	BILL TYPE	PROVISIONAL
JAMMU LOAD & DESPATCH, METERING AND TESTING(LDM & T DIV)GLADNI, NARWAL,	BILL NO	103B00520181050
JAMMU -180001 JAMMU AND KASHMIR	BILL DATE	06^July-2018
GST No.:	HSN No. :	27160000

PROJECT **SALAL**

SALAL POWER STATION.PO JYOTIPURAM VIA REASI, DISTT. RIAS1182312 - REASI JK IN - INDIA

PROJECT **GST** No.: 01AAACN0149C3ZB

Date ot commercial Uperation	COD	19950401		Energy Charge Rate - AC-Normative	ECR_NOR	0.616	KS/KWH
Project age	|P_AGE	23	year	Energy Charge Rate - AC-Actual	ECR.ACT	0.613	Rs/KwH
Annual DE	ADE	3082.000000	MU	Secondary Energy Charge Rate	SE_RATE1419	0.900	Rs/KwH
Auxilliary Consumption-Normative	ACJJOR	1.000	%	Plant Availability Factor (or the Month	PAFM	102.977	%
Auxiliary Consumption-Actual	ACJ\CT	0.600	%	Saleable Design Energy for the month -AC-Actual	SLDEIVLACT	412.780368	MU
Annual Fixed Charges Billed	AFC	330.622800	Cr	Saleable Design Energy for the month	SLDEM	411.119280	MU
Normative Plant Availability Factor	NAPAF	60.000	%	Saleable Capacity Share	CS	22.390	%
Saleabe Annual design energy	SLDE	2685.038400	MU	No of days for the month	NDM	30	Days
Saleabe Annual design energy-AC-Actual	SLDE.ACT	2695.887040	MU	No of days in year	NDY	365	Days
Project Scheduled Energy prev year	PSCH_PY1	3082.693626	MU				
Project Scheduled Energy prev to prev year	PSCH_PY2	3235.747407	MU				

(A) Power Statioivwise Energy Calcu ation for the snth of 018)

Scnedulea Energy	PSCH	468.758741	MU	Project Energy Charges @§C"ft	P£C_DE_ECR	253503652	Rs
Free Energy	PFP	57.226838	MU	Capacity Charges	PCC	233195507	Rs
Saleable Energy	PSLE	411.531903	MU	RLDC Charges	PRLDC	368615	Rs
Project Saleable Energy upto DE - AC - Actual	PSLE_DEJ\CT	412.780368	MU	**Total** Charges	PTC	487067774	Rs
Project Saleable Energy upto DE	PSLE_DE	411.531903	MU				
Saleable Energy upto DE@ECR	PSLE_DE_ECR	411.531903	MU				

(B) Beneficiary-wise Power Calculation In (MU)

Description		*Prev Jun-2018*	*NewJun-2018*	*Jun-2018*
Beneficiary Scheduled Energy	**BSCH**	**U.U0UUUU**	**161.206131**	**161.206131**
Free Power	**BFP**	**0.000000**	**57.226838**	**57.226838**
Saleable Energy	**BSLE**	**0.000000**	**103.979293**	**103.979293**
Benif Saleable Energy @ECR	**BSLE_DE_ECR**	**0.000000**	**103.979293**	**103.979293**

(C) Bill Details for the Month ol *Jun-2018*

	Description		*Pnv Jun-2018*	*New Jun-2018*	*Jun-2018*
i 2 3	Benil Energy Charges upto DE @ECR	BEC_DE_ECR	0 0	64,051,244	6^,051,244
	Beneficiary Capacity Charges Benef RLDC	BCC		59,332,357	59,332,357
	Charges	BRLDC		126,767	126,767
Total Charges				**123,510/368**	**123.510,** *W]*

(D) Outstanding ■ Principal (Rs)

Description	Previous Balance	Amount Billed	Amount Received	Rebate Allowed	Adjustments	Total Oustandin
Principal	1,372,563,189	123,510,368	80,800,000	**0**	0	1,415,273,557

Jw.

CP^Gfc^WcM"^ ♦Aejco^sc*^

As:

1 PCC ■ (0.5 * AFC' 1,00,00,000 (PAFM (NAPAF)' (NDM / NDY))

2 ECR =0.5* AFC'10/SIDE

3 ECRJVCT*AFC*0.5'10/8LDE_ACT

4 GAIN_ON_AC - (ECR_NOR-ECR_ACT) * BSCH MOOOOOO * 40%

5 M_ECR ■ IF (MJUJE *0) THEN 0 ELSE 0.5 * AFC * 10 / (M_AOE * (1 - AC0914 /100) * (1-FREE_POWERf100))

6 BEC_DE_ECR ■ BSLE_DEJECR * ECR * 10,00,000

7 BEC_DE_MECR"BSLE_PEJIECR*MECR' 10,00,000 B

BCC"PCC'CS/(10O-FREE_POWER)

CPrashant Ag

Cad^)

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At