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पावर ग्रिड कारपोरेशन ऑफ इंडिया लिमिटेड
(भारत सरकार का उद्यम)

POWER GRID CORPORATION OF INDIA LIMITED
(A Government of India Enterprise)

पावरग्रिड

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CIN : L40101DL1989GOI03812

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Ref No: CC/RC/T.R 19-24/

Date: 30/07/2018

The Secretary,
Central Electricity Regulatory Commission,
3rd & 4th Floor, Chandralok Building,
36 Janpath, New Delhi-110001

Sub: Terms and Conditions of Tariff Regulation for the Tariff Period starting from 01st April 2019
- Submission of comments on Consultation paper reg.

Dear Sir,

This is in reference to public notice Ref L-1/236/2018/CERC dated 24/05/2018 vide which comments/ suggestions were sought on the subject consultation paper.

In this regard, please find three copies (03) of comments/suggestions of POWERGRID on various issues raised in the Consultation paper.

Thanking you,

के. वि. वि. आयोग
2200
CERC
31 JUL 2018
प्राप्त हुआ
हस्ताक्षर

Yours faithfully,

Abhay Choudhary
(Abhay Choudhary)
ED (Commercial & Reg. Cell)

जे ड (री. पु)

Encl: As above

P-5804

Ref No: CC/RC/T.R 19-24/ Date: 30/07/2018

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Encl: As above

Comments on
CERC's Consultation Paper for
(Terms and Conditions of Tariff)
Regulations, 2019

30th July 2018

Power Grid Corporation of India Limited
(A Government of India Enterprise)
पावर ग्रिड कारपोरेशन ऑफ इंडिया लिमिटेड
(भारत सरकार का उद्यम)

Response to CERC Consultation Paper 2019-24

Contents

1) *General*

At the outset, we appreciate the efforts put in by CERC staff in bringing out the Consultation Paper touching upon every aspect of the transmission tariff and proposing several options to spur discussion among various stakeholders. The paper succeeds in highlighting various aspects of transmission tariff in depth, the existing scenario in the power sector and likely developments in the future that shall have an impact on tariff determination. We understand that the objective of CERC is to ensure a balance between consumer's interest and the financial viability of developers while attracting steady investments towards the development of the power sector**. We appreciate the suggestion put forth by CERC that any change in the Regulations in the ensuing Tariff period that shall have any financial implications be levied only on new projects/assets**, so as to avoid complications in the functioning of the existing projects/assets. We suggest that to have regulatory certainty and financial stability of the company, any changes in the Regulation shall be brought out only for the projects **for which financial closure shall be achieved after 31st March 2019.**

It is known that electricity plays a crucial role in expansion and development of any economy. To support the needs of India's growing economy, it is imperative that all segments of electricity undergo strengthening and expansion. The Indian transmission sector plays a special role in delivering the generated energy to the customers in a reliable and efficient manner. POWERGRID, being the country's major Transmission Licensee, has always been in the forefront to facilitate transfer of power from generators to load centers through its transmission network that is spread across the length and breadth of the country. It strives to provide superior service to its customers by building and maintaining one of the largest and most robust interconnected grid networks in the world.

In the Consultation Paper, a comparative analysis of various components in the cost of per unit of electricity (per unit) in 2009-10 vis-à-vis that in 2016-17 is given. As per the analysis, the cost of inter-state transmission system (ISTS) has increased by 69.56% i.e. from Rs. 0.23 per unit to Rs. 0.39 per unit during the subject period while the average cost of supply has increased from Rs. 5.07 per unit to Rs. 6.67 per unit. While there is no denial that there has been an increase in the per unit cost of transmission, mere comparison of costs could be misleading as it does not fully capture the contribution of transmission sector in reducing the cost of power procurement, enhancing the flexibility and system reliability during this period as explained below:

- The prevailing transmission planning philosophy advocates the planning of the transmission system in accordance with the generation capacity addition. As per norms, the investments in generation, transmission and distribution should be in the ratio 2:1:1. During the subject period, generation capacity (comprising of Central Sector generation companies and IPPs) increased from 76,493 MW to a level of 2,22,881 MW in 2016-17, with investments in the order of Rs. 7.3 lakh crore. This means that corresponding to above investment in generation, required investment in transmission is of the order of Rs. 3.65 lakh crore. In comparison, the investment made in ISTS transmission network by POWERGRID and other ISTS Licensees is of the order of Rs. 1.46 lakh crore during the said period, which is only 40% of the required investment as per norms. However, an illusion of large increase in transmission charges is due to the reasons that the load in the country did not increase in line with the projected load demands during the referred period. During the last year, the load growth has picked up, as demonstrated by the increase in peak load from 159 GW in 2016-17 to 173 GW in May'18. Therefore, it can be safely concluded that, as the load steadily increases, the per unit charges of transmission shall decrease. Further, the generation capacity based on renewable resources has increased from 15.5 GW in 2009-10 to 57.2 GW in 2016-17 (growth of 269%). As per GoI policy, transmission charges are not levied on the renewable generation even though the transmission network has facilitated flow of energy from these generators also. Thus, the zonal annual tariff/Point of Connection charges which have been used for working out the transmission cost would have been lower if renewable energy had also been considered while arriving at them. Hence, the percentage increase in the transmission cost would be far lower considering the growth of renewable energy in the period considered.

- POWERGRID wishes to highlight that though transmission costs constitute only ~5.84% of the total costs of supply for Distribution Utilities, transmission network provides them with immense benefits, which are given in brief as below:

  - <u>Reduction in power procurement costs:</u> As of today, every Distribution Utility has the flexibility of sourcing the cheapest power available at any location, thereby reducing their power purchase cost. For example, Delhi was able to surrender the expensive power of Jhajjar STPP in lieu of cheaper alternatives. The robust transmission network has in turn created a pressure on the Generation projects to adopt cost control measures, thereby bringing in efficiencies.

  - <u>Reduction in congestion:</u> The growth of ISTS transmission network has facilitated merit order dispatch and has turned into reality the concept of 'One Nation One Grid'. The congestion in the system has reduced drastically from 17% in 2012-13 to 4% in 2016-17. The lack of transmission results in higher losses in terms of energy which cannot be supplied to meet the load demand. For example, in 2013-14, the volume of electricity in exchange that could not be cleared due to congestion was 5591 MU. Considering the cost of un-cleared units @ Rs 3.59, the quantifiable loss of about Rs. 2000 Cr was incurred apart from other indirect socio-economic losses to the society and nation as a whole.

  - <u>Enabler of Power market:</u> The growth in transmission has ensured flexibility in power transfer thus enabling steady and uninterrupted growth of a developed power market from scratch. On all India basis, Short-term transaction has increased from 65 BU in 2009-10 to 119.23 BU in 2016-17, whereas STOA rates have reduced from about Rs. 7.3 per unit in 2008 to Rs. 2.5 per unit in 2016-17. If we take particular example of Southern Region (SR), which was facing acute Power shortage when the Southern Region was yet to be connected to the NEW grid, there was a situation of price split in the market. Power purchase costs from the open market, MTOA and STOA at that time reached to as high as Rs. 10/unit. A few years later, when SR was connected to the NEW grid with adequate expansion in inter regional capacity, the prices in open market in SR witnessed reduction by 70% to around Rs. 3/unit. Thus, a fractional increase in transmission cost helped the Distribution Utilities in saving of about Rs. 1 to Rs. 2 in the per unit power purchase costs. In addition, the transmission grid has facilitated private generators also, who were unable to sign long term PPAs, to sell power to any beneficiary in the country by signing Medium Term/Short Term PPAs thereby reducing their financial stress.

- Reliability: The grid has become more efficient, reliable, and secure to facilitate enhanced energy transfer.

- Renewable integration: The Government of India plans to enhance renewable energy in a big way so that it reaches to a level of 227 GW by 2022. From 2011-12 Renewable Generation has increased from 24.5 GW to 70.5 GW as on 31.05.2018. As, the share of energy from renewable sources increases in the grid, there is a simultaneous need for balancing power due to the intermittent nature of renewable energy sources. Availability of robust transmission system has enabled the grid to provide required balancing power from far ends of the grid. It has enabled a smooth and reliable renewable integration without letting this intermittent nature disturb the grid stability. Further, as the contribution of renewable will increase to around 227 GW as envisaged, transmission will play pivotal role in maintaining grid stability and reliability by providing inertia and balancing power.

It is therefore submitted that assessment of the transmission sector in the total value chain should be in a holistic manner considering both costs and benefits obtained, tangible and intangible, and any conclusions based only on cost increase could be misleading. We, at POWERGRID, believe that the benefits of investment in the transmission sector far outweigh the transmission charges associated with it. In view of the above discussion, the costs associated with investments in the transmission sector should be viewed in a positive sense, since the benefits being reaped are significant and shall be multifold in the future.

As per the National Electricity Policy formulated by CEA and published in January 2018, multiple Government initiatives such as 'Saubhagya' wherein free electricity connections to all households (both APL and poor families) in rural areas and poor families in urban areas will be provided, 'Power for All' which aims to provide round the clock electricity to each household, 'Dedicated Freight Corridor', 'Make in India' and 'Electric Vehicles' would lead to growth in electricity demand. Further, the Government of India's vision of doubling the per capita electricity consumption in the next 6-7 years shall fuel the load growth. These initiatives are expected to increase the peak demand to 225.751 GW in 2012-22 and to 298.774 GW in 2026-27 from 173 GW presently.

POWERGRID wishes to highlight that the prime cause of the increase in transmission tariff is increasing needs of the economy and a greater focus to tap market efficiency in the power sector. The need to meet the peak demand of the system and to provide a reliable access to the cheaper generation capacity resulted in expansion and strengthening of the transmission system, which caused the increase in transmission tariff as mentioned by CERC in the Consultation Paper.

Given the scale of investments required in the transmission sector as per Govt. targets, POWERGRID feels that a focused Regulatory impetus in the coming tariff block of 2019-24 is imperative in case of transmission to facilitate mobilization of debt at competitive rates from the market and also generation of adequate internal resources to meet requirement of equity deployment. **POWERGRID feels that the existing Regulations of CERC with respect to the tariff structure are comprehensive in nature, with a simplified structure that is easy to comprehend and implementable by all stakeholders.** Furthermore, the familiarity with the existing structure provides more stability to POWERGRID and other Transmission Licensees and to the consumers. In addition, the current revenue projections and debt servicing obligations (repayment terms and interest payments) are based on the existing tariff structure. **Therefore, POWERGRID maintains that the existing tariff structure should be generally retained for providing a reliable and competitive service to its customers**.

Detailed topic wise views of POWERGRID on various aspects covered in the Consultation Paper are given in subsequent sections.

2) S. No. 7 : Tariff Design for Inter-State Transmission System

Issues raised by CERC

Currently, a single part tariff structure is followed for recovery of transmission costs from Discoms. This includes costs for providing access and the transmission service charge. CERC believes that this is good for long-term access; however, with the introduction of short and medium term transactions, the participants seek access to the transmission system but do not necessarily avail the service unless there is actual transaction. Hence, there is a requirement to recognize the access service separately from the transmission service.

Options Proposed

CERC suggests a two-part tariff, where the first part is linked with access service and the second part can be linked with transmission service. The charges for access service is a fixed component while the charges for transmission service is variable in nature.

The fixed component can consist of either (i) annual fixed cost of some of fixed transmission system designated for access and immediate evacuation, (ii) annual fixed cost of the evacuation transmission system or (iii) part of annual fixed cost of the entire transmission system consisting of debt service obligations, interest on loan, guaranteed return;

The variable components may consist of either (i) common transmission system or system strengthening schemes excluding immediate evacuation transmission system, (ii) common transmission system excluding evacuation transmission system or (iii) sum of incremental return above guaranteed return, operation and maintenance expenses and interest on working capital.

The recovery of fixed component can be linked to the extent of access (Transmission Access Charge) and variable component can be linked to the extent of use, to be recovered in proportion to the power flow (Transmission Service Charge). The fixed component may be linked to evacuation system or on normative basis based on aggregate transmission charges of the identified transmission system under the contract. The variable component may be linked with yearly transmission charges based on actual flow or actual dispatch against long-term access.

Our Comments/Suggestions

1. The transmission system, unlike generation, is a fixed element and is planned for peak capacity (installed generation capacity) to facilitate full evacuation of power based on the requirement of generators and demand customers.

2. The expenses incurred by a Transmission Licensee are fixed and no additional variable cost is incurred for transfer of additional power upto the rated capacities, unlike generation where the costs are linked to power generation. Even for hydropower plants, it is possible to link the tariff to energy generated by plant. Therefore, comparison of transmission with generation is not prudent. While for a generating company, fuel cost is variable i.e. depends upon quantum

of generation, the entire cost structure of a Transmission Licensee is fixed in nature. The cost components proposed to be charged as variable component for a Transmission Licensee, are included in fixed cost for thermal generating companies.

3. CERC has suggested that the recovery of fixed component can be linked to extent of access and variable component can be linked to extent of use (i.e. in proportion to the power flow). It is submitted that the power flow in a particular transmission system depends upon a number of variables and grid conditions including seasonal variation, peak/off-peak load, scheduling of generation as per merit order dispatch, generation from renewable sources, outage of lines due to over voltage etc., which are beyond the control of the Transmission Licensee. Thus, power flow or utilization of the asset varies considerably from time to time and is completely dependent on the grid operation controlled by the Grid Operator.

4. **Since the Transmission Licensee has no role to play in planning of the transmission line or its utilization after its implementation, POWERGRID recommends ensuring full recovery of annual revenue required for the transmission system, thus making the revenue recovery independent of the consumption by the Distribution consumer (utilization of the transmission system).**

5. The proposed methodology of usage-linked charges basically relates to the sharing of transmission charges among various users based on their consumption. **The recovery of transmission tariff in these two parts should be therefore dealt with by CERC in Sharing Regulations and not in Tariff Regulations**, which solely deal with determination of tariff of transmission elements. In the existing scenario, the Tariff Regulations deal with determination of various components of revenue requirement leading to annual fixed cost of a transmission asset, while the Sharing Regulations translate the revenue requirement to the tariff to be billed to various entities. In fact, the current mechanism of PoC charges captures the transmission tariff based on utilization to certain extent. **Hence, CERC may deliberate on this topic, while amending the Sharing Regulations.**

6. CERC has suggested various options for calculating the fixed and variable component. POWERGRID advises against adoption of these options. In the first and second options, the demarcation of various systems as evacuation system or common system/grid strengthening system shall be subject of dispute. For example, a transmission system may be identified alongwith the generation project but after implementation it may be used for power transfer from other projects as well. Thus, from planning perspective, these lines are evacuation transmission system whereas from utilization point of view, such systems are system strengthening schemes.

7. POWERGRID advises against adoption of the third option proposed by CERC as the suggested variable components (i.e. incremental return above guaranteed

return, operation and maintenance expenses and interest on working capital) are essentially fixed in nature, i.e. independent of the customer's consumption.

8. When a Transmission Licensee is given the responsibility to implement a transmission scheme, power flow through the lines in the scheme is not a consideration for the Transmission Licensee before making investment in the scheme. Therefore, after the investment has been made, the risk of recovery based on variation of power flow should not be borne by Transmission Licensee. Otherwise, no Transmission Licensee would invest in the line where power flow is projected to be low/intermittent even if it is required for enhancing the stability and reliability of the grid or that has been planned with a higher capacity to conserve scarce Right of Way.

9. Since 2011, as recommended in the Tariff Policy, most of the transmission projects are being awarded through tariff based competitive bidding, which results in discovery of single part tariff. However, the paper suggests introduction of two-part tariff for cost plus assets where the tariff is determined based on Regulations. In a meshed network, recovery of tariff based on power flow for some elements and fixed tariff for other elements is not possible. Further, existence of multiple systems of recovery adds complexity and makes it difficult to understand for stakeholders.

3) S.No. 8: Deviation from Norms

Issues raised by CERC

Regulation 48 of the CERC Tariff Regulations allows determination of transmission charges of a Transmission Licensee in deviation of norms, provided that the levelised tariff over the useful life of the project on the basis of the norms in deviation does not exceed the levelised tariff calculated on the basis of the norms specified in these Regulations. The paper argues that since the tariff determined by CERC acts as ceiling, there is no embargo on the generating stations or the Transmission Licensee to charge lower tariff. This provides a scope for creating some competition.

Options Proposed

The paper proposes the following option for Regulatory Framework and invites comments on the same:

a) Possible option could be to develop for incentive and disincentive mechanism for different levels of dispatch and specifying the target dispatch expanding the scope of Regulation 48 above.

Our Comments/Suggestions

1. The above issue is pertinent to generation companies only and hence, may not be applied to Transmission Licensees. The merit order dispatch is decided based on the variable cost of per unit generation of electricity and the cost of transmission has no role in it. Thus, lowering the tariff of transmission system below the tariff determined for recovery of annual fixed cost will only result in lower recovery of revenue for the company and will not resolve the issue brought

up by CERC in this section. The assets under cost plus regime should be allowed to recover their full yearly transmission charges.

4) S.No. 11 and S.No. 37: Capital Cost – Benchmarking & Normative Tariff

Issues raised by CERC

The Consultation Paper discusses issues and challenges with respect to the existing methodology of approval of capital cost based on projected capital expenditure (investment approval), including variation between actual project cost vis-a-vis projected capital cost, additional capital expenditure, absence of benchmark capital cost, use of the audited annual accounts to ascertain the claim of the capital expenses and revision of capital cost of licensees upon CoD (which the customers may not be aware of).

In alternative approach to tariff design, CERC contemplates determination of capital cost on normative basis as against the existing practice of detailed cost component wise examination. Though the analysis is carried out for Generation projects, views are sought for Transmission as well.

Options Proposed

The paper proposes two options for Regulatory Framework and invites comments on the same:

(a) Shifting to benchmark/reference cost for prudence check of capital cost. However, credible benchmarks may not be available;
(b) Restricting the fixed rate of return on equity to normative equity as envisaged in the investment approval or on benchmark cost and allowing return on additional equity (due to increase in cost due to uncontrollable factors) based on weighted average of interest rate of loan portfolio or rate of risk free return;
(c) It also proposes introduction of incentive for early completion and disincentive for slippage from scheduled commissioning.

The paper also invites comments and suggestions on the following (alternate approach to tariff determination):

(a) Would it be advisable to undertake econometric analysis to arrive at benchmark capital cost;
(b) Variables to be considered for determining capital cost on normative basis;
(c) Other methodologies for benchmarking the capital cost for transmission projects.

Our Comments/Suggestions

1. Econometric analysis for determination of prudent costs would require database spanning across multiple variables that influence capital costs.
   a. Captial cost in the context of transmission assets depends upon multiple variables:
      i. *Project specific conditions* such as terrain, project location, Right of Way (RoW) Constraints (including urbanization, river/highway/ railway line crossings, crossing of other transmission lines, forest area)

and weather conditions may lead to different capital costs of similar transmission assets;

ii. *Market forces* driven by demand supply balance viz availability of competition among vendors, purchase quantum (one time order vs repeat orders), input cost variations, economic environment etc. and

iii. *Technology* adopted for implementation of the substation (AIS or GIS) and requirement of reactive compensation etc.

b. Keeping track of all such factors that influence discovery of prudent costs, whether project specific or market forces driven, is practically challenging. To substantiate, the below table illustrates the variation in cost per km of transmission lines falling under same wind zones, soil conditions and topography. As can be observed from the table, for instance, the cost for a 765 kV line varies from Rs. 166.15 lakhs per km to Rs. 210. 79 lakhs per km within similar regions. Also, the variation in cost per km of transmission lines falling under different wind zones, soil conditions and topography has been demonstrated in the table.

Asset Name	Region	DOCO	Line length in km	Completion cost (Rs. Lakhs)	Cost per km (Rs. Lakhs)
765 kV S/C Transmission Lines under same wind zone/Soil condition/Plain area					
Bareilly-Lucknow S/C	NR-III	01.04.2014	251	41704.85	166.15
Gaya-Varanasi S/C	NR-III	21.04.2015	273	57546.81	210.79
Jaipur-Bhiwani S/C	NR-I	07.10.2016	276	49343.72	178.78
765 kV D/C Transmission lines under different wind zone/Soil condition/ plain area					
Champa-Raipur D/C	WR-I	24.05.2014	149	67005.6	449.70
Angul-Srikakulam D/C	SR-I/ ER-II	01.02.2017	276.49	139487.89	504.50
Chittorgarh -Ajmer D/C	NR-I	31.12.2017	211	101482.97	480.96
400 kV Transmission Lines under same wind zone/Soil condition/plain area					
Barh-Gorakhpur D/C	NR-III	07.06.2015	349.17	97166.05	278.28
Sikar-Jaipur D/C	NR-I	16.02.2017	169.00	22820.21	135.03
Lucknow-Kanpur D/C	NR-III	01.06.2017	159.61	25221.01	158.02
400 kV D/C Transmission lines under different wind zone/Soil condition/ plain area					
Ranchi-Chandwa-Gaya D/C	ER-I	12.07.2016	190.00	55996.46	294.72
Betul-Khandwa D/C	WR-I	24.08.2017	168.64	40241.28	238.62
400 kV D/C Transmission lines under different wind zone/Soil condition/ Hilly area					
Balipara -Bongaigaon D/C	NER	07.11.2014	309.00	107030.77	346.38
Silcher-PK Bari D/C	NER	01.08.2015	128.76	40879.20	317.48
Kishenpur - New Wanpoh D/C	NR-II	31.07.2017	135.00	54324.00	402.40

c. Results of any econometric model may significantly vary from actual costs and would result in severe losses for the Transmission Licensee, if benchmarks are set low or for the consumers, if the benchmarks are set too high.

Therefore, econometric analysis for determination of capital cost is not advisable, since it may not be pratically possible to factor in all the considerations mentioned above in any econometric model.

2. In many countries across the world including South Africa, Australia, Canada, Sri Lanka and Malaysia, the transmission assets are regulated under revenue cap regime and the transmission operator's guaranteed regulatory revenue is derived from capital cost based on the historical cost of acquisition of assets in these countires. While Canada, Sri Lanka and Malaysia consider the actual capital cost in rate base, South Africa and Australia index the initial capital cost with inflation to determine the asset base for respective year.

3. An experience of participation in Brazil auctions suggests that the core of any benchmarking exercise lies in competitively discovered prices, spanning across multiple market players which are determined rigorously for specificities of each asset and updated frequently based on data obtained from existing players. Enabling steps like development of competitive markets to develop baseline of capital cost benchmarks and then their frequent periodic updation needs to be ensured in a detailed manner before any steps related to benchamrking of captial costs are taken.

4. It is important to note that for 'Cost Plus' projects undertaken by POWERGRID, the capital cost is discovered through a transparent Open Competitive Bidding process. The company has also introduced e-reverse auction for all equipment/transmission line procurements except where it is not permitted as per the guidelines of funding agency. Thus, the cost represents the lowest prices available at the time of bidding of various packages. Even the World Bank has accepted POWERGRID's procurement system under its alternate procurement arrangement. POWERGRID being a Public Sector Undertaking is invariably bound by definite rules and is subjected to host of mandatory checks and balances across the entire procurement process which interalia include the statuatory agencies, funding agencies etc.

5. **Thus, in the existing scenario, CERC may continue with the prevailing methodology of carrying out the prudence check of the capital cost while determining the tariff and not adopt a benchamarking approach for determination of capital cost. However, in the event CERC decides to go in for benchmarking of the capital cost, the risk of the Transmission Licensee needs to be mitigated by considerable increase in the return on equity. Further, benchmarking cost should be arrived at after considering all the factors as stated in para 1 above.**

6. Restricting the rate of return on the normative equity and allowing return on additional equity based on weighted average interest rate of loan or risk free rate would militate against the very concept of return on equity which has to be

greater than the cost of debt. The cost of the transmission projects mainly increases due to the change in scope of the work as a result of RoW constraints (consequently change in route), terrain, soil conditions etc. The cost may further increase due to change in cost of equipment based on prevailing inflationary trend and/or demand and supply position in the market. Such additional costs incurred as due to uncontrollable factors are permitted for inclusion in project cost following prudence check by CERC. Since the additional equity is also deployed by the developer and for reasons beyond its control, it would not be prudent to lower the return on additional equity. Further, under the cost-plus regime, the tariff is based on actual cost incurred and includes additional cost incurred by Licensee owing to uncontrollable factors. Lowering of rate of return would defeat the principles behind the cost plus Regulations.

7. Incentive for early completion has been allowed by CERC in the 2009-2014 and 2014-19 Regulations and should be continued in the ensuing Tariff Regulations to motivate the utilities to complete the projects within the specified period. **However, the commissioning should be delinked with the power flow in the asset, as the same is beyond the control of the Transmission Licensee** and is attributable to the developer of the upstream (generator)/downstream (STU) network.

8. There should be no disincentive for delay in completion of the project due to the following:

    a. Under the present methodology, CERC is exercising prudence while deciding the capital cost for allowance/disallowance of IDC & IEDC in the event of delay in a project from its schedule completion. If the slippage is due to controllable factors of the Transmission Licensee, the IDC & IEDC for that period is not allowed resulting in lower tariff for the Transmission Licensee for complete life of the project. The company has to bear this disallowance through its equity which itself is a huge dis-incentive for the company.

    b. Since there is no return on equity deployed during the construction stage, the effective rate of return on equity, considering the overall return over the life of the project including the construction period, in normal course is less by approx. 250-400 basis points lower than the ROE allowed in the tariff [as demonstrated in point 11 (Rate of Return on Equity)]. In case of delay, the effective rate of ROE further reduces affecting the cash flow and thereby the financial viability of the project. Thus, the developer is already penalised for the delay (controllable and uncontrollable), and the proposed option would cause unbearable burden on the licensee.

    c. Inherently all infrastructure projects particularly linear projects such as transmission projects are subjected to delay due to factors beyond the control of the developers. Hence, penalizing the developer for the same is unjust and should be avoided.

5) S. No. 12 : Renovation & Modernisation

Issues raised by CERC

The Consultation Paper discusses the provisions related to renovation & modernisation in the existing Tariff Regulations. One of the issues highlighted in paper is filing of petitions for R&M by the companies without providing an estimate of life extension, which makes it difficult to justify the R&M expense. It further discusses advantages of R&M with up gradation owing to reduction in upfront investment in new lines. The corrosion and other issues of transmission lines passing through coastal areas have also been discussed.

Options Proposed

The paper proposes that R&M of transmission system could include Residual Life Assessment of sub-station and transmission lines, Upgradation of sub-station and transmission line, System Improvement Scheme (SIS) and replacement of equipment. CERC may allow Renovation & Modernisation (R&M) for the purpose of extension of life beyond the useful life of transmission assets. Alternatively, CERC may allow special allowance for R&M of transmission assets. Such provision will enable the transmission companies to meet the required expenses including R&M on completion of 25/35 years of useful life of sub-station/transmission line without any need for seeking resetting of capital base.

Our Comments/Suggestions

1. The provision for Renovation & Modernisation (R&M) should be continued in the ensuing Tariff Regulations for the purpose of extension of life beyond the useful life of transmission assets.
2. In Transmission System, generally the replacement of defective/problematic equipment varies from 10% to around 30% of the overall project cost and balance old assets continue to remain in service even after 25/35 years of useful life. Therefore, to avoid depreciation of those old equipment which have not been replaced and which shall remain in service, provision of R&M should be included in the Tariff Regulation in line with those provided in Tariff Regulations 2014 with exclusion of provision Clause 15 (4) of Tariff Regulations 2014, which stipulates as under:

   Quote
   "Any expenditure incurred or projected to be incurred and admitted by the commission after prudence check based on the estimates of renovation and modernization expenditure and life extension, and after deducting the accumulated depreciation already recovered from the original project cost shall form the basis for determination."
   Unquote

   Therefore, R&M should be continued for Transmission in line with the provisions provided in the Tariff Regulations, 2014 with specific exclusion as brought out above.

3. After completion of useful life, it is imperative to replace certain equipment in order to avoid any potential threat to grid stability and ensure reliability of operations. Further, a few equipment may be required to be replaced due to obsolescence or non-availability of spare parts or services, increase in fault level etc. However, the existing process involves preparation of detailed report, along with an estimation of extension of useful life, which may not be possible in many cases. Hence, in order to simplify the process, a Special Allowance may be allowed for Transmission Licensees on a 'per km'/'per MVA' basis on lines similar to that being allowed to coal-based/lignite fired thermal generating stations. Alternatively, Special Allowance may be linked to capital cost of transmission assets.

6) S.No. 13: Financial Parameters

Issues raised by CERC

The paper proposes more weightage for normative parameters to induce greater efficiency during operation as well as in development phase.

Options Proposed

CERC has invited comments from stakeholders for continuation of normative approach for specifying financial parameters and alternatives, if any.

Our Comments/Suggestions

1. The parameters relevant for determining the revenue requirement for a Transmission Licensee include Return on Equity, Interest on Loan, Depreciation, Interest on Working Capital and Operation and Maintenance Expenses.

2. The rate of Return on Equity is fixed for projects by CERC at the beginning of the Control Period. The equity base to be used for calculating RoE is also capped at normative levels by CERC. The rate of depreciation allowed is also applied based on norms defined by the CERC. The working capital base is also normatively defined and the interest on it is linked to market rates specified explicitly in the Regulations to promote efficiency. Operation and Maintenance expenses are also allowed based on norms determined by CERC, with an escalation fixed by it at the beginning of Control Period. As can be seen, most of the parameters are already based on norms driven by operational and financial efficiency.

3. Interest on Loan is based on actual weighted average interest rate of Licensee. In view of reasons explained in the point 12 (Cost of Debt) of this document, it would not be prudent to adopt a normative approach for this parameter.

4. Thus, the existing approach provides sufficient incentive for operational and financial efficiency. **Accordingly, the existing approach may be continued with modifications as suggested for various parameters in individual sections of this document.**

7) S.No. 14: Depreciation

Issues raised by CERC

The paper discusses the factors affecting the depreciation viz. rate base, which includes subsequent additions also, method of depreciation and useful life. It also discusses the issues faced in assessing depreciation in cases pertaining to Renovation and Modernization, particularly in case where special allowance is allowed.

Options Proposed

The paper proposes several options for Regulatory Framework and invites comments on the same:

a) Increase the useful life of well-maintained plants for the purpose of determination of depreciation for tariff.
b) Continue the present approach of weighted average useful life in case of combination, due to gradual commissioning of units;
c) Reassess life of assets at the start of every tariff period or every additional capital expenditure
d) Extend useful life of transmission assets to 50 years and bring in corresponding changes in treatment of depreciation
e) Reduce rates which will act as a ceiling

Our Comments/Suggestions

1. The life of the existing assets should not be revised on following accounts:

   a. The CEA (Technical standards for Electric Plant and Electric Lines) Regulations 2010 requires sub-stations to be designed for a life of 25 years. Accordingly, the manufacturers supply equipment in Indian market designed for similar life span. The existing equipment procured for various projects, thus, have a useful life as stated in the above Regulations.

   b. The life span of the equipment is governed by a number of parameters during its service-span like the loading pattern, high voltage, type and frequency of faults experienced by the transmission system and such other technical considerations. The equipment in Indian grid conditions are heavily stressed due to over voltage, feeding of fault currents due to frequent faults in downstream systems, pollution and natural calamities etc., which reduces the life of the equipment. These adverse conditions also deteriorate the insulation level of the electrical equipment, which is an important component in determining the life of equipment.

   c. Owing to obsolescence, technological upgradation or closing of production line by OEMs/non-existence of OEMs, spares and service facilities may not be available, which limit the ability of POWERGRID to maintain the assets within the useful life.

   d. Further, an important aspect to be considered is the fact that the investment decisions for existing assets were based on the life of assets to be around 25/35 years. If the asset life is increased or depreciation rates are reduced, the servicing of debt would become impossible pushing the Transmission Licensee into financial stress and default. **A change in the regulatory**

approach in the suggested manner will bring about regulatory uncertainty and may therefore not to be considered.

<u>Considering the above practical constraints, the revision in life of the existing assets is not recommended</u>.

2. The existing treatment of weighted average useful life in case of combination of assets, due to gradual commissioning of assets, should be allowed to continue.

3. The additional expenditure during the fag end of life of a project cannot be the basis for consideration of re-assessment of useful life. A substation consists of number of equipment. Some of these might need replacement owing to corrective maintenance or preventive maintenance. Such expenditure is towards replacement of faulty equipment to ensure reliability of the system. Further, the equipment are replaced progressively considering the nature of the same, which saves the costs for both the company and the beneficiaries. However, such additional expenditure during the fag end of life may not provide assurance of enhanced life for the whole system since majority of the equipment in the transmission system are old and have completed major portion of their useful life.

4. Further, additional expenditure after Renovation and Modernization (or Special Allowance) should be considered based on prudence check and should not be restricted upfront in the Regulations. Though, the R&M program is based on detailed report and is expected to enhance useful life of assets, failure of equipment under real time operations cannot be predicted. Thus, operation of equipment over the enhanced life cannot be guaranteed. Therefore, any proposed additional capitalisation after R&M should be subject to prudence check by CERC. Such a proposition will reduce the risk in investments made under the R&M. At the same time, enhanced life of equipment would mean that the consumers get the same service at lower cost, which serves their interest as well.

5. The reassessment of life of assets at the beginning of every tariff period may act as a disincentive for proper maintenance of assets. The provision for reassessment, which would also include assessing an asset with potential reduction in life, may be sub optimally utilized to propose a reduction in the life of an asset for ensuring higher depreciation. **Therefore, fixed life of an asset encourages better maintenance**, whereas reassessment may incentivize the reverse.

6. With respect to new transmission assets, it may not be prudent to increase the useful life to 50 years due to the following reasons:

   a. As stated above in para 1 of this section, the equipment supplied in the Indian market conforms to the existing Technical Standards, which specify a useful life as stipulated in the Tariff Regulations. **An increase in useful life would require POWERGRID to procure equipment designed for a higher life, which would substantially increase the initial capital cost**.

   b. The equipment operating under the Indian grid conditions are heavily stressed primarily due to over voltage condition, frequent faults in downstream system, seasonal pattern, pollution in cities/costal areas and other specific locational factors resulting in stress in equipment thereby deteriorating the insulation level of the equipment, which impacts the life of the equipment. These factors limit the ability of POWERGRID to reliably operate the transmission equipment for a longer life, even with regular maintenance.

c. **Based on experience of POWERGRID, the availability of spares and service facility for equipment is limited after 25 years** owing to obsolescence, technological upgradation or closing of production line by OEMs/non-existence of OEM. This affects the ability to maintain the equipment for a longer duration.

Thus, it is recommended that the useful life of transmission system components as specified in the existing Regulations be retained in the ensuing tariff period.

7. **A change in treatment of depreciation would severely impact the ability of POWERGRID to meet debt obligations** and mobilize/generate adequate internal resources for the planned investment. Further, it is also likely to have negative impact on tariffs, considering an increase in interest rates. Thus, the current methodology may not be changed, considering the facts highlighted below:

a. Over the past 10 years, 95% of the bonds issued in domestic market were of tenure less than 15 years.

Analysis of Domestic Bond issues for the period FY2008-09 to 2017-18

Sl. No	Financial Year	No of Issues	Issue amount	Tenor < 10 Yrs		Tenor (>10-15) Yrs		Tenor (>15-20) Yrs		Tenor (>20-25) Yrs		Tenor (>25-30) Yrs		Tenor >30 Yrs	
				Nos	Amount	Nos	Amount	Nos	Amount	Nos	Amount	Nos	Amount	Nos	Amount
1	FY 2008-2009	746	2680.93	622	1571.1	120	1104.27	1	2.08	3	3.48	0	0	0	0
2	FY 2009-2010	808	2948.58	634	1887.61	137	877.06	30	174.57	7	9.34	0	0	0	0
3	FY 2010-2011	999	3287.33	720	1797.92	179	1001.65	65	353.48	30	123.27	4	8.82	1	2.2
4	FY 2011-2012	1422	4397.22	1182	2545.8	185	1467.97	46	329.8	9	53.65	0	0	0	0
5	FY 2012-2013	1560	4639.11	1196	2923.47	326	1440.4	22	218.82	13	54.95	3	1.48	0	0
6	FY 2013-2014	1545	4376.81	1220	2497.33	223	1110.02	66	625.41	33	131.14	0	0	3	12.92
7	FY 2014-2015	2277	5925.13	2039	4096.61	217	1718.91	16	109.18	5	0.43	0	0	0	0
8	FY 2015-2016	2305	5663.37	1975	4203.67	294	1287.77	22	142.59	14	29.34	0	0	0	0
9	FY 2016-2017	2413	8805.43	2133	6489.84	271	2254.05	6	56.93	1	3.35	2	1.26	0	0
10	FY 2017-2018	1831	7955.95	1532	6444.31	220	1406.99	56	96.34	17	3.24	3	4.04	3	1.03
TOTAL		**15906**	**50679.86**	**13253**	**34457.66**	**2172**	**13669.09**	**330**	**2109.20**	**132**	**412.19**	**12**	**15.60**	**7**	**16.15**
	% to Total issues				**67.99%**		**26.97%**		**4.16%**		**0.813%**		**0.031%**		**0.032%**

Data source: Bloomberg

Further, the domestic banks are not willing to lend for duration longer than 15 years. 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 atleast 120-150 basis points, which will lead to increase in interest on loan component to 14-18%, negatively impacting both POWERGRID and consumers.

b. The existing rate of interest currently offered by the two public sector funding agencies in the power sector viz. Power Finance Corporation and Rural Electrification Corporation for long-term loans ranges from 10.75%

p.a. to 11.75% p.a. In comparison, POWERGRID has been able to procure debt at much cheaper rates of 7.5%-9% p.a. This is owing to current regulatory regime of allowing sufficient cash flow to meet debt obligations. A change in Regulations would impact cost of borrowing and tariffs adversely.

c. Change in depreciation to straight line over life of the asset would result in a higher burden on consumers on account of interest on loan component. For instance, consumers would have to shell out an extra 411 crore over the life of an asset with capital cost of 1000 crore, if the depreciation recovery is reduced from current levels and is made on straight line.

d. As of 31st March, 2018, POWERGRID has an outstanding debt of Rs. 1,30,213 crore out of which Rs. 128,062 crore is repayable by 31st March, 2029. The repayment terms for this debt have already been agreed with the lenders considering the cashflows as per CERC Tariff Regulations and cannot be changed. A change in methodology of depreciation would impact the ability of POWERGRID to service debt, resulting in defaults.

e. Further, the debt of Rs. 1,30,213 crore, comprises majorly privately placed bonds (approx. Rs. 78,000 crore) having tenure ranging between 10-15 years with no prepayment option & ECBs of Rs. 35,000 crore, which leaves option of refinancing for merely (approx.) 15% of the loans. Any refinancing of POWERGRID loans with longer tenure loans would result in customers paying a higher interest on loan as part of tariff.

f. A reduction in cashflows on account of proposed depreciation rates would require POWERGRID to deploy a greater proportion of internal resources to meet debt service obligations, which would limit its ability to mobilize internal resources for further investment. **Thus, the existing investment programme involving transmission projects of about Rs. 94,000 crore would come under risk.**

8) S.No. 15: Gross Fixed Asset (GFA)

Issues raised by CERC

The paper discusses the existing GFA approach and the reasons for adopting the same in past.

Options Proposed

The paper proposes several options for Regulatory Framework and invites comments on the same:

a) An option could be to base the returns on the modified gross fixed assets arrived at by reducing the balance depreciation after repayment of loan in respect of original project cost.
b) Comments and suggestions are invited from the stakeholders on any other possible regulatory options or to continue with the existing mechanism.

Our Comments/Suggestions

The Consultation Paper rightly recognizes that the GFA Approach incentivized the Equity investors to efficiently operate and maintain the infrastructure even after the plant is fully depreciated and it facilitates generation of internal resources required for further capacity additions. All these considerations are no less valid in the current state of Indian power sector which has to grow manifold in the coming years to support the economic development of our country, as explained below:

a. As per the Central Electricity Authority Report 2016 – "20 year (2016-2036) Perspective Transmission Plan Report", massive transmission corridors may be needed towards Northern and Southern Regions in next 20 years.

b. Further, the National Electricity Policy published by CEA in January 2018 envisages that the Government initiatives of 'Saubhagya', 'Power for All', 'Dedicated Freight Corridor', 'Make in India' and 'Electric Vehicles' would lead to growth in electricity demand. Further the Government of India's vision of doubling the per capita electricity consumption in the next 6-7 years shall fuel the load growth. These initiatives are expected to increase the peak demand to 225.751 GW during 2021-22 and to 298.774 GW during 2026-27 resulting in the overall installed capacity rising from current level of 326 GW to 479 GW during 2017-22 and to 619 GW during 2022-27. This would require significant addition in transmission capacity requiring investment to the tune of more than Rs. 2 lakh Cr in the next 8-10 years.

c. Additionally, with the increase in penetration of renewables, there is also need to develop adequate balancing facilities and mechanisms for handling variable nature of renewable energy. This would require strengthening and augmentation of transmission systems, particularly due to the uneven distribution of hydro generation in our country.

d. The above requirements would have to be met by increasing the capacity of the existing system and adding new transmission system. In addition, deployment of latest technology would be required to operate large and complex integrated power system network including VSC based HVDC technology, Dynamic reactive compensation, PMU/PDC based Synchro-phasor Technology/Wide Area Monitoring System (WAMS), Phase Shifting Transformers and Series Reactors and 1200kV UHVAC, which would increase the need of initial capital investment.

e. Considering, the huge investments required to be made, it is imperative that the developers are allowed to generate internal accruals. Thus, the existing approach of allowing return on GFA should be continued.

f. The paper proposes to calculate modified GFA by reducing the accumulated depreciation from GFA after 12 years of commissioning of the project and base the return post loan repayment on this modified GFA. This would be equivalent to adopting NFA approach after 12 years. In effect, GFA principle would apply for 12 years and NFA principle for balance period for the same asset, which doesn't seem to be a sound commercial principle.

g. It is pertinent to note here that the ATE had passed a judgment dated 16th May 2006 in favour of POWERGRID, stating that any mechanism by which the equity is gradually reduced proportionately reducing the rate of return below the specified rate of return is not legal. The judgment was upheld by Supreme Court in judgment dated 24th February 2016 in appeal no. 256 of 2007. The relevant extract is reproduced below:

Quote
32. Taking cue from the aforesaid Judgment of the Hon'ble Supreme Court, the Appellant is entitled to earn specified rate of return on the equity invested in the project in accordance with law. Any mechanism by which the equity is gradually reduced proportionately reducing rate of return below the specified rate of return shall not be legal.
Unquote

Accordingly, **POWERGRID recommends continuation of the existing GFA approach.**

h. The Regulator allows return only after the date of commercial operation of a project. However, the Transmission Licensees do not get any return on equity deployed during construction period of the project. **In view of above, in case this proposal is adopted, the return on equity deployed during construction stage of the project may also be allowed to the developer or the status quo should be maintained / the existing approach should be continued.**

i. In view of reasons explained in the subsequent section - Point 10 (Return on Investment) of this document, a higher return may be allowed to POWERGRID if RoCE is adopted for new projects.

9) S.No. 16: Debt: Equity Ratio

Issues raised by CERC

CERC observes that some utilities in private sector operate with a very high financial leverage. In addition, it observed that financial institutions are willing to extend finance upto debt:equity ratio of 80:20 depending on the credit appraisal of the utilities. Further, it states that when demand for capacity addition is low, maintaining debt:equity of 70:30 may need review.

Options Proposed

In light of its above observations, CERC has proposed modifying the normative debt-equity ratio to 80:20 in respect of new plants, where financial closure is yet to be achieved and invites comments on the same.

Our Comments/Suggestions

As explained in the point 8 (Gross Fixed Asset) of this document, contrary to the assumption that demand in capacity addition is low, there is a huge need for investment in the Indian Power Sector in the next decade. The Indian debt market may find it difficult to fund the investments at 80:20 debt equity ratio due to reasons given below:

1. With increased leverage, since deployment of owner's equity reduces, the project financing risk of lenders increases, which is likely to result in higher interest rates being charged. Since debt component would be four times the equity component, even small increase in cost of debt can wipe out the benefit of higher leverage.
2. Increasing the leverage in a Licensee's capital mix poses a higher risk for equity holders of the firm. Whereas interest on debt is a fixed income stream for the lenders, the return to equity holders comes only after discharge of such cost of debt obligations. The impact of change in debt to equity ratio on expectation of return on equity can be demonstrated by reworking the CAPM using the recommended debt to equity ratio of 80: 20 for re-levering the Un-levered Beta. The same has been demonstrated in Annexure 1. <u>The required rate of return on equity consequent to debt to equity ratio of 80: 20 works out to be 24.44% against 19.18% with debt to equity ratio of 70: 30.</u>
3. In such a scenario, the benefits envisaged from leverage (on account of current interest rates being lower than return on equity) would be offset by higher requirement of return on equity, leading to potential increase in transmission charges.
4. In addition to the increased risk for the Transmission Licensee, an increase in leverage would result in increasing the exposure of transmission users to the risk of excessive volatility of interest rates.
5. The Tariff Policy 2016 also provides for a debt:equity ratio of 70:30 for financing of future projects. The proposed draft Tariff Policy issued in May 2018 carries a similar provision.
6. Presently loan covenants signed with the lenders stipulate the debt equity ratio of 75:25. The ratio is presently maintained at 70:30 and lenders expectation from POWERGRID is also the same.
7. <u>**It is therefore recommended that normative debt to equity ratio should be retained at 70:30**.</u>

10) S.No. 17: Return on Investment

Issues raised by CERC

As per the Tariff Policy 2016, the rate of return should be determined based on the assessment of overall risk and prevalent cost of capital. Further, it should lead to generation of reasonable surplus and attract investment for the growth of the sector.

Options Proposed

The Consultation Paper states that CERC may adopt either Return on Equity (RoE) or Return on Capital Employed (RoCE) approach for providing the return to the investors as per the Tariff Policy. It invites comments and suggestions on the continuation of fixed rate of return approach or alternatives, if any.

Our Comments/Suggestions

1. Under the RoE regime, the equity invested in a project continues to generate returns till the assets are under operation, however in the case of RoCE, the total capital invested in a project continues to diminish as time progresses, thus affecting the NFA which is dependent on the eligible asset base.
2. As explained in point 8 (Gross Fixed Asset) in this document, huge investments would be required in the transmission sector in next 8-10 years. Therefore, it is imperative that sufficient returns are allowed to investors on the invested equity capital to generate adequate internal resources for further investment. As observed above, adopting a RoCE regime would imply a reduction in returns, which would hamper the forecasted investments into the sector.
3. Additionally, it may not be feasible to implement the ROCE approach for the company as a whole as by virtue of several variables including age of assets, additional capitalisation in schemes, varying cost of debt, debt - equity ratio of projects etc., clubbing all schemes under the RoCE approach may not be possible.
4. Regulatory certainty, particularly in matters related to return on investment, depreciation etc. which significantly impact the project cash flows and investor returns, is a key consideration for investors in the sector. This aspect is also given significant weightage by international rating agencies such as Standard and Poor's, Fitch Ratings and Moody's while assessing the credit rating of Indian power sector entities. CERC while framing the Tariff Regulations for 2014-19 has rightly decided to continue with the Return on Equity approach in view of the fluctuating interest rates, shallow debt market and considering the financial health of Utilities and other serious issues faced by Developers in the sector such as fuel shortages etc. These factors still continue to plague the Indian power sector and given the large anticipated investment requirement in the sector, it is essential to retain the investor confidence in the regulatory environment by continuing to follow the current tariff setting principles on matters related to RoE, depreciation etc.
5. However, in any scenario, it is imperative that the return allowed to POWERGRID on existing assets be protected as the investment decisions, debt raising etc. are based on current Tariff Regulations. If a shift to RoCE is unavoidable, an equivalent rate of return may be computed under the methodology adopted by the regulator to maintain the same rate of return under the existing RoE methodology.

11) S.No. 18: Rate of Return on Equity

Issues raised by CERC

The Consultation Paper discusses the recent market developments – (i) No need for new capacity additions as per draft National Electricity Plan 2016, (ii) Low PLF of thermal plants, (iii) low and stable interest rates and (iv) downward pressure on IRR of new projects owing to thrust on Tariff Based Competitive Bidding.

Options Proposed

The paper proposes several options for Regulatory Framework and invites comments on the same:

a. Review of rate of RoE considering the present market expectations and risk perception of power sector for new projects;
b. Have different rates of return for generation and transmission sector and within the generation and transmission segment, have different rates of return for existing and new projects;
c. Continue with pre-tax Return on equity or switch to post tax Return on equity;
d. Differential additional return on equity for different line length of transmission lines and different size of substation;
e. Reduction of return on equity in case of delay of the project (at present early completion of projects is incentivized by additional 0.5% RoE however there is no reduction in RoE in case of delay)

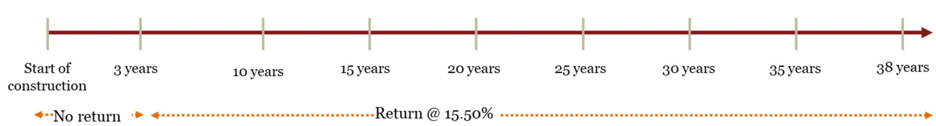
Our Comments/Suggestions

1. Risk profile of Generation and Transmission projects is different, in line with difference in the nature of two businesses. A Transmission Licensee suffers from challenges related to procuring Right of Way and varying terrain spanning across the length and breadth of the country. The expectation of returns for a Transmission Licensee must be in line with risk perception and market expectations.

2. As explained in point 8 (Gross Fixed Asset) in this document, huge investments would be required in the transmission sector in next 8-10 years. The assumption that adequate capacity exists (including capacity under construction) to meet the demand over next 8-10 years is moot and therefore, it is imperative that sufficient returns are allowed to investors on the invested equity capital.

3. The rate of return should be commensurate with market expectations and ensure viability of the project. An important indicator is the expected internal rate of return which can be gauged from the effective return on equity available for developers considering the return allowed during the lifetime, including the construction period. The computation of the same is shown below:

    i. Effective return on equity for a project with investment of 333 crore, construction period of 3 years and useful life of 35 years and allowed return on equity at rate of 15.50% works out to be 13.46%.



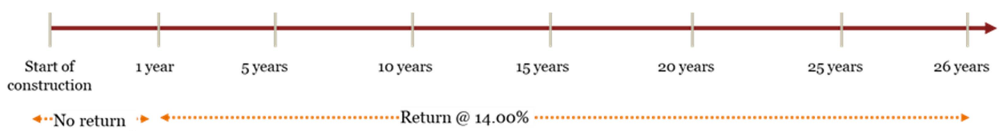
	Const. Period			Operation Period (Useful Life)													
Year	1	2	3	4	5	6	7	8	9	10...20		21	22	23	24	25......37		38
Inflow / Outflow	-40	-40	-20	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	16.54	19.36	19.36	19.36	19.36	19.36	52.66
IRR	**13.46%**																	

Effective return @ 13.46%

    ii. The effective return reduces with delay in construction of the project which may be due to uncontrollable factors including challenges in RoW, topography etc. For a delay of 1 year, the effective rate of return reduces from 13.46% to 13%.

4. While undertaking transmission projects that involve usage of new technologies, longer transmission lines and higher MVA substations, Transmission Licensee is posed with higher than usual risks. It is therefore recommended that while the <u>base return on equity of 15.5% should be retained</u>, an <u>Additional Return on Equity</u> should be allowed, over and above <u>Base Return on Equity</u> for projects that impose higher risks on the Licensee in line with the higher tariff adopted in such cases for transmission projects awarded under TBCB on the pretext of difficult region project [Transmission of electricity for North Eastern Region Strengthening Scheme-VI (NERSS-VI), CERC Order 90/AT/2017 dated 06.07.2017 and NER System Strengthening Scheme II (Part-B), CERC Order 81/AT/2017 dated 12.06.2017]. Such consideration is not available under cost plus projects since the project schedules for North East Projects are same as for other regions and even if delays are condoned, no return on equity deployed during the construction period is permitted which pulls down the overall project IRR. e.g. NER – Agra HVDC project under cost plus was delayed on account of severe working conditions, ROW etc., but still the burden of that delay has not been passed on to the beneficiaries. Instead, POWERGRID executed that project with IRR ~6%.

5. For renewable plants, the CERC has allowed a rate of return of 14%. Considering a construction period of 1 year, the effective RoE for a renewable project works out to be 14.41%, which is higher than effective return for a transmission project. <u>In order to match the effective rate of return for a renewable project, the rate of return for Transmission Licensee works out to be 16.81%.</u>



	Const. Period	Operation Period (Useful Life)															
Year	1	2	3	4	5	6	7	8	9	10…14		15	16	17	18	19	20…25		26
Inflow / Outflow	-100	14	14	14	14	14	14	14	14	14	14	15.4	19.93	19.93	19.93	19.93	19.93	19.93	53.23
IRR	14.41%																		

Effective return @ 14.41%

Considering the fact that a renewable project with a much lower gestation period and with limited geographical exposure involves considerably less risk than a transmission project, atleast an equivalent rate of return should be allowed to Transmission Licensees.

6. The rate of return on equity is regulated for both intra-state and inter-state transmission projects in India. While, both inter-state and intra-state assets are allowed rate of return of 15.5% by the appropriate Commission, it is important to appreciate the fact that the risks involved in an inter-state transmission project is significantly higher due to involvement of agencies across multiple states. Further, the projects executed by inter-state Transmission Licensees are more complex and require a higher gestation period, which results in a lower effective rate of return than for an intra-state transmission project. Considering the above facts, a rate of return providing a similar effective rate of return as intra-state Transmission Licensees should be allowed to the inter-state Transmission Licensees.

7. Further, we have computed the expected rate of return required for POWERGRID, based on Capital Asset Pricing Model (CAPM). CAPM is the most widely used method to estimate the required rate of return and is also adopted by CERC. According to this method, the expected rate of return on equity can be calculated as:

   $R_a = R_f + [\beta \, x \, (R_m - R_f)]$

   Where:
   R_a = Expected rate of return
   R_f = Risk-free rate
   β = Beta of the security
   R_m = Expected return on market

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

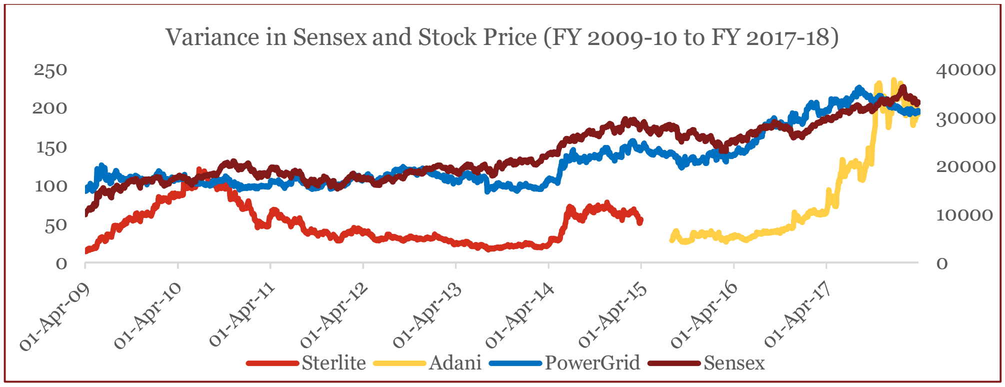
   - Step 1 • Calculate historical market returns for the past 9 years (2009 – 2017) using BSE Sensex data to determine Rm
   - Step 2 • Calculate risk free rate for similar period of 9 years using 10 year govt. bond yields
   - Step 3 • Estimate the Beta for POWERGRID using data of listed Indian transmission companies

   The beta for POWERGRID has been estimated as depicted below:

   Calculate equity beta for major listed transmission 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 POWERGRID's financial leverage

   The unlevered beta is then calculated using the following formula:
   Unlevered Beta = $(Levered\ beta\ to\ equity\ beta)/((1+((1-tax\ rate)x(debt/equity)))$

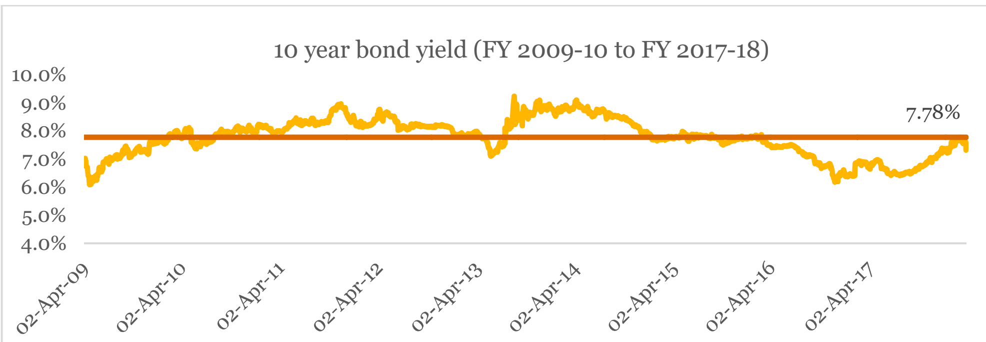
   Calculation of market return
   The market return has been estimated based on historical data of returns of BSE Sensex over past 9 years from FY 2009-10 to FY 2017-18. This data spans across last tariff period (2009 – 14) and major part of current tariff period (2014 – 18). It also excludes the outlier effect caused by global recession during FY 2008-09.



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

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

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



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

Estimation of expected Beta for POWERGRID

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

Firm	Equity / Levered Beta	D/E	Tax Rate	Un-levered Beta
Adani Transmission Ltd.	1.59	2.06	21.11%	0.605
POWERGRID	0.68	2.33	20.68%	0.239
Sterlite Technologies Ltd.	1.26	1.40	25.87%	0.627
Overall Average				**0.490**

- For Sterlite, data used from FY 2009-10 to FY 2014-15, post which the power entity was de merged and taken private
- For Adani, data used from July 2015 – Mar 2018, since it got listed in July 2015
- For POWERGRID, data used from FY 2009-10 to FY 2017-18, consistent with R_f and R_m

The unlevered beta works out to be 0.490.

The average un-levered Beta for all Indian transmission players is levered using financial leverage for POWERGRID to give expected Equity Beta.

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

= 0.490 x (1 + (1-0.2255) x (70/30))

= 1.3755

Thus, the Beta for calculation for expected return for POWERGRID is estimated at 1.3755.

Estimation of expected Rate of Return for POWERGRID

Expected rate of return = $R_a = R_f + [\beta \times (R_m - R_f)]$

= 7.78% + [1.3755 x (16.07% - 7.78%)]

= 19.18%

Thus, it can be observed that using the CAPM method, the expected return works out to be 19.18%, much more than the existing return of 15.50%.

9. The expected rate of return was also computed based on return allowed by Regulators in other countries. The transmission business is regulated in most part of the world, with a regulated rate of return allowed to the Licensees. The return on equity for transmission business in India has been estimated based on return allowed in five countries. The countries have been selected based on factors including development status, geographic region, the structure of transmission sector and the regulation of the transmission sector etc.

10. In order to estimate the required rate of return in India, following steps were carried out:

    i. ***Finding 'expected rate of return' in a country***
    The expected rate of return for transmission business can be estimated using the allowed rate of return for a transmission entity by regulator in a country.
    Expected rate of return = Risk free rate + Business risk premium

    ii. ***Calculating 'business risk premium' for a country***
    Using the equation in previous step:
    Business risk premium = Expected rate of return - Risk free rate

    iii. ***Estimating 'business risk premium' for India***
    Business risk premium (India) = Business risk premium (other country) + Δ Country risk premium

    Country risk premium: default spread based on rating by independent agencies (such as Moody's) adjusted for the additional volatility of equity market. So,

    Δ Country risk premium = Business risk premium (India) – Business risk premium (other country)

iv. ***Calculating 'expected rate of return' in India***

Expected rate of return (India) = Risk free rate (India) + Business risk premium (India)

The calculation for estimation of business risk premium in India is shown below:

Country	Risk free rate (A)	Allowed return (B)	Business risk premium in that country (C = B - A)	Rating-based Default Spread* (D)	Country risk premium (CRP)* (E)	Δ Country risk premium # (F = CRP (India) – E)	Business risk premium (India) (G = C + F)
Australia	2.52%	7.10%	4.58%	0.00%	0.00%	2.19%	6.77%
South Africa	8.52%	16.70%	8.18%	2.26%	2.54%	-0.35%	7.83%
Malaysia	4.00%	10.89%	6.89%	1.23%	1.38%	0.81%	7.70%
USA	2.25%	10.57%	8.32%	0.00%	0.00%	2.19%	10.51%
Germany	3.80%	7.39%	3.59%	0.00%	0.00%	2.19%	5.78%
Brazil	5.83%	14.71%	8.88%	3.08%	3.46%	-1.27%	7.61%
Average	**7.70%**						

Negative 'Δ Country risk premium' implies countries riskier than India and positive implies countries less risky than India.

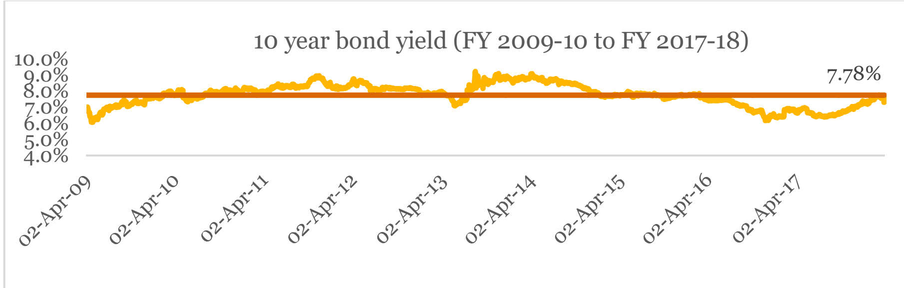
* Country risk premium for India (CRP (India))* = 2.19%

Source:

- Australia: AER's decision on transmission revenue for AusNet for 2017-22 (AusNet operates transmission network in Victoria)
- South Africa: Eskom application to NERSA for approval for electricity tariff 2018-19
- Malaysia: Tariff for Peninsular Malaysia under Incentive-based regulation mechanism by Energy Commission
- USA: FERC decision on RoE for New England Transmission Operators (NETO), 2014
- Germany: Return on investment under incentive regulation in Germany
- Brazil: Regulator (ANEEL) allowed "rate of return on own capital" in transmission auction 02/2017 for Lot 7

Country Default Spreads and Risk Premiums by Aswath Damodaran (Professor at Stern School of Business at New York University

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



Thus, the rate of return for transmission business in India can be estimated at **7.70%+7.78% = 15.48%,** based on international benchmarking**.**

Therefore, the current rate of Return on Equity @15.5% is in line with the return allowed by regulators in other countries.

11. We also compared the return allowed to developers in other regulated infrastructure sectors in India – Aviation (airport operators) and natural gas transmission.

   i. ***Aviation***

   Airport Economic Regulatory Authority of India (AERA) sets Fair Rate of Return (FRoR) for a control period 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 forecasted cost of existing debt and forecasted cost of future debt to be raised during the control period

   $$FRoR = (g \times Rd) + ((1-g) \times Re)$$

   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	16.00%	AERA's order on determination of Aeronautical Tariff for IGI Airport, Delhi for second control period (2014-19)
2	Chhatrapati Shivaji International Airport, Mumbai	16.00%	AERA's order on determination of Aeronautical Tariffs in respect of Chhatrapati Shivaji International Airport, Mumbai for the first Regulatory Period (2009-14)
3	Rajiv Gandhi International Airport, Shamshabad, Hyderabad	16.00%	AERA's order on determination of Aeronautical Tariffs in respect of Rajiv Gandhi International Airport, Shamshabad, Hyderabad for the first control period (2011-16)
4	Kempegowda International Airport, Bengaluru	16.00%	AERA's order on determination of Aeronautical Tariffs in respect of Kempegowda International Airport, Bengaluru, for the first Control Period (2011-16)

It can be observed that for an entity like airport with limited geographic spread, the allowed return of 16% is more than the electricity transmission 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:

$$WACC = g * Rd * (1 – Tc) + (1\text{-}g) * Re$$

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

$$WACC = g * Rd * (1 – T_c) + (1\text{-}g) * Re$$

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

⇨ $Re = 22.66\%$

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

12. The observation of a declining interest rate trend in para 18.5 of the Consultation Paper perhaps is premised on the fact that the RBI has cut the Repo rate from 8% in January' 2014 to 6% in August' 2017 leading to a benign interest rate regime in the country. The current interest rate situation is entirely different with 10 year G Sec yields touching 8% amidst inflation concerns and adverse balance of payment position. In the international markets also interest rates are hardening as the US Federal Reserve has indicated increases in their Policy Rates following recovery in the US economy. RBI has also recently increased the Repo Rate by 25bps, a first in the last four and a half years signalling a reversal in the interest rate cycle. The ROE has to be fixed considering the interest yield expectations during the control period viz. 2019-24 and not historical interest rate trends of 2014-19. Therefore, the risk free rate

considered for determining the ROE should be forward looking and reflect the expected G Sec yields during 2019-24.

13. From the thorough assessment of allowed Return on Equity by factoring in risk perception and market expectations, it can be clearly concluded that the existing allowed rate of Return on Equity is proving to be inadequate for transmission business in India. It is therefore pertinent to ensure that Base Return on Equity at 15.50% is protected to guard the Licensee against business and market risks.

14. A lower than the prevailing rate of return may put the future investment at risk. During the last decade, POWERGRID has gone to the equity markets twice and raised money to allow for sufficient resources for investment in this strategic sector. POWERGRID cash situation is so constrained that in the past it was unable to give full dividend to the GoI as per DIPAM guidelines and sought relaxation.

15. With regards to proposal of providing differential additional rate of return for different line lengths in case of the transmission system and different sizes of substation, we suggest that there should be no differential additional return on equity for different size of transmission elements within the same Region. The additional return on equity should be provided to individual elements, which can be put to regular use independently and not on the complete project. The same is being suggested owing to following reasons:

    i. The additional return on equity of 0.5%, as per the current Regulations, is admissible if the entire project is completed within the specified time completion schedule provided in the Regulations.

    ii. Standardization of construction period makes sense if the projects are of homogeneous nature and are not influenced by any external factors.

    iii. The completion time schedule for Transmission project specifies qualifying time schedule for individual elements and not for the projects. Therefore putting additional condition on completion of project with timeline specified exclusively for elements is not justified. **Accordingly, the additional ROE may be allowed on stage wise completion of transmission elements**, which can be put into regular service independently in line with generation projects.

    iv. In case of transmission projects, the physical boundary of the projects spans across different geographies traversing several states. Based on its experience, POWERGRID believes that the defined timelines are far more aggressive than the actual time required for implementation, keeping in view the issues for Right of Way, socio-political factors, forest approvals, infrastructure support etc. which could vary significantly across geographies/states even for similar projects in plain areas.

    v. The development of transmission lines is also dependent on the system requirements for stable operations of the grid which may require prioritization. Further different time schedule may be required for similar nature of projects due to system requirements which may range between 12-28 months. Similarly, for substation, the acquisition of land in different states takes different time ranging from 10-20 months, as land is a State matter. Therefore, incentive for a transmission project should be provided element wise.

vi. Presently, additional RoE is not given to brown field substation project and transmission lines having line length less than 50 km.

vii. With regard to different additional ROE for different size of project, POWERGRID believes that additional ROE should be same for all types of projects since the additional ROE is in terms of a percentage of equity component and same would automatically capture the size of the project. However, it may be increased for projects implemented in different terrains.

viii. CERC had provided pre-tax return during 2009-14 period but has reverted to post tax return in the current tariff period keeping in view the consideration that the utilities should be reimbursed actual tax outgo and any tax benefits should be passed on to the consumers. Though at present the tax holiday benefit u/s 80 IA of the Income Tax Act, 1961 is no more available, there are other benefits such as accelerated depreciation etc. which reduce the actual tax burden. Determining an equitable pre-tax rate applicable to all assets (each of which would have different tax benefits and tax burden, and in case of generation assets, different beneficiaries), would be a challenge and therefore, the current system may be continued.

ix. As explained in point 8 of this document, the licensees are not given any return on equity during the construction period, which pulls down the effective ROE for the equity investors. In case of delayed projects, though CERC condones the delay due to uncontrollable factors and allows IDC and IEDC for the delayed period, however, no compensation for the return on equity is allowed. This significantly reduces the effective ROE. Reduction of ROE for delay in projects would cause double jeopardy to the developers and is not equitable.

12) S.No. 19: Cost of Debt

Issues raised by CERC

The Consultation Paper discusses the key trends observed during the recent times – (i) Increase in corporate bonds outstanding as a % of GDP, (ii) Availability of alternative source of funds owing to development of bond market and (iii) Reduction in lending rates of bank.

Options Proposed

The paper proposes several options for Regulatory Framework and invites comments on the same:

a) Continue with existing approach or to switch to normative cost of debt and differential cost of debt for the new transmission and generation projects;
b) Review of the existing incentives for restructuring or refinancing of debt;

c) Linking of reasonableness of cost of debt with reference to certain benchmark viz. RBI policy repo rate or 10 year Government Bond yield and have frequency of resetting normative cost of debt.

Our Comments/Suggestions

1. Adoption of normative approach for determining cost of debt has been put across for discussion by CERC in view of the recent trends observed which seem to point towards falling interest rates and also the increase in corporate bond market activity. A careful analysis of key cost of debt indicators discussed by CERC is given below.
    a. *10 year Government Securities yield (G Sec rate)* – it has been plotted in **Annexure 2**, from where it can clearly be observed that <u>G Sec rate has increased from 6.4% in Jan 2017 to 7.99% in Jun 2018</u>. The G Sec rates are also observed to be high in terms of volatility.
    b. *Repo rate* – CERC refers that RBI's policy rate (Repo rate) have fallen from 8% in 2014 to 6% in August 2017 and have stayed at those levels ever since. However, if we factor in the most recent changes in monetary policy rates by RBI, it can be seen that <u>for the first time since 2014, Repo rate has been hiked in June 2018 and it stands at 6.25%.</u> The tightening of monetary policy is backed up with RBI's macroeconomic reasoning, including the efforts to tame increased levels of inflation. This clearly indicates that Repo rate may have already bottomed out and can further increase. (**Annexure 2**)
    c. *MCLR rates* – CERC has also drawn reference to the new MCLR based regime which has been developed as a mechanism to ensure passing on of lower repo rate to consumers. It can be seen from the trend of MCLR rates of leading banks viz., SBI, HDFC and ICICI (**Annexure 2**) that after bottoming out in 2017, the MCLR rates are on the rise indicating increase is cost of borrowing. e.g. <u>SBI's MCLR has risen from 7.95% in Nov 2017 to 8.25% in June 2018</u>. (Annexure 2)
2. From the analysis above, <u>it can be clearly observed that the interest rates after having seen a downtrend since 2014 have already started to reverse and the outlook is upward looking</u>. This reflects high degree of volatility in the cost of debt expectations. Therefore, <u>linking cost of debt to benchmarks such as G Sec rate, Repo rate or MCLR rates shall expose transmission system users to risk of interest rate volatility and hence is not recommended</u>.
3. The cost of borrowing funds for POWERGRID is one of the lowest in market. While, the two public sector funding agencies viz. Power Finance Corporation and Rural Electrification Corporation offer interest rates for long-term loan ranging between from 10.75% p.a. to 11.75% p.a., <u>POWERGRID has been able to raise debt efficiently using a basket of debt instruments (illustrated in response to point 7 (Depreciation) of this document) at a much cheaper rate of 7.5%-9% p.a.</u> with a tenure of 10-15 years. This is largely owing to a high credit rating and the present regulatory regime of allowing actual interest rates as a pass through in the tariff. An attempt to link the cost of debt in tariff to benchmarks may eliminate the comfort available to lenders, thereby increasing the cost of lending to POWERGRID, which will have adverse impact on tariffs.

4. Moreover, the benchmarks would have to be set considering the available rate of interest in the market for all the players and would have to be higher than the prevailing rates to provide a cushion to the company in view of the high fluctuations in interest rates (as depicted in point 1), which would negatively impact the consumers. Thus, it is recommended that the present regime of allowing interest rates based on actuals should be continued.

5. However, since the aim of this exercise is to moderate the burden on transmission system users, the onus of reduction in cost of debt should be left with Licensee and the Licensee should be adequately incentivized to reduce the same. Therefore, it is recommended that in order to incentivize active pursuit of savings consequent to refinancing of loans, the gains should be shared in the ratio of 1:1 between the beneficiary and the Licensee.

13) S.No. 20: Interest on Working Capital

Issues raised by CERC

The paper states the existing methodology of allowing interest on working capital. Further, it discusses the change in interest rate regime to Marginal Cost of funds-based Lending rate (MCLR) and its implications on rate of interest allowed for working capital.

Options Proposed

It proposes the following options and invites comments on the same:

(a) Following the approach of allowing IWC based on the cash credit or adopting any alternate approach;

(b) While working out requirement of working capital, maintenance spares are also accounted for. Since O&M expenses also cover a part of maintenance spares expenditure, a view may be taken as regards some percentage, say, 15% maintenance spares being made part of working capital or O&M expenses.

Our Comments/Suggestions

1. The current methodology of allowing interest on working capital has been debated and refined over the past control periods. A working capital base consisting of O&M expenses, spares and receivables is established. The interest on the same is allowed based on normative interest rate based on base rate, plus a margin. This allows the licensee to maintain sufficient working capital, at the same time incentivizing licensee to ensure efficiency in procurement of funds. Thus, the present approach of linking interest rate to benchmarks plus sufficient margin may be continued.

2. With regard to option of review of consideration of maintenance spares as part of working capital or O&M expenses, it is important to note that there are two type of spares:

   (i) Mandatory spares (initial spares)
   (ii) O&M spares

   The initial spares are allowed based on provisions in CERC Tariff Regulations. These are procured at the time of implementation of the project and are capitalised. Accordingly, these are accounted as zero cost in O&M expenses upon consumption.

However, in addition to the initial spares, POWERGRID is required to maintain further spares to reduce downtime considering prevalent fault level in the system and lead-time required to procure these spares in an event of a failure. The inventory of these spares is maintained from the internal resources of the company and is reflected in O&M expenses only upon utilization in case of an exigency. Thus, it can be concluded that these is no duplication of expenditure on account of spares.

3. As of 31st March 2018, the inventory of these spares was INR 1038 Crore. The procurement and storage of these spares entails inventory carrying costs. In addition, the quantum of requirement of such spares would increase progressively as the transmission assets grow older. Hence, it is essential that the cost of spares should be considered as part of the working capital base and interest on the same should be allowed as a part of tariff.

14) S.No 21: Operation and Maintenance Expenses

Issues raised by CERC

The paper discusses challenges pertaining to specifying a fixed escalation rate owing to variation in WPI and CPI. Further, the fixed escalation rate does not capture the variation due to unexpected expenses such as wage revision etc. It proposes working out the O&M expenses on the basis of MVA capacity instead of individual components. It further discusses about variation in O&M expenses on account of economies of scale in case of expansion of capacity of an existing transmission substation. The paper suggests rationalization/usage of multiplication factor similar to generating stations for transmission system, where the generating stations receive lower amount towards O&M expenses in case of addition of units in same generating station. The paper also acknowledges higher O&M requirement for older generating plants/transmission system.

Options Proposed

The paper proposes several options for Regulatory Framework and invites comments on the same:

(a) Review the escalation factor for determining O&M cost based on WPI & CPI indexation as they do not capture unexpected expenditure;
(b) Rationalization of O&M expenses in case of addition of components;
(c) Have separate norms for O&M expenses on the basis of vintage of the transmission system;
(d) Treatment of income from other business (e.g. telecom business) while arriving at the O&M cost.

Our Comments/Suggestions

1. The O&M expenses consist of employee costs, R&M expenses and Administration & General expenses. The increase in employee cost every year is expected to atleast match the increase in Consumer Price Index. This is much more valid for a public sector organization like POWERGRID, where the

salary is indexed to dearness allowance, which is in-turn derived based on inflation. Hence, the employee cost component of O&M costs may be indexed to CPI. A similar practice is followed by most of the State Commissions. Additionally, components like variable pay (Performance Related Pay), which are an essential part of employee compensation should be allowed and not removed while normalizing the expenses.

2. Based on practice followed by various State Commissions for distribution and transmission, the O&M expenses may be allowed based on norms and indexed to a factor derived from CPI and WPI in ratio of 60:40. Similarly, A&G costs may be allowed based on norms and indexed to WPI.

3. Accordingly, CERC may individually determine the three components of O&M expenses. Employee costs may be indexed to CPI, R&M may be normative and linked to an index derived from CPI:WPI in ratio of 60:40 and A&G may be normative indexed to WPI. Auto-indexation may be allowed by CERC, where the Licensee may revise O&M costs based on actual inflation and charge the differential of previous year in the next year of the control period. CERC may review the indexation performed by the Licensee at the time of truing up.

4. The normative O&M expenses are computed by the CERC by considering the overall number of substations and the circuit kilometers through the concept of equivalent substations and circuit kilometers. The expenses are averaged out over the network and derived on per bay and per kilometer basis. Thus, these average expenses represent the O&M expenditure required for the network and are independent of addition of further components in the existing system. It is important to note that in case of newly commissioned substations, where few bays are installed, the allowed O&M expenses may not be enough initially to recover the actual expenses. A reduction of O&M expenses for additional bays/lines will have further impact on the recovery of expenses and will erode the internal accruals. Thus, considering the above factors, it shall not be prudent to reduce the allowance for O&M expenses on addition of components.

5. The paper suggests linking recovery of O&M expenses based on MVA capacity. It may not be advisable to adopt this approach on account of the following factors:

   a. The methodology may not allow claiming of O&M expenses for switching stations which do not have any transformer installed in it.

   b. There are only few substations with less number of bays and high MVA capacity when compared with substations with lower MVA and higher number of bays.

   c. In case of extension of bays in any substation, without any increase in MVA capacity, which is a likely case for majority of the future projects, additional O&M expenses would not be allowed to the Licensee, even though the company would require expenditure on account of O&M. The present concept of linking O&M expenses to number of bays takes care of this aspect as opposed to the proposed concept of linking O&M to MVA capacity.

6. Other business operations of Transmission Licensee are dealt with by CERC through separate Regulations. A portion of income as specified in the said Regulations is used to reduce the annual transmission charges. Accordingly, income from other business of a Transmission Licensee should not be taken into consideration while determining O&M expenses.

15) S.No 26.5: Transmission Availability Factor

Options Proposed

The paper proposes several options for Regulatory Framework and invites comments on the same:

a) Existing approach for computation of Transmission system availability and weightage factors to be applied for outage hours for transformer and reactors;
b) Review of the incentive formula for HVDC bi-pole and HVDC back-to-back stations at par with AC system;
c) Specify appropriate region (import or export) for certifying the availability of Inter-regional links (AC and HVDC line) for the purpose of incentive and recovery of annual fixed charges; and
d) Review of the existing methodology or procedure for computation of availability, monthly availability and cumulative availability;

Our Comments/Suggestions

POWERGRID submits following with regard to calculation of transmission system availability:

1. <u>Normative target availability on annual basis and recovery of AFC on monthly basis with progressive availability for the period.</u>

   a. **Weightage factor:**
   CERC while notifying the Tariff Regulations 2009 introduced the weightage factors for ICTs and Reactors. The multiplication factor of 2.5 for ICT was derived by equating a 200km long D/C line with twin conductors with a 315 MVA ICT and the multiplication factor for reactor was indicated as one fourth the weightage of a 315 MVA transformer. However, the same was discontinued in Tariff Regulations, 2014 due to the following issues:

      i. Circuit I and Circuit II of a line were treated as independent elements and were taken care of separately in availability calculations. 2.5 multiple was derived in Regulation by equating one 315 MVA transformer with two circuits of 200kms. But while certifying availability by RPC each circuit was considered as one element separately and transformer was also considered as one element but the weightage factor for transformer was still considered as 2.5 x MVA capacity of the transformer which was a gross anomaly as both circuits are separated in calculation, the weightage factor for the transformer should have also been halved i.e. 1.25.

      ii. POWERGRID is having different capacity transformers like 1500 MVA, 1000 MVA, 500 MVA, 450 MVA, 315 MVA, 250 MVA, 100 MVA, 50 MVA, 15 MVA, 5 MVA. In all cases 2.5 was multiplied with MVA capacity as weightage of the transformer. When 200 km D/C line was equated with 315 MVA transformer, it was not logical to apply 2.5 multiple for transformers of all capacities. The multiple factor for 1500 MVA ICT should have been 0.53 instead of 2.5. Similarly different weightage should have been considered for different capacity of transformers.

iii. In case of transmission lines, POWERGRID is having lines of length varying from 0.5 km to more than 400 km with single conductor, twin conductor, triple conductor and quad conductor etc. There are a number of single circuit lines also. Hence determining the multiple factor for weightage of transformer by equating one 315 MVA transformer with D/C twin line of 200 km and applying the same weightage to different capacity of transformers was unjustified.

iv. In case of switchable reactor, POWERGRID is having different MVAR capacity Reactors like 20 MVAR, 50 MVAR, 63 MVAR, 80 MVAR, 125 MVAR, 240 MVAR, 330 MVAR etc. Determination of weightage factor by equating with 50 MVAR capacity reactor and applying the same multiple factors for all reactors was also not justified.

In view of above, the weightage factors considered in the availability calculation in Regulation 2009-14 is not logical.

b. **POWERGRID submits following additional submission for consideration for ensuing Tariff Regulations 2019-24:**

(i) It is proposed to modify methodology for calculation for transmission system availability as given below:

The fixed cost of the transmission system or communication system forming part of transmission system shall be computed on annual basis, in accordance with norms contained in the Regulation, aggregated as appropriate, and recovered on monthly basis as transmission charges (inclusive of incentive) from the users, who shall share these charges in the manner specified in the Regulation.

The transmission charges (inclusive of incentive) payable for a calendar month for transmission system or part shall be calculated in accordance with the following formulae.

Transmission charges for April (TC1) = (AFC) x (NDP1 / NDY) x (TAFP1 / NATAF)
Transmission charges for May (TC2) = AFC x (NDP2 / NDY) x (TAFP2 / NATAF) – TC1
Transmission charges for June (TC3) = AFC x (NDP3 / NDY) x (TAFP3 / NATAF) – (TC1+TC2)
Transmission charges for July (TC4) = AFC x (NDP4 / NDY) x (TAFP4 / NATAF)– (TC1+TC2+TC3)

....
Transmission charges for Feb (TC11) = AFC x (NDP11 / NDY) x (TAFP11/NATAF) – (TC1+TC2+TC3+TC4+TC5+TC6+TC7+TC8+TC9 +TC10)

Transmission charges for March (TC12) = AFC x (TAFY / NATAF) – (TC1+TC2+TC3+TC4+TC5+TC6+TC7+TC8+TC9+TC10+TC11)

TC = Transmission charges inclusive of incentive up to the Nth month

Where
AFC= Annual fixed cost specified for the year in rupees.
NATAF = Normative Annual Transmission Availability Factor in percentage.
NDPN=No of days upto the end of Nth month of the financial year
NDY = No. of days in the year.
TAFPN= Transmission availability factor in percentage achieved upto the end of the Nth month of the year
TAFY = Transmission availability factor in percentage achieved for the year.

Preventive maintenance is planned every year and is carried out as per the annual maintenance plan in a particular month. Sometimes major overhauling of transmission elements like Transformers / Reactors / Circuit Breakers / Series Compensators / terminal equipment of HVDC systems, are carried out and in such cases, the outage duration for maintenance is much higher than the normal maintenance.

The above outages will have impact on availability of the transmission system of a month in which shutdown has been taken for annual maintenance and hence reduction in revenue in that month. Since AMP and major overhauling work is yearly activity and considering outage in a particular month is not logical.

In view of the above, it is proposed to have annual availability for recovery of transmission charges.

(ii) Proposal: Change SIL to NSC for determination of weightage of transmission lines.

Presently the weightage factor for transmission lines in availability calculation as per Regulation 2014 (Terms and conditions of Tariff) is line length multiplied by SIL (compensated). It is proposed to replace SIL with NSC (Number of sub-conductors in the line) in weightage factor of transmission lines in availability calculation for the tariff block 2019-24.

For this, CERC gave the following justification in statement of reasons while formulating the Tariff Regulations 2009:

Quote

"SIL has no direct relationship with the power carrying capability of a transmission line. For example, SIL of a 400 kV line with twin moose conductors is 515 MW, and a 400 kV line with quad Bersimis conductor has SIL of 691 MW (1.34 times of the former), whereas the later can easily carry twice the amount of power. Further, SIL loses its significance totally in case a line has a shunt reactor or series compensation. SIL is therefore not suitable criterion for weightage in line availability."

Unquote

(iii) Proposal: Removal of penalty clause related to generation backing down for HVDC bipole system installed without (n-1) concept.

The HVDC Bipoles connected directly to the generating stations are for evacuation of bulkpower. All these HVDC bipoles have been installed without (n-1) concept i.e. in case of outage of one pole there will be no other alternative path available for evacuation of complete generated power and the generating stations are forced to go for backing down some generation. The AC transmission elements in the grid are installed with (n-1) concept. Since HVDC bipoles are installed without (n-1) concept, hence the penalty clause of doubling the outage period in case of generation backing down should not be applicable for HVDC system.

Hence it is proposed to remove the same from availability calculation of HVDC Bipoles.

2. With regard to review of incentive formula for HVDC bi-pole and HVDC back-to-back stations at par with AC system, following submissions are made:

   a. Line lengths of HVDC bipoles are generally very high (Talcher – Kolar - 1369 km, Agra – BNC – 1753 km etc.) and in some cases, it is equivalent to 4 to 6 AC D/C lines in terms of its length. Such long HVDC transmission lines are passing through various terrains and exposed to all kind of environmental conditions. Therefore there is high probability of outage of HVDC lines due to various reasons. Any fault in HVDC transmission lines will bring down the availability. Had there been 4 to 6 AC D/C lines in place of HVDC Bipole, the drop in availability of the combined AC lines would be much lower as probability of occurring fault will be in one line only.

      In view of above, the normative target annual availability for long HVDC Bipoles is required to be reduced to 92% from 95% in next Tariff Regulations.

b. Regional availability of AC transmission system is the availability of huge number of elements along with transformers and reactors whereas HVDC transmission elements are few only (mostly two numbers in a Region). Outage of one AC transmission element may not have much impact on overall availability of regional transmission system, whereas in case of outage of one HVDC element, there is drastic reduction in availability of HVDC Transmission system e.g. considering outage of one month of an element of AC or HVDC, the impact shall be as below:

- Availability of AC system:
  Drop in availability may not come down below normative target availability as there is huge number of transmission elements.

- Availability of HVDC system:
  In case of single HVDC element in a region – the availability will be zero and no tariff is recovered. In case of two elements in the region – the availability will be 50% and hence drastic reduction in recovery in tariff in addition to loss of incentive.

<u>In view of above, normative target availability for AC and HVDC system cannot be defined at par</u>.

3. With regard to the appropriate region for certifying the availability of inter-regional links, following submissions are made:

a. **Inter-regional HVAC system**

All the inter-regional AC transmission lines from one region to other region should be clubbed for certification of availability provided sharing of the transmission lines are same. In case power flow is in one direction for most of the period of the year, then availability certification is to be done by importing region, in case power flow takes place in both the direction, then certification of availability is to be done by the Region in which major portion of all the lines falls.

b. **HVDC System**

(i) <u>Back to Back System</u>
HVDC back to back system is installed in a particular region and availability should by certified by respective RPC of the region wherein the system is installed. Based on this availability certificate, transmission charges will be recovered.

(ii) <u>HVDC Bipole:</u>
In HVDC Bipole, terminal stations of the HVDC Bipole systems are in two regions. All these HVDC transmission systems were built for power flow from one region to other region. The certification of availability of these HVDC Bipole Systems should be by the RPC of

receiving region i.e. beneficiary region. In view of that certification of availability should be done by respective RPC as per the following:

- Talcher – Kolar HVDC system – certification by SRPC
- Champa – Kurukshetra HVDC System – certification by NRPC
- BNC – Agra & Alipurduar – Agra HVDC system – certification by NRPC

4. With regard to the appropriate region for certifying the availability of AC inter-regional links, following submissions are made:

   a) Detailed procedure for computation of availability as given in para (1) above.

   b) Additionally following submission are made:

      (i) Time frame for certification of transmission system availability

      As per BCD Regulation, the Bill #3, a quarterly adjustment bill for the transmission charges, is raised at the end of every quarter. One of the components of Bill#3 is the income towards the incentive based on availability certificates for various months of the quarter issued by the RPCs. It is essential to have transmission system availability certificates in time to raise the Bill#3 in time. In view of this, following schedule may be incorporated in the Regulation for certification of availability by respective RPC.

      - Submission of outage data by Transmission Licensees to RLDC / constituents – By 5th of the following month
      - Review of the outage data by RLDC / constituents and forward the same to respective RPC – by 20th of the following month
      - Issue of availability certificate by respective RPC – by 3rd of the next month.

      (ii) Proposal : Removal of additional 12 hours penalty clause in case of two trippings in a year for AC transmission elements as per the following clause in the Regulations, 2014.

      "Provided also that for AC system, two trippings per year shall be allowed. After two trippings in a year, additional 12 hours outage shall be considered in addition to the actual outage."

      Operating the transmission system with reliability and stability is important and POWERGRID has been putting its best effort to achieve this objective. However, tripping of transmission elements do take place due to various reasons like flashover across the insulator string due to higher level of pollution specially during foggy / rainy season, infringement caused due to excessive growth of vegetation & reluctance by owners/restriction imposed by forest department to lop them, bush fire, burning of agricultural waste by villagers, miscreant action, celebration of festival (kite, procession etc.) by villagers, lightning strike on transmission lines, landslides, cyclonic storm, non-clearance of fault by protection elements of adjoining system of other power utility, overloading etc.

CERC may appreciate that none of the above phenomenon causing unwarranted tripping of transmission elements are due to negligence by Transmission Licensee. As such penalizing the Transmission Licensee for none of its fault is against the principle of natural justice.

In view of the above, it is prayed to remove this clause.

(iii) Proposal : Delinking Tariff Regulations with Standard of Performance Regulations, 2012

Clause 6(i) in Appendix III of CERC Tariff Regulations, 2014 stipulates as under:

Quote

Outage time of transmission elements for the following contingencies shall be excluded from the total time of the element under period of consideration.

i. Outage of elements due to acts of God and force majeure events beyond the control of the transmission licensee. However, onus of satisfying the Member Secretary, RPC that element outage was due to aforesaid events and not due to design failure shall rest with the transmission licensee. A reasonable restoration time for the element shall be considered in accordance with Central Electricity Regulatory Commission (Standard of performance of inter-state transmission licensees) Regulation, 2012 as amended from time to time and any additional time taken by the transmission licensee for restoration of the element beyond the reasonable time shall be treated as outage time attributable to the transmission licensee. ……

Unquote

Linking Standard of Performance (SoP) with CERC Tariff Regulation, 2014 is not justifiable because of following reasons :

(i) SoP Regulation specifies the maximum time period for restoration of transmission element and does not take care of extent of damage & work involved in restoration process, site working condition, accessibility to site, climatic condition, law and order situation, resolution of right of way issues etc.

(ii) The objectivity of SoP (as notified in SoP Regulation) is to ensure compliance of the standards of Performance by the inter-state Transmission Licensees and to provide for an efficient, reliable, coordinated and economical system of electricity transmission, non-adherence of which would entitle the affected parties to compensation.

(iii) In SoP, monthly availability for transmission elements set at 90% and tower collapse shall not be counted for the purpose of calculation of monthly availability of AC transmission line and HVDC bi-pole line. But Tariff Regulations 2014 considers this outage for the purpose of availability calculation as per clause 6(i) of appendix III.

In view of the above, Standard of Performance Regulation, 2012 may be delinked from Tariff Regulations for the purpose of availability calculation and continue with the guideline as given in Tariff Regulations, 2009.

Therefore, it is prayed to incorporate the following as per Regulations prior to 2014:

"6. Outage time of transmission elements for the following contingencies shall be excluded from the total time of the element under period of consideration.

i) Outage of elements due to acts of God and force majeure events beyond the control of the transmission licensee. However, onus of satisfying the Member Secretary, RPC that element outage was due to aforesaid events and not due to design failure shall rest with the transmission licensee. A reasonable restoration time for the element shall be considered by Member Secretary, RPC and any additional time taken by the transmission licensee for restoration of the element beyond the reasonable time shall be treated as outage time attributable to the transmission licensee. Member Secretary, RPC may consult the transmission licensee or any expert for estimation of reasonable restoration time. Circuits restored through ERS (Emergency Restoration System) shall be considered as available."

(iv) <u>Proposal : Removal of upper cap of transmission system availability of 99.75% for claiming incentive in tariff</u>.

The relevant clause of Tariff Regulation, 2014 stipulates that:

"Provided further that no incentive shall be payable for availability beyond 99.75 %":

At para 40.26 of Statement of Reasons in respect of Tariff Regulation, 2014, following is stated:

"Views of the stakeholder that setting high target of normative target availability will force the utilities to compromise the maintenance of the system resulting in threat to stability and reliability of the grid……….Commission observed that outage required for carrying out annual maintenance for different transmission elements is in the range of 8 to 12 hours."

It may be noted that annual maintenance is carried out as per annual maintenance plan (AMP) prepared by POWERGRID for different transmission elements staggered over different months in a year. Maintenance of non-shutdown nature is also being carried out regularly as per AMP. Maintenance involving shutdown is carried out generally once in a year. Besides, shutdowns are sometime requisitioned for undertaking maintenance of emergency nature or to undertake breakdown maintenance. Unless there is any problem in the system, it is not required to take additional shut-down for maintenance purpose of an element. Major maintenance like overhauling etc. is also carried out by POWERGRID for which longer shutdown is required. All these maintenance activities on transmission element involving shutdown are mostly carried out in a particular month or spread in two months causing dip in monthly availability of the respective element. However, in rest of the months of the year, the availability of these elements remains at 100% in case no contingency arises requiring forced shutdown of the element. In that case, the availability of the transmission element will be higher than the upper limit of availability i.e. 99.75% as stipulated in the Regulation for rest of the months of the year. Thus, there will be impact on availability only in a particular month in which shutdown or forced outage is availed but not in rest of the months of the year. The loss in incentive due to drop in availability in a month may be allowed to be recovered with higher availability of elements in rest of the months of the year. Restricting incentive with upper cap in availability is thus totally unjustified and needs to be omitted.

It is needless to mention that maintaining higher standard of performance involves lot of cost and effort. This needs to be considered by all stakeholders. Moreover consistent higher level of performance requires regular upkeep of system without compromising the maintenance practice. As such putting cap of any nature on the performance level merely for the purpose of limiting incentive to the Transmission Licensee is against the principle of natural justice.

Capping of performance level can be counterproductive and is against the overall interest of the grid. 0.25% of 8760 available hours in a year is equal to 22 Hrs. Vide para 40.26 of Statement of Reasons in Tariff Regulation, 2014, CERC observed that "outage required for carrying out annual maintenance for different transmission element is in the range of 8 to 12 hours". Thus Regulation is not incentivizing the Transmission Licensee to keep the element in service for the balance 10 to 14 hours. In fact, Transmission Licensee may keep the element out of service in the name of maintenance without any reason resulting reduction in Total Transmission Capacity of different transmission corridors and the beneficiaries will be deprived of the additional power causing overall inefficiency in the economy of the country.

Regulation does not provide any incentive to utilize opportunity outages. By availing opportunity outages for maintenance activities, overall outage of an element reduces and thereby improves the stability and reliability of the grid. Hotline maintenance is very difficult and risky for individuals carrying out the maintenance activities. However, Regulation does not provide any incentive to carry out the possible maintenance activities through hotline technique for reducing the overall down time of the transmission element in the grid.

CERC itself has appreciated maximization of availability of transmission system vide clause 17 of order dated 15.07.2004, CERC has mentioned that:

"we have reviewed the matter, particularly on consideration of the fact that uninterrupted availability of the transmission system is vital for ensuring continuous supply of power to the consumers. Therefore, every effort needs to be made towards maximization of availability of the transmission system and this explains the necessity to incentivize the efforts required to be made by the transmission licensee."

In fact, CERC has introduced capping of availability for incentive purpose in Regulation 2004 as under:

"Provided that no incentive shall be payable above the availability of 99.75% for AC system and 98.5% for HVDC system."

The said provision was subsequently amended by CERC vide clause 18 of order dated 15.07.2004 which reads as under

"Further, to enable the transmission licensee to maximize availability of the transmission system by using modern maintenance techniques, such as hotline washing, we propose to dispense with the upper limit of target availability for payment of

incentive"

Vide para 40.21 of Statement of Reasons in respect of tariff Regulation, 2014, CERC has indicated as below:

"Commission shall be guided by factors which encourage good performance and the principles rewarding efficiency in performance."

In view of all the above explanations, it is prayed that the upper cap of transmission system availability of 99.75% for incentive purpose may be omitted.

16) S.No. 26.5: Transmission Losses

Issues raised by CERC

CERC observes that presently there is no regulatory framework on specifying norms for transmission losses. The current scheduling framework considers 4.5-5% losses for inter-state transmission system and 4-4.5% losses for intra-state transmission system, leading to a total loss of 9-10%, which has a negative impact on cost of supply. The losses are only dependent on best operational practices, efficient planning etc.

Options Proposed

In light of the observations, CERC has proposed to introduce norms for inter-state transmission losses based on factors within control and international benchmarks.

Our Comments/Suggestions

1. A normative benchmarking regime for transmission losses is only effective when the causes of the losses are within control of the Transmission Licensee.

   - The transmission loss in the EHV/HV system is purely technical in nature and has two broad components: (i) fixed losses (iron core losses) and (ii) variable the I^2R losses.
   - The R (resistance) depends on the configuration of the transmission system and type of conductor, which are decided in the planning stages as per planning criteria/guidelines of CEA. Further, the I (current passing through the conductor) depends on the loading of the line, which is decided by the grid operator considering the generation and consumption of power, at a given point of time.
   - Since the configuration of the transmission system is decided following a transparent and consultative process involving the CEA and various stakeholders through forums such as Regional Power Committees, Standing Committees etc. and the National Load Despatch Centre (POSOCO) is responsible for scheduling and dispatch of electricity depending on supply demand balance in accordance with the grid standards, the transmission losses are beyond the control of the Transmission Licensee.

Therefore, POWERGRID feels that it is not advisable to introduce norms for inter-state transmission losses since the factors which determine transmission losses are not within the control of Transmission Licensees.

17) S.No 27: Incentive

Issues Raised by CERC

The paper states that currently, the incentive is being recovered only through monthly formula of billing and collection of transmission charges. It proposes a review of the concept of NATAF specified by CERC in Tariff Regulations, 2014 in absence of clear provision regarding reconciliation of annual transmission charges and incentive with monthly billing.

Options Proposed

(a) Review the norms for availability of transmission system.

Our Comments/Suggestions

1. The transmission systems require an annual maintenance to be carried out to ensure smooth operation of the system. This requires shutdown of the system and due to various reasons, maintenance activities are to be planned / scheduled only in particular period of the year. This affects the availability of transmission system during that particular period leading to reduction in incentive/transmission charges. Accordingly, the yearly availability may be considered for determination of tariff and incentive in tariff. However monthly billing can be raised for incentive based on progressive monthly availability certified by Member Secretary, RPC and final adjustment may be done at the end of the year when final yearly availability certificates are received from Member Secretary, RPC.

2. The target availability norms for AC system is 98% and HVDC system is 95%. However, there is no incentive for higher availability for AC system up to 98.5% and for HVDC system up to 96%. The incentive should be available to the POWERGRID for availability beyond the performance norms i.e. 98% for AC system and 95% for HVDC system.

3. There is no incentive available for availability higher than 99.75%. Incentive should be available till 100% availability.

4. It is important to note that there is difference in computation of availability incentive between the TBCB and cost plus systems. For every percentage increase in the availability, there is an incentive of 2% of the transmission charges in TBCB vis-à-vis 1% in cost plus regime. Moreover, the target availability for incentive consideration for a TBCB system is 98% vis-à-vis 98.50% for Cost plus. As such, TBCB projects can earn upto 3.5% of tariff as availability incentive. However, under cost plus this comes to around 1.269%. **A similar incentive framework should be applied to the cost plus assets.**

18) S.No. 30: Late Payment Surcharge and Rebate

Issues raised by CERC / Options Proposed

The paper proposed to link late payment surcharge with MCLR and proposed rate of late payment surcharge can be some premium over and above MCLR.
Further, as per the existing Regulations, the rebate is provided if payment is made within 2 days of presentation of the bill. Valid mode of presentation of bill, (email, physical copy etc.), authorised signatory and definition of two days (working days or including holidays) may need elaboration.

Our Comments/Suggestions

1. The provision of a late payment surcharge at a fixed rate has been consistently followed by CERC i.e. in Tariff Regulations 2004 and Tariff Regulations 2009 also. Similarly, the State Commissions have also provided for fixed rate as late payment surcharge (Gujarat, Maharashtra, Madhya Pradesh, Punjab, Haryana), which is higher than the prevailing rate of interest.
2. Unlike interest on loan or interest on working capital, the late payment surcharge is imposed as a deterrent on the beneficiaries for delayed payment of the bills beyond the due date. Such delayed payment is a default by the beneficiaries and should be discouraged as the delayed payments affects the cash flows of the licensee. The late payment surcharge should be sufficiently high to ensure prompt payments. Otherwise the beneficiaries may treat the payables as a source of finance putting undue burden on Transmission Licensees.
3. In any event, it is necessary to provide for a fixed rate for late payment surcharge. If the late payment surcharge is linked to the bank rate or lending rates, this would create uncertainty and varied calculations for determining the actual late payment surcharge. Such floating rate of late payment surcharge is impracticable. A fixed rate allows for certainty, consistency in approach and unambiguous calculation.
4. The tax statutes and other statutes dealing with payment also provide for a fixed rate as interest for delayed payment.

19) S.No. 31: Non-Tariff Income

Issues raised by CERC /Options proposed

The paper proposes a review of the rate (Rs. 3000/km) at which the revenue from telecom business of Transmission Licensees is adjusted.

Our Comments/Suggestions

1. In the current arrangement, the entire risk of other businesses is borne by POWERGRID and the consumers are immune to such risk in a competitive market like the Telecom industry. No downside in such other ventures is shared with the consumers and only the charges pursuant to the transmission network are shared with the beneficiaries.

- POWERGRID entered into Telecom business during the year 2001 and continued to incur losses for first 8 years of operation with cumulative losses amounting to approx. Rs. 210 Cr. upto 2008-09. Telecom business turned profitable from 2009-10 onwards.
- Since the OPGW and equipment installed have almost completed their life, the replacement of the same is also planned in near future, involving major investment.
- The Telecom Regulatory Authority of India (TRAI) has reduced the ceiling bandwidth charges in its Telecom Tariff Order (TTO) 2014 over TTO-2005 by about 58% as illustrated below:

Capacity	Ceiling Tariff Recommended by TRAI (Rs.)		% Reduction
	TTO-2005	TTO-2014	
E1	8,50,000	3,41,000	-59.9%
DS3	1,59,000	26,54,000	-56.9%
STM1	1,65,00,000	69,65,000	-57.8%
	Average Fall in Tariff		-58.2%

- Due to intense competition in telecom industry, discounts even >90% are offered on the TRAI ceiling tariffs and consequently, the actual tariff charged to customers has reduced considerably during the last 2-3 years. As per market sources and expectations of customers, it is envisaged that this trend of falling per unit bandwidth prices will continue.
- In order to expand the Network, POWERGRID has made considerable efforts and made investments towards laying/leasing Underground Optical Fibre (UGOFC), associated maintenance, laying OPGW on behalf of State Transmission Utilities and leasing it back from them. This leasing charge is an income to the State Utilities.
- In addition to Right of Way, Telecom Business involves multiple cost items viz. One time Entry fee of Telecom Unified License, Annual Recurring License Fee payable to Department of Telecommunications (Licensor), investment in optical cables (Underground & OPGW) and telecom equipment, manpower expenses and other related O&M expenses. The investments under telecom are done as a separate business case. If OPGW is laid on POWERGRID's transmission line exclusively for Telecom, entire cost of OPGW is booked under Telecom and ROW charges are shared with the beneficiaries. Further, in case OPGW fibres are shared between POWERGRID and Telecom, the cost booking of OPGW is taken care as per CERC Order in Petition no. 68/2010 dated 08.12.2011.
- POWERGRID Telecom network is acting as a reliable & redundancy network, serving projects of national importance such as National Knowledge Network, Government Departments, PSUs etc. POWERGRID network is also highly reliable in hilly areas and areas prone to floods, earthquakes, cyclones etc. Thus, our network is employed in national service.

2. Further, as per direction of CERC, Rs. 3000/km is being adjusted from the revenue of POWERGRID from Telecom Business and is being credited to the beneficiaries. This takes care of the treatment of income from other business and hence no separate adjustment is required.

In view of the above, and considering the uncertainty prevailing in Telecom industry, it is submitted that revenue share in vogue may be allowed to continue till the telecom market is stabilized as most of telecom companies are running in losses only and many companies are on the verge of closing down.

20) S.No. 32: Standardization of Billing Process

Issues raised by CERC

CERC observes that currently, generating companies and the Transmission Licensees are following different practices for raising bills on the basis of tariff order, which may lead to disputes in billing.

Options Proposed

In light of its above observations, CERC has proposed for consideration whether standardization of billing process including formats, verification, timeline etc. may be done in order to avoid possible disputes in billing.

Our Comments/Suggestions

In case of transmission, billing is carried out by CTU for all the Transmission Licensees based on RTA issued by respective RPCs on the basis of PoC rates notified by CERC. The billings carried out by CTU are based on methodology stipulated by CERC in Billing, Collection and Disbursement procedure under CERC Sharing Regulations.

In order to avoid possible disputes in transmission billing, CTU carries out reconciliation exercise with beneficiaries and Transmission Licensees on regular basis.

Considering that transmission and generation are two distinct businesses, CTU and generating companies are raising the bills based on their nature of businesses. It is submitted that no dispute in billing due to different formats of these companies has been raised by the beneficiaries so far.

21) S.No. 35: Commercial Operation or Service Start Date

Issues raised by CERC

The Consultation Paper discusses the issues related to commissioning of transmission system and consequent declaration of Commercial Operation Date - (i) delays in trial operations and commissioning due to non-availability of evacuation system and/or adequate load; and (ii) mismatch between the commercial operation of a generating station and the associated transmission systems which has an impact on specifying COD and consequently, on the IDC of the generating station or the transmission system.

The paper suggests specifying a methodology for trial operation for bay equipment, Inter-connecting transformer, Reactors, Fixed Series Compensation, and transmission lines. It further stresses the need to ensure completion of data telemetry and communication by RLDCs/ NLDC/ SLDCs for declaring COD of transmission system.

The Paper proposes introduction of provisions (or an Indemnity Agreement) to streamline the process of the declaring commercial operation date in case of the delay due to factors beyond control of Licensee (such as delay in upstream/downstream system).

Options Proposed

(a) Addressing the shortcomings in existing methodology for trial operation for transmission element;
(b) Issue of trial operation and commissioning of the project when a generating station is ready but cannot be operated due to non-availability of load or evacuation system;
(c) Issue of acceptance of COD of transmission line if the generating project or upstream/ downstream transmission assets are not commissioned;
(d) Pre-requisite of completion of data telemetry and communication facilities for declaring COD of transmission system;
(e) Linking of commercial operation date with schedule commencement date of the Long Term Access Agreement;
(f) Linking the commercial operation date of the transmission system with the commissioning of the generating units or stations;
(g) Separation of the commercial operation date of the transmission element or system from the service start date under the contract.

Our Comments/Suggestions

1. Generation, Inter State Transmission and Intra State Transmission are distinct businesses which have inherently different time frames for implementation, risk factors and challenges associated with it.

2. Generation, Transmission and Distribution companies have their own methodology for funding and implementing the project and therefore there is a possibility of mismatch in commissioning. In majority of the cases, the delay is due to uncontrollable factors.

3. Linking the COD of transmission with COD of generation/downstream network is not prudent as the Transmission Licensee has completed its scope of work and <u>implementation of generation/downstream network is beyond its control. Therefore, COD of transmission system should be approved when the scope of the Transmission Licensee is complete</u>.

4. ***Regarding mismatch between generation and transmission:*** the generation plants are set up to meet the load demand of the DISCOMs and PPA are signed between them for the supply of power. Particularly, in case of Central Sector Plants, the PPA provides for power supply at the bus-bar by the generator and it is the responsibility of the beneficiaries to arrange transmission from switchyard to the load centers. For implementation of transmission system identified for the generation project, BPTA/TSA is signed by beneficiaries with Transmission Licensees. Thus, it is the responsibility of

the beneficiaries to co-ordinate the development of transmission and generation, Therefore, the liability for payment of transmission charges should be fixed on generator/beneficiaries in case of mismatch with generation. In case the same is payable by beneficiaries, the same may be recovered by the beneficiaries from the generators as per the terms and conditions of PPA. As per the present Regulations, in case there is a delay in transmission and generation is commissioned, an alternate arrangement is to be provided by the Transmission Licensee to prevent bottling up of generation. Thus, the above methodology should be continued in the new Regulation also.

5. ***Regarding mismatch between Inter State Transmission and Intra State Transmission:***

a. In most of the cases, while planning a transmission system, a new substation is planned mostly on request of States to enable them to draw their share from ISGS as well as to meet load growth. Sometimes, substation is planned to anchor a long AC line.

b. 2 or 3 no. of 220kV bays per 315/500 MVA transformer are provided as per the CEA guidelines considering the future requirements also.

c. Further, the implementation of substations is taken up after consent by States in respective SCMs/ RPCs.

d. It is the responsibility of states to draw power from ISTS, through implementation of 220 kV downstream lines.

e. Implementation of downstream network is commenced 1 or 2 years after ISTS projects due to less gestation period.

f. In case, States are not able to implement the downstream network matching with ISTS, transmission licensee should not be penalised for that. If DOCO of transmission licensee is shifted to match with the downstream network, the project IRR gets reduced considerably. During the mismatch period, transmission licensee is deprived of return on equity, O&M charges, depreciation even though it has to incur expenditure on Debt servicing and O&M of the Asset. Thus, entire risk is transferred to Transmission licensee despite timely completion of its scope.

g. In such cases, policy should be adopted so that the transmission licensee should get revenue on the investment made by it and at the same time, States should implement downstream system matching with ISTS.

h. In case of ISGS plants, their fixed charges (which are very high as compared to transmission charges) are payable by the states irrespective of the scheduling of power from these plants. Transmission charges are also akin to the fixed cost and should be payable irrespective of drawl of power by states.

i. If the objective is to minimize the liability of defaulting States, the ISTS system should be included in PoC Pool from its DOCO irrespective of implementation of downstream network. In PoC mechanism, the transmission charges of assets are shared by all the states. In this case also, the defaulting state is also sharing the charges of substations in other states, even though it has defaulted in implementing downstream network in this case. Also defaulting state is already getting penalised by not being able to draw power in absence of downstream network.

j. Alternatively, the transmission charges of unutilised ISTS system from its DOCO should be paid by the defaulting State. This will act as a deterrent for delaying the downstream network.

6. One of the options proposed is to link the COD with scheduled commencement date of Long Term access agreement (LTAA). It may be submitted that implementation of transmission system is sometimes preponed to meet requirement of power transfer as requested by beneficiaries and generator (e.g. startup power by generator, part operationalization of LTA to meet PPA obligations of generator and DISCOM, inter-regional transfer of power etc.). Moreover, in certain cases, the scheduled date of commissioning is not mentioned in the LTAA and is linked to commissioning of the system. Further, now most of the systems are being implemented under TBCB, where the CoD is granted based on scheduled date of commissioning defined in TSA or the actual date of completion, if before SCoD. Declaration of COD of various elements of a system has to be on same grounds since the grid is a meshed network and the LTA agreements contain transmission elements to be implemented under both Cost Plus and TBCB. Therefore, POWERGRID proposes against linking of COD with scheduled commencement date of LTAA.

7. As explained in Point 11 (Rate of Return on Equity) of this document, if the COD is shifted for matching with the upstream/downstream network, the effective rate of return is reduced and project IRR is also reduced despite the Transmission Licensee completing the project in time. Therefore, the current provision should be continued and COD should not be shifted matching with COD of generation/downstream network.

8. From the experience of participating in the Brazil Transmission Auctions, it can be concluded that the Concessionaire shall automatically start earning the annual revenue from the date of availability of commercial operation. The Concession Contract also allows an incentive to anticipate commercial operation i.e. advance the date of commencement of the Commercial Operation to any time between the scheduled date and the required date (the date informed by users of the facility to ANEEL or the date indicated by the sectorial planning). Therefore, there is abundant clarity in declaration of commercial operation date and start of revenue receipts thereof.

9. **Based on the above examples, it is recommended that the Regulation should allow automatic declaration of commercial operation of a project based on operational readiness**.

22) S.No. 36: Energy Storage System

Issues raised by CERC /Options Proposed

The paper recognizes the need to energy storage systems and states that it may part of the inter-state transmission system or the inter-state generation station. It also proposes options for regulatory framework for storage systems. The storage facility as a part of inter-state transmission system may be subjected to regulatory approval while storage facility as a part of the generating capacity may be as per the consent of the procurer for availing storage facilities. The paper opines that the energy storage at transmission level can be used for overall optimization of power from the grid or as ancillary support services. Further it proposes determination of annual fixed charges of the storage facility based on ramping rate, auxiliary consumption, Return on Equity (ROE), Interest on Loan, Depreciation, Operation & Maintenance cost and Interest on Working Capital.

Our Comments/Suggestions

1. Energy storage systems at transmission level may be used as ancillary services. The utilization of energy storage system will depend upon grid conditions & its application. Some of the important factors which may be considered during designing of tariff are discussed as under:

    a. **Life:** Life cycle of energy storage system depends on technology and application. Pumped storage system, compressed air energy storage system, flywheel, flow batteries have longer life (more than 15 years) whereas Lithium Ion, NaS, Advanced Lead Acid batteries have smaller life (about 5-10 years). Further, there are two considerations, cycle life and calendar life. During utilisation, it may happen that due to excessive use, cycle life completes before calendar life. Therefore, suitable methodology is to be devised to consider above parameters during fixation of annual fixed costs.

    b. **Duration of Support**: Generally, the energy storage systems for power applications have energy rating constraint while energy storage systems for energy applications have power rating constraints. In order to bring them at same level, it is important to consider the duration of support (5 min. or 15 min) as one of the factor in determination of fixed tariffs.

    c. **Availability**: Energy storage systems are used when grid conditions require them. In normal conditions, these may remain idle. Therefore, it is important to provide proper weightage to availability. Provision of incentives may also be kept with respect to availability of the system.

    d. **Ramp Rate**: ESS with fast ramp rate provides better support as compared to others with lesser ramp rate. Therefore, it is important to provide some minimum standard ramp rate while establishing ESS in the system. System with higher ramp rate may be provided better compensation.

    e. **Efficiency**: During the operation of the system, there shall be some energy losses in the system on account of battery losses, conversion losses etc. These losses will be paid by energy storage system provider, therefore energy charges on per unit bases on account of these losses may be defined in the tariff structure or it may be included in O&M charges.

f. **Auxiliary losses**: The operation of energy storage system may require some energy usage for air-conditioning, lighting etc. These losses will vary according to type of technology & its application. Therefore, these losses may also be considered in tariff designing as O&M charges.

g. **Type of applications**: The operations of energy storage system changes according to type of applications, which in turn changes the operation scenario. For instance, the frequency regulation may require frequent start stop operations, while energy time shift may have lesser but regular start stops.

2. Energy storage systems is an evolving technology and may be kept at par with Renewable Energy. Hence, all provisions regarding connectivity, open access, transmission charges etc. may be extended to such installations.

23) S.No. 37: Alternative Approach to Tariff Design

a. Normative Tariff by Benchmarking of Capital Cost

As explained at point 4 (Capital Cost – Benchmarking and Normative Tariff) of this document, econometric analysis for determination of capital cost is not advisable.

b. Normative Tariff by Fixing AFC as a Percentage of Capital Cost

Issues raised by CERC

The Paper explores an option of fixing the total AFC as a percentage of initial capital cost. CERC analyzed data for 30 generating stations and observed significant correlation between AFC approved for first year of operation and the approved capital cost. However, the detailed analysis reflected that the standard deviation was high which establishes a need for analyzing a larger dataset for arriving at a conclusive percentage figure of AFC to initial capital cost.

Options proposed

1. Whether it is a good idea to determine AFC as percentage of capital cost on normative basis?
2. Possible methodologies to establish the relation between AFC and capital cost so that it meets the interests of both buyers and sellers?

Our Comments/Suggestions

1. The section proposes a different approach to tariff determination as an alternate to the current methodology of elaborate examination of data and determination of individual components. However, the proposal does not specify details of analysis, methodology and its implementation. Moreover, the analysis has been carried out for thermal generation plants only, even though comments have been invited from Transmission Licensees as well. Since, nothing specific has been proposed regarding Transmission, it would be difficult to provide detailed comments on the same. However,

extending the analysis carried out by CERC to Transmission projects, our comments on approach proposed by CERC are as below:

a. While proceeding to work out AFC as a percentage of capital cost, the basic premise of CERC is that a strong correlation exists between AFC and capital cost, thereby signaling a possibility of benchmarking AFC as a percentage of capital cost. It is pertinent to mention that statistical correlation should only be used with *independent variables* i.e. when the two variables do not have any interdependence. In the current context, the AFC is a derivative of capital cost where various components of fixed cost including depreciation, interest on loan, return on equity and a portion of interest on working capital are derived from the approved capital cost. Thus, AFC and capital cost are *dependent variables* and establishing a correlation between the two is statistically incorrect. Thus, the basic premise of CERC proposition needs to be revisited.

b. CERC has carried out the analysis for working out AFC as a percentage of capital cost, wherein the O&M expenses are also included. It is to be noted that the allowance for O&M expenses is derived based on the normalized O&M expenses in past years and is independent of capital cost. Also, Interest on Working Capital contains some O&M linked parameters which form a part of the Working Capital base. Thus, it may not be feasible to establish a normative AFC by linking it to capital cost, to the extent of linkage with O&M expenses.

c. It is pertinent to note that an approach similar to India is used by regulators in developed and developing countries across the world, where various components are determined individually to compute the revenue requirement of a transmission utility. This includes countries such as Australia, Netherlands, Malaysia, Nigeria, South Africa and Ghana.

c. *Normative Tariff by fixing each component of AFC as a Percentage of total AFC*

Issues raised by CERC

As a next option for alternate tariff design, the Paper explores determination of tariff on normative basis by fixing each component of AFC as percentage of total AFC. CERC analyzed data for 30 generating stations and plotted trajectories of each of the five components of annual fixed cost (i.e. return on equity, interest on loan, depreciation, operation and maintenance, interest on working capital etc.) of the generating stations for the period from CoD till 2016-17. CERC observed that all components expressed as percentage of AFC were decreasing with time, except O&M expenses. Accordingly, the Paper proposes clustering components of AFC into two groups - “Group of AFC Components which escalate/increase over the period” and “Group of AFC Components which de-escalate / decrease over the period”.

Further, the paper observes that the overall trend line is influenced by two major factors - “Additional Capitalization (Add. Cap) / De Capitalization (De Cap.)” and “Change in Control Period”. Hence, it proposes restricting Add. Cap to the period between CoD and Cut-Off Date and allowing recovery of any capitalization allowed after cut-off after as a separate revenue stream. In order to eliminate the effect of change in control period, the paper proposes, restricting the application of revised tariff principles to plants commissioned during the control period, with existing plants being governed by tariff principles as applicable on their CoD.

Options proposed

(a) Possible methods to cluster the AFC components;

(b) Methodology to be adopted to determine the escalable (increasing)/ non-escalable (decreasing) factor;

(c) Whether escalable (increasing) / non-escalable (decreasing) factors should remain same for all transmission systems (or) they be separate for each of the transmission systems based on vintage / capacity etc.;

(d) Whether isolation of "Additional Capitalization" as a separate stream of revenue would provide for recovery of AFC on a normative basis in realistic terms?

(e) Other methodologies to treat "Additional Capitalization" for determination of AFC on normative basis;

(f) Whether applicability of change in tariff principles in each control period for the new plants would allow regulatory certainty to the existing plants?

(g) Other methodologies to minimize the impact on AFC on account of change in control period.

Our Comments/Suggestions

CERC's proposal is based on analysis carried out for thermal generation plants and does not specify details of analysis, methodology and its implementation for transmission system. Since comments have been invited from Transmission Licensees as well while nothing specific has been proposed, it would be difficult to provide detailed comments on the same. However, extending the analysis carried out by CERC to Transmission projects, our comments on approach / options proposed by CERC are as below:

1. Presently AFC comprises of five components, out of which two viz., RoE and depreciation are already computed on normative basis. The cost of debt is computed on actual basis. If it is computed on normative basis, norms have to be arrived at by considering the prevailing market interest rates. If these are set low, it will be loss to the Transmission Licensee and if these are set high, beneficiaries would be at loss. As explained in earlier sections, POWERGRID is raising debt at very efficient rates which are lower than the market rates, thus passing on the benefits to the beneficiaries.

2. Regarding O&M expenses it is to submit that O&M as a percentage of AFC can vary depending upon the configuration of transmission asset (i.e. mix of transmission lines, substations etc.). Therefore, benchmarking O&M expense as a percentage of overall AFC may not be similar for all the projects.

3. Further to the above observations, comments on the various questions raised by CERC are given below:

    a. In the proposed clustering of AFC components, it is pertinent to note that in addition to O&M being increasing/escalable, a significant portion of working capital is also linked to O&M expenses, and is hence escalable. It is suggested that working capital may be bifurcated into two parts

        i. Working Capital (Non Escalable): linked to AFC i.e. 2 months of receivables

        ii. Working Capital (Escalable): linked to O&M expenses i.e. 1 month O&M expenses, maintenance spares (15% of O&M expenses)

    b. Methodology of determining extent of increase / decrease in escalable / non escalable factors should incorporate following considerations:

        i. Non escalable – should factor in changing interest rates across projects and changing rate of return on equity across tariff periods

        ii. Escalable – should factor in inflation related changes, as explained in point no. 14

    c. With respect to the proposal for determining escalable / non escalable factors separately for transmission systems based on vintage / capacity, it is suggested that the factors should be determined separately for different types of transmission systems. This is essential considering the variation in O&M as explained in Sl. No.2 above.

    d. As proposed in the paper, the Additional Capitalization or any other capital expenditure allowed during the life of the project may be allowed a separate stream of revenue to isolate the recovery of AFC from its impact.

    e. As regards the issue of regulatory certainty, it is advisable to restrict the applicability of revised tariff principles to new plants and continue the Regulation of existing projects by tariff principles as applicable on their CoD.

24) S.No. 41: Application for Tariff Determination: Review of Process in Case of Transmission System

Issues raised by CERC

The paper highlights the issue of large number of tariff petitions in case of transmission projects owing to the commissioning of different elements over a period of time. Further, it also provides suggestions on reduction of number of tariff petitions.

Options proposed

The paper seeks comments and suggestions from the stakeholders on simplification of the process for disposal of tariff petitions.

Our Comments/Suggestions

A transmission project executed by POWERGRID consists of various assets like Transmission Line, Substation bays and equipment like ICTs, Reactors, STATCOMs, etc. The various assets of a project are completed progressively and sometimes there is a difference of two – three years in completion of first asset and last asset of the project.

As per present Regulations, the Transmission Licensee may file petition in CERC for tariff determination six months prior to commissioning of an asset. Thus, whenever any asset is likely to be commissioned, tariff petition is filed for the same based on anticipated date of commissioning and completion cost by submitting management certificate for the same. Based on these, provisional tariff is allowed by CERC after conducting provisional hearing. After the actual commissioning of the asset, the documents related to DOCO and auditor certificate for actual completed cost are submitted for computation of final tariff. After final hearing, final tariff is allowed by CERC after applying prudence check on various components of AFC. Thus, it requires two hearings and two orders to be issued by CERC for determination of tariff of an asset. Further, a petition is generally filed for assets in a project anticipated to be commissioned within next 3-4 months, thus leading to large no. of petitions within a single project. In the present tariff block, 282 no. of tariff petitions have been filed by POWERGRID so far. For these petitions, 239 no. of provisional hearings and 216 no. final hearings have been held by CERC, resulting in issuance of 213 no. of provisional orders and 190 no. of final orders.

Handling such large number of petitions is a matter of concern for both CERC & POWERGRID and leads to pendency of petitions. This sometimes result in provisional orders being issued much after the corresponding assets are commissioned which creates huge burden on beneficiaries for payment of accumulated charges in a short period of time.

It is also seen that when petitions are filed in anticipation of DOCO and provisional order is issued before DOCO, on certain occasions, commissioning gets delayed due to RoW issues, clearances, etc. This leads to overbilling upon beneficiaries and return of the excess billed amount with interest by POWERGRID.

To tackle the above situation and also to reduce the burden of CERC as well as POWERGRID by way of reducing the number of petitions, POWERGRID suggests an alternative option as described below.

1. Transmission Licensees to be allowed to bill provisional tariff from date of the commissioning of the asset without approaching CERC for the same. CERC may define norms for provisional tariff to be billed for each type of asset based on time over-run and cost over-run. Suggested norms are given below:

S. No.	Attributes	Provisional Billing as % of YTC
1.	No Time/Cost over run	95%
2.	Time over run upto 6 months and/or 10% cost over run	92%
3.	Time over run upto 12 months and/or 15% cost over run	88%
4.	Time over run upto 24 months and/or 20% cost over run	84%
5.	Time over run beyond 24 months and/or 25% cost over run	80%

2. POWERGRID shall inform CERC at the end of every quarter, the assets commissioned in the previous quarter and included in billing along with the provisional YTC.

3. POWERGRID shall approach CERC with the tariff petition for final order after the commissioning of the asset which shall include all the details such as the scheme approval in Standing Committee Meeting and RPC, Investment approval by Company's board, all the requisite certificates i.e. CEA/RLDC/CMD certificate, DOCO letter, along with the Auditor Certificate and complete tariff forms. To reduce the number of petitions, POWERGRID shall file the petition for final order for an asset or group of assets if the capital cost of the asset (or group of assets) is above a threshold amount (say, Rs 100 Cr.) or if there are no further assets in the project anticipated to be commissioned in that financial year.

4. The tariff petition shall undergo prudence check by CERC and final tariff shall be determined by CERC after hearing.

5. As the petition is filed on actual DOCO, uncertainties regarding DOCO are avoided, number of tariff petitions is substantially reduced and number of hearings and orders issued by CERC is reduced by at least 50%. As effort shall be made for clubbing of petitions within a project, the number of petitions for final order shall also be reduced.

6. In case provisional tariff being billed and received by the company is more than the final tariff approved by CERC, POWERGRID shall reimburse the excess amount received with interest. In case provisional tariff being billed and received by the company is less than the final tariff approved by CERC, the Company shall raise the bills for the balance amount with interest.

It is envisaged that, the above process will reduce the number of petitions, hearings, submissions and orders substantially.

25) Sl. No. 42: Goods and Service Tax (GST)

Issues raised by CERC

CERC observes that Goods and Services Tax (GST) has replaced various Central and State level taxes, which will have bearing on the determination of tariff in the next control period.

Options Proposed

In light of its above observations, CERC has proposed for a prudence check of impact of pre-GST and post-GST taxation regime on the costs.

Our Comments/Suggestions

The impact of GST on any transmission tariff elements should be considered as pass through at actuals.

26) Additional Submissions

1. ***Introduction of Compensatory Allowance:***
   a. With time and with the improvement in technology, supplier changes their line of production of similar nature of equipment or totally stops the production of equipment and switch over to different type of equipment.

   b. It is seen that after 15/20 years, some of the manufacturers/suppliers have become untraceable and number of OEMs have also closed their establishments. This obsolescence of product and non-availability of spares/services, which is beyond the control of POWERGRID, have forced POWERGRID to go for replacement of problematic/unreliable equipment for smooth and reliable operation of the grid.

   c. Therefore, to meet the expenses on these types of new assets of capital nature, after commissioning of the system and during the O&M phase, Compensation Allowance may be considered during the 11th to 25th year of commissioning of the project in line with those provided for Generating Station.

2. ***Introduction of Initial Spares norms for Brown Field GIS Substation, Fixed Series Compensator, TCSC,* Static Var Compensator (SVC) and STATCOM*:***
   a. These equipment are of new technology, fewer in numbers and are from foreign manufacturer, thus, the Transmission Licensee is required to ensure adequate supply of spares beyond the norms.

   b. Being imported items, the lead time of procurement is much higher than any onshore equipment. Hence more spares are required to be kept to take care of any contingency so that the system does not remain idle for want of spares. Hence, there is need to provide higher initial spares norms for new technology assets.

   c. In case of GIS Substation, up-gradation of the same is carried out by the OEMs and difficulties are being faced in getting the spares for the earlier design systems. Spares norms for GIS system of 5%, as indicated in the current Tariff Regulation 2014, is therefore not adequate as compared to the spares already procured for the projects which are under commercial operation. Further, in case of Brown Field substation, the new equipment may be of different make/design or of latest technology as compared to the existing assets. Therefore new set of spares has to be procured in order to ensure reliability of operations and grid stability. Therefore, there is a need to specify higher initial spare norms for GIS (Brown Field) separately.

3. *Spare Transformers & Reactors*

Power Transformers and Reactors are very critical for maintaining availability and reliability of the grid. In case of any failure of Transformers, there will be power disruption to the Consumer/ states. For safe operation of the grid, optimum spare needs to be maintained. Based on past experience of POWERGRID and other International utilities, following norms for keeping spare transformer/ reactor may be adopted:

i. Transformer:
   - One 1phase Transformer for each category in each state in 400kV and 765kV rating equipment.
   - At least one spare transformer of each type in every state for each category for 3 phase 400kV rating equipment if the population is less than 20 nos.
   - At least two number of spare 400kV 3 phase Transformer in every state if the population is 20 nos. or more.
   - For 220kV and below 3 phase Transformer one Transformer with highest MVA rating in every state.

ii. Reactor:
   - One 1 phase Reactor for each category in each state in 400kV and 765kV rating equipment.
   - At least one spare Reactor of each type in every state for each category for 3 phase 400kV rating equipment.
   - At least two number of spare 400kV 3 phase Reactor in every state if the population is 20 nos. or more.

4. *Classification & Depreciation Rate for IT equipment & Software*

a. The IT equipment and Software have no salvage value after they are put into service and therefore CERC has allowed them to be 100% depreciable.

b. The Transmission Licensees uses SCADA, Wide Area Measurement (WAMS), Fibre Optic Communication system, Remote Terminal Unit, Private Automatic Branch Exchange and Radio Communication System etc. for managing inter-state transmission of electricity. These equipment are to be categorized as under:

   i. SCADA and WAMS System: Supervisory Control and Data Acquisition System (SCADA) and Wide Area Measurement Systems (WAMS) consists of mainly Computer Hardware and Software. Therefore, we propose that SCADA and WAMS may be considered as IT equipment including software.

ii. RTU/PMUs: These devices are installed at the substations and are used to measure the voltage, current, frequency, power flows, phase angle etc. and transmit the values along with the digital status of equipment to upstream control center for further analysis and visualizations. These equipment by in large are electronic equipments with processors and embedded software which also have the nearly same life cycle as IT equipment therefore, generally falls in the category of IT equipment. Therefore, clarification may be given to include these equipment under IT equipment and software.

iii. SDH, Multiplexer, NMS and PABX: SDH and Multiplexers are the end equipment where the fiber is terminated and signals are converted from optical to electrical and channel routing is made from one end to other end. Similar to IT equipment, all the telecom equipment are electronics based and are mostly software driven with very short life. Due to the ever changing nature of the underlying technology, the obsolescence of these products is very fast. The Network Management System (NMS) is used to monitor the communication system from a centralized location and consists of IT hardware and software. Similarly PABX system is IP based equipment and consists of electronic components which are similar to other telecom equipment. Similarly auxiliary power supply system may also be given the same treatment.

c. In view of the above, these types of equipment may be considered under the category of IT equipment including Software as under:

(a)	SCADA/WAMS Hardware	: IT Equipment
(b)	SCADA/WAMS Software	: IT Software
(c)	RTU/PMU	: IT Equipment
(d)	SDH, Multiplexer, NMS and PABX	: IT Equipment

d. Since the useful life of software are very short – approx. 3 years, therefore, the software should be allowed to be depreciated at much faster rate.

e. CERC Regulations on Fees and charges of Regional Load Despatch Centre and other related matters (RLDC Regulation), have provisioned that the software assets are to be depreciated at 30%.

f. Keeping in view the above and the salvage value for IT Equipment as Nil, the depreciation rate for software may be provisioned as 33.33%.

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Annexures

Annexure 1: Estimation of expected Rate of Return for POWERGRID with resetting of debt to equity ratio to 80: 20

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

Firm	Equity / Levered Beta	D/E	Tax Rate	Un-levered Beta
Adani Transmission Ltd.	1.59	2.06	21.11%	0.605
POWERGRID	0.68	2.33	20.68%	0.239
Sterlite Technologies Ltd.	1.26	1.40	25.87%	0.627
Overall Average				**0.490**

- For Sterlite, data used from FY 2009-10 to FY 2014-15, post which the power entity was de merged and taken private
- For Adani, data used from July 2015 – Mar 2018, since it got listed in July 2015
- For POWERGRID, data used from FY 2009-10 to FY 2017-18, consistent with R_f and R_m

Equity Beta

The overall average unlevered beta for all transmission players works out to be 0.515, which is levered using modified proposed financial leverage (80: 20) to give expected Equity Beta.

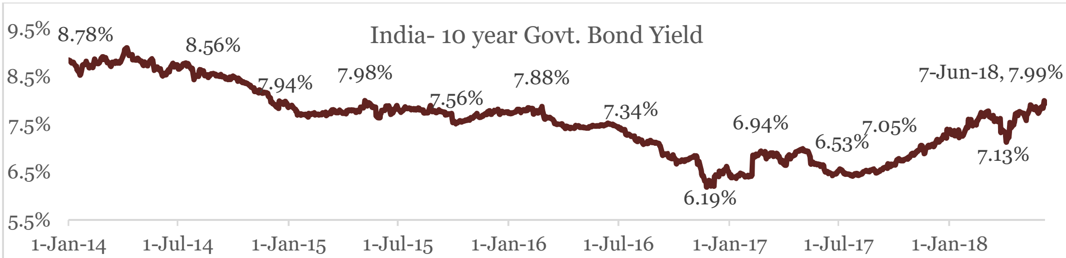
Re-levered Beta = Un-levered Beta x (1 + ((1 – Tax Rate) x (Debt/Equity)))
= 0.490 x (1 + (1-0.2255) x (80/20))
= 2.01

Expected Rate of Return on Equity

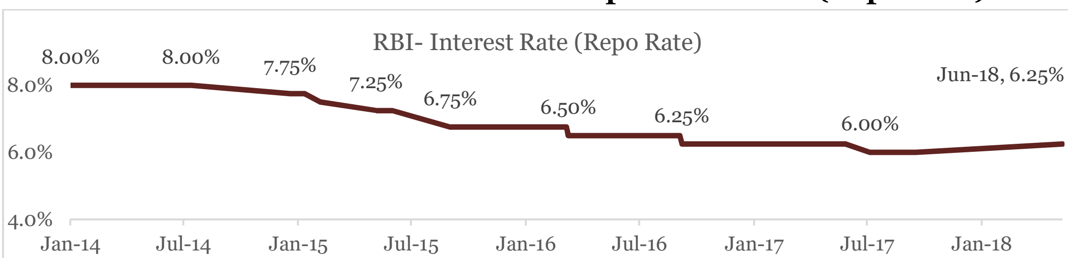
Expected rate of return = R_f + [β x (R_m – R_f)]
= 7.78% + [2.01 x (16.07% - 7.78%)]
= 24.44%

Annexure 2: Key Cost of Debt benchmark indicators

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

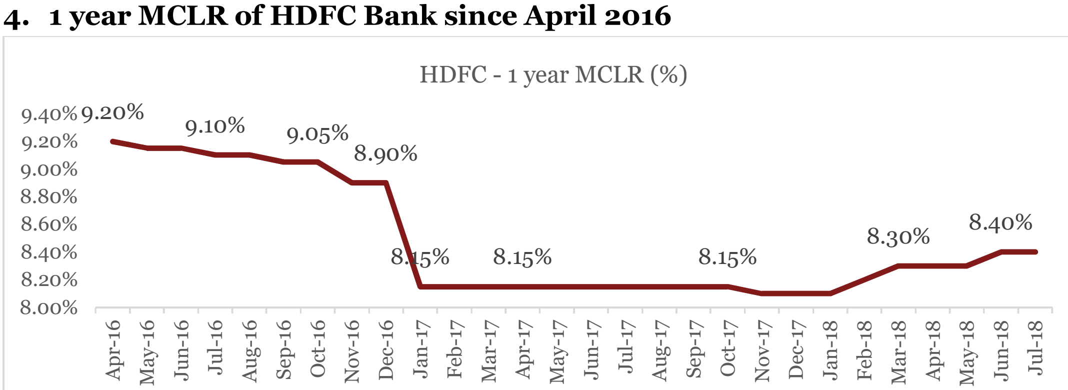


2. Historical trends of RBI determined Repurchase Rate (Repo Rate)

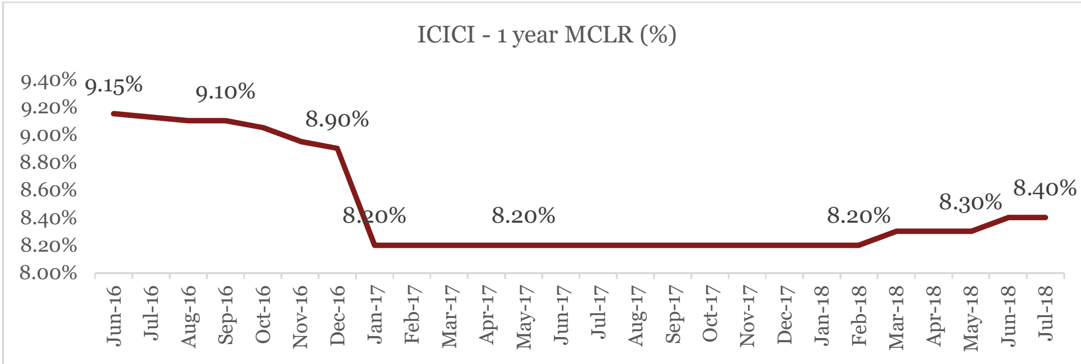


3. 1 year MCLR of State Bank of India since April 2016

4. 1 year MCLR of HDFC Bank since April 2016



5. 1 year MCLR of ICICI Bank since April 2016



Comments on CERC's Consultation Paper
for (Terms and Conditions of Tariff) Regulations, 2019

Regulatory Cell
POWERGRID