एनएचपीसी लिमिटेड
(भारत सरकार का उद्यम)
NHPC Limited
(A Govt. of India Enterprise)

आज़ादी का अमृत महोत्सव

भारत 2023 INDIA

विभागाध्यक्ष (वाणिज्यिक),
एनएचपीसी कार्यालय परिसर,
सेक्टर33-, फरीदाबाद
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(आई एस ओ 9001/14001/45001 प्रमाणित)/ (ISO9001/14001/45001 Certified)

पत्र संख्या: NH/Commercial/2023/566 दिनांक: 31/07/2023

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

Sub:-Comments on Approach Paper for Terms and Conditions of Tariff for the period commencing from 1st April 2024 - Reg.

Ref:- Public Notice No L-1/268/2022/CERC dated 26.05.2023
Public Notice No L-1/268/2022/CERC dated 13.07.2023

Sir,

In reference to above referred public notices, comments / suggestions of NHPC on Approach Paper for Terms and Conditions of Tariff for the period commencing from 1st April 2024 are enclosed for further necessary action. The soft copy of the same has also been emailed to tariff-reg@cercind.gov.in.

Thanking You,
Encl: As above

Yours Sincerely,

31/07/23

(M K Gupta)
Group General Manager (Comml.)

एनएचपीसी
NHPC

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(भारत सरकार का उद्यम)
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आज़ादी का अमृत महोत्सव

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सचिव
केंद्रीय विद्युत नियामक आयोग,
तीसरी और चौथी मंजिल, चंद्रलोक बिल्डिंग,
36 - जनपथ, नई दिल्ली- 110 001
फैक्स: 011-23753923

Sub:- 1 अप्रैल 2024 से शुरू होने वाली अवधि के लिए टैरिफ के नियमों और शर्तों के लिए दृष्टिकोण पत्र पर टिप्पणियाँ

Ref:- Public Notice No L-1/268/2022/CERC dated 26.05.2023
Public Notice No L-1/268/2022/CERC dated 13.07.2023

महोदय,

उपरोक्त संदर्भित सार्वजनिक नोटिस के संदर्भ में, 1 अप्रैल 2024 से शुरू होने वाली अवधि के लिए टैरिफ के नियमों और शर्तों के दृष्टिकोण पत्र पर एनएचपीसी की टिप्पणियां / सुझाव आगे की आवश्यक कार्रवाई के लिए संलग्न हैं। इसकी सॉफ्ट कॉपी tariff-reg@cercind.gov.in पर भी ईमेल की गई है

धन्यवाद,

संलग्न: उपरोकतानुसार

सादर,

31/07/23

(एम के गुप्ता)
समूह महाप्रबंधक (वाणिज्य)

COMMENTS/ SUGGESTIONS OF NHPC ON APPROACH PAPER ON TERMS AND CONDITIONS OF TARIFF REGULATIONS FOR TARIFF PERIOD 01.04.2024 TO 31.03.2029

NHPC Ltd.

NHPC OFFICE SECTOR 33 FARIDABAD

July 2023

Contents

1. Introduction

Tangible and Intangible benefits of hydro power plants

In recent decades, India has made significant achievements in the energy sector by introducing various policies and reforms to support the deployment of renewable energy in the country as well as to ensure electricity access to all its citizens. India is on the path of clean energy transition, guided by the Nationally Determined Contribution (NDCs) targets, with an aim to reduce emission intensity of its Gross Domestic Product (GDP) by 45% by 2030 and achieve net zero carbon emissions by 2070. India also aims to install electricity generation capacity of 500 gigawatts (GW) i.e. 50% of generation capacity from non-fossil sources by 2030. Going ahead, bridging the demand-supply gap in an optimal manner remains a critical barometer for the socio-economic development of the country. Over the years, the energy requirement as well as the peak demand in the country has been constantly rising owing to improvements in standards of living, rising income, expanding economy, urbanization and industrialization and this trend is expected to continue in the future. As per CEA, the all-India total energy consumption is expected to reach 1610 BUs by FY 2026-27 i.e. at a CAGR of 7.18% from FY 2021-22 to FY 2026-27 and a further 2133 BUs by FY 2031-32 i.e. at a CAGR of 5.79% from FY 2026-27 to FY 2031-32. In response to the projected increase in demand, the role of generation planning remains fundamental in ensuring that India continues to move along the 'zero deficit' trajectory. There is a need to constantly reassess these forecasts based on the impact of geopolitical realities and policy measures in the energy sector.

The importance of Hydro power has increased especially in view of the commitment of the Government to achieve 500 GW of non-fossil fuel power by 2030. There are various inherent benefits of Hydropower that makes it lucrative for investors to invest in. The same are summarised as follows:

a) **Clean source of energy**- Hydropower is a clean and green source of energy with limited carbon emission (primarily by storage projects). A study of nearly 500 global hydropower reservoirs by International Hydropower Association (IHA) in 2021 found the median value of emissions intensity (amount of GHG emitted per unit of energy produced) for **hydropower to be 23 gCO2 eq/kWh compared to the 820 gCO2 eq/kWh and 490 gCO2 eq/kWh released by coal-based and gas-based power plants** respectively.

b) **Benefits of multipurpose dams**- Hydropower projects with multipurpose dams contribute to flood control and irrigation by regulating the downstream flow of water. They also have other benefits like creation of navigation facilities, development of fisheries, drinking water supply, ground water recharging, recreation and tourism, and associated employment generation.

c) **Black start capability**- Hydropower plants do not need any outside source of power to start. This allows system operators to provide auxiliary power to other generation sources that could take hours or even days to start.

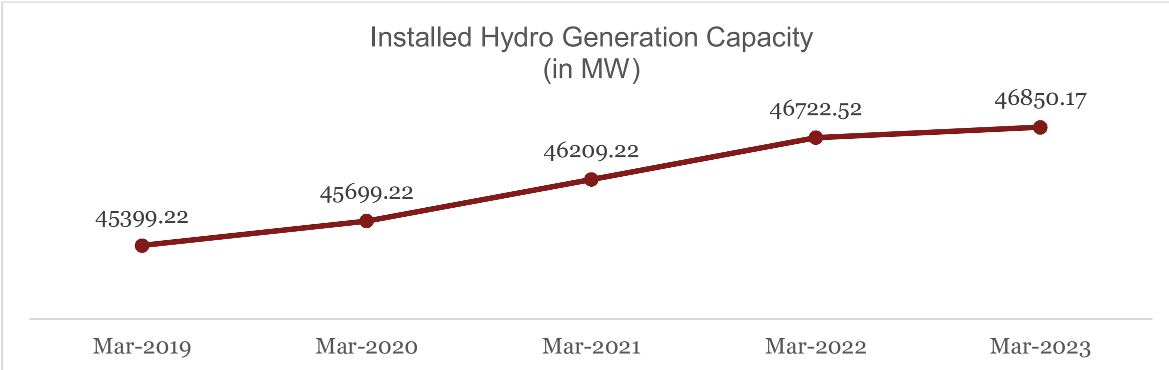
d) **Peak shaver asset**- The ability of hydropower plants to quickly change their output helps them to serve peak demand.

e) **Low operating cost**- Hydropower plants have a low operating cost, almost half of that of the thermal power plants.

f) **Long economic life**- The plant life of hydropower projects is normally in the range of 40–50 years. In fact, their operating life can be increased to 100 years through timely renovation and modernisation, which also helps in higher revenue generation for investors.

g) **Socio-Economic Benefits**- Hydropower development provides several socio-economic benefits including job creation, drinking water supply, flood moderation, tourism and recreation, development of remote and backward areas, royalty income to state governments, etc.

Hydro Power also has a critical role to play in balancing the Solar and Wind Energy so that the Grid stability is maintained. Hydro projects would contribute to achieving the power generation target from non-fossil fuel and additionally, act as a balancing force for the other intermittent energy sources like wind and solar, which constitute the major part of the power generation from non-fossil fuel. For this, the viability of the Hydro Projects needs to be analysed by calculating the costs and benefits at a systemic level, rather than at the level of individual consumer or single project. The Government has accorded a high priority to the stability of the grid - in view of the higher share of intermittent power in the energy mix. As per CEA, the installed generation capacity of hydropower has increased by 1450 MW only in the last 5 years as shown in the chart below.



Recognizing this important role of Hydro Power in the future and to address the issues impeding hydro power development, a few policy initiatives have been taken.

Further, GoI has published the guidelines to promote development of Pump Storage Projects considering their usefulness in maintaining grid stability and facilitating VRE integration. For this GoI has identified relevant sites with a potential of 73 GW for development of PSPs and indicated the same to different agencies. Also, as per CEA, as on 31.3.2023, ~30 GW of hydro generation capacity is in different stages of execution and may come up in next 5-6 years.

In order to achieve the ambitious target of 500 GW of RE by 2030, the impetus for hydro generation is needed along with the solar and wind generation. With a substantial exposure in power sector, the lenders would require assurances about recovering their debts. Therefore, an environment of regulatory certainty and gaining investors' confidence will be a key factor for developing the hydro generation sector.

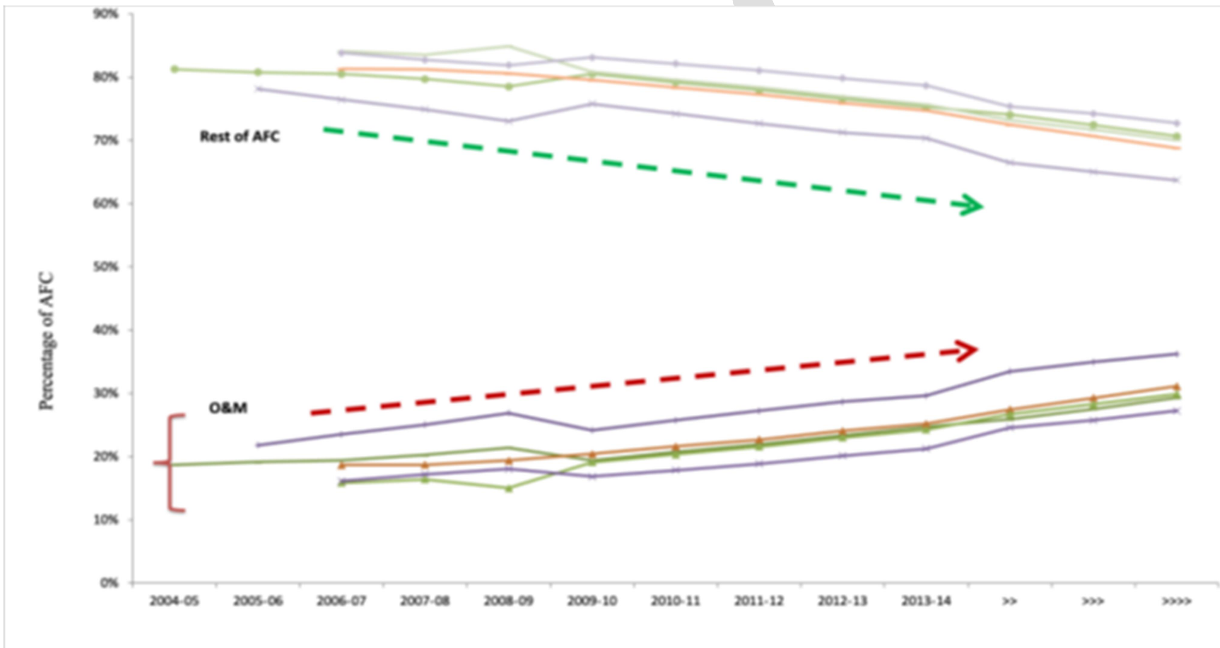
2. S. No. 3.1: Tariff Determination – General Approach

Summary of the Issue

The Power Sector has been evolving and has witnessed different phases of development requiring different approaches to the tariff design. Historically, a cost-of-service approach was adopted wherein the utilities were assured of full recovery of reasonable expenses along with the pre-determined returns that were embedded in the tariff. The cost-plus tariff allowed comfort to utilities and other investors that were in business with such utilities. This comfort is important for continuing the development of the power sector. Over the years, the Hon'ble Commission has gradually shifted from the cost-of-service model to a more efficient hybrid approach wherein most of the components of the tariffs are allowed on a normative basis irrespective of actual costs. This gradual shift has helped the utilities to get used to the new approach and make relevant changes in their approach.

The Hon'ble Commission while framing the Tariff Regulations for 2019-24 period, in its Approach Paper had carried out a study of 30 generating stations to analyse the trends of various AFC components and to see whether these components follow a specific trajectory. The observations made by the Hon'ble Commission noted that components of AFC were clustered as follows:

- AFC Component that increases over a period – O&M Expenses
- AFC Components that decrease over a period – rest of AFC components



1. From the past data it was observed that there are variations in some of the cost determinants, and if a normative regime is to be adopted for the AFC Components to incorporate the impact of various factors like change in ACE (additional capital expenditure), market dynamics, etc the following factors are to be duly accounted from time to time:
   - Weighted Average Rate of Interest
   - Interest on Working Capital
   - ACE
2. Apart from the Y-o-Y variation which could be station specific, a normative tariff for these stations would only be feasible only when the tariff determined is asset specific.

3. The advantage of adopting a normative tariff approach is that the tariff determined is very close to the actuals and hence, eliminates the chance of a major gain or loss and eliminates the need for periodic tariff filings.

The approach to be followed for the Normative approach is as follows:

4. **Existing projects (For existing generating stations that have been in operation for more than five years)**:

The normative tariff is calculated through the following steps:

- The capital cost as on 01.04.2024 is considered for the determination of the tariff for FY 2024-25. The AFC components for the base year (FY 2024-25) can be determined individually and then clubbed under the following two categories:
    a. AFC excluding O&M expenses
    b. O&M expenses
- Once the above two major components of AFC are determined for FY 2024-25 (Base Year), the above two components for the rest of the years of the tariff period shall be determined for the project based on specified indexation.
- The indexation factor for the N+1th year shall be calculated based on AFC for N+1 year divided by the AFC for the N year and the indexation is then determined for the period based on the ACE for the previous year.
- The indexation specified can be with regard to the previous year, i.e. AFC component for the Nth year/AFC component for the (N-1th year).
- Post expiry of each tariff period, the Commission shall call upon relevant data and revise only the indexation factor pertaining to "AFC excluding O&M component" approved at the time of tariff determination for each Project for each year. There shall be no revision to the indexation with regard to O&M expenses pertaining to the past tariff period.
- The Commission may issue a combined Order specifying the station-wise revised indexation factor and based on the revised indexation of the past tariff period, generating station can refund/recover the differential amount as done presently.
- Further, in case any additional capitalisation is incurred or is required, the petitioner may file a separate petition seeking approval of capital expenditure and once such capital expenditure is allowed, the variation on account of additional capitalisation on the AFC can be serviced by first computing the impact on the AFC and then adjusting the same through the same indexation mechanism as specified above.

- Energy Charges are already allowed based on normative performance parameters and actual fuel costs and are proposed to be continued.

5. **For New Projects**: (COD on or after 1.4.2024 or projects that are yet to complete operations for 5 years as on 1.4.2024)
   - The capital cost can be approved on actual basis up to cut-off date. Further, additional capitalisation post cut-off date can be allowed on normative basis.
   - The tariff components of AFC shall be determined and trued up on actual basis till the financial year in which the cut-off date of such generating stations ends.
   - Thereafter, from 6th financial year onwards, the above AFC categories can be determined based on indexation mechanism as proposed for the existing projects.
6. The approach for **the Performance Based Hybrid Approach** is as follows:
   - The second alternative to further simplifying the tariff determination process is to continue with the current practice of tariff determination with more AFC components being allowed on a normative basis.

Options Proposed

The Paper proposes the following:

- **Approach 1**: Shift to a normative tariff, wherein, once capital costs are approved on an actual basis after prudence check, all other AFC components are determined on normative basis.
- **Approach 2**: Further simplification of the existing Performance Based Hybrid Approach, wherein on the basis of admitted capital cost, AFC components can be approved based on actuals or norms as may be specified for the control period. Further, additional capitalization may be allowed on certain counts on a normative basis.

Our Recommendation

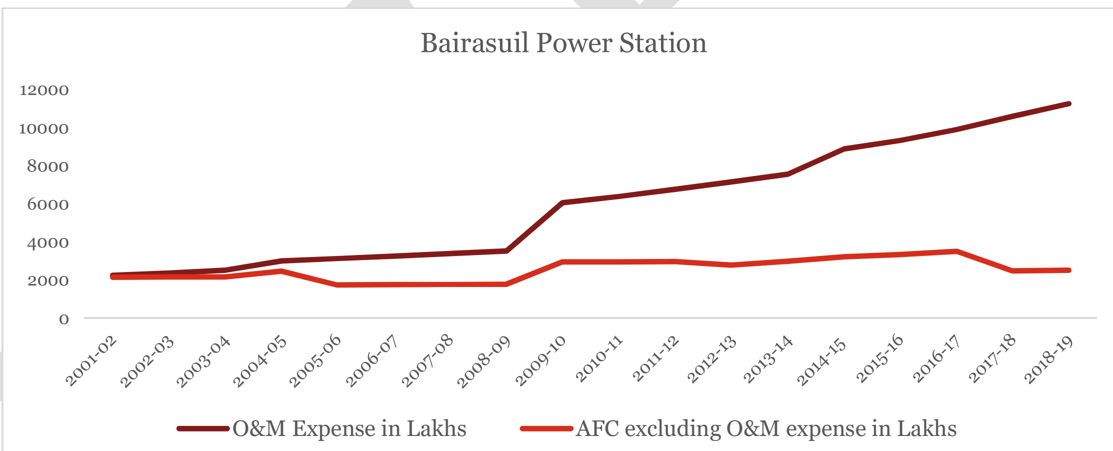
1) In case of the **Normative approach**, we are of the view that the indexation would not work as different assets and different projects especially hydro power plants have different issues and thus the rate of increase and decrease of various components varies plant to plant basis. Further, the indexation factor is being calculated on the basis of the determined tariff only and are then being trued up based on the additional capitalization, which is being done presently as well. Thus, the additional calculation of indexation factor will further increase the complexity of tariff

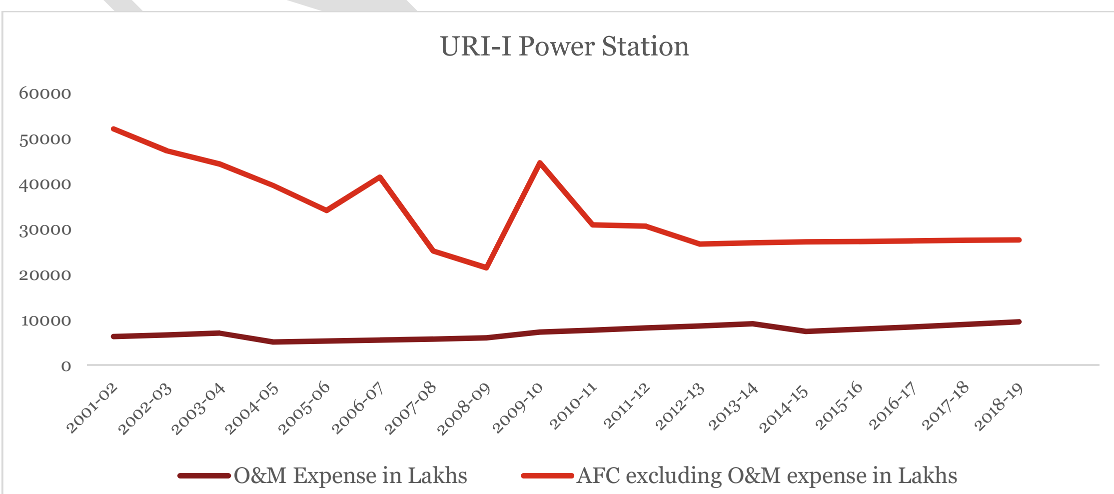
determination. Moreover, the current approach followed by the Hon'ble Commission follows normative approach for all the components of AFC for hydro power plants except the interest on loan component. The interest on loans cannot be calculated on a normative basis, hence, we are of the view that the first approach is not fit for the Hon'ble Commission to follow.

2) To further our argument regarding lack of effectiveness of the 'Normative Approach', we have taken the example of two hydro power plants "Bairasuil Power Station" and "URI-I Power Station" which are operational for more than 5 years.

We have considered the AFC from FY 2001-02 to FY 2018-19 for both the hydro power stations and separated the AFC components as:

- AFC Component that increases over a period – O&M Expenses
- AFC Components that decrease over a period – rest of AFC components





From above graphs of two hydro generating stations, a clear divergence in the trendlines of both components, i.e. O&M Expenses and AFC components excluding O&M Expenses can be noted. In the case of Bairasuil Power Station, the AFC cost excluding O&M expense is increasing along with the O&M expense, instead of decreasing as proposed in the Normative Approach, whereas, in the case of URI-I Power Station, the AFC cost excluding O&M expense is decreasing with fluctuations and O&M expense is increasing steadily as proposed in the Normative Approach. This divergence in the AFC components, especially in the AFC components excluding O&M expenses is present across all other hydro generating stations of NHPC, which signifies that the Normative Approach is not feasible for the hydro generating stations.

3) The second approach i.e. **the Performance Based Hybrid approach** proposed by Hon'ble Commission is similar to the current approach followed by the Hon'ble Commission. In case of hydropower plants, most of the parameter of AFC are determined on normative basis:
   - ROE is based on flat rate on normative equity,
   - Depreciation for 12 years is as per rates in regulation and spread out thereafter,
   - O&M expenses are provided on normative basis based on actual expenses of previous 5 years,
   - Working Capital is calculated on normative values and does not change as per actual fuel expenses and rate of interest on working capital is also on normative basis (SBI 1 Year MCLR + 350 basis points)
   - Interest on loan is calculated based on actual weighted average rate of interest on loan which is presently the only actual component in tariff calculation.

4) As evident from above, the second approach is similar to the current approach followed by the Hon'ble Commission i.e. all components are calculated on normative basis except Interest on Loan, which is computed as per actual weighted average rate of interest of the loans of the project or the company as a whole.

5) NHPC is of the view that the Hon'ble Commission may explore the option to link the interest on loan with reference rate providing sufficient cushion to protect interest of generation utilities. The same can be linked with the benchmark rates by

   a) allowing normative rate of interest of 250 basis points above the average State Bank of India Marginal Cost of Funds based Lending Rate (MCLR) (one year tenor) prevalent during the period October to March of previous financial year along with actual FERV to be reimbursed to the developer, or

b) allow normative rate of interest of 450 basis points above the State Bank of India Marginal Cost of Funds based Lending Rate (MCLR) (one year tenor) prevalent during the period October to March of previous financial year and the developer shall bear the risk of FERV.

Hence, it is proposed that Hon'ble Commission should continue with the existing approach and can further simplify the existing approach by adopting normative approach for rate of interest on loan instead of weighted average rate of interest on loan based on actual portfolio.

3. **S. No. 4.2.3: Reference Cost for Approval of Capital Cost – Benchmark Cost v/s Investment Approval Cost**

Summary of the Issue

The approval of capital costs that has been debated while framing earlier Tariff Regulations is the reference cost that needs to be considered while approving the capital costs. Currently, the methodology used for reference cost is the Investment Approval Cost, which can be replaced by the Benchmark cost.

However, in the absence of a better reference/ benchmark cost due to the paucity of reliable data and the complexities and difficulties involved, the Commission in previous control period has relied on Investment Approval for approving capital costs. With regards to hydro generating stations, the costs significantly vary from one generating station to the other generating station depending on several aspects such as choice of technology, design, reservoir based/Pondage/ROR, etc. and hence one benchmarked cost may not be the true representation of all such plants based on which actual costs can be disallowed.

Options Proposed

The Paper discusses the following:

- Shifting to benchmark/reference cost for prudence check of capital cost. However, credible benchmarks may not be available.

The Paper also invites comments and suggestions on the following:

- Other efficient reference costs that can be considered for prudence checks

Our Recommendation

Determining the capital costs of hydro generating stations involves various methods and factors that can vary depending on the location, project size, design, and other specific considerations. Currently, according to **CERC Tariff Regulations 2019,** the components considered while calculating the capital cost for hydro generating plants shall include the following:

- **Project Size**: The installed capacity of the hydroelectric generating station is a significant factor influencing the capital costs. Larger projects may have higher capital costs but lower capital cost per MW due to the scale of construction and equipment required.
- **Technology and Design**: The type of hydroelectric technology and design, such as run-of-river, reservoir, or pumped storage, affects the capital costs. Different designs involve varying construction requirements, civil works, and equipment choices, which impact the overall cost estimation.
- **Civil Works and Infrastructure**: The cost of civil works, including dam construction, intake structures, penstocks, powerhouses, and transmission infrastructure, is an essential component of the capital costs and varies as per site location.
- **Electro-Mechanical Equipment**: The cost of turbines, generators, transformers, control systems, and other electro-mechanical equipment needed for power generation is a significant component of the capital costs and varies as per head and design discharge of the project.
- **Land Acquisition and Environmental Factors**: The expenses associated with land acquisition, rehabilitation and resettlement, environmental impact assessments, and mitigation measures are considered when estimating capital costs.
- Cost of approved rehabilitation and resettlement (R&R) plan of the project in conformity with National R&R Policy and R&R package as approved; and
- Cost of the developer's 10% contribution towards Rajiv Gandhi Grameen Vidyutikaran Yojana (RGGVY) and Deendayal Upadhyaya Gram Jyoti Yojana (DDUGJY) project in the affected area.
- **Hydrological factors:** Key hydrological factors which affect the capital cost that are considered by CERC include catchment characteristics, streamflow data, flow duration curves, design flood, reservoir operation, sediment management and climate change impact.

Here are some common methods used to estimate the capital costs of hydroelectric projects across the world:

1) **Engineering Cost Estimates**: Detailed engineering studies and cost estimates are conducted by experts in the field, considering factors such as site preparation, civil works, equipment costs,

transmission infrastructure, environmental considerations, and project management. These estimates provide a comprehensive breakdown of the capital costs.

Examples of countries where such estimates are commonly performed include the United States of America, Canada, Brazil, China, and Norway.

2) **Cost Indexing**: Cost indexing involves using historical data and cost indices to adjust previously completed projects' costs to current prices. It accounts for inflation and market fluctuations over time.

   For example, cost indexes are used to update hydroelectric project costs in countries like the United Kingdom, Australia, Germany, Japan and South Africa.

3) **Benchmarking**: Comparing the costs of similar hydroelectric projects recently completed or under construction can provide valuable reference points. Benchmarking allows for the identification of cost trends, potential cost savings, and project-specific adjustments.

   Countries like Norway, Canada, Brazil, China, and the United States of America often serve as benchmarks due to their extensive experience and significant number of completed hydroelectric projects.

4) **Parametric Estimating**: Parametric estimating involves developing cost models based on specific project parameters such as installed capacity, dam height, reservoir volume, turbine type and construction methods. These models are then used to estimate the capital costs based on the chosen parameters.

   For instance, it is applied to estimate the capital costs of hydro stations in countries like France, Russia, Colombia, Ethiopia and Vietnam.

5) **Comparative Cost Analysis**: Comparative cost analysis involves comparing the costs of different types of hydroelectric stations (e.g., run-of-river, reservoir, pumped storage) or different technologies (e.g., Francis turbine, Kaplan turbine) to identify the most cost-effective options for a specific project.

   Examples of countries with different types of hydroelectric stations where comparative cost analysis can be applied include Norway (reservoir-based projects), Nepal (run-of-river projects), and Switzerland (pumped storage projects).

6) **Financial Modelling**: Financial modelling incorporates factors such as interest rates, financing terms, and project timelines to estimate the capital costs and potential returns on investment. It considers factors beyond the construction phase and provides a comprehensive view of the project's financial feasibility.

Countries like the United States, United Kingdom, Canada, Germany and Australia are examples where financial modelling is commonly used.

7) **Industry Reports and Studies**: Consulting reports, industry studies, and market research publications provide insights into the current capital costs of hydroelectric projects. These reports often provide cost ranges and trends based on global or regional data.
   Examples of countries with comprehensive industry reports and studies on hydroelectric projects include the United States, China, Brazil, Canada, and India.

As we can observe that except the "Engineering Cost Estimates" method and "Parametric Estimating" method for determining the capital cost, all other methods used in different countries across the world requires competitively discovered prices spanning across multiple market players which are determined rigorously for specificities of each asset and updated with high frequency which requires a robust database.

Apart from this, it is important to note that capital costs for hydroelectric projects can vary significantly depending on local factors, such as geographical conditions, regulatory requirements, labour costs, and the availability of construction materials. Therefore, local expertise and detailed analysis are crucial for accurate cost estimation. Along with these factors there are other parameters which vary from one hydro generating stations to the other hydro generating stations such as the choice of technology, design, reservoir based/Pondage/ROR, etc as mentioned above.

Every hydro project is unique in nature and quite location-specific and therefore has different sort of features in combination such as underground power house or surface power house, scattered or compacted sites, storage or run-of-river, head race tunnel or dam toe etc. which significantly affects the cost and construction period of project even of same magnitude/capacity. Therefore, the cost of two projects can't be compared based on historical data/similarity/magnitude/benchmarking. Therefore, we are of the view that Investment Approval costs approved by GOI or the Company Management which is arrived only after in-depth technical & financial evaluation by various specialised Govt. agencies like CEA, CWC, CSMRC, GSI, PIB, CCEA, etc can only be considered as prudence check for the project cost.

Considering the above facts, we request CERC to continue with the existing approach of considering reference cost as per the Investment Approval.

4. S. No. 4.2.1: Interim Tariff

Summary of the Issue

The entire fixed charge throughout the life cycle of a project is dependent on the approval of capital cost by the Commission. The Commission has been approving the capital cost of the projects on a case-to-case basis after carrying out due prudence. Currently, the utilities seek approval of the capital cost of new projects on an anticipated basis, which helps utilities minimise the time gap between the commissioning of the project and the generation of cash flows by means of tariff.

Options Proposed

The provisions for interim-tariff can be continued in the next tariff period as well.

Our Recommendation

In the present CERC Tariff Regulations 2019, no interest is allowed for the time period between COD of the plant till the date of issuance of order by the Hon'ble Commission. The present provision of interim tariff reduces the time gap between the actual COD of the project and the generation of cash flows. Further, it allows the generating station to claim the interest of the differential tariff almost right after the COD of the project. The interim tariff can be allowed by the Hon'ble Commission at the time of COD of the project which can be determined either based on the initial investment cost or hard cost of the project or as per the Investment Approval. **Therefore, Hon'ble Commission is requested to continue with the provisions for determination of interim-tariff in the next tariff period as well.**

5. S. No. 4.2.4: Capital Cost of Hydro Generating Stations

Summary of the Issue

Primary reasons for higher tariffs in the hydro plants is the higher capital costs incurred due to increase in the cost of flood moderation and enabling infrastructure. The Commission has been carrying out prudence check on the capital cost of hydro generating stations based on actual costs incurred. It has been observed that the major works of these projects are normally awarded through cost based competitive bidding with price escalation clauses. But since projects go on for years due to inordinate delays leading to cost overruns and time overruns, the price bids are rendered irrelevant. Hence, the Commission seeks suggestions regarding alternate ways to bid hydro projects as per the policy/guidelines that may be specified by the Government of India from time to time and ways to expedite the development of hydro generating stations especially in the construction phase.

Options Proposed

- Funding the costs towards the advancement of local area under enabling infrastructure, i.e., roads and bridges, on a case-to-case basis which could be:
  - as per actuals, limited to Rs.1.5 crore per MW for up to 200 MW projects and
  - Rs. 1.0 crore per MW for above 200 MW projects, as per the Ministry of Power guidelines

Our Recommendation

The option proposed by the Commission to allow the expenses towards the advancement of the Local Area for alleviating public resistance and delays is a welcome step because it is observed that the construction of hydro generating stations does impact local areas, especially those falling under the catchment area. As the people are affected, there is generally a growing dissatisfaction against the developer, which needs proper redressal. Generally, developers voluntarily carry out local area development initiatives such as building roads, schools, and clinics for the benefit of the people and to mitigate resistance to the ongoing works of project, however, the scope of the works get restricted due to the approved CSR plan. Some of the initiatives which can be taken up the project developer to maintain a healthy relationship with the local stakeholders of the project are enumerated hereunder:

(a) Creation of amenities in project areas like medical facilities like hospital /medical van, teaching facilities, community hall/marriage hall, panchayat bhawan, local shopping complex, township, temple/church etc.

(b) Creation of drinking water /sanitation facilities.

(c) Construction of nallah, kachha/cemented roads in deep villages in the project area.

(d) Any works/activities required to avoid any hindrances and for faster execution of the project.

The Hon'ble Commission has proposed that such expenses towards advancement of local area can be met through budgetary support for funding the enabling infrastructure, i.e., roads and bridges. However, scope of this budget head is limited to road/bridges required to connect major components like Dam, Power House, TRT whose cost is already included in DPR. Expenditure for the initiative enumerated above is not included in DPR and accordingly inclusion of such cost in enabling infrastructure shall require the approval of the union cabinet. Accordingly, recovery of such expenditure through this route is not feasible.

NHPC is of the view that since the above fund is granted by the Ministry of Power on prudence basis as per concurrence of CEA and is restricted to the amount as per 'In-principal' approval, Hon'ble Commission may allow the expenses on various local area development activities as part of the Capital Cost for tariff determination. The savings on account of these expenditures shall be huge in comparison to the expenditure carried out for development towards local area, as it will enable the developer to complete the projects in shorter span of time, which will lead to savings of additional cost on account of time and cost overrun.

Development of Hydro generating stations: Apart from the bidding process regulated by the Central Electricity Regulatory Commission (CERC), there may be alternative ways to bid for hydro projects in India. These alternative methods can vary depending on the specific circumstances, project size, and the policies of the state or regional authorities. Few alternate ways to bid for hydro projects:

- **Competitive Bidding through State Agencies**: Some states or state-owned agencies may conduct competitive bidding for hydro projects independently i.e. without involving the regulatory commissions. These agencies may have their own guidelines and criteria for bidding, evaluation, and selection. It is advisable to keep track of announcements and notifications from such agencies and follow their prescribed processes.
- **Public-Private Partnerships (PPPs):** In certain cases, hydro projects may be awarded through public-private partnership models. Under this approach, the government or relevant authorities partner with private entities to develop and operate the hydro project. The bidding process for PPPs can involve a combination of technical and financial evaluation, as well as negotiations on revenue-sharing or other contractual arrangements. The specific procedures for PPP bidding can vary based on the project and the involved parties.
- **Direct Negotiation or Unsolicited Proposals:** In exceptional cases, authorities may consider direct negotiation or unsolicited proposals for hydro projects. This approach allows interested parties to submit project proposals directly to the relevant authority, showcasing their technical and financial capabilities. However, it is important to note that direct negotiations

or unsolicited proposals are typically subject to stricter scrutiny and may require additional justification and approval.

- **Joint Ventures or Consortium Bidding:** Collaborative bidding through joint ventures or consortiums is another alternative approach. Companies can form partnerships or consortiums to pool their resources, expertise, and financial capabilities to bid for hydro projects collectively. This strategy allows for sharing risks, leveraging complementary strengths, and increasing competitiveness in the bidding process.

It's crucial to note that the availability and suitability of alternative bidding methods can depend on various factors, including the specific project, state regulations, and the prevailing policies of the concerned authorities. Hence, it is necessary to consult with industry experts, legal advisors, and relevant stakeholders to determine the most appropriate bidding approach for each specific hydro project in India.

To expedite the development of hydro generation stations in India, especially during the construction phase, several strategies can be employed to streamline processes, optimize resources, and overcome potential obstacles. Some ways to accelerate hydro project development are as follows:

- **Efficient Planning and Design**: Thorough planning and design can help identify potential challenges early on and streamline the construction process. Conducting comprehensive feasibility studies, detailed engineering designs, and accurate project scheduling can minimize the likelihood of delays and rework during construction.
- **Streamlined Permits and Clearances**: Timely acquisition of necessary permits and clearances is crucial for the smooth progress of construction activities. Project developers should proactively engage with regulatory authorities and relevant stakeholders to expedite the approval process. Building strong relationships and ensuring compliance with environmental, forest, and other regulatory requirements can help avoid unnecessary delays.
- **Project Management and Oversight**: Effective project management is essential to ensure coordination, monitor progress, and address any bottlenecks promptly. Employing experienced project managers and utilizing project management software and tools can improve efficiency, minimize delays, and facilitate timely decision-making.
- **Skilled Workforce and Resource Allocation**: Availability of skilled labor and efficient resource allocation are vital for timely construction. Ensuring the availability of skilled

professionals, efficient manpower planning, and proper allocation of construction equipment and materials can help expedite the construction phase.

- **Advanced Construction Techniques**: Utilizing modern construction techniques and technologies can accelerate construction timelines. Prefabrication, modular construction, and mechanization can help reduce on-site construction time, improve quality control, and enhance overall efficiency.
- **Contractual Agreements**: Developing clear and comprehensive contractual agreements with contractors, suppliers, and other stakeholders can help establish timelines, milestones, and performance criteria. Clearly defined responsibilities, effective project oversight and periodic performance reviews can minimize disputes and ensure timely project completion.
- **Financial Planning and Funding**: Adequate financial planning, including securing sufficient funding and arranging timely disbursements, is crucial for construction progress. Establishing clear financial milestones and ensuring the availability of funds at critical project stages can prevent construction delays.
- **Engaging Local Communities**: Building positive relationships with local communities and addressing their concerns can help overcome potential obstacles during construction. Engaging in regular communication, providing employment opportunities, and contributing to local development initiatives can foster support and cooperation.
- **Collaborative Approach**: Collaborating with experienced partners, contractors, and consultants who have a track record in hydro project development can expedite construction activities. Leveraging their expertise, networks, and resources can help overcome challenges and accelerate project timelines.
- **Incentives**: Incentives like higher return on investments/equity for projects completed in a timely manner, higher return for dam/reservoir based projects and Pumped Storage Projects and scalable tariff adjusted for year-on-year inflation will further motivate the developers to complete the project on time.

Consulting with industry experts, engaging with relevant stakeholders, and closely monitoring the project's progress can help identify and implement effective measures to accelerate construction timelines in the Indian hydro power sector.

6. S. No. 4.3: Capital Cost for projects acquired post NCLT Proceedings

Summary of the Issue

It is observed that the acquisition costs of assets under Corporate Insolvency Resolution Process (CIRP) have been considerably lower than the historical value of the assets, and the creditors must take a haircut, and so too the defaulting entities, who have had to forego their equity investments.

The tariff under Section 62 needs to be determined on the cost-plus principle, therefore, the acquisition value should be considered. Further, if the acquisition price is higher than the historical value, the same may be capped at the historical value of such assets, as consumers should not be burdened with the asset premium quoted.

Tariff provisions to be included to address the issue of the cost of debt servicing, including repayment, that were allowed as a part of the tariff during the CIRP process.

Options Proposed

- Tariff under Section 62 needs to be determined on the cost-plus principle, therefore, the acquisition value should be considered. Further, if the acquisition price is higher than the historical value, the same may be capped at the historical value of such assets, as consumers should not be burdened with the asset premium quoted.
- Tariff provisions to be included to address the issue of the cost of debt servicing, including repayment, that were allowed as a part of the tariff during the CIRP process.

Our Recommendation

The calculation of capital costs for hydro generation plants (both under construction and fully operating plants) acquired through National Company Law Tribunal (NCLT) proceedings would involve several factors.

Factors considered for capital cost calculation for acquisition of Under Construction hydro generation plants:

1. **Acquisition Cost**: This includes the purchase price paid for the already constructed component of hydro generation project and the supplied E&M and HM equipment, which is determined through the bidding process in accordance with the NCLT proceedings. The bid amount, including any associated costs such as legal fees and transaction expenses, forms part of the capital cost.
2. **Project Development Cost**: This includes the costs projected to be incurred during the assessment phase of the hydro generation project. It encompasses expenses related to project

feasibility studies, environmental impact assessments, land acquisition, obtaining necessary permits and clearances, if not already taken and engineering and design activities, if needed.

3. **Construction Costs**: The construction costs involve the expenses associated with completion of pending works for commissioning of hydro generation plant. This includes civil works, excavation, structural construction, installation of turbines and generators, electrical and mechanical systems, and any other infrastructure required for the project.
4. **Equipment Procurement**: The cost of procuring the necessary remaining equipment for the hydro plant, such as turbines, generators, transformers, control systems, and other machinery, is included in the capital cost. It encompasses the purchase price of the equipment, transportation costs, import duties (if applicable), and installation expenses.
5. **Engineering and Project Management**: The fees paid to engineering consultants and project management teams involved in overseeing the construction of the hydro plant are considered as part of the capital cost. This includes design, supervision, and coordination services throughout the construction phase.
6. **Financing Costs**: If the acquisition of the hydro generation plant involves financing, the associated financing costs need to be considered. This includes interest payments during the construction period, loan arrangement fees, and other financing charges.
7. **Contingency Allowance**: A contingency allowance is typically included to account for unforeseen expenses or cost overruns during the construction phase. It serves as a buffer to mitigate risks and uncertainties.
8. **Technology Transfer Cost**: Technology transfer cost is the cost which have to be paid to the OEM of the project so that they can share the intricacies of the design with the acquirer which will enable them to call out competitive biddings for the remaining work.

Factors considered for capital cost calculation for acquisition of already operating (at least from 2 years to 5 years) hydro generation plants:

1. **Acquisition Cost**: This includes the purchase price paid for the hydro generation plant, which is determined through the bidding process in accordance with the NCLT proceedings. The bid amount, including any associated costs such as legal fees and transaction expenses, forms part of the capital cost.
2. **Rehabilitation and Modernization**: Hydro generation plants acquired through NCLT proceedings often require rehabilitation and modernization to restore their operational efficiency. The costs associated with refurbishing the plant's infrastructure, upgrading equipment, and implementing technological advancements are considered.

3. **Financing Costs**: If the acquisition involves financing, the interest payments, loan origination fees, and other financing charges associated with the project financing are included in the capital cost.
4. **Regulatory and Compliance Costs**: Hydro generation plants in India must comply with various regulatory and environmental requirements, if not already obtained. The expenses related to obtaining permits, licenses, clearances, and complying with statutory regulations are factored into the capital cost.
5. **Contingency and Miscellaneous Costs**: A contingency allowance is included to account for unforeseen expenses or cost overruns during the rehabilitation or modernization process. Miscellaneous costs such as insurance, site preparation, and project management expenses are also considered.

The acquisition cost is most suited for the projects acquired post NCLT proceedings, however, the additional cost that is required to be expensed for completion of remaining works for under construction projects or operationalizing the asset of already constructed power stations should also be considered, as these assets remained stranded for longer duration of time during the NCLT proceedings.

Further, the Hon'ble Commission has emphasized to mandatorily award work and services contracts for developing projects under the regulated tariff mechanism through a transparent process of competitive bidding, duly complying with the policy/guidelines issued by the Government of India as applicable from time to time in the approach paper. We agree with the Hon'ble Commission's views, however, in some of the cases, especially for the under-construction projects acquired post NCLT proceedings where work had already been awarded and various supplies and works were completed before the beginning of CIRP process, the same may not be possible. It is pertinent to note that every hydro generating plant is unique from construction point of view. Accordingly, the work already executed by existing EPC contractor is usually unique and in such a scenario, either the pending works can only be completed by the existing contractor, or it has to be awarded freshly to a different contractor through competitive bidding which may lead to scrapping up of progress made by previous entity due to technological exclusivity. Therefore, the Hon'ble Commission is requested to allow the award of remaining work on single sourcing basis to get the work executed and project commissioned at the earliest on case-to-case basis.

In regard to the Tariff provisions for addressing the issue of the cost of debt servicing, including repayment, that were allowed as a part of the tariff during the CIRP process, the intention of CERC is not clear. NHPC's understanding of the statement is that the cost of debt referred in the statement is the interest on loan component of tariff recovered as part of tariff by the original developer while operating power station during CIRP process. With the same understanding, NHPC is of the view that the existing tariff levels were not enough to cover the debt and interest payment and these coupled with the operational inefficiencies had forced the existing entities to file for insolvency, the disallowance of debt servicing during CIRP process may result in shut down of plant by the developer. This will increase the restoration period and restoration cost after acquisition of the project. **Therefore, till the time, CIRP process concludes, the existing tariffs allowed may be continued along with cost of debt servicing.**

7. S. No. 4.4: Computation of Interest During Construction

Summary of the Issue

There have been instances wherein the developer did not incur any IDC till SCOD as interest liability for the project started after SCOD and due to the above provision, in case the delay is not condoned, the entire IDC gets disallowed, which does not seem to be appropriate.

In addition to this, it has been observed that in the original IA of a project, the cost of project approved has IDC expenses included under no delay scenario. Even in delay scenarios, the actual IDC is well within the approved IDC limit but in cases of non-condonation the utilities are denied IDC expenses.

Options Proposed

The paper proposes the following:

- Existing mechanism wherein the pro-rata deduction (based on delay not condoned) is done on IDC beyond SCOD.
- Pro-rata IDC may be allowed considering the total implementation period wherein the actual IDC till the implementation of the project is pro-rated considering the period upto SCOD and period of delay condoned over total implementation period.
- IDC approved in the original Investment Approval to be considered while allowing actual IDC in case of delay.

Our Recommendation

1. According to the CERC Tariff Regulations, 2019, Interest during construction (IDC) shall be computed corresponding to the loan from the date of infusion of debt fund, and after taking into account the prudent phasing of funds upto SCOD.

2. In case of additional costs on account of IDC and IEDC due to delay in achieving the COD, the generating company or the transmission licensee as the case may be, shall be required to furnish detailed justifications with supporting documents for such delay including prudent phasing of funds in case of IDC and details of IEDC during the period of delay and liquidated damages recovered or recoverable corresponding to the delay.
3. If the delay in achieving the COD is not attributable to the generating company or the transmission licensee, IDC and IEDC beyond SCOD may be allowed after prudence check and the liquidated damages, if any, recovered from the contractor or supplier or agency shall be adjusted in the capital cost of the generating station or the transmission system.
4. If the delay in achieving the COD is attributable either in entirety on in part to the generating company or the transmission licensee or its contractor or supplier or agency, in such cases, IDC and IEDC beyond SCOD may be disallowed after prudence check either in entirety or on pro-rata basis corresponding to the period of delay not condoned and the liquidated damages, if any, recovered from the contractor or supplier or agency shall be retained by the generating company or the transmission licensee, as the case may be.
5. The Hon'ble Commission proposes to continue with the existing mechanism with a little tweak that the IDC beyond SCOD is pro-rated based on the condonation/non-condonation of the delay. The allowable IDC in this case would be calculated as

$$\boxed{₹\ X + [Y*(A/B)]}$$

, i.e., only IDC pertaining to delay is pro-rated.

X= IDC upto SCOD

Y=IDC beyond SCOD till actual COD

A= no. of months of delay condoned

B=total no. of months of delay

6. The other option proposed by the Commission is that the total IDC is pro-rated based on the SCOD and delay condoned with respect to the actual no. of months taken for the project to be commissioned. The allowable IDC in this case would be calculated as

$$\boxed{₹\ (X + Y)*[(A+B)/C)]}$$

where

X= IDC upto SCOD

Y=IDC beyond SCOD till actual COD

A= no. of months approved for the project to be commissioned

B=total no. of months of delay condoned

C=total no. of months taken for the project to be commissioned

7. NHPC follows a prudent phasing practice, wherein most of the payments are done at the later stages of the construction period in order to reduce IDC and IEDC incurred towards the project. We are of the view that the Hon'ble Commission may go ahead with the second approach wherein the IDC allowed is on the basis of total IDC worked out till actual COD and complete period of construction.
8. The third proposed option for the IDC Computation is that even in case of delay if the IDC computed is less than the approved IDC as per the IA, the IDC may be allowed. In case of several projects where there is substantial delays due to uncontrollable factors, the utilities need to get new project cost approved vide the Revised Cost Estimates (RCE). The RCE covers the revised cost of the project along with the revised estimate of IDC and IEDC. Therefore, the Hon'ble Commission is requested to consider the Investment Approval / Revised Cost Estimate whichever latest is available, while allowing IDC for time overrun cases which is subject to revision as per final approved RCE.

8. S. No. 4.5: Price Variation

Summary of the Issue

In case of time overrun due to delay in commissioning of projects, it not only increases IDC and IEDC, it may also result in increase in the hard cost in case the contract provides for cost escalation beyond SCOD. If the impact corresponding to such delay is disallowed for the delay not condoned it appears logical to extend the same treatment to price variation.

Options Proposed

The Paper proposes the following:

- The utilities may be mandated to submit the statutory auditor certificate along with the petition duly certifying the price variation corresponding to delay and the same may be allowed on pro-rata basis corresponding to the delay condoned.
- A separate form may also be specified to submit the relevant information pertaining to price variation.

Our Recommendation

1. The whole aim/ concept of the approach paper is to simplify the tariff determination process. The calculation of the price escalation for the period for which delay has not been condoned is not a straight forward process as the same is based on various indices at the start of the period and the end of the period with some non-escalable portion as well in the price adjustment formula. Therefore, getting into the calculation of price variation paid for delay not condoned at micro level shall again increase the complexity of tariff determination.

2. Further, price variation in the EPC contracts can occur on two different accounts; first one is on account of natural inflation in the cost of raw material and third party sourced within the ambit of contract timelines and secondly, it may be due to additional increase in competition cost due to time overrun and subsequent, increase in raw material prices due to inflation.

3. However, NHPC deals with the Price Variation as per the contractual prowess. The brief of the relevant clauses of the contracts are provided below:

   "The following conditions shall apply:

   (a) Price adjustment will be applied only if the resulting increase or decrease is more than two percent (2%) of the Contract price.

   (b) No price increase will be allowed beyond the original delivery date unless covered by an extension of time awarded by the Employer under the terms of the Contract. No price increase will be allowed for periods of delay for which the Contractor is responsible. The Employer will, however, be entitled to any price decrease occurring during such periods of delay.

   (c) The total adjustment (plus or minus) shall be subject to a ceiling amount of 25% of the Contract price during contractual completion period.

   (d) In case, Government of India stops publishing any of the price indices at any time and announces a new series with a linking factor for conversion of index of new series to the old series, regulation of price variation will be done using the indices of new series along with linking factor from the period the indices of old series becomes unavailable. However, if the new series released by the relevant source does not have the linking factor, the new series shall be used without use of Linking Factor and current as well as base indices of new series shall be used from the date, indices of old series becomes unavailable.

   (e) No price variation will be admissible on the amount of advance payment made to the Contractor.

(f) If the currency in which the Contract price is expressed is different from the currency of the country of origin of the labor and/or materials indexes, a correction factor will be applied to avoid incorrect adjustments of the Contract price. The correction factor shall correspond to the ratio of exchange rates between the two currencies on the base date and the date for adjustment as defined above. The correction factor 'Z' shall be calculated as Z=Z0/Zn applicable to the respective

component factor of P1 for the formula of the relevant currency.

Where,

Z0 = number of units of the currency of the source country of index, equivalent to one unit of the currency of payment on the date of base cost index , and

Zn = corresponding number of such currency units as on the date of current index."

4. The price variation clauses in the contracts takes care of the delay in work due to contractor and thus the price variation due to delay is not factored in the hard cost of the project. Further, generally the price variation in the contract is restricted to a certain percentage. Also, the price variation on the supply is restricted to the L1 schedule irrespective of the delay in the project.
5. Thus, keeping in view the complexity of the price variation calculation for the delay not condoned and the provision of price variation in the case of default of contractor, NHPC is of the view that the Hon'ble Commission should continue with the existing approach as price variation has no impact on capital cost corresponding to delay period and also remains within the Investment Approval/Revised Cost Estimate in most of the cases.

9. S. No. 4.6 Renovation and Modernization

Summary of the Issue

As per the Regulation 27 of the CERC Tariff Regulations 2019, the generating stations and transmission licensees can opt for R&M for the old generating and transmission systems that have outlived their useful life with the consent of the beneficiaries. In addition to this, Regulation 28 of the CERC Tariff Regulations 2019 provides for a Special allowance in lieu of R&M. Presently, the utilities have the option to choose between R&M and Special Allowance.

Options Proposed

- In view of the benefits of undertaking R&M as against going for fresh capital investment, the current provisions may be continued.

- The utilities that opt for a special allowance for the first year of the tariff period shall have to continue with the same for the rest of the tariff period.

Our Recommendation

1. The renovation and modernization costs incurred by hydro power plants in India can vary significantly depending on various factors, such as the age and condition of the plant, the scale of upgrades required, and the specific technologies implemented.
2. Renovation and Modernization (R&M) involves an overhaul of major components of a system. It is a long process involving preparation of Detailed Project Report that includes identification of specific parts to be replaced/repaired, assessing cost involved in R&M, cost-benefit analysis, schedule of completion, etc. It may be required to involve specialized agencies or obtain inputs from OEM. Further, the generation company is required to obtain the approval of the Commission before taking up the work.
3. Generally, the costs associated with the renovation and modernization of hydro power plants in India involve several aspects, including:
   - **Equipment Upgrades**: This includes refurbishing or replacing key components like turbines, generators, transformers, and control systems. The cost of these upgrades can depend on the size and capacity of the plant.
   - **Civil Works**: Renovation and modernization often involve civil engineering works such as dam rehabilitation, canal repairs, and infrastructure improvements. The costs can vary depending on the scope and complexity of these projects.
   - **Automation and Control Systems**: Implementing advanced automation and control systems can enhance operational efficiency and monitoring capabilities. The costs can include the installation of new monitoring equipment, instrumentation, and control software like the SCADA systems.
   - **Environmental and Safety Compliance**: Upgrades may be required to meet environmental regulations, improve safety measures, and mitigate any adverse impacts on the ecosystem. This can involve investments in environmental protection measures, fish ladders, fish passage systems, and other related infrastructure.
   - **Transmission and Grid Connectivity**: Upgrades to generating station switchyard infrastructure and grid connectivity may be necessary to facilitate efficient power transmission from the hydro power plant to the point of connectivity of the transmission licensee. These costs depend on the distance and complexity of grid interconnections.

4. It is important to note that the specific costs associated with the renovation and modernization of hydro power plants can vary on a case-by-case basis. Detailed cost estimates and project approvals are typically determined by the individual hydro power plant authorities, government bodies, or project developers involved. We can also see that the costs mentioned above are huge in terms of monetary value as compared to other thermal or renewable energy sources and hence can't be put under the Special Allowance category as proposed in the approach paper. Hence, we request Hon'ble Commission to continue with the current approach itself i.e. granting renovation and modernization cost separately on a case-on-case basis in case of hydro generating stations.
5. **Higher Equity Ratio for R&M Projects**: Renovation and Modernisation is an effective way of addition of capacity with minimum investment and in minimum possible time as it does not require the detailed investigations and obtaining host of clearances. The R&M expenditure is about Rs.3-3.5 Crore per MW in comparison to about Rs.12 Crore per MW for a greenfield hydro project. As the investment base is small and the standard Debt-Equity ratio is 70:30, the quantum of equity deployed by the developer is meager and thus, the total return from a renovated plants are also meager for the developer.
6. Further, post R&M of the project, the tariff of the project is calculated on the basis of new cost incurred for R&M plus the salvage value. **The salvage value is nothing but actually the unrecovered equity of the original investment and the additional capitalization during the useful life of the project. Thus, the salvage value should be continued in the form of equity only post R&M and the new investment can be bifurcated in the ratio of 70:30 as Debt: Equity ratio. Thus, the actual equity component in the total cost works out to be in the range of 43% to 47% depending on the new investment and pre R&M Capital Cost.**
7. **It is therefore proposed that R&M of plant may be allowed at Debt-Equity ratio of 50:50 so as to ensure reasonable quantum wise income to hydro power developers through RoE.**

10. S. No. 4.7: Initial Spares

Our Recommendation

The current CERC Regulations 2019 allows a ceiling of 4.00% of Plant and Machinery cost for initial spares of hydro generating stations. Generally, certain mandatory spares are supplied along with the mother plant equipment, by the supplier, as part of the major contract packages. As such, the cost of the same is included in the cost of mother plant equipment, and the segregation of cost of spares from the cost of mother plant is not possible. In such scenarios, the Hon'ble Commission has assumed the initial spares to be procured up to the ceiling limit along with the mother plant equipment and doesn't allow to procure required initial spares within the cut-off date.

Therefore, it is proposed that 2.00% of Plant and Machinery cost may be considered as limit for initial spares for the cases where segregation of spares provided with mother plant is not available and were procured along with the mother plant.

11. S. No. 4.8.1: Delay towards obtaining Forest Clearance

Summary of the Issue

Apart from land acquisition, delays on account of getting forest clearances may also be beyond the control of utilities and therefore have been condoned in the rightful cases. In view of the same, delays on account of forest clearances can also be considered for inclusion as uncontrollable factor provided that such delays are not attributable to the generating company or the transmission license.

Options Proposed

Continued inclusion of delay on account of land acquisition as an uncontrollable factor and on the further inclusion of delay on account of forest clearances as an uncontrollable factor.

Our Recommendation

Hydroelectric power projects in India often face delays due to the process of obtaining forest clearance. The clearance is required because the construction and operation of hydroelectric projects can involve the clearance of forest land and the potential impact on the environment and wildlife. The forest clearance process aims to assess and mitigate these impacts while ensuring sustainable development.

The Commission, while framing the CERC Tariff Regulations, 2019, in its Explanatory Memorandum, observed as follows:

> *"2.5.5 The Commission has observed while dealing with tariff petitions, that matters pertaining to acquisition of land or getting right of way, have become one of the main causes of delay in commissioning of projects. In the existing 2014 Tariff Regulations, only force majeure and change in law have been specifically identified as uncontrollable factors. However, the Commission has noticed that, land acquisition and Right of Way issues have been largely outside the control of the project developer and accordingly, the Commission has also been condoning the delay and allowing the associated cost to form part of the capital cost. In the light of these practical issues, the Commission has proposed to include time and cost over-runs on account of*

land acquisition, as an uncontrollable factor, except where the delay is attributable to the generating company or the transmission licensee…"

The Hon'ble Commission in the Paper discusses that delay on account of land acquisition and forest clearance may be considered in the list of Uncontrollable factors along with Force Majeure and Change in Law. Since the delays faced by hydro projects in obtaining forest clearance can vary depending on the specific project, location, and regulatory processes involved, the initiative taken by the Hon'ble Commission of continued inclusion of delay on account of land acquisition as an uncontrollable factor and on the further inclusion of delay on account of actual time taken for forest clearances as an uncontrollable factor will support the feasibility of the hydro generation projects.

Further, **NHPC is facing severe delay for clearance of trees on forest land even after obtaining forest clearance, which again has to be approved from the concerned statutory authority. Hon'ble CERC in its order dated 24.01.2021 in Petition No 354/GT/2018 for determination of tariff in respect of TLDP-IV Power Station condoned the delay of 3.5 months due to non-felling of trees and non-removal of tree logs. It is therefore, requested to also consider delay in getting the forest land cleared as part of the uncontrollable factors**.

Additional Submission: The present CERC Tariff Regulations 2019 provides for delay in execution of the project on account of contractor or supplier or agency of the generating company or transmission licensee as controllable factor. Central generating stations follows the various guidelines for the award of the work as laid down by Government of India. Thus, while awarding work utmost care is taken in technical and financial evaluation. Notwithstanding, there can be instances where the contractor fails to execute the work and abandon the contract. Subsequently, being a central generating station, NHPC has to again follow the complete process of award of work which results in time overrun. Moreover, the technical and financial competent contractors for hydro power development are very few in number which also makes the process of award of work a time consuming one. **Therefore, it is proposed that the delay in execution of the project on account of contractor or supplier or agency of the generating company or transmission licensee may be brought out of the ambit of controllable factors and be dealt on case-to-case basis.**

12. S. No. 4.9: Differential Norms – Servicing Impact of Delay

Summary of the Issue

The Hon'ble Commission has observed that in several cases the delays are attributable to lack of timely clearances, forest approvals, etc. which require constant and rigorous follow up. In most of these cases, it has been observed that these delays could have been restricted if the approvals were sought more assertively instead of merely through written correspondence. Further, it is always not possible for the Commission to ascertain if adequate efforts have been made at the senior level to get the clearances. Therefore, in order to encourage rigorous pursuit of such approvals, even if delay beyond SCOD is condoned for any reasons, some part of the cost impact corresponding to the delay condoned may be disallowed.

Options Proposed

Comments/Observations were invited from Stakeholders on the following:

1. To encourage rigorous pursuit of such approvals from statutory authorities, even if delay on account of clearances/ approvals are condoned, a part of the cost impact (Say 20%) corresponding to the delay condoned may be disallowed.
2. Alternatively, corresponding ROE may be allowed at the weighted average rate of interest on loans.
3. The current mechanism of treating time overrun may be continued, considering that utilities are automatically disincentivized if the project gets delayed.

Our Recommendation

1) NHPC has been quite active in pursuing the statutory authorities for getting clearances and approvals at the earliest. However, we don't have any control over the approval processes of the statutory authorities. Further, NHPC starts the board approval process after getting the necessary approvals such as environmental, forest etc. and therefore, are usually not the part of the delays during the construction from the Investment Approval date.
2) NHPC has mostly faced the issue of the local disturbances, delay due to force majeure events such as floods, landslides, etc and delay in getting forest land cleared during the construction phase. However, NHPC gets actively involved with the local authorities in case of local disturbances and other statutory authorities in order to resolve the issue in a timely manner.
3) Similarly, allowing RoE at the rate of weighted average rate of interest on loans for the capital base corresponding to cost and time overruns allowed over and above project cost as per investment approval will lead to reduced returns over the already reduced IRR. The reduced RoE will lead to an additional penalty apart from already reduced IRR due to extended timelines.
4) 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 return. 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 40 years.

(i) Scenario 1

Assumptions

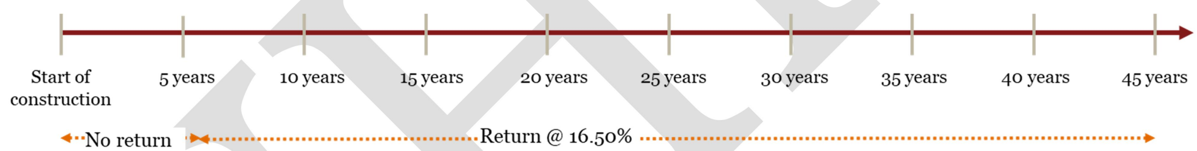
Project Construction time - 5 years

Useful Life: 40 years

Equity infusion during the construction period is as follows:

In Rs.Crores

Year	1	2	3	4	5
Opening Equity	0	10	25	50	80
Additional Equity	10	15	25	30	20
Closing Equity	10	25	50	80	100
Average Equity	5	17.5	37.5	65	90



Const. Period **Operation Period (Useful Life)**

Year	1	2	3	4	5	6	7	8	9	10......17	18	19	20	21	22	23	24	25......37	38	39	40	41	42	43	44	45
Inflow / Outflow	-10	-15	-25	-30	-20	16.5	16.5	16.5	16.5	16.5 16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5 16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5
IRR	**13.20%**																									

Effective return @ 13.20%

(ii) Scenario 2

Assumptions

Project Construction time - 5 years

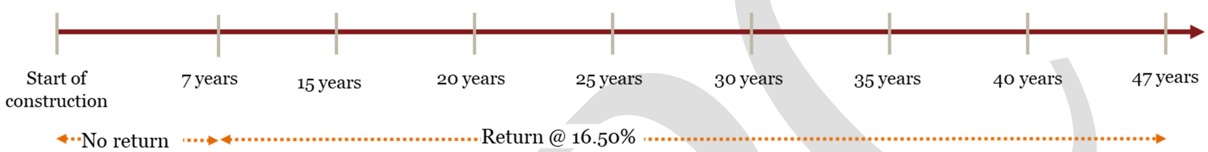
Project Delay – 2 years

Useful Life: 40 years

Equity infusion during the construction period is as follows:

In Rs.Crores

Year	1	2	3	4	5	6	7
Opening Equity	0	10	20	35	50	70	90
Additional Equity	10	10	15	15	20	20	10
Closing Equity	10	20	35	50	70	90	100
Average Equity	5	15	27.5	42.5	60	80	95



	Const. Period							Operation Period (Useful Life)																					
Year	1	2	3	4	5	6	7	8	9	10……17	18	19	20	21	22	23	24	25……37	38	39	40	41	42	43	44	45	46	47
Inflow / Outflow	-10	-10	-15	-15	-20	-20	-10	16.5	16.5	16.5 16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5 16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5
IRR	**11.76%**																												

Effective return @ 11.76%

5) Effective return for a hydro generation project reduces to 11.76% from 13.20%, considering a delay of 2 year, since return on equity starts only after commencement of commercial operation of the project.

6) **Hon'ble Commission is requested to continue with the third approach, as in most of the cases we are able to complete the projects within the stipulated timelines. In some of the cases where we face the issue of clearances from statutory authorities, delay on account of local agitation etc., we proactively try to resolve the situation at the earliest. Further, the developer already getting penalised by the way of reduced IRR over the life of asset**.

13. S. No. 4.10.1: Normative Add Cap – Generating Station

Summary of the Issue and options proposed:

Normative Add Cap – Existing Generating Station with cut-off date on or before 31.03.2024:

- In the case of a specific hydro generating station, the additional capitalization is recurring in nature, and hence station wise normative additional capitalization may be approved in the form of special compensation which shall not be subject to any true up and shall not be required to be capitalized.

- While determining such special compensation for hydro generating station, costs incurred towards works presently covered under **Regulation 26 to Regulation 29**, wherever applicable, may not be included as these expenses may be allowed separately.
- Lastly, discharge of liabilities of works already admitted by the Commission as on 31.03.2024 may be allowed as and when such liability is discharged.

Normative Add Cap – Existing Generating Station whose cut-off date shall fall in the upcoming tariff block 2024-29:

- By extending the cut-off date from the current 3 years to 5 years, which shall allow time to close contracts and discharge liabilities and eliminate the need to allow additional capitalization post cut-off date unless in the case of Change in Law and Force Majeure.
- However, based on past data of similar existing generating stations, if there is a need to allow additional capitalization that may be legitimately required post cutoff date other than those presently allowed under Regulation 26 to 29, the same may be allowed as special compensation as proposed in the case of existing station that have crossed the cut-off date.
- The other points regarding Capital Spares and Discharge of Liabilities remain same as the above.

Our Recommendation

Extension of cutoff date from 3 to 5 years for allowing add cap is a welcome step as expenditure up to 85% of the total cost is incurred at the time of COD of the project and balance 15% expenditure is generally completed within first 5 years of the operation of the project in most of the cases. But in some of the projects which are executed in the remote locations of the country there are many hindrances such as non-availability of competent contractors or contractor not turning up after tender, transporting huge machineries, getting statutory clearances etc., which might cause a delay in the completion of the pending works and the remaining works of the project under original scope might not get completed within 5 years from the COD of the project. In the approach paper, it has been proposed that the expenses incurred for the works under original scope after 5 years shall be met through Special compensation by CERC, however, these expenses being specific in nature may result in expenses which the petitioner will not be able to meet through special compensation. **Therefore, it is proposed that any expenses incurred towards works carried under original scope should be allowed under Add Cap itself after prudence check through a true up process on a case-to-case basis.**

Hence, we are of the view that **only expenditure incurred towards replacement of asset which are recurring in nature should be put under the Special compensation and all other expenses incurred by the generating station should be allowed through Add Cap after prudence check and verified through a true up process**. Further, the special compensation to be allowed should be determined based on the life of the project as in the initial stages and at the fag end the requirement may be higher as compared to the period between 10 to 25 years of hydro generating station.

14. S. No. 4.11: GFA/NFA/Modified GFA Approach

Summary of the Issue

Prior to 2019, the GFA approach for all generating stations was adopted for the primary reason that it provides internal resources for capacity replacement/ addition through return on equity. The CERC Tariff Regulations 2019 adopted a modified GFA approach for a few specific generating assets that were funded through a debt-equity ratio of 50:50 or are about to complete their useful life. The NFA approach is based on gradual reduction of fixed assets wherein the Net Fixed Assets are considered for the purposed of computation of tariff. The NFA approach may result in reducing returns for investors as the project ages and reduce bankability of power sector projects which could be detrimental.

Options Proposed

The Paper proposes the following:

- Increasing the Investors' confidence by ensuring assured returns is important, and further considering the recent spikes in power tariffs in power exchanges indicating shortage of power availability, investment in Power sector needs a boost, and therefore the existing GFA approach, being a balanced approach may be continued.

Our Recommendation

1. The Hon'ble Commission had proposed a modified GFA approach in the 2019 Tariff Regulations. But the Hon'ble Commission observed the following:

   "7.1.7 It is observed that many of the generating stations and transmission systems which were commissioned on or before the commencement of tariff period 2004-09, and which have either completed or about to complete their useful life, have a debt-equity ratio of

50:50. The Commission sees strong logic to bring uniformity of the capital structure of all the projects. Therefore, the excess equity of the projects is required to be aligned at par with normative debt to equity ratio.

7.1.8 The Commission, after considering all the relevant aspects carefully, has decided that the proposed reduction of equity to the extent of 30% instead of salvage value will be more pragmatic approach, as it takes care of the interest of both the investors and consumers. Accordingly, in case of a generating station or a transmission system which has completed its useful life as on or after 1.4.2019, if the equity actually deployed as on 1.4.2019 is more than 30% of the capital cost, equity in excess of 30% shall not be taken into account for tariff computation and will be deemed to paid from the accumulated depreciation."

2. The GFA approach provides for internal resources for capacity replacement through return on equity even when the cumulative depreciation goes beyond the debt component. Whereas, in the NFA approach, the returns are allowed on the remaining equity component after adjusting for the depreciation received beyond the debt component.
3. Since, the GoI has set a target of 500 GW of RE by 2030, it will require a significant investment in the hydro generation sector not only to fulfil the Hydro Purchase Obligation which is a separate entity under Renewable Purchase Obligation but also to complement solar and wind capacity addition from the point of view of grid stability and reliability.
4. The required investment has to be funded through the internal accruals, direct investment from the investors and the financing institutions. Therefore, increasing the Investors' confidence is a necessity in such case and providing regulatory certainty will be a key factor and we agree with the Hon'ble Commission's views of continuing with GFA approach in this regard.

15. S. No. 4.12.1: Segregation of Normative O&M Expenses

Summary of the Issue

In the past, the O&M expenses for Generating Stations have been approved based on actuals incurred in the past along with a certain escalation rate to cater to inflation and other changes. O&M expenses were divided into three broad types i.e., Employee Expense, R&M Expense and A&G Expense. Mostly the Employee expenses are required to give effect to Pay/Wage Revision impact, so O&M expenses may be divided into two categories only, Employee Expenses and all other expenses.

Options Proposed

- O&M norms may be specified under the following two categories i.e., Employee Expenses and Other O&M Expenses comprise Repair and Maintenance and Administrative and General Expenses.
- To give effect to the impact of pay/wage revision, 50% of the actual wage revision can be allowed on a normative basis.

Our Recommendation

1) We would like to highlight that the employees are not mapped in the systems project wise and are only mapped department wise. Allocating the employee expenses based on projects would be tedious exercise and may also lead to erroneous results as corporate and regional employee oversee multiple projects and in such a scenario, allocating the employee expenses would be difficult. Therefore, we would urge Hon'ble Commission to continue with the existing approach of allowing the O&M expenses as per norms.
2) In the scenario, if the Hon'ble Commission proceeds with the approach of segregating the O&M expenses, the escalation rate for both the expenses should be defined separately as Employee expenses will be a function of AICPI and 3% increment allowed; and other O&M expenses will majorly be a function of composite index (ration of CPI and WPI). In this approach the impact of pay revision need to be allowed separately as per actuals. Further, for segregating the O&M Expenses, the expenses towards the contractual employees should be considered as part of Other O&M Expenses as they are hired for some specific works as per the agreement with the third party.
3) The alternative approach of keeping the O&M expenses as combined and allowing 50% of the actual wage revision on a normative basis, essentially means remaining 50% has to be met through the existing norms or from the gains accrued on account of efficient operations. This approach will result in under recovery of cost of generation for the generator which is in clear contradiction to Section 61(d) of Electricity Act, 2003 which provides for **safeguarding of consumers' interest and at the same time, recovery of cost of electricity in a reasonable manner**. Further, the implementation of wage/pay revision and quantum of increase in expenses is beyond the control of the Petitioner and are governed as per Central and State government policies. Therefore, the impact of pay revision may be allowed separately as per actuals as and when the same is notified by the Government under change in law. For the normative purpose, an adjustment in trajectory may be considered in line with

actual increase in employee expenses during the 2nd and 3rd Pay Commission. Hon'ble Commission in its order dated 05.12.2012 in Petition No 5/MP/2012 has allowed actual increase in employee cost on account of 2nd wage revision subject to ceiling of 50% of salary and wages (Basic + DA) of the employee pre wage revision. Similarly, Hon'ble Commission in its various orders in Calendar year 2022 has allowed the actual impact of 3rd wage revision over and above the normative O&M already allowed.

4) **Therefore, Hon'ble Commission is requested to continue with the existing approach of notifying O&M Expenses along with the normative impact of wage revision at 50% of pre revision wage revision salaries. If the Hon'ble Commission still decides to segregate O&M expenses, it is proposed to provide separate escalating factors for both the components.**

16. S. No. 4.12.4: Inclusion of Capital Spares

Summary of the Issue

Since some of the spares (Initial, Capital and Maintenance) are being allowed based on actuals and some are being allowed on a normative basis, considerable effort is required to map these expenses. Further, the challenge with capital spares is that these expenses are non-recurring and sporadic, so benchmarking them can be difficult.

Options Proposed

- Calculating Capital Spares through normative basis itself by analyzing the capital spares expenses from past 15-20 years and finding some correlation and predictability of such expense.
- Alternatively, instead of including all such capital spares as part of normative O&M expenses, recurring and low value spares below Rs. 20 lakhs may be made part of normative O&M expenses, while for capital spares with a value in excess of Rs. 20 lakhs, utilities may submit the same on a case-to-case basis.

Our Recommendation

We are of the opinion that, the option proposed by the CERC to include all the capital spares below Rs. 20 lakhs as normative O&M expense is a welcome step because currently as per the CERC 2019 regulations, all the capital spares expenses above 1 lakh are required to be claimed

separately from the beneficiaries' post approval from CERC. This will ensure the timely recovery of expenses expensed towards the capital spares.

17. S. No. 4.12.5: Impact on account of Change in Law and Taxes

Summary of the Issue

There are no provisions with regard to allowing additional expenses on account of any change in law resulting in an increase in O&M expenses. However, including the same may lead to recurring impacts, and claims that may result in regulatory overburden.

Options Proposed

The Paper proposes the following:

- A provision may be put into place for allowing the impact of change in law on O&M expenses

Our Recommendation

NHPC is of the view that the additional expenses incurred by the Generating Company due to 'Change in Law' and 'Change in Taxes' are the genuine expenses incurred by the Company for generation of power and any under recovery in these expenses shall result in under recovery of cost of generation. However, the ambit of 'Change in Law' and 'Change in Taxes' is very broad and all these expenses cannot be covered under normative expenses, which is explained below:

1) "Change in Law" means occurrence of any of the following events:
   a) enactment, bringing into effect or promulgation of any new Indian law
   b) adoption, amendment, modification, repeal or re-enactment of any existing Indian law
   c) change in interpretation or application of any Indian law by a competent court, Tribunal or Indian Governmental Instrumentality which is the final authority under law for such interpretation or application
   d) change by any competent statutory authority in any condition or covenant of any consent or clearances or approval or license available or obtained for the project
   e) coming into force or change in any bilateral or multilateral agreement or treaty between the Government of India and any other Sovereign Government having implication for the generating station or the transmission system regulated under these regulations.
2) "Change in taxes" means the following:
   a) Change in interpretation or administration of an existing tax structure
   b) Elimination of one or several taxes to establish or increases a different tax structure

3) There are certain expenses that are prone to change in law such as GST rate for different services, increase in employee expenses due to pay revisions, any additional levies/duties etc. imposed by the local authorities/government.

As on date, the utilities don't have any clarity around the changes that may occur in this regard. Hence, it would be difficult to incorporate the same in base norms to be notified for the control period. Further, there is ambiguity in terms of prospective timeline in which these changes may occur. **Therefore, the above expenses may be allowed on actuals under change in law as and when they are notified and implemented and a separate provision for claim of such expenses may be kept in the regulation.**

18. S. No. 4.13: Depreciation

Summary of the Issue

In previous regulations, the tenure of the loan considered is 12 years, whereas the life of most of the assets is between 25 and 40 years. It is observed that shorter loan duration and higher depreciation in the initial years have resulted in front loading of tariffs. Considering that nowadays loans are available for 15-18 years, the possibility of increasing the loan tenure for the computation of depreciation rates needs to be explored. Excessive front loading of tariffs increases resistance to future investments. For example, external loans have much lower interest rates, therefore, spreading depreciation over longer periods in the case of external loans can be a viable option for reducing costs in the initial years, which shall, however, include FERV factor and other financing cost. Therefore, there is a need to create a balance and align the depreciation rate with the actual loan tenure and life of the assets.

Options Proposed

A depreciation rate may be specified considering a loan tenure of 15 years instead of the current practice of 12 years. Further, additional provisions may also be specified that allow lower rate of depreciation to be charged by the generator in the initial years if mutually agreed upon with the beneficiary(ies)

Our Recommendation

1. The existing treatment of weighted average useful life in case of combination of units, due to gradual commissioning of units under different stages, should be allowed to continue provided all the units are commissioned within a reasonable span of time.

2. The reassessment of the life of assets or change in tenure of loan repayment at the beginning of every tariff period may act as a disincentive for proper maintenance of assets and also impacts the maintenance of cash flows for the generating station.

3. An important aspect to be considered is the fact that the investment decision by investors/lenders for existing assets were based on the loan tenure of 12 years as considered by the Hon'ble Commission in the previous tariff regulations. As a prudent business practice, NHPC has been raising debt every year in staggered manner with total repayment schedule of 10 & 15 years having moratorium period ranging from 1 to 5 years with repayment in yearly instalments ranging from 5 to 10 years. The details of Bonds raised over past ten years is enclosed as **Annexure-ll**. In addition to above, in recent past NHPC has also raised term loans from banks to meet the CAPEX requirements of two of our construction projects viz Subansiri lower project & Parbati-ll Project. In addition to above, the Corporation has raised funds through monetization of return on equity to meet debt requirements of these two construction projects. The details of funds raised from banks including monetization along with term & conditions is enclosed as **Annexure-Ill.** Further, as a case study, please find attached details of the loans raised, loan repaid during construction & after COD in respect of Parbati-lll project for ready reference as **Annexure-IV.** A change in the regulatory approach in the suggested manner will result in regulatory uncertainty and may therefore not to be considered.

4. Over 90% of the bond issued in domestic market were of tenure less than 15 years. Further, the domestic banks are not willing to lend for duration longer than 10-12 years due to huge exposure of banks in the infrastructure sector. Consequently, the options to raise loans of longer duration are very limited in the domestic market. Moreover, the interest rates of long duration loans are higher by at least 120-150 basis points, which will lead to increase in interest on loan component, thereby negatively impacting both NHPC and beneficiaries.

Calculating depreciation and interest on loan under current regime of CERC: Under the existing Tariff Regulations 2019, the depreciation allowed is equivalent to the normative loan repayment for first twelve years. Further, the Tariff Regulations 2019 also considers normative debt to equity ratio of 70:30 for a project.

5. The below table illustrates the calculation of depreciation and interest in loan for an asset with GFA of Rs. 142.86 lakhs (normative loan of Rs. 100 lakhs) and useful life of 40 years. The interest rate is assumed to be 10%.

Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Depreciation	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	1.38	1.38	1.38	1.38	1.38	1.38	1.38	1.38
IOL	9.58	8.75	7.92	7.08	6.25	5.42	4.58	3.75	2.92	2.08	1.25	0.42								
Total	17.08	16.25	15.42	14.58	13.75	12.92	12.08	11.25	10.42	9.58	8.75	7.92	1.38	1.38	1.38	1.38	1.38	1.38	1.38	1.38

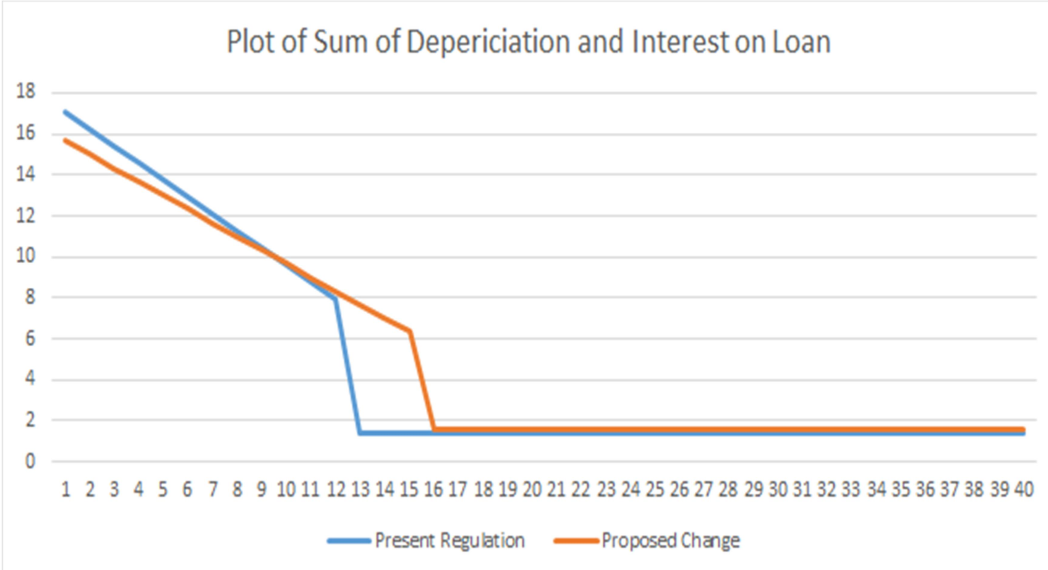
Year	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40
Depreciation	1.38	1.38	1.38	1.38	1.38	1.38	1.38	1.38	1.38	1.38	1.38	1.38	1.38	1.38	1.38	1.38	1.38	1.38	1.38	1.38
IOL																				
Total	1.38	1.38	1.38	1.38	1.38	1.38	1.38	1.38	1.38	1.38	1.38	1.38	1.38	1.38	1.38	1.38	1.38	1.38	1.38	1.38

6. **Calculating depreciation and interest on loan under new scenario with loan duration of 15 years:** Based on the calculation above, the interest on loan for a loan duration of 15 years works out to be 9.48%. For an asset with GFA of Rs. 142.86 lakhs and useful life of 40 years and a loan of interest rate of 9.48%, the depreciation and interest on loan is calculated below:

Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Depreciation	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	1.54	1.54	1.54	1.54	1.54
IOL	9.67	9.00	8.33	7.67	7.00	6.33	5.67	5.00	4.33	3.67	3.00	2.33	1.67	1.00	0.33					
Total	15.67	15.00	14.33	13.67	13.00	12.33	11.67	11.00	10.33	9.67	9.00	8.33	7.67	7.00	6.33	1.54	1.54	1.54	1.54	1.54

Year	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40
Depreciation	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54
IOL																				
Total	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54

7. The total of depreciation and interest on loan under the two scenarios is plotted below:



8. The difference between the two scenarios and the net impact is depicted in the table below:

Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Depreciation	(1.50)	(1.50)	(1.50)	(1.50)	(1.50)	(1.50)	(1.50)	(1.50)	(1.50)	(1.50)	(1.50)	(1.50)	4.62	4.62	4.62	0.17	0.17	0.17	0.17	0.17
IOL	0.08	0.25	0.42	0.58	0.75	0.92	1.08	1.25	1.42	1.58	1.75	1.92	1.67	1.00	0.33	0.00	0.00	0.00	0.00	0.00
Net Impact	(1.42)	(1.25)	(1.08)	(0.92)	(0.75)	(0.58)	(0.42)	(0.25)	(0.08)	0.08	0.25	0.42	6.29	5.62	4.96	0.17	0.17	0.17	0.17	0.17

Year	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40
Depreciation	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17
IOL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net Impact	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17

9. On comparing both the scenarios mentioned above, it is observed that the net impact is negative for NHPC in the initial 12 years and positive for rest of the useful life. However, the net impact over the entire life is negative. The same can be inferred by calculating the NPV of the total of depreciation and interest on loan. The discount rate is taken as 16.50% - the maximum rate of return on equity for hydro power plants.

NPV (existing scenario)	NPV (new scenario)	Net impact
72.27	70.39	(1.88)

10. It was observed that under all scenarios, the utilities are negatively impacted. Hence, we are of the view that the Hon'ble Commission may retain the current methodology of depreciation.

11. The hydroelectric projects have long gestation period. In case of debt funding of these projects' moratorium is sought from lenders up to the COD of the projects and thereafter the debt is repaid in yearly instalments, say 12 equal yearly instalments matching with the depreciation allowed in tariff. Thus, the end-to-end total tenure of debt becomes 15 to 18 years which itself is very long. Further, considering depreciation rate specific to a loan tenure of 15 years instead of the current practice of 12 years (after COD) shall lead to serious difficulty in debt servicing of the loans.

12. **Therefore, from the above-mentioned calculations and reasoning, we would urge the Commission to continue with the existing approach of considering loan tenure as 12 years for depreciation computation. If in case, the Commission proceeds with the proposed approach, it should be applied for new assets where investment approval or COD is provided/ obtained post notification of the revised tariff regulations and the rate of depreciation should be fixed at 4.67% (=70/15) which shall ensure the debt servicing in 15 years**.

19. S. No. 4.14.1: Weighted Average Rate of Interest and FERV

Summary of the Issue

As per the prevailing Tariff Regulations, the weighted average interest rate calculated on the basis of the actual loan portfolio deployed towards the asset by the utility is considered the cost of debt. The cost of debt thus arrived as is applied to the normative outstanding loan to compute the annual interest expenses of the utility, which are allowed to be passed through in the tariff. In addition to the same, in the case of foreign debt, the utility is required to carry out hedging to take care of exchange rate variations, the cost of which is allowed to be recovered separately.

It has been observed while dealing with tariff petitions, the loans are not availed for specific project, and in such cases, it becomes a cumbersome task to ascertain one to one co-relation between assets and loans, which also requires considerable time and effort. To address the same, the possibility of computing interest on loans on the basis of the actual weighted average rate of interest for a company as a whole can be explored.

Options Proposed

The Paper proposes the following:

- To simplify the approval of interest on loans, the weighted average actual rate of interest of the generating company may be considered instead of project specific interest on loans.
- Further, the cost of hedging related to foreign loans be allowed on actual basis, without allowing any actual FERV.

Our Recommendation

1. The hydro generation projects have the highest per MW capital cost in comparison to other sources of energy. Therefore, loans are raised from the market that are specific to the need of the project considering the tenure of the loan matched with COD of the project. However, for some of the projects which have very high cost per MW and are unviable because of their geographical locations, but the projects are of national importance, the Government of India sometimes provides direct grant or cheaper loans to make these projects viable.
2. The approach proposed in the paper to calculate interest on loan based on weighted average interest rate of the company shall result in passing on the benefit of project specific reliefs provided by the Government to beneficiaries of other projects and may turn those projects unviable. Therefore, consideration of weighted average interest rate of a particular project if project specific loans are available may be continued.
3. However, for the purpose of computation of carrying cost on the normative loan for equity infused above 30%, the weighted average interest rate of the company may be considered.
4. **Alternatively, if the Hon'ble Commission deemed it necessary to allow interest on loan as per weighted average rate of interest for the company to make the process simpler, the Hon'ble Commission may link the rate of interest with certain benchmarks such as SBI MCLR + some basis points for projects where cheaper loans have not been provided by the Government of India and to continue with the existing approach of weightage average rate of interest for the projects where subordinate debt/ cheaper loans have been provided by the Government of India.** Considering the existing loan portfolio, NHPC would be able to recover the interest costs for all the projects on average basis at the rate of SBI MCLR plus some basis points.
5. **For hedging related to foreign loans**: As per present RBI norms also, hedging is not mandatory. As per current RBI norms, hedging is mandatory only in case of Infrastructure companies if the average maturity of the External Commercial Borrowings (ECB) is less than 5 years. Under such cases also, companies are required to hedge 70% of the ECB exposure (P+I) only. In this regard, the detailed calculations as a case study in case of one of our projects i.e. Dhauliganga H.E. Project wherein Corporation has availed foreign currency loan in JPY is

attached as *Annexure-I*. It is submitted that in the CERC tariff notification applicable for the 2019-24 period, both hedging cost as well as exchange rate fluctuation is pass through in tariff as the case may be and there is an option on generator to decide whether to go for hedging of the foreign currency loan or to keep the loan un-hedged keeping the exchange rate fluctuation risk with himself and ultimately with the beneficiary. In case of Dhauliganga project NHPC has not gone for hedging of the loan and has kept the foreign currency loan un-hedged. The enclosed case study clearly shows that in case Corporation had gone for hedging of loan at the time of beginning of the tariff period i.e. in the year 2019 then Corporation would have paid cost of Rs. 225.28 crore in four years of the tariff period as hedging cost (assuming the hedging rate being 6.00% p.a. in case of JPY loan). On the other hand, by keeping the foreign currency loan un-hedged, Corporation has incurred the cost of only Rs. 15.73 crore in the form of exchange rate variation. This is mainly because the rate of JPY in April 2019 was Rs. 0.6330 and has come down to Rs. 0.6208 in March 2023. Thus, the decision of keeping the foreign currency loan un-hedged has saved Rs. 209.56 crore (Rs. 225.28 cr - Rs. 15.73 crore) and has ultimately resulted in saving to beneficiaries. Thus, we are of the view that the existing provisions of passing of FERV or hedging cost may kindly be remained un-changed and decision in this regard may kindly be left to the generator.

6. Hon'ble Commission throughout the approach paper has emphasized on simplification of tariff determination process and moving more towards the normative parameters. Therefore, instead of considering weighted average rate of the corporation or the project or going for hedging of foreign loans or going for reimbursement of FERV, **following two options are proposed for the projects where subordinate debt/ cheaper loans have not been provided by the Government of India:**
    a) **A normative rate of interest of 250 basis points above the average State Bank of India Marginal Cost of Funds based Lending Rate (MCLR) (one year tenor) prevalent during the period October to March of previous financial year may be allowed along with actual FERV to be reimbursement.**
    b) **Allow a normative rate of interest of 450 basis points above the average State Bank of India Marginal Cost of Funds based Lending Rate (MCLR) (one year tenor) prevalent during the period October to March of previous financial year and the developer with the risk of FERV with developer only.**

20. S. No. 4.15: Return on Equity (RoE) v/s Return on Capital Employed (RoCE)

Summary of the Issue

Under the RoE method, return at a specific percentage is calculated based on market data and is allowed only on equity investments whereas interest on debt is allowed based on the actual interest rate. Under the RoCE approach, the return on total capital employed is allowed based on the weighted average cost of capital (WACC). The issue whether to adopt the RoE or RoCE method has been deliberated in this paper.

Options Proposed

The Paper proposes the following:

- After much deliberation and discussion, the Hon'ble Commission is of the view that the present system of the RoE method may be continued given the various bottlenecks in adopting the RoCE method currently.

Our Recommendation

1. To illustrate the impact of RoCE approach, revenue under both the existing approach and RoCE approach was modeled as follows:

   Three scenarios were modeled:

   Scenario I: Allowed revenue under the existing model with separate components of return on equity and interest on loan. The loan repayment is considered equal to allowed depreciation.

   Scenario II: Allowed revenue under the RoCE model with return based on WACC on the asset base (closing gross fixed assets less the cumulative depreciation).

   i. The debt-to-equity ratio and hence WACC is assumed to be constant throughout the asset life.
   ii. The depreciation is assumed to be same as under the existing model.
   iii. Working Capital is included in the asset base.

   Scenario III: It is similar to scenario II. However, in this scenario, the debt-to-equity ratio varies through the project life and consequently the WACC changes throughout the lifecycle. However, the cost of equity and cost of debt is assumed same across.

   The scenario modeling was based on the following assumptions:

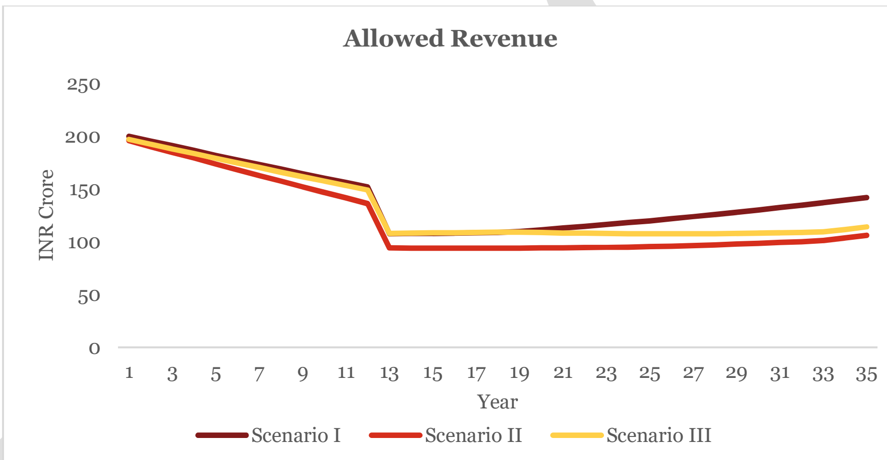
i. The date of commercial operation of the asset has been assumed to be occurring at the beginning of the financial year, irrespective of the actual DOCO date.

ii. It is assumed that the tariff of the asset is regulated as per the norms of tariff regulations 2019-24 throughout the asset life.

iii. The input parameters are assumed to be constant to be constant throughout the asset life.

Results:

a) Allowed revenue under different scenarios: The below graph shows the allowed revenue under the three scenarios listed above.

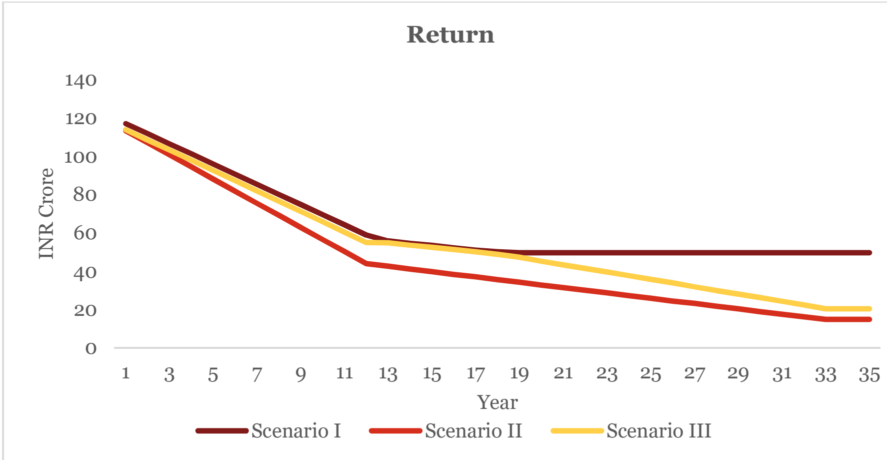


It can be clearly seen that the existing approach allows more revenue for the same asset compared to RoCE approach. It may be noted that, the initial increase in revenue is on the account of additional capitalization in the initial years. Also, a sudden dip can be observed in the thirteenth year due to reduction in depreciation after twelfth year.

The below table presents NPV (Rs. crores) of the allowed revenue using WACC as discount rate.

Scenario I	Scenario II	Scenario III
1350.35	1260.60	1322.09

b) Return under different scenarios: The below graph shows the total return, including the interest on working capital under the three scenarios listed above.



The total return under scenario I (existing RoE methodology), reduces for the first 12 years on account of reducing interest on loan (assuming no additional capital expenditure after third year) and remains constant thereafter at the level of return on equity. However, it can be observed that the return under the RoCE approach reduces constantly throughout the life as the capital invested into the projects continues to diminish since the eligible asset base for allowing the returns is the net fixed assets. Under Scenario III, the return on assets is same as the Scenario I till the loan is completely paid off and thereafter reduces on account of reduction in equity.

The below table presents NPV (Rs. crores) of the return using WACC as discount rate.

Scenario I	Scenario II	Scenario III
690.76	605.25	656.93

2. From the above analysis it can be seen that the existing RoE based approach provides better return. It ensures an assured return on equity once invested. The interest rate is also allowed as a pass-through component protecting against risk of fluctuation in interest rate.
3. On the other hand, RoCE based approach allows returns on a diminishing asset base. Also, the interest rate is benchmarked, exposing the project owner to the risk of interest rate fluctuation. **Thus, from the sector growth perspective, the existing RoE approach is better than RoCE approach as it provides the generating companies with enough internal resources to invest in the future projects. Hence, we are of the view that the Hon'ble Commission may continue with the existing RoE approach**.

21. S. No. 4.16: Return on Equity

Summary of the Issue

To ensure that RoE is fair to both investors and consumers, the return allowed should be commensurate with the returns available from alternate investment opportunities with comparable risk. Different models, viz. Discounted Cash Flows (DCF), Risk Premium Model (RPM), Capital Asset Pricing Model (CAPM) etc. are available for the estimation of the cost of equity/ RoE. However, the Commission has been largely dependent on the CAPM model for arriving at RoE during previous tariff periods.

Options Proposed

The Paper proposes the following:

- Review of Rate of RoE to be allowed, including that to be allowed on additional capitalisation that is carried out on account of Change in Law and Force Majeure.
- Comments and suggestions are sought from stakeholders for the CAPM methodology for estimation of RoE and alternative suggestions, if any.

Our Recommendation

1. The additional capitalisation that is carried out on account of Change in Law and Force Majeure are essential and has to be prioritised over other projects for compliance and continuity purposes. Therefore, the reduction in RoE for such capital expenditure will demotivate the entities and may lead to delay in compliance with the relevant laws.

The Hon'ble Commission in the approach paper has suggested the following methodology for determining the expected rate of return using the CAPM:

> "*The average 10-year GOI securities rate over a one-year horizon may be considered a risk free rate*
>
> *Daily data on the SENSEX and BSE Power Index for the latest 5 years may be considered for equity beta estimation.*
>
> *Market Risk Premium reflecting the historical returns for a period of 30-years or beyond instead of the existing practice of considering 20 years may be considered for MRP estimation. Alternatively, MRP may be computed using any other method, including the Survey Method.*"

2. Considering a horizon of 5 years for computing beta doesn't allow the period of uncertainty to be averaged out such as impact of COVID 19 pandemic where the markets were volatile. The beta computation should be in line with the computation of Market risk premium. Further, the use of

extended periods of market data in CAPM is described in various literature as well, highlighting the decrease in standard error of risk premium with the increase in estimation period. [*Aswath Damodaran, 2014, Applied Corporate Finance (4th Edition)]*

3. As highlighted above, the beta and market risk premium should be in congruence, therefore, a similar period should be considered for computing beta and market risk premium. Further, most of the entities in the power sector were listed in last 2 decades. Therefore, **it would be prudent to consider market risk premium based on 20 years of data instead of 30 years**.

4. Allowing the RoE by linking the rate of return with market interest rates such as G-Sec rates /MCLR/ RBI base rate would require an extensive study of risk profile of business for finalizing the margin to be allowed over and above the selected reference rate. Further, this margin would vary from entity to entity and would be difficult to normalise as it depends upon risk profile, organisations size, projected cash flows etc.

5. Since most of the investments will be done in the assets with useful life of 25-40 years, therefore, it would be prudent to consider a longer duration of periods for computing the beta, risk free rate and market risk premium and consequently, the expected rate of return on equity.

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:

The formula used:

$$\mathbf{Re = Rf + \beta \times (Rm - Rf)}$$

Where:

Rf = risk-free rate

β = equity beta

Rm-Rf = equity market risk premium

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

- Step 1 •Calculate historical market returns for the past 20 years (2003 – 2023) using BSE Sensex data to determine Rm
- Step 2 •Calculate risk free rate for similar period of 20 years using 10 year govt. bond yields
- Step 3 •Estimate the Beta for hydro power using data of listed Indian generating companies

The beta for NHPC has been estimated as depicted below:

Calculate equity beta for major listed generating firms and determine average of equity betas → Calculate each firm's financial leverage and determine average of financial leverage → Un-lever the average equity beta using average financial leverage to get average un-levered beta → Re-lever the average un – levered beta using normative financial leverage

The unlevered beta is then calculated using the following formula:

Unlevered Beta = $(Levered\ beta\ ot\ equity\ beta)/((1+((1-tax\ rate)x(debt/equity)))$

i. *Calculation of market return*

The market return has been estimated based on historical data of returns of BSE Sensex. The market return for a period from 2003-23 was 19.80%.

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

Risk free rate is estimated using yield of 10-year government bond. The Risk free rate (Rf) based on 10-year Indian government bond yield for 2003-23 period works out to be 7.30%.

iii. *Estimation of expected Beta for NHPC*

We have assumed the corporate tax rate as 25% and the unlevered beta is calculated through the formula:

Calculations of Unlevered Beta

Firm	Equity / Levered Beta	D/E	Tax Rate	Un-levered Beta
NTPC	0.698	1.500	25%	0.329
NHPC	0.642	0.800	25%	0.401

SJVNL	0.417	1.010	25%	0.237
TATA POWER	1.022	1.700	25%	0.449
ADANI POWER	1.228	2.560	25%	0.421
Overall Average	**0.801**			**0.367**

Re-levering the Beta

The average Un-levered Beta for key Indian generation players is levered using normative financial leverage for NHPC to give expected Equity Beta.

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

= 0.367 x (1 + (1-0.25) x (70/30))

= 1.010

Thus, the Beta for calculation for expected return for NHPC is estimated at 1.010.

iv. Calculating the expected rate of return

Expected rate of return = Rf + [b x (Rm – Rf)]

= 7.30% + [1.010 x (19.80% - 7.30%)]

= 19.93%

Thus, it can be observed that using the CAPM method, the expected return works out to be 19.93%, which is much higher than the existing number of 15.50% or 16.50%.

Expected Rate of RoE based Return on Equity Allowed in Other Infrastructure Sectors in India

i. Aviation Sector

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

$$FRoR = (g \times R_d) + ((1-g) \times R_e)$$

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

S.No.	Airport	Allowed RoE	Source
1	Indira Gandhi International Airport., Delhi	15.41%	AERA's order on determination of Aeronautical Tariff for IGI Airport, Delhi for second control period (2019-24); (Debt-Equity – 48%:52%)
2	Chhatrapati Shivaji International Airport, Mumbai	15.13%	AERA's order on determination of Aeronautical Tariffs in respect of Chhatrapati Shivaji International Airport, Mumbai for the first Regulatory Period (2019-24); (Debt-Equity – 48%:52%)
3	Rajiv Gandhi International Airport, Shamshabad, Hyderabad	15.17%	AERA's order on determination of Aeronautical Tariffs in respect of Rajiv Gandhi International Airport, Shamshabad, Hyderabad for the first control period (2021-26) ; (Debt-Equity – 48%:52%)
4	Kempegowda International Airport, Bengaluru	15.05%	AERA's order on determination of Aeronautical Tariffs in respect of Kempegowda International Airport, Bengaluru, for the third Control Period (2021-26); (Debt-Equity – 48%:52%)
5	Chennai International Airport (Airports Authority of India)	14%	AERA's order on determination of Aeronautical Tariffs in respect of Chennai International Airport, for the third Control Period (2021-26); 14% RoE allowed even though 100% equity funding was done

It can be observed that for an entity like airport with limited geographic spread, the allowed return of ~15% is comparable to electricity sector and that too is allowed with higher equity component in comparison to equity component allowed in the electricity sector.

ii. Natural Gas Transmission

The regulator for natural gas transmission, the Petroleum and Natural Gas Regulatory Board, has set a fixed RoCE of 12% for the sector.

Assuming 'Weighted Average Cost of Capital (WACC)' based approach to return on capital employed, the WACC can be calculated as:

$$WACC = g * Rd * (1 - Tc) + (1-g) * Re$$

Where:

g: gearing

Rd = Cost of debt

Tc = Tax rate

Re: Cost of equity

Based on the below assumption, the return on equity (Re) can be calculated as:

S. No.	Parameter	Assumed value	Basis
1.	Gearing (g)	70%	Based on normative gearing in power sector of country
2.	Cost of debt (R_d)	10.62%	SBI base rate + 1%
3.	Tax rate (T_c)	30%	Tax rate for corporate business in India

$$WACC = g * Rd * (1 - T_c) + (1-g) * Re$$

⇨ $12\% = 0.7 * 10.62\% * (1-30\%) + (1-0.7) * R_e$

⇨ $Re = 22.66\%$

For a sector requiring infrastructure spread across a larger geography, the allowed return is significantly higher than the electricity transmission business.

Effective RoE for Hydropower projects in India

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 40 years.

(iii)Scenario 1

<u>Assumptions</u>

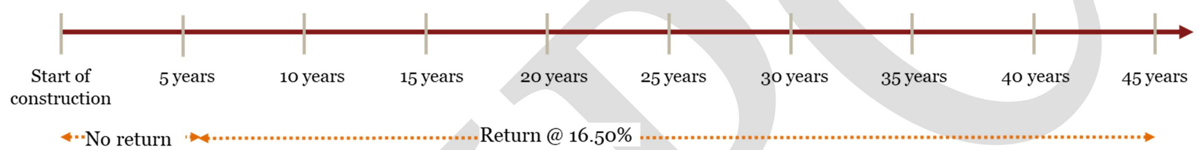
Project Construction time - 5 years

Useful Life: 40 years

Equity infusion during the construction period is as follows:

In Rs.Crores

Year	1	2	3	4	5
Opening Equity	0	10	25	50	80
Additional Equity	10	15	25	30	20
Closing Equity	10	25	50	80	100
Average Equity	5	17.5	37.5	65	90



Const. Period | **Operation Period (Useful Life)**

Year	1	2	3	4	5	6	7	8	9	10……17		18	19	20	21	22	23	24	25……37		38	39	40	41	42	43	44	45
Inflow / Outflow	-10	-15	-25	-30	-20	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5
IRR	**13.20%**																											

Effective return @ 13.20%

(iv) Scenario 2

<u>Assumptions</u>

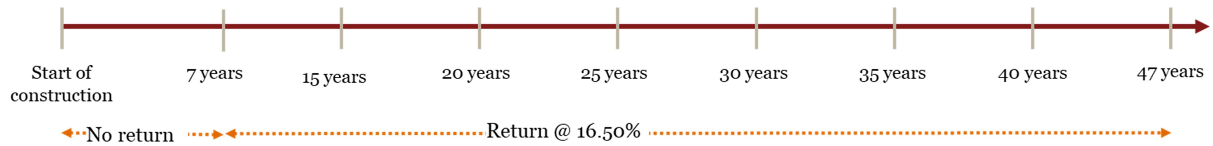
Project Construction time - 7 years

Useful Life: 40 years

Equity infusion during the construction period is as follows:

In Rs.Crores

Year	1	2	3	4	5	6	7
Opening Equity	0	10	20	35	50	70	90
Additional Equity	10	10	15	15	20	20	10
Closing Equity	10	20	35	50	70	90	100
Average Equity	5	15	27.5	42.5	60	80	95



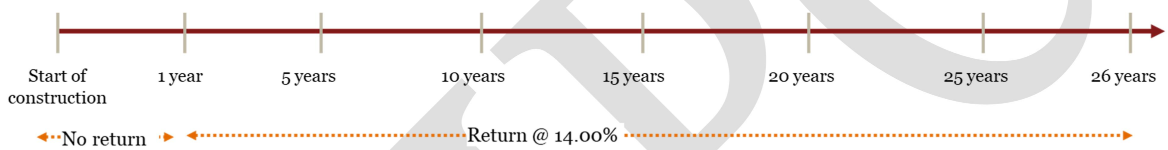
Const. Period — Operation Period (Useful Life)

Year	1	2	3	4	5	6	7	8	9	10……17		18	19	20	21	22	23	24	25……37		38	39	40	41	42	43	44	45	46	47
Inflow / Outflow	-10	-10	-15	-15	-20	-20	-10	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5	16.5
IRR	**11.76%**																													

Effective return @ 11.76%

Comparison with effective return in Renewable Sector

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



Const. Period — Operation Period (Useful Life)

Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19		10	21	22	23	24	25	26
Inflow / Outflow	-100	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
IRR	**13.40%**																										

Effective return @ 13.40%

If similar effective rate of return is to be earned by Hydropower plants based on the scenarios considered in 6.2 (D), the allowed RoE should be as follows:

Scenario	Construction Period	Effective rate of return	Required RoE
1	5 years	13.40%	16.90%
2	7 years	13.40%	19.68%

Effective RoE for Transmission Sector

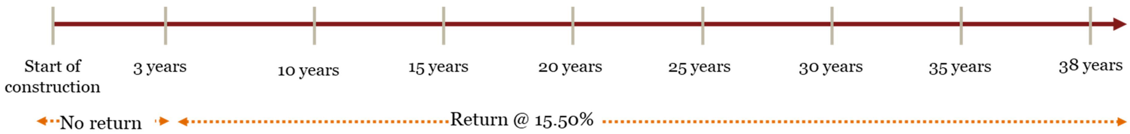
<u>Assumptions:</u>

Project Construction time period - 3 years

Equity of 100 lakhs is phased in the ratio of 40%:40%:20% during the period of construction

No equity addition during the project life

Useful Life: 35 years



	Const. Period			Operation Period (Useful Life)																					
Year	1	2	3	4	5	6	7	8	9	10……17		18	19	20	21	22	23	24	25……32		33	34	35	36	37	38
Inflow / Outflow	-40	-40	-20	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5
IRR	**13.13%**																									

Effective return @ 13.13%

Effective return for a transmission project comes at 13.13% considering no return during the construction period. This return is significantly higher than the 11.68% return for hydropower project (7-year construction period).

Effective RoE for Thermal Generation Sector

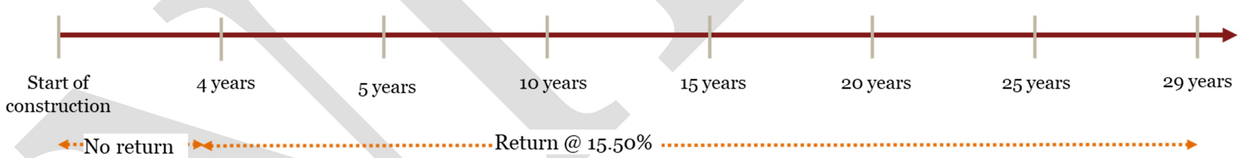
<u>Assumptions:</u>

Project Construction time period - 4 years

Equity of 100 lakhs is phased in the ratio of 20%:30%:30%:20% during the period of construction

No equity addition during the project life

Useful Life: 25 years



	Const. Period				Operation Period (Useful Life)																								
Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29
Inflow / Outflow	-20	-30	-30	-20	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5
IRR	**12.22%**																												

Effective return @ 12.22%

Effective return for a transmission project comes at 12.22% considering no return during the construction period. This return is significantly higher than the 11.68% return for hydropower project (7-year construction period).

Furthermore, hydroelectric projects have long gestation period and involves huge degree of risks viz Geological surprises, Social, Political, natural Calamities & other risks. The rate of RoE on hydroelectric projects should necessarily factor all such risks to provide reasonable return to the developers of the projects. The current RoE of 15.50%/16.50% has failed significantly to attract private developers to come forward for development of the hydroelectric projects. ***Thus, there is need to increase the RoE on hydroelectric projects to attract investment for the development of hydroelectric projects.***

Key Issue: In the present CERC Tariff Regulations, 2019 Return on Equity on Change in Law, Force majeure, safety and security is allowed at the weighted average rate of interest on loan. These works are generally carried out as per requirement of various guidelines or at the recommendation of third-party security agencies and therefore, the generating station does not have a free choice on not to execute these works. It is therefore, requested that the normal RoE should be allowed on these works. Further, linking RoE with the actual weighted average rate of interest disincentivize the generating station having better loan portfolio and excellent credit rating. Therefore, Hon'ble Commission is requested to allow ROE at normal rate for additional capitalization under Change in Law, Force Majeure or Safety and Security of the plant.

22. S. No. 4.18: Interest on Working capital

Summary of the Issue

For the section 4.18.1: Working Capital Requirement:

It is observed that the working capital norms are efficient, so the existing norms may be retained.

For the section 4.18.2: Working Capital Requirement:

As per the existing Regulations, the Bank Rate for the purpose of computing the Interest on Working Capital (IoWC) is defined as one-year MCLR plus 350 bps.

Options Proposed

- Stakeholders may comment as to whether the same may be continued or may suggest any better alternative to the same.

Our Recommendation

For the hydro power plants, water usage charges/ water cess has been levied by various states which is being paid to home states. These bills are being raised and paid to home states on monthly basis and then the bills are being raised to beneficiary states for reimbursement. As per the present methodology 45 days are provided to beneficiaries after raising of bills to clear the outstanding dues, however, the hydro generators have to pay these levies on monthly basis, thus leading to cash crunch issue. The annual payment in regard to water cess to various states is to the tune of Rs 1500-1600 cr. **Therefore, it is proposed to include water cess / water usage charges based on design energy or any other statutory charges or taxes levied on monthly basis reimbursable to the generating company under working capital to compensate for loss of interest.**

23. S. No. 4.17: Tax Rate

Summary of the Issue

The Commission has clearly specified that the MAT rate shall be considered for grossing up RoE in cases where the company is paying MAT, as the MAT Rate cannot be higher than the rate notified under the relevant Finance Act. A similar analogy is relevant in case the company is required to pay Corporate Tax Rate or falls under any other tax bracket as per the relevant Finance Act as applicable from time to time. In such cases, the grossing up of RoE shall be at the effective tax rate which can be a rate in between MAT and the Corporate Tax Rate, or any other tax bracket as may be specified from time to time, however, such effective tax rate considered for the grossing up of RoE under no circumstances can be higher than the rate specified under the relevant Finance Act.

Options Proposed

The Paper proposes that the Base Rate of RoE may be grossed up as following:

- At MAT rate (If not opted for Section 115 BAA)
- At effective tax rate (if not opted for Section 115BAA) subject to ceiling of Corporate Tax Rate
- At reduced tax rate under Section 115BAA of the Income Tax Act or any other relevant categories notified from time to time subject to ceiling of rate specified in the relevant Finance Act.
- Further, tax shall be allowed only in cases where the company has actually paid taxes as under no circumstances tax can be allowed to be recovered if the company has not paid any tax for the year under consideration.

Our Recommendation

1.0 In CERC Tariff Regulations, 2014, the concept of an effective tax rate was introduced which was also made applicable to Tariff Regulations for 2019-24. This was done in order to pass on the benefits and concessions available in income tax to the beneficiaries.

1.1 In-fact, during the earlier tariff period, i.e. FY 2009-14, the concept of applicable tax rate was used for grossing up the rate of Return on Equity [ROE]. However, the concept of Effective Tax Rate was introduced by the Hon'ble Commission vide Tariff Regulations, 2014 in order to allow the net of tax ROE of 15.5%/16.5% for Tariff Period 2014-19 which was also continued in Tariff Regulation 2019-24.

1.2 The concept of Effective Tax Rate is a tax neutral approach wherein the benefits and concessions available in income tax are passed on to the beneficiaries and on the other hand, it allows generating company to get net of taxes ROE of 15.5%/16.5%.

1.3 Every company is first required to compute tax on the 'taxable income' as per the Normal Provisions of the Income Tax Act. While computing 'taxable income', the company has to make adjustments on account of various disallowance/deductions and exemptions allowed under the provisions of Income Tax Act. Thus, the taxable income is different than the income shown in Profit and loss account.

Grossing up Return on Equity [ROE] while paying tax under Normal Provision of Income Tax

2.1 In the case of income tax payment under normal provision of Income Tax Act [Corporate Tax] the views of the Commission is that the grossing up of ROE shall be at the effective tax rate which can be a rate in between MAT and the Corporate Tax Rate or any other tax bracket as may be specified from time to time, however, such effective tax rate considered for the grossing up of ROE under no circumstances can be higher than the rate specified under the relevant Finance Act i.e. Corporate Tax/MAT. This view is not correct as the Effective Tax Rate of the generating company may be higher than the Corporate Tax rate and vice versa. The major reasons for higher effective tax rate than the corporate tax rate are as follows:

2.1.1 While determining whether a particular expenditure is deductible or not, the first requirement must be to enquire whether the deduction is expressly prohibited under any other provision of the Income tax Act.

2.1.2 If it is not so prohibited, then the allowability may be considered under Section 37(1) of Income Tax Act, 1961.

2.1.3 Section 40 and 40A of Income Tax Act, 1961 provides for non-deductible expenses or payments.

2.1.4 Under Section 43B of Income Tax Act, 1961, certain deductions are to be allowed only on actual payment.

<u>Grossing up of ROE by the generating company while paying tax under MAT</u>

3.1 In certain Truing Up cases of NHPC Limited, CERC has summarily grossed up the ROE with MAT rate instead of 'Effective Tax Rate'. Further, in the proposed regulation, Hon'ble Commission has also proposed that if the generating Company is paying MAT, the income tax rate for grossing up purpose will be MAT.

3.2 In this regard following is submitted:

3.2.1 As per the provisions of section 115JB, 'book profit' is to be computed in accordance with Explanation 1 below sub-section (2) of section 115JB. As per Explanation 1, 'book profit' means profit as shown in the Profit and loss account, as increased and reduced by various items mentioned in this Explanation, which includes amount set aside as provisions made for meeting liabilities, other than ascertained liabilities, and also amounts set aside as provision for diminution in value of any asset which will include provision for bad debt/obsolete stocks/stores, etc.

3.2.2 Thus, the book profit on which MAT is to be paid is different than the profit as per Profit and loss account.

3.2.3 Thereafter, every company is required to compare the **(i)** tax liability under the Normal Provisions as computed in terms of para 2 hereinabove and **(ii)** the MAT tax liability as computed in terms of para 3 hereinabove. In case the liability under MAT exceeds the tax payable under Normal Provisions [Corporate Tax] of the Income Tax Act, then the company has to pay tax as computed under MAT provisions.

3.2.4 However, the tax so paid in excess by way of MAT over and above the tax payable under the Normal Provisions [Corporate Tax] is allowed to be carried forward as MAT Credit and to be adjusted in the year in which the tax liability under Normal Provisions is more than the tax liability under MAT Provisions.

3.2.5 Accordingly, whatever tax is paid by way of MAT in excess of the tax liability under normal provisions, full credit of the same is allowed in the subsequent years.

3.2.6 In this connection, it would be pertinent to note that in case tax paid in the year under MAT is more than the MAT rate consequent to the adjustment in book profit, the MAT credit allowed to be carried forward will be higher than the MAT computed as per the version of CERC for allowing MAT Rate while grossing up ROE.

3.2.7 In-fact, in the subsequent year when there is a liability under the Normal Tax Provisions, the MAT Credit to be adjusted under the Normal Tax Provisions will be higher i.e. Actual MAT paid and not the MAT as per MAT rate as allowed by CERC. With the result that the regular tax liability of that year will also be lower since in such year, tax rate to be taken into consideration will be the net actual normal tax paid, i.e. after MAT Credit carried forward.

3.2.8 In other words, net tax paid in this year will be lower and, in this year, the adjustment will be that of actual MAT tax paid and not the MAT computed as per MAT rate.

3.2.9 Thus, in the year in which tax is being computed under MAT, the generator is allowed tax on the basis of MAT rate instead of effective tax rate, whereas in the year in which tax liability is arising under normal tax [Corporate Tax], the same will be computed after adjustment of MAT carried forward, which is based on effective tax rate and not the MAT rate as allowed by CERC.

3.2.10 In this connection, example for above is given hereunder:

Year 1 - While generating company paying tax under MAT

Particulars	Amount (Rs./-)
Profit as per P/L Account	100 cr
Taxable Income	40 cr
Book profit for 115JB (MAT)	110 cr
Tax Rate	30%
MAT Tax Rate	18%
Normal Tax (@ 30% of Rs. 40 crore)	12 cr
MAT (@ 18% of Rs. 110 crore)	19.8 cr
Tax to be paid by generating company (Higher of the two)	19.8 cr
MAT to be allowed as per interpretation of Honourable Commission (18% of profit)	18 cr
Carry forward of MAT credit	7.8 cr (19.8 – 12 cr)
<u>Note:</u>	

If ROE is grossed up with MAT Rate (i.e. 18%) instead of Effective Tax Rate i.e 19.80% (19.80/100*100) beneficiary will only pay Rs. 18.00 Crore and remaining tax shall be borne by the generating Company.

Year 2 - While generating company paying tax under Normal Provisions with utilization of MAT Credit)

Particulars	Amount (Rs./-)	
Profit as per P/L Account	100 cr	
Taxable Income	160 cr	
Book profit for 115JB (MAT)	90 cr	
Tax Rate	30%	
MAT Tax Rate	18%	
Normal Tax (@ 30% of Rs. 160 crore)	48 cr	
MAT (@ 18% of Rs. 90 crore)	16.20 cr	
Tax Payable (Higher of the two)	**CERC Version** 48.00 cr	**NHPC Version** 48.00 cr
MAT credit utilized	7.80 cr	6 cr
Net effective tax to be allowed by Honourable Commission	40.20 cr	42 cr
Reconciliation of Tax Paid and Recovered:-		
Actual Tax Paid in both years (i.e. Year 1 and Year 2)	(19.80 + 40.20) = 60.00 Crores	
Tax Recovered from Beneficiary in both years as per proposed commission view (i.e. Year 1 and Year 2)	(18.00+40.20) = 58.20 Crores	
Short Recovery of Tax	= 1.80 Crores	

Note:

1. **Thus, the net tax of Rs. 1.80 cr will be lost as per the interpretation of Hon'ble Commission since this amount shall be considered while calculating effective tax rate whereas the same has not been actually paid by the beneficiaries.**

2. **Accordingly, the carry forward amount of MAT Credit of year 1 will be divided in two parts. Beneficiaries portion of Rs. 6.00 Crore [18-12] which will be allowed in future for calculation effective tax rate when generating company paying tax under Corporate Tax and remaining portion of MAT credit of Rs. 1.80 Crore shall not be considered for calculation of effective tax rate.**

3.2.11 It is further submitted that MAT Tax is not different than the Normal Tax. MAT is only a mechanism to collect tax with full adjustment by way of MAT Credit against Normal Tax.

4.0 Conclusion:

4.1 In view of the above discussions, it is submitted that the mechanism of Effective Tax Rate, as explained above, should be continued for future Tariff Periods also so that recovery of net of taxes ROE may be possible from the beneficiaries. It is a tax neutral exercise on the part of the generator.

4.2 Accordingly, Base Rate of ROE may be continued to be allowed to be grossed up at Effective Tax Rate (both under MAT/Normal Tax) only as explained above for Future Tariff Periods also irrespective of whether the same is lower/higher than the MAT/Corporate Tax Rate.

4.3 Further, utilization of MAT Credit shall also be construed as actual tax paid while calculating Effective Tax Rate.

24. S. No 4.22 Treatment of Arbitral Award – Servicing of Principal and Interest Payment

Pursuant to the decision taken by the CCEA, for revival of construction sector NITI Ayog vide OM no. 14070/14/2016-PPPAU dated 05.09.2016 titled "Measures to revive construction sector-reg" has stipulated that all the work executing agencies are required to pay @75% of the total payout (arbitral award including interest thereon) should be released to contractor against a bank guarantee subject to final order of the court.

The said amount paid is shown as Advance paid in the balance sheet and cannot be capitalized till the settlement of the case and thus, the same cannot be claimed in the tariff by NHPC. This is resulting in loss of interest to the company. Therefore, Commission is requested to kindly provide some provision to allow the petitioner to claim tariff on the said amount or allow the generating company to claim the interest on the finally settled amount from the date of payment of advance till the settlement date.

Further, provision for amicable settlement of dispute may also be introduced. If dispute is settled amicably, i.e. without any court order/arbitral tribunal order, such awarded amount after approval of the Board of the respective company be considered fit for capitalization. Such process is less time consuming and the potential interest burden of the consumer is substantially decreased. **Presently, Vivad se Vishwas II (Contractual Disputes) has been issued which provides for final settlement of the contractual disputes at 65% of award amount in case of arbitral award and 85% amount in case of court orders. Hon'ble Commission is requested to provide provision in the tariff regulations to allow the generating companies to claim tariff of the settlement amount under this scheme.**

25. S. No 4.23: Treatment of interest on differential tariff after truing up

Summary of the Issue

The differential amount of tariff as per previous tariff order or interim tariff order and trued up tariff order needs to be recovered or refunded with simple interest in six equal monthly instalments

Options Proposed

Interest may be allowed to be charged on the differential amount by the utility only until the issuance of the order, and no interest may be allowed during the recovery in six equal monthly instalments.

Our Recommendation

Commission has proposed to charge the interest till issuance of order and no interest has been allowed for the six months recovery period. This approach will result in loss of working capital interest to the generating companies. **Therefore, it is proposed to allow the recovery of differential tariff in six equated monthly installments (EMI) instead of equal monthly installments**.

26. S. No. 5.1: Normative Annual Plant Factor (NAPAF)

Summary of the Issue

The Normative Annual Plant Availability Factor (NAPAF) has been specified considering the past years' data and best industry practices. However, due to changing dynamics such as technological improvement, better O&M practices, and shorter shutdowns and outages, the PAF has improved. For Hydro generating stations, PAF is also impacted due to changing hydrology, and restrictions imposed on the flow of water, and changes in the pattern of water usage in the case of multipurpose dam projects. Hence the existing norms of NAPAF needs review.

Further, it is observed that current Regulations, although specifies the mechanism for computing PAF of storage based hydro generating stations, do not specify a methodology for computing PAF of Run-of River (ROR) Plants. There is a need to specify a mechanism for the same, and based on such a specified mechanism, the current NAPAF value may need reconsideration.

Options Proposed

The Paper discusses the following:

- Review of existing norms of NAPAF due to improvement of PAF because of technological improvement, better O&M practices, and shorter shutdowns and outages.
- Suggestions for finding mechanism for computing PAF for ROR Plants.

Our Recommendation

Mechanism for computing PAF for RoR plants used in other Countries:

1. **United States**: In the United States, the Federal Energy Regulatory Commission (FERC) regulates the calculation of availability factors for hydroelectric projects. The PAF for RoR hydro plants is typically determined by dividing the actual energy generated during a specific period by the energy that could have been generated if the plant had operated at its full capacity for the same duration.
2. **European Union**: In the European Union, the calculation of the PAF for RoR hydro plants may vary across member states. Generally, the PAF is computed by dividing the actual electricity generation over a given period by the maximum achievable generation capacity, considering factors such as water availability, maintenance downtime, and grid curtailment.

   Canada: Canada has different provincial regulations for determining the PAF of hydroelectric plants, including RoR facilities. Typically, the PAF is calculated as the ratio of the actual energy produced by the plant during a specified period to the energy that could have been generated if the plant had operated at its full capacity for the same duration.

One option can be to re-introduce the methodology that was being adopted in the CERC Tariff Regulations, 2004. Based on Regulation XI (b) under Chapter 3 of the Tariff Regulations, 2004, the methodology can be specified as follows:

"In case of purely run-of-river power stations, declared capacity means the ex-bus capacity in MW expected to be available from the generating station during the day (all blocks), as declared by the generating station, taking into account the availability of water, optimum use of water and availability of machines;"

In the approach paper, Commission has identified that the present regulation does not specify methodology for calculation of PAF for RoR plants. Therefore, Commission has decided to re-introduce the methodology adopted in 2004 tariff regulations. However, in the proposed methodology, only DC has been defined.

We are of the view that Run of River (RoR), Hydro Power Stations having limited or no storage system. Operation of such Power Plant depends on the real time inflow. During high hydro season, the sufficient inflow is available to operate the Power Station on its MCR, however, during lean season, the operation of all units on its MCR on continuous basis (12-time blocks) is not possible being less inflow. If the DC of purely RoR plant is calculated based on Ex-bus capacity in MW expected to be available during next day, then the recovery of capacity charge by the hydro generator would be difficult and will put hydro sector in distress. Hon'ble Commission will appreciate the fact that most of ROR power stations of NHPC are located in the state of J&K and lot of operational difficulties are faced especially related to law and order issues and high level of silt (specially in Salal power station). Presently, allowance is allowed by the Commission in NAPAF determination under special circumstances, e.g. abnormal silt problem or other operating conditions, and known plant limitations

Therefore, following is proposed:

The Declare Capacity of purely RoR Hydro Power Plants may be calculated based on average of any maximum declaration of 12 time blocks (3 hours) in a day, which is the current the practice subject to maximum of NAPAF presently fixed by CERC to avoid further stressing the plant.

However, more clarity may be provided whether that calculation of PAF shall be as per DC calculation as defined in the approach paper or will the methodology of Capacity index will be introduced for RoR plants.

27. S. No 5.1.2: Recovery of Energy Charge for Hydro Generating Stations

Summary of the Issue

The tariff structure for hydro generating stations follows a two-part tariff in which the 50% of the recovery of AFC is linked to achieving NAPAF, and the balance 50% is termed as Energy Charge and its recovery is linked to actual generation.

In the event of any shortfall in actual generation below the saleable design energy (the same is allowed to be recovered as per Regulation 44(7)) then the hydrological risk is being passed on to the consumers. Along with this the existing provisions of the shortfall in recovery of AFC are leading to complications in the recovery process, wherein the affected generating company has to file petitions seeking such recovery.

Options Proposed

The Paper discusses the following:

- Ways to simplify the tariff recovery process.

Our Recommendation

1. According to CERC Regulation 44(7):

   "Shortfall in energy charges in comparison to fifty percent of the annual fixed cost shall be allowed to be recovered in six equal monthly installments:

   Provided that in case actual generation from a hydro generating station is less than the design energy for a continuous period of four years on account of hydrology factor, the generating station shall approach the Central Electricity Authority with relevant hydrology data for revision of design energy of the station."

   We are of the view that more clarity is required on the change in the methodology, which Commission is envisaging for recovery of AFC components - 50:50 for Capacity Charges and Energy Charges. The existing mechanism of AFC recovery from Capacity Charges and Energy Charges in 50:50 ratio, is a well settled mechanism as it balances the interest of generating station as well as the beneficiaries. Further, the Commission is allowing recovery on account of generation lower than design energy only in cases which is beyond the control of the generation company; else the loss on AFC is on the account of Generation Company only. **Therefore, it is proposed that Hon'ble Commission may continue with the existing mechanism of recovery of AFC with the liberty for recovery of shortfall in energy charges for reasons beyond the**

control of generating station directly from the beneficiaries, the details of which along with calculation shall be submitted at the time of truing up.

28. S. No. 5.10: Incentives

Summary of the Issue

Incentives in the existing Tariff Regulations have been linked to NAPLF, NAPAF and NATAF.

Options Proposed

The Paper discusses the following:

- Incentives linked to generation in excess of target PLF/NAPAF especially during peak periods, in the case of hydro stations and old pit-head generating stations, may need a review in order to encourage higher generation from such plants. This will result in increased generation from such plants and will also benefit beneficiaries.

Our Recommendation

The National Tariff Policy dated 28.01.2016 states as follows:

*"**5.0 GENERAL APPROACH TO TARIFF***

….

6.11 Tariff policy lays down the following framework for performance based cost of service regulation in respect of aspects common to generation, transmission as well as distribution. These shall not apply to competitively bid projects as referred to in para 6.1 and para 7.1 (6). Sector specific aspects are dealt with in subsequent sections.

….

f) Operating Norms

Suitable performance norms of operations together with incentives and disincentives would need to be evolved along with appropriate arrangement for sharing the gains of efficient operations with the consumers. Except for the cases referred to in para 5.11(h)(2), the operating parameters in tariffs should be at "normative levels" only and not at "lower of normative and actuals". This is essential to encourage better operating performance. The norms should be efficient, relatable to past performance, capable of achievement and progressively reflecting increased efficiencies and may also take into consideration the latest technological advancements, fuel, vintage of *equipments, nature of operations, level of service to be provided to consumers etc. Continued and proven inefficiency must be controlled and penalized.*

.....”

In the existing tariff regulations, the hydro generating stations have their incentives linked to availability in excess of target NAPAF which is linked to DC as declared by the power station, however, no incentive has been linked for energy generation during peak period. Thus, a hydro power plant is generally getting a tariff in the range of Rs.1.5 to Rs.5/kWh (considering composite tariff instead of ECR with most of the plant having tariff below Rs.3/kWh) for providing energy during peak hours in comparison to Market Clearing Price (MCP) of Rs.8 - Rs.10/kWh in Power Exchange during peak hours. Further, a hydro generating station has to supply energy at the rate of Rs.1.2/kWh or ECR, whichever is lower, once the saleable schedule energy of the power station exceeds the saleable design energy. Thus, on one hand the hydro generators are not incentivized for the generation of energy during peak hours, on the other they have to supply power at lower rates once design energy is achieved.

In view of NHPC, there is need for providing incentives to ROR/ ROR with storage plants. Few suggestions are as under:

a) The energy generated by hydro power plants during peak hours should be linked to market rate. This is more essential in case of ROR plants if the Hon’ble Commission comes up with the methodology of calculation of DC as proposed in the approach paper as the ROR plants shall have no incentives for maximizing their generation during peak hours. It is therefore, proposed to provided incentive at the rate of 10% of MCP during peak hours for energy generated during peak hours.

b) The hydropower plants should be incentivized properly for energy generated beyond design energy. Presently, hydro generated plants are paid incentive at Rs 1.2/kWh or ECR, whichever is lower, which is very minimal based on the support provided by the hydropower plant. Therefore, it is proposed to either link the secondary energy rate with the market or increase the rate from Rs 1.2/kWh. Further, presently the secondary energy charge rate is provided based on the lowest Energy Charge Rate of Thermal Power Plant to have the highest priority on merit order dispatch and therefore the secondary energy charge rate should not be allowed to go below the secondary energy charge rate. It is therefore proposed to not limit the secondary energy charge rate to ECR, whenever ECR is below the secondary energy charge rate.

S. No. 6.3 & 6.6: Decommissioning/Upgradation/Replacement of Assets

Summary of the Issue

With growing concerns of inefficient generation assets and their impact on climate change, sometimes these assets are decommissioned before completion of their useful life. These assets have both decommissioned cost as well as some salvage value. Regulation 19 (5) of the Tariff Regulations 2019 has a provision of getting assets replaced or removed from service on account of upgradation or obsolescence. The Paper discusses ideas for treatment of unrecovered depreciation.

Options Proposed

The Paper discusses the following:

- Possible approaches to recover or refund the impact of decommissioning costs in case the generating stations/transmission systems are decommissioned before the completion of their useful lives, if such decommissioning is done in compliance of a statutory order or due to technological obsolescence duly approved by RPC.

Our Recommendation

1. Decommissioning of assets is only applicable for the thermal stations and It's not applicable for the hydro power plants.
2. For replacement or upgradation of assets, NHPC has replaced some of the equipment mainly on account of technological obsolescence, for example upgradation to the SCADA systems, where the existing communication equipment had not completed the useful life. Therefore, for such cases, the recovery of unrecovered depreciation may be allowed separately by the Hon'ble Commission.
3. There are two approaches that the Hon'ble Commission may follow regarding the treatment of unrecovered depreciation:
    a. Either allow remaining deprecation as part of tariff spread over the remaining useful life, or
    b. One time allowance of unrecovered depreciation, that may be allowed to be recovered in three monthly instalments.

29. S. No. 6.7: Assumed Deletions

Summary of the Issue

As per the extant methodology, the Commission verifies the expenditure on replacement of assets; and if found justified, the same is allowed for the purpose of tariff, provided that the capitalization of the asset is considered against the de-capitalization of the original value of the corresponding old asset. However, in certain cases where de-capitalization is affected in books during the years following the year of capitalization of a new asset, the decapitalization of the old asset for the purpose of tariff, is affected from the very same year in which the capitalization of the new asset is allowed. Such decapitalization, which is not a book entry in the year of capitalization, is termed "Assumed deletion".

Options Proposed

The Paper discusses the following:

To continue to consider the gross value of the asset being de-capitalized, by de-escalating the gross value of the new asset @ 5% per annum until the year of capitalization of the old asset.

Our Recommendation

Assumed Deletion is carried out in tariff forms under two cases:

a. The asset under consideration is part of a larger scheme and the individual value of the asset may not be available.

b. The value of the old asset is available in the books of account; however, the asset has not been decapitalized during the year of capitalization of new asset.

In view of NHPC, assumed deletion in cases where the value of old asset is available, it is proposed that the value of old asset may be considered as provided by the generating station as the value of old asset is as per books of accounts.

In case of asset where value of old individual asset is not available, it is proposed that the value of old asset may be decapitalized by de-escalating the gross value of the new asset using the Cost Inflation Index (CII) issued by Income Tax Department, Government of India as submitted by the generating company at the time of filing the tariff petition as the same methodology is followed in preparation of annual accounts as well which shall be provided at the time of filing of petition.

30. Additional comments

a) Tariff norms required for Pumped Storage Projects (PSP)

Summary of the Issue

Separate tariff norms required for Pumped Storage Projects (PSP).

Background

Pumped Storage Hydro (PSH) is the most flexible form of hydropower plant which has the capability to aid in peak shifting by pumping power during non-peak hours and supplying power during peak hours. In India, most of the PSP plants have a capacity to provide 5-8 hours of storage. PSH plants also have capacity to provide balancing support, system inertia, frequency response, grid regulations, black start capacity and operation in synchronous condenser mode. We can also see that the world focusses on storage-based solutions based on green power, it is high time we look forward to hydro based PSPs (Pump Storage Projects) in the country providing them with necessary support. Hence, we request CERC to develop separate tariff norms and develop the recovery mechanism for PSP as per the various guidelines and market scenario.

The existing tariff recovery mechanism for PSPs in the present regulation is as under:

"(1) The fixed cost of a pumped storage hydro generating station shall be computed on annual basis, based on norms specified under these regulations, and recovered on monthly basis as capacity charge. The capacity charge shall be payable by the beneficiaries in proportion to their respective allocation in the saleable capacity of the generating station, i.e., the capacity excluding the free power to the home State:

Provided that during the period between the date of commercial operation of the first unit of the generating station and the date of commercial operation of the generating station, the annual fixed cost shall be worked out based on the latest estimate of the completion cost for the generating station, for the purpose of determining the capacity charge payment during such period.

(2) The capacity charge payable to a pumped storage hydro generating station for a calendar month shall be:

(AFC x NDM / NDY) (In Rupees), if actual Generation during the month is >= 75 % of the Pumping Energy consumed by the station during the month and {(AFC x NDM / NDY) x (Actual Generation during the month during peak hours/ 75% of the Pumping Energy consumed by the

station during the month) (in Rupees)}, if actual Generation during the month is < 75 % of the Pumping Energy consumed by the station during the month.

Where,

AFC = Annual fixed cost specified for the year, in Rupees

NDM = Number of days in the month

NDY = Number of days in the year

Provided that there would be adjustment at the end of the year based on actual generation and actual pumping energy consumed by the station during the year.

(3) The energy charge shall be payable by every beneficiary for the total energy scheduled to be supplied to the beneficiary in excess of the design energy plus 75% of the energy utilized in pumping the water from the lower elevation reservoir to the higher elevation reservoir, at a flat rate equal to the average energy charge rate of 20 paise per kWh, excluding free energy, if any, during the calendar month, on ex power plant basis.

(4) Energy charge payable to the generating company for a month shall be:

= 0.20 x {Scheduled energy (ex-bus) for the month in kWh – (Design Energy for the month (DEm) + 75% of the energy utilized in pumping the water from the lower elevation reservoir to the higher elevation reservoir of the month)} x (100 – FEHS)/ 100.

Where,

DEm = Design energy for the month specified for the hydro generating station, in MWh

FEHS = Free energy for home State, in per cent, as mentioned in Note 3 under Regulation 55 of these regulations, if any.

Provided that in case the Scheduled energy in a month is less than the Design Energy for the month plus 75% of the energy utilized in pumping the water from the lower elevation reservoir to the higher elevation reservoir of the month, then the energy charges payable by the beneficiaries shall be zero."

Recommendations:

a. The present regulations only consider a scenario where the energy has been arranged by the beneficiaries DISCOMs. These need to be revised in view of the fact that the energy required for pumping can be arranged by the developer from RE sources in view of waiver of inter-state transmission charges allowed when the pumping energy from RE sources is at least 51% of total pumping energy.

b. Ministry of Power has issued guidelines to promote development of Pump Storage Projects on 10th April 2023, wherein following points have been highlighted

i. No free power and LADF to be provided by PSPs

ii. Monetization of services offered by PSPS, like spinning reserves, reactive support, black start ability, frequency response ancillary services and faster start-up and shutdown,

iii. 80% power generated when PSPS operate as conventional hydro power stations during monsoon period (i.e. no pumping energy required for power generation) would be offered to the Home State at the rate of secondary energy fixed by the Central Electricity Regulatory Commission. The developer shall be allowed to sell the remaining energy to cover their Operation & Maintenance costs and other expenses.

iv. ln the event of capacity contracted not being fully utilized by the contracting agency, the developer would be free to transfer the usage of the capacity to other interested entities so that resources do not remain idle. The gains made shall be shared with the original beneficiary in the ratio of 50:50

These provisions need to be suitable incorporated along with modalities in the existing Tariff Regulations for PSPs.

c. The present regulation talks about payment of energy charges @ 20 paise/kWh when schedule energy of the month is greater than Design Energy of the month plus 75% of total energy pumped. The condition proposed can be achieved in a scenario when PSP is an on-river PSP and is generating electricity without pumping during high inflow season or the energy has been generated in excess of 75% of the pumped energy i.e. the cycle efficiency is higher than 75%. Therefore, the incentive provided to PSP in the form of energy charge may be reviewed as per the guidelines of MoP.

d. The Commission may also lay down the modalities of determination of Tariff for PSPs developed under RTC mode for plants whose tariff is to be determined as per Section-62 of The Electricity Act, 2003 for the projects allocated by the sates and to be developed under RTC model.

b) Incentive for early commissioning of projects

Summary of the Issue

Need for Incentive for early commissioning of projects

Recommendation

Unlike thermal or gas generating plants, each of the hydropower plants have different design criteria based on their geographical locations, geology of the area, local factors such as availability of construction materials, etc., which leads to longer gestation period. Further, the hydro generation plays an important role of smoothening the peak load due to lower ramping up time, grid reliability and stability. Therefore, there is a need to incentivise the early commissioning of the hydro projects and accordingly, an additional RoE of 0.5% to 1.00% may be considered based on 5 years or higher (in case of large projects) of construction time from the award of the EPC contract for the project.

Annexure-I

CASE STUDY IN CASE OF ERV VS HEDGING COST IN CASE OF JPY LOAN OF DHAULIGANGA PROJECT TARIFF PERIOD 2019 TO 2024 (UPTO MARCH 2023)												
YEAR	PERIOD	LOAN JPY	REP JPY	INT JPY	RATE JPY	RATE 01.04.19	REP RS	INT RS	REP ERV	INT ERV	ALT-I TOTAL ERV	ALT-II HEDGING COST @ 6%
2019-20												
ID-107	18.07-2019	1697766000	121269000	19363835	0.635967	0.6330	77123082	12314760	359805	57452	417258	32240576
ID-107	17.01.2020	1576497000	121269000	18278727	0.644250	0.6330	78127553	11776070	1364276	205636	1569912	29937678
ID-129	18.06.2019	7160940000	397830000	82125191	0.645017	0.6330	256607113	52972144	4780723	986898	5767622	135986251
ID-129	18.12.2019	6763110000	397830000	77988849	0.649780	0.6330	258501977	50675594	6675587	1308653	7984240	128431459
ID-153	18.09-2019	8815710000	293857000	57773091	0.661012	0.6330	194243003	38188706	8231522	1618340	9849862	167410333
ID-153	18.03.2020	8521853000	293857000	55240285	0.692217	0.6330	203412811	38238264	17401330	3271164	20672494	161829988
2020-21												
ID-107	17.07.2020	1455228000	121269000	16689272	0.7011890	0.6330	85032489	11702334	8269212	1138025	9407237	27634780
ID-107	19.01.2021	1333959000	121269000	15466615	0.7044000	0.6330	85421884	10894684	8658607	1104316	9762923	25331881
ID-129	18.06.2020	6365280000	397830000	73401269	0.7128150	0.6330	283579191	52321526	31752801	5858522	37611324	120876667
ID-129	18.12.2020	5967450000	397830000	68813691	0.7111080	0.6330	282900096	48933966	31073706	5374900	36448605	113321876
ID-153	17.09.2020	8227996000	293857000	53921551	0.7022200	0.6330	206352263	37864792	20340782	3732450	24073231	156249644
ID-153	18.03.2021	7934139000	293857000	51148024	0.6658410	0.6330	195662039	34056451	9650558	1679752	11330310	150669300
2021-22												
ID-107	16.07.2021	1212690000	121269000	13831310	0.6783360	0.6330	82261128	9382276	5497851	627056	6124908	23028983
ID-107	18.01.2022	1091421000	121269000	12654503	0.6482320	0.6330	78610446	8203054	1847169	192753	2039923	20726085
ID-129	17.06.2021	5569620000	397830000	63875148	0.6677500	0.6330	265650983	42652630	13824593	2219661	16044254	105767084
ID-129	15.12.2021	5171790000	397830000	59638531	0.6690600	0.6330	266172140	39901756	14345750	2150565	16496315	98212292
ID-153	17.09.2021	7640282000	293857000	50070012	0.6684820	0.6330	196438115	33470902	10426634	1776584	12203218	145088955
ID-153	16.03.2022	7346425000	293857000	47359282	0.6456662	0.6330	189733541	30578289	3722060	599864	4321924	139508611
2022-23												
ID-107	18.07.2022	970152000	121269000	11065048	0.5783750	0.6330	70138958	6399747	-6624319	-604428	-7228747	18423186
ID-107	18.01.2023	848883000	121269000	9842391	0.6242000	0.6330	75696110	6143620	-1067167	-86613	-1153780	16120288
ID-129	17.06.2022	4773960000	397830000	54750127	0.5823000	0.6330	231656409	31880999	-20169981	-2775831	-22945812	90657500
ID-129	16.12.2022	4376130000	397830000	50463373	0.6036000	0.6330	240130188	30459692	-11696202	-1483623	-13179825	83102709
ID-153	16.09.2022	7052568000	293857000	46218473	0.5561000	0.6330	163413878	25702093	-22597603	-3554201	-26151804	133928266
ID-153	17.03.2023	6758711000	293857000	43570539	0.6206000	0.6330	182367654	27039877	-3643827	-540275	-4184101	128347922
						TOTAL	**4249233051**	**691754225**	**132423867**	**24857621**	**157281489**	**2252832314**
									ADDITIONAL F.I. IN CASE OF HEDGING			2095550826

Annexure-II

DETAILS OF BONDS RAISED OVER A PERIOD, MORATORIUM PERIOD & TOTAL TENOR

Particulars	Sanction Details			Repayment Terms	Closing Balance as on 31.05.2023 Rs/Crore	Effective Rate of Interest
	Agreement Date/ Settlement Date	Tenor	Amount			
P-SERIES BONDS	01.02.2010	15 Years	2000.00	10 equal annual installments commencing from 01.02.2016 to 01.02.2025	400.00	9.00%
Q-SERIES BONDS	12.03.2012	15 Years	1266.00	12 equal annual installments commencing from 12.03.2016 to 12.03.2027	422.00	9.25%
R1 SERIES BONDS	11.02.2013	13 Years	82.20	12 equal annual installments commencing from 11.02.2015 to 11.02.2026	20.55	8.70%
R2 SERIES BONDS	11.02.2013	14 Years	382.08	12 equal annual installments commencing from 11.02.2016 to 11.02.2027	127.36	8.85%
R3 SERIES BONDS	11.02.2013	15 Years	892.00	10 equal annual installments commencing from 11.02.2019 to 11.02.2028	446.00	8.78%
TAX FREE BOND 1A SERIES	02.11.2013	10years	50.81	On maturity i.e. 2.11.2023	50.81	8.18%
TAX FREE BOND 1B SERIES	02.11.2013	10years	60.77	On maturity i.e. 2.11.2023	60.77	8.43%
TAX FREE BOND 2A SERIES	02.11.2013	15years	213.12	On Maturity i.e. 2.11.2028	213.12	8.54%
TAX FREE BOND 2B SERIES	02.11.2013	15years	85.61	On maturity i.e. 2.11.2028	85.61	8.79%
TAX FREE BOND 3A SERIES	02.11.2013	20years	336.07	On maturity i.e. 2.11.2033	336.07	8.67%
TAX FREE BOND 3B SERIES	02.11.2013	20years	253.62	On maturity i.e. 2.11.2033	253.62	8.92%
S1 SERIES BONDS	26.11.2014	10years	365.00	10 equal annual installments commencing from 26.11.15 to 26.11.2024	73.00	8.49%
S2 SERIES BONDS	26.11.2014	15years	660.00	12 equal annual installments commencing from 26.11.2018 to 26.11.2029	385.00	8.54%
T SERIES BONDS	14.07.2015	15 Years	1474.92	12 equal annual installments commencing from 12.07.2019 to 14.07.2030	983.28	8.50%
U SERIES BONDS	27.06.2016	15 Years	540.00	On maturity i.e. 27.06.2031	540.00	8.24%
U1 SERIES BONDS	07.07.2016	14 Years and 355 Days	360.00	On maturity i.e. 27.06.2031	360.00	8.17%
V2 SERIES BONDS	06.06.2017	10 Years	1475.00	5 equal annual installments w.e.f.06.06.2023 to 06.06.2027	1475.00	7.52%
W2 SERIES BONDS	15.09.2017	10 Years	750.00	5 equal annual installments w.e.f.15.09.2023 to 15.09.2027	750.00	7.35%
X- SERIES BONDS	08.02.2019	10 Years	1500.00	7 equal annual Installments w.e.f. 08.02.2023 to 08.02.2029	1285.71	8.65%
Y- SERIES BONDS	07.10.2019	10 Years	1500.00	5 equal Installments w.e.f. 07.10.2025 to 06.10.2029	1500.00	7.50%
Y1 SERIES BONDS	03.01.2020	10 Years	500.00	5 equal Installments w.e.f. 03.01.2026 to 03.01.2030	500.00	7.38%
AA SERIES BONDS	11.02.2020	10 Years	1500.00	5 equal Installments w.e.f. 11.02.2026 to 11.02.2030	1500.00	7.13%
AA-1 SERIES BONDS	11.03.2020	10 Years	500.00	5 equal Installments w.e.f. 11.03.2026 to 11.03.2030	500.00	6.89%
AB SERIES BONDS	24.04.2020	10 Years	750.00	5 equal Installments w.e.f. 24.04.2026 to 24.04.2030	750.00	6.80%
AC SERIES BONDS	12.02.2021	15 Years	1500.00	10 equal Installments w.e.f. 12.02.2027 to 12.02.2036	1500.00	6.86%
AD SERIES BONDS	20.02.2023	15 Years	996.00	12 equal Installments w.e.f. 20.02.2027 TO 20.02.2038	996.00	7.59%
Total- Bonds					15513.90	

Annexure-III

NHPC Limited																
Domestic Finance Section																
PARTICULARS	DATE OF FIRST DISBURSEMENT	AMOUNT OF FIRST DISBURSEMENT (Amount Rs. In Crore)	DATE OF SECOND DISBURSEMENT	AMOUNT OF SECOND DISBURSEMENT	DATE OF THIRD DISBURSEMENT	AMOUNT OF THIRD DISBURSEMENT	Repayment schedule	FIRST REPAYMENT START ON	BENCHMARK	RESET TERM	Allocation	INITIAL			W.E.F. 01.04.2023	
												SPREAD	BENCHMARK	RATE	BENCHMARK	RATE
TL-HDFC Bank Ltd. -2000 Cr.	11.02.2022	1500	15.03.2022	300	30.03.2022	200	92 MI @ Rs. 21.74 cr	01.03.2024	T-Bill (3month)	Reset every three months on 1st April, 1st July, 1st Oct and 1st Jan. First reset shall take place on 01.04.2022/23.	Sub. Lower Rs. 1500 cr & Parb-II Rs. 500 cr	1.93%	3.73%	5.66%	6.88%	8.81%
									T-Bill (1month)			1.50%			6.66%	8.16%
TL-CENTRAL BANK OF INDIA - 1000 Cr.	31.03.2022	500	29.06.2022	500	0	0	92 MI @ Rs. 10.87 cr	01.05.2024	REPO RATE		Parb-II Rs. 1000 cr	1.39%	4.00%	5.39%	6.50%	7.89%
HDFC Bank Ltd. -1016.39 Cr. ROE Rs. 130.80 p.a.) plus Rs. 3.00 cr SE) (SECURITIZATION of RoE - CPS-I PS)	25.02.2022	1016.39	0	0	0	0	120 MI @ Rs. 10.90 cr (Rs 1308 cr)	31.03.2022	T-Bill (3month) (3.71%+1.53%)		Sub. Lower Rs. 1016.39 cr	1.53%	3.71%	5.24%	6.88%	8.41%
SBI Bank Ltd. -1876.37 Cr. (ROE Rs 206+40+23=269.04 cr) +Rs. 1.15 cr SE (Monetizations of Free Cash of URI-I PS)	09.02.2022	1876.37	0	0	0	0	120 MI @ Rs. 22.42 cr (Rs 2690.40 cr)	31.03.2023	MCLR (3month) (7.60%+0.05%)		Sub. Lower Rs. 1876.37 cr	0.05%	8.00%	8.05%	8.10%	8.15%
TL-J&K BANK -600 Cr.	23.03.2023	600	0	0	0	0	108 MI @ Rs. 5.55 cr	01.04.2024	REPO RATE		Sub. Lower Rs. 600 cr	1.25%	6.50%	7.75%	6.50%	7.75%

Annexure-IV

Details of Loan

Name of the Power Station: Parbati-III

(Amount in lacs)

Source of Loan[1]	LIC	UCO BANK	Q-SERIES BONDS	Punjab & Sind Bank	Corporation Bank	Canara Bank	Syndicate Bank	State Bank of India-1000 Cr.	State Bank of Hyderabad	R-2 SERIES BONDS
Moratorium Period	7 Years 2&1/2 Months	3 YEARS	4 YEARS	3 Years	3 Years	3 Years	3 Years	3 Years & 3 Months	3 Years	3 YEARS
Moratorium effective from	17-02-2005	31-12-2009	12-03-2012	16-01-2012	05-01-2012	13-01-2012	30-01-2012	28-03-2013	28-03-2013	11-02-2013
Repayment Period	12 Years	12 Years	12 YEARS	12 Years	12 Years	12 Years	12 Years	12 Years	12 Years	12 YEARS
Repayment effective from	30-04-2012	31-12-2012	12-03-2016	17-01-2015	05-01-2015	16-01-2015	02-02-2015	27-06-2016	28-03-2016	11-02-2016
Parbati-III	31153.00	20000.00	9000.00	7000.00	5913.00	15000.00	2227.00	10000.00	11875.00	24792.00
COD	24-03-2014	24-03-2014	24-03-2014	24-03-2014	24-03-2014	24-03-2014	24-03-2014	24-03-2014	24-03-2014	24-03-2014
Total Tenure (in Years)	19.00	15.00	16.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00
Repyt during Const (in Years)	1.90	1.23								
Repyt during O&M period (in Years)	17.10	13.77	16.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00

Source of Loan[1]	1-A SERIES Tax Free BONDS	1-B SERIES Tax Free BONDS	S-1 SERIES BONDS	S-2 SERIES BONDS	V SERIES BONDS	V2 SERIES BONDS	W1 - SERIES BONDS	W2 - SERIES BONDS	IOB
Moratorium Period	10 YEARS	10 YEARS	1 YEARS	4 YEARS	1 Years	6 Years	1 YEARS	6 YEARS	3
Moratorium effective from	02-11-2013	02-11-2013	26/11/2014	26/11/2014	24-01-2017	06-06-2017	15-09-2017	15-09-2017	16-01-2012
Repayment Period	Bullet	Bullet	10 YEARS	12 YEARS	5 Years	10 Years	5 YEARS	5 YEARS	12
Repayment effective from	02-11-2023	02-11-2023	26/11/2015	26/11/2018	24-01-2018	06-06-2023	15-09-2018	15-09-2023	16-01-2015
Parbati-III	1481.36	3200.00	8302.00	2888.00	21926.08	30466.42	9898.08	9872.53	20000
COD	24-03-2014	24-03-2014	24-03-2014	24-03-2014	24-03-2014	24-03-2014	24-03-2014	24-03-2014	24-03-2014
Total Tenure (in Years)	10.00	10.00	11	16	6	16	6	11	15
Repyt during Const (in Years)									
Repyt during O&M period (in Years)	10.00	10.00	11.00	16.00	6.00	16.00	6.00	11.00	15.00