Comments on CERC

Draft (Terms and Conditions of Tariff) Regulations, 2019

28th January 2019

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

Comments on Draft CERC Tariff Regulations 2019-24

Contents

1. Chapter 1: Preliminary 3
1.1. Force Majeure 3
1.2. Operations & Maintenance Expenses 3
2. Chapter 2: Date of Commercial Operation 4
2.1. Implementation Agreement 4
2.2. Treatment of mismatch in date of commercial operation with Generation 5
2.3. Treatment of mismatch in date of commercial operation with other Transmission Licensee 7
3. Chapter 3: Procedure for Tariff Determination 9
3.1. Tariff Determination 9
3.2. Application for determination of tariff 10
3.3. Requirement of Management Certificate to be signed by Director of the Company 11
3.4. Truing up petition to be filed within 180 days 12
3.5. Determination of Tariff 12
3.6. Interim Tariff 13
3.7. Variation in Projected Capital Expenditure 13
3.8. In-principle Approval in Specific circumstances 15
4. Chapter 5: Capital Structure 16
4.1. Reduction in Equity after Useful Life 16
5. Chapter 6: Computation of Capital Cost 18
5.1. Exclusions from capital cost 18
5.2. Initial Spares 20
5.3. Ceiling norms for Initial Spares for new technology equipment 21
5.4. Ceiling norms for Initial Spares for Communication System 22
5.5. Benchmarking of capital costs – database 22
6. Chapter 7:Computation of Additional Capital Expenditure 24
6.1. Treatment of O&M Additional Capitalization 24
6.2. Treatment of Additional Capitalisation on account of R&M 25
7. Chapter 8: Computation of Annual Fixed Cost 26
7.1. Capital Investment and Return 26
7.1.1. Maintenance of Existing Rate of Return on Equity 26
7.1.2. No Provision for Additional Return on Equity 33
7.1.3. Reduced Return on Equity on additional capitalization after cut-off date 34
7.2. Working Capital 35
7.2.1. Changes in norms for working capital 35
7.3. Depreciation 35
7.3.1. Classification & Depreciation Rate for IT equipment and Software 35
7.3.2. Treatment of Fibre Optic 37
7.4. Depreciation of Batteries and Relay 37

7.5. O&M Norms for Transmission System 37
7.6. O&M Norms for Communication System 46
7.7. Operation and Maintenance Expenses 47
8. Chapter 11:Computation of Capacity Charges and Energy Charges 49
8.1. Methodology for calculation for transmission system availability 49
8.2. Treatment of availability of Communication System 51
9. Chapter 12 : Norms of Operations 54
9.1. Removal of upper cap of transmission system availability of 99.75% for claiming incentive in tariff. 54
10. Chapter 13: Scheduling, Accounting and Billing 56
10.1. Rebate 56
10.2. Late Payment Surcharge 56
11. Chapter 14: Sharing of Benefits 58
11.1. Sharing of Non – Tariff Income 58
12. Chapter 15: Miscellaneous Provisions 61
12.1. Deferred Tax liability with respect to previous tariff period 61
13. Appendix - II: Procedure for Calculation of Transmission System Availability Factor for a Month 62
13.1. Treatment of Outages 62
13.2. Treatment in case of disputes 62
14. Annexure I (Part – III): Tariff Filing Forms for Determination of Tariff 64
14.1. Tariff Forms 64

1. Chapter 1: Preliminary

1.1. Force Majeure

Draft CERC Tariff Regulations, 2019

3(26) 'Force Majeure' *for the purpose of these regulations means the event or circumstance or combination of event ....*
(a) Act of God including lightning, drought, fire and........
(b) Any act of war, invasion, armed conflict or act of foreign enemy, blockade, embargo, revolution.....
(c) Industry wide strikes and labour disturbances having a nationwide impact in India;
(d) Delay in obtaining statutory approval for the project except where the delay is attributable to project developer;

Our Comments/Suggestions

1. In addition to disturbances having nationwide impact, the Force Majeure clause should also cover local/ state/ region wide disturbances within its scope.

1.2. Operations & Maintenance Expenses

Draft CERC Tariff Regulations, 2019

3(48) 'Operation and Maintenance Expenses' or 'O&M expenses' *means the expenditure incurred for operation and maintenance of the project, or part thereof, and includes the expenditure on manpower, maintenance, repairs and maintenance spares, consumables, insurance and overheads and fuel other than used for generation of electricity, water charges and security expenses;*

Our Comments/Suggestions

Transmission Licensees are required to incur expenditure towards forest lease maintenance charges, lease rent on lease hold land, annuity payments to land owners/other authorities as per terms and condition of land acquisition/under provisions of law. Since these expenses are recurring in nature and are to be paid on annual basis based on relevant government notifications, it is suggested that the word 'annuity, lease rent and other statutory payments' may be included to account for the above expenses in the definition of O&M expenses.

2. Chapter 2: Date of Commercial Operation

2.1. Implementation Agreement

Draft CERC Tariff Regulations, 2019

"3(34) 'Implementation Agreement' means any agreement or any covenant entered into (i) between the transmission licensee and the generating company or (ii) between transmission licensee and developer of the interconnected transmission system for the execution of generation and transmission projects in a coordinated manner, ***laying down the project implementation schedule and mechanism for monitoring the progress of the projects;****"*

5(2) In case the transmission system or element thereof executed by a transmission licensee is ready for commercial operation but the interconnected generating station or the transmission system of other transmission licensee as per the agreed project implementation schedule is not ready for commercial operation, the transmission licensee may file petition before the Commission for approval of the date of commercial operation of such transmission system or element thereof:

Provided that the transmission licensee seeking the approval of the date of commercial operation under this clause shall give prior notice to the generating company or the other transmission licensee and the long term customers of its transmission system, as the case may be, regarding the date of commercial operation;

Provided further that the transmission licensee seeking the approval of the date of commercial operation of the transmission system under this clause shall be required to submit the following documents along with the petition:
(a) Energisation certificate issued by the Regional Electrical Inspector under Central Electricity Authority;
(b) Trial operation certificate issued by the concerned RLDC for charging element with or without electrical load;
(c) Implementation Agreement, if any, executed by the parties;
(d) Minutes of the coordination meetings or related correspondences regarding the monitoring of the progress of the generating station and transmission systems;
(e) Notice issued by the transmission licensee as per the first proviso under this clause and the response;
(f) Certificate of the CEO or MD of the company regarding the completion of the transmission system including associated communication system in all respects.

Our Comments/Suggestions

1. Not all the documents at (a) to (f) above should be mandatory as supporting evidences as the facts of each case is different.
2. In case of State Transmission Utilities (STUs) implementing the downstream/interconnected network, the timeline of implementation is lesser than that of Inter State Transmission System (ISTS). Thus the implementation of ISTS network is required to be started much before the implementation of STU network. However, the progress of ISTS assets are discussed/informed during the Regional Power Committee meetings.
3. Hence, it is suggested that the implementation schedule of ISTS network as agreed upon in various such meetings viz., Regional Power Committee, Standing Committee of Transmission, progress reports etc., should also be considered as supporting evidence for the purpose of this clause.

2.2. Treatment of mismatch in date of commercial operation with Generation

Draft CERC Tariff Regulations, 2019

6(1) - Treatment of mismatch in date of commercial operation: (1) In case of mismatch of the date of commercial operation of the generating station and the transmission system, the treatment of the transmission charges shall be determined as under:

(a) <u>Where the generating station has not achieved the commercial operation as on the date of commercial operation of the associated transmission system (which is not before the SCOD of the generating station)</u> and the Commission has approved the date of commercial operation of such transmission system in terms of Regulation 5(2) of these regulations, the generating company shall be liable to pay the transmission charges of the associated transmission system in accordance with clause (5) of Regulation 14 of these regulations to the transmission licensee till the generating station or unit thereof achieves commercial operation;

(b) Where the associated transmission system has not achieved the commercial operation as on the date of commercial operation of the concerned generating station or unit thereof, <u>the transmission licensee shall make alternate arrangement for the evacuation from the generating station at its own cost</u>, failing which, the transmission licensee shall be liable to pay the transmission charges to the generating company at the rate of the applicable transmission charges of the region as determined in accordance with the Sharing Regulations till the transmission system achieves the commercial operation.

<u>Provided that despite making alternative arrangement of evacuation, if the associated transmission system does not achieve the date of commercial operation within the six months of date of commercial operation of the generating station, the transmission licensee shall be liable to pay to the generating company the applicable transmission</u>

charges of the region as determined in accordance with the Sharing Regulations in addition to the above.

Our Comments/Suggestions

1. In most of green-field thermal generation projects, a part of the transmission system associated with generation is required to be ready for operation prior to SCOD of generation for the start-up power requirement. For this, normally, Implementation Agreement is signed and transmission charges are to be paid by the generation till its LTA operationalization as per present Sharing Regulations. To address the requirement of start-up power, 'which is not before the SCOD of the generation' may be deleted from clause 6(1)(a).
2. As per clause 6(1)(a) transmission charges of associated transmission system (ATS) is to be paid by the generator for the period of mismatch. The ATS consists of immediate evacuation system and system strengthening. The immediate evacuation system is generation specific while system strengthening is mainly required to meet the requirement of the beneficiaries and may also be required with other projects as well. Therefore, in case the generation is delayed, the generator should pay the transmission charges of immediate evacuation system while the transmission charges for other elements should be included in PoC Pool irrespective of commissioning of generator.
3. As per clause 6(1)(b), the transmission licensee in the event of delay of more than six months beyond the date of commercial operation of the generating station, despite making an alternate arrangement of evacuation at its own cost, shall be liable to pay to the generating company the applicable transmission charges of the region, as per the Sharing Regulations, which is generally much higher than the YTC of the transmission line. Since the said alternate arrangement is being made at defaulting transmission licensee's risk and cost, imposition of transmission charges applicable in the region to be paid to the generating company after a period of six months is not equitable and is penal in nature. It is a double jeopardy for the Transmission Licensee as it is incurring expenditure for making alternate arrangement and then paying penalty also. In any case, the delay in implementing the transmission system by any licensee is not intentional as it actually lowers the Project IRR and defers the recovery of revenue. Further this provision may not encourage the Transmission Licensee to make an alternate arrangement in the interim period thereby jeopardizing the intent of ensuring actual evacuation of power. As the purpose of power evacuation is getting served, the provision for payment of transmission charges after six months should be removed.
4. Since the actual cost of delayed transmission assets is not available to determine the penalty, it is proposed that provisional penalty may be calculated based on FR cost. The difference in the tariff, if any, based on final cost as approved by the Commission shall be adjusted after date of commercial operation (DOCO) of transmission system.

5. Therefore, the clause 6(1)(b) may be modified to include that in case transmission system is delayed, due to reasons solely attributable to the Transmission Licensees, transmission charges of immediate evacuation system to be paid by Transmission Licensee for the period of mismatch or till alternate arrangement is made by the Transmission Licensee, whichever is earlier. In the event the YTC of immediate evacuation system is not available, the YTC may be worked on normative basis based on the FR cost subject to truing up on actual YTC.

2.3. *Treatment of mismatch in date of commercial operation with other Transmission Licensee*

Draft CERC Tariff Regulations, 2019

6(2) In case of mismatch of the date of commercial operation of the transmission system and the transmission system of other transmission licensee, the treatment of the transmission charges shall be determined as under:

(a) Where an interconnected transmission system of other transmission licensee has not achieved the commercial operation as on the date of commercial operation of the transmission system (which is not before the SCOD of the interconnected transmission system) and the Commission has approved the date of commercial operation of such transmission system in terms of Regulation 5(2) of these regulations, the other transmission licensee shall be liable to pay the transmission charges of the transmission system in accordance with clause (5) of Regulation 14 of these regulations to the transmission licensee till the interconnected transmission system achieves commercial operation;

(b) Where the transmission system has not achieved the commercial operation as on the date of commercial operation of the interconnected transmission system of other transmission licensee, the transmission licensee shall be liable to pay the transmission charges of such interconnected transmission system to the other transmission licensee and in the absence of transmission charges, at the applicable transmission charges of the region as determined in accordance with the Sharing Regulations till the transmission system achieves the commercial operation.

Our Comments/Suggestions

1. Inherently all infrastructure projects particularly linear projects such as transmission projects are prone to delay due to factors beyond the control of the developers viz., project specific conditions such as terrain, project location, land issues, Right of Way (RoW) constraints (including urbanization, river/highway/ railway line crossings, crossing of other transmission lines, forest area). Generally the delay in implementation of transmission projects due to reasons not attributable to defaulting Transmission Licensee is condoned.
2. Generally, there is a great difference in scope of work of the two Transmission Licensees e,g. one Transmission Licensee will make the line (say having YTC of Rs.

100 cr) whereas other Transmission Licensee will make the substation (say having YTC of Rs. 40 cr). Further, the substation bays at two ends of line may be implemented by two separate Transmission Licensees. Thus, if bays at one end are delayed, the developer will have to pay transmission charges of line and other side substation bays, which are much higher than the transmission charges of substation bays under its scope. On the other hand, if the line is delayed, that Transmission Licensee will pay YTC of only substation bays at each end which is much smaller penalty. The penalties imposed on the Transmission Licensees in such cases are disproportionate and hence not equitable and are not as per fair contract practices. Therefore, the penalties on any Transmission Licensee should be limited to the revenue to be recovered by that Transmission Licensee.

3. Further, penalizing the developer for the conditions beyond its control is unjust and should be avoided.
4. Under TBCB route also, the penalty for delay is limited to the transmission charges of the element being executed by the defaulting agency. In line with the same, in case of mismatch, the penalty on the defaulting agency should be limited to the YTC of the smaller element for the period of mismatch. Transmission is implemented to serve the beneficiaries and its TSA is signed with the beneficiaries. Therefore, it is suggested that the transmission charges of the commissioned element should be recovered from the PoC Pool and the penalty amount recovered from the defaulting entity should be credited back to PoC Pool. In the event the YTC of system is not available, the YTC may be worked on normative basis based on the FR cost subject to truing up on actual YTC.

Therefore, the clause 6(2) may be modified to include that lower of the two transmission charges to be paid by defaulting licensees as penalty. The transmission charges of the commissioned element should be recovered from the PoC Pool and the penalty amount recovered from the defaulting entity should be credited back to PoC Pool. In the event the YTC of system is not available, the YTC may be worked on normative basis based on the FR cost subject to truing up on actual YTC.

3. Chapter 3: Procedure for Tariff Determination

3.1. Tariff Determination

Draft CERC Tariff Regulations, 2019

"8. Tariff determination

(1) Tariff in respect of a generating station may be determined for the whole of the generating station or unit thereof, and tariff in respect of a transmission system may be determined for the whole of the transmission system or element thereof or associated communication system:
Provided that:

(i) In case of commercial operation of all the units of a generating station or all elements of a transmission system prior to 1.4.2019, the generating company or the transmission licensee, as the case may be, shall file consolidated petition in respect of the entire generating station or transmissions system for the purpose of determination of tariff for the period 1.4.2019 to 31.3.2024;
(ii) In case of commercial operation of units of generating station or elements of the transmission system on or after 1.4.2019, the generating company or the transmission licensee shall file a consolidated petition, in accordance with the provisions of Procedure Regulations, combining all the units of the generating station or all elements of the transmission system which are anticipated to achieve the date of commercial operation during the next two months from the date of application;"

Our Comments/Suggestions

1. As per proposed Regulation, the Transmission Licensee shall be required to file a consolidated petition in CERC for tariff determination two months prior to commissioning of an asset.
2. 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. Based on these, provisional tariff is allowed by CERC after conducting provisional hearing.
3. Considering the same and that the revenue are commenced and billing for the assets is required to be carried out immediately after their commissioning for servicing the assets, the interim Tariff Order needs to be issued within 60 days from filing of petition to ensure that the tariff for the asset is available as on date of commercial operation of the project/element.

4. Since the process from the date of filing of petition to CERC provisional order on an average generally takes a period of 5 months, the Commission may provide that the Transmission Licensee may be allowed to file the petition for the elements which are anticipated to be commissioned within 120 days for the date of filing of the petitions.

3.2. Application for determination of tariff

CERC Tariff Regulations, 2019

"9. Application for determination of tariff:

(1) The generating company or the transmission licensee may make an application for determination of tariff for new generating station or unit thereof or the transmission system or element thereof in accordance with the Procedure Regulations within 60 days of the anticipated date of commercial operation:

Provided that where the transmission system comprises various elements, the transmission licensee shall file an application for determination of tariff for a group of elements on capitalization of not less than 80% of the cost envisaged in the Investment Approval or Rs. 500 Crore, whichever is lower., as on the anticipated date of commercial operation;

Provided further that the generating company or the transmission licensee, as the case may be, shall submit Auditor Certificate and in case of non-availability of Auditor Certificate, a certificate duly signed by an authorised person, not below the level of Director of the company, indicating the capital cost incurred as on the date of commercial operation and the projected additional capital expenditure for respective years of the tariff period 2019-24;"

Our Comments/Suggestions

1. POWERGRID implements transmission schemes based on recommendations of CEA/ RPC/Standing Committee/National Committee on Transmission. Therefore, the size of the scheme and its configuration etc. are beyond POWERGRID's control. A transmission scheme executed by POWERGRID consists of various assets like Transmission Line, new Substation, Substation bays and equipment like ICTs, Reactors, STATCOMs, etc. Various assets of a scheme are completed progressively and sometimes there is a difference of two – three years in completion of first asset and last asset of the scheme.

2. As per the draft regulations, it is proposed that tariff filing before the Commission would be based on capitalization of not less than 80% of the cost envisaged in the Investment Approval or Rs. 500 Crore (whichever is lower). As there are certain elements of transmission system which may achieve timely commercial operation and may be put to use in early stages of the transmission system project schedule while others may take longer time due to RoW problems, forest clearance issues etc., the transmission licensee would not be able to charge tariff from beneficiaries, even

though the assets are being utilized, till the time such conditions as specified in the proposed regulations are achieved.

3. Such delay in filing of petition and subsequent tariff determination would lead to deferment of revenue to the licensee leading to mismatch in timing of cash flows. After commissioning of the asset, expenses are incurred on O&M and loan repayment, while the charges shall be allowed to be billed only upon determination of tariff by the Commission. Further, the recovery of Return on Equity, which is allowed only upon commissioning of the asset, is deferred due to delayed charging of tariff from beneficiaries.

4. In respect of Communication System, projects comprise of multiple links and commissioning of these links are not necessarily inter-dependent for providing data and voice connectivity. For example, typically a Communication project of Rs. 40 Cr cost comprising of 20 links with a commissioning schedule of 24 months, may get its first lot of links commissioned just after 6 months of award followed by rest of the links.

5. It is therefore recommended that to safeguard licensees from being denied the true benefit of timely returns, the Transmission Licensee may be allowed to file an application for determination of tariff under any of the following conditions:

   - on capitalization of 50% of the cost envisaged in the Investment Approval or Rs. 200 Crore, whichever is lower, as on the anticipated date of commercial operation of an asset;
   - filing of one petition under a project in a financial year for assets already commissioned/anticipated to be completed during the year;
   - filing of two petitions under a Communication System project in a financial year (i.e., at the end of 2nd and 4th quarter of each financial year) for links already commissioned/anticipated to be completed during the year.

3.3. Requirement of Management Certificate to be signed by Director of the Company

Draft CERC Tariff Regulations, 2019

9(1) Third Proviso – The Transmission Licensee shall submit Auditor Certificate and in case of non-availability of Auditor Certificate, a certificate duly signed by a authorized person, not below the level of Director of the company.

Our Comments/Suggestions

1. Since the final certificate for capital expenditure is required from the Auditors, it is not feasible to provide it alongwith the petition which is filed prior to commissioning. Therefore, Auditor Certificate shall be provided during the final hearing stage.

2. As such, difference in tariff based on provisional certificate and the Auditor Certificate, if any, is to be returned back to the beneficiaries with interest. Therefore, the Transmission Licensee does not have any interest in inflating the cost in provisional cost certificate.

3. Therefore, it would be prudent that the initial certificate can be signed at the level of Regional Executive Director, who have been empowered by the management to do so.

3.4. Truing up petition to be filed within 180 days

Draft CERC Tariff Regulations, 2019

9(2) –In case of an existing generating station or unit thereof, or transmission system or element thereof, the application shall be made by the generating company or the transmission licensee, as the case may be, within a period of 180 days from the date of notification of these regulations, based on admitted capital cost including additional capital expenditure already admitted and incurred up to 31.3.2019 (either based on actual or projected additional capital expenditure) and estimated additional capital expenditure for the respective years of the tariff period 2019-24 along with the true up petition for the period 2014-19 in accordance with the CERC(Terms and Conditions of Tariff) Regulations, 2014.

12 - The tariff of the generating stations and the transmission systems for the period 2014-19 shall be trued up in accordance with the provisions of Regulation 8 of CERC (Terms and Conditions of Tariff) Regulations, 2014 along with the tariff petition for the period 2019-24. The capital cost admitted as on 31.3.2019 based on the truing up shall form the basis of the opening capital cost as on 1.4.2019 for the tariff determination for the period 2019-24.

Our Comments/Suggestions

Auditor certificates pertaining to transmission projects for the purpose of truing up petitions can be prepared only after the completion of audit of financial year 2018-19 which is expected to be completed by end of May'19. Further, POWERGRID needs to file approx. 450 nos of truing up petitions. Considering the time required for preparation of truing up petitions incorporating actual expenditure during 2018-19 as per the Audited Accounts, filing for such cases can only commence from July'19. Keeping in view the same and huge numbers of truing up petition to be filed, it is requested to increase the time limit for filing true up petitions from 180 days to 270 days from the date of effectiveness of the Regulations i.e. till Dec'19.

3.5. Determination of Tariff

Draft CERC Tariff Regulations, 2019

10(1) & 10(2) - Petition to be made as per Annexure –I of the Regulations.

Our Comments/Suggestions

The Annexure – I which deals with the detailed requirements of the Petition to be filed with the Commission for the Transmission assets needs to be modified based on the comments/suggestion made herein against the respective provisions.

3.6. Interim Tariff

Draft CERC Tariff Regulations, 2019

10(3) – The Commission may grant interim tariff in case of new projects.

Our Comments/Suggestions

1. The CERC Tariff Regulations 2014-19 provided for an interim tariff upto 90% of the annual fixed charges claimed in respect of the transmission system by the licensee till final tariff is determined by the Commission. The difference between the provisional tariff and final tariff was billed subsequently.
2. It provided a sound mechanism for the licensee to match the cash flows by allowing the licensee to charge major portion of tariff from the date of commercial operation of the asset.
3. As per the current practice, interim (provisional) tariff granted by the Commission are included by the Validation Committee in the calculation of PoC rates based on the Tariff Regulations, 2014.
4. To ensure timely tariff to Transmission Licensees, the provision may be modified as under:

   "If the information furnished in the petition is in accordance with these regulations and is adequate for carrying out prudence check of the claims made, the Commission may consider to grant interim tariff upto 90% of the annual fixed charges in case of new projects within 60 days (or 90 days if 120 days are provided in Clause 8 for filing of petition respectively) from the date of application for the purpose of inclusion in the PoC charges in accordance with the CERC (Sharing of Inter State Transmission charges and losses), Regulations, 2010 as amended from time to time."

3.7. Variation in Projected Capital Expenditure

Draft CERC Tariff Regulations, 2019

*"10 (8) Where the capital cost considered in tariff by the Commission on the basis of projected additional capital expenditure exceeds the actual additional capital expenditure incurred on year to year basis by more than **10%,** the generating company or the transmission licensee shall refund to the beneficiaries or the long term transmission customers as the case may be, the tariff recovered corresponding to the additional capital expenditure not incurred, as approved by the Commission, along*

with interest at 1.20 times of the bank rate as prevalent on 1st April of the respective year.

*10 (9) Where the capital cost considered in tariff by the Commission on the basis of projected additional capital expenditure falls short of the actual additional capital expenditure incurred by more than **10%** on year to year basis, the generating company or the transmission licensee shall recover from the beneficiaries or the long term customers as the case may be, the shortfall in tariff corresponding to difference in additional capital expenditure, as approved by the Commission, along with interest **at the bank rate** as prevalent on 1st April of the respective year."*

Our Comments/Suggestions

1. The regulations propose levy of penal interest at the rate of 1.2 times the bank rate for projected additional capital expenditure being higher than the actual capital expenditure by 10% and at the bank rate for projected additional capital expenditure being lower than the actual capital expenditure by 10%.
2. The expenses incurred during closing stages of the project can vary depending upon number of factors, which may be beyond the control of the licensee (viz. price variation due to inflation, claims and counter claims, arbitration awards, retention payments, defect liability etc.). Therefore, it is proposed that there should not be any difference in interest rate applicable for capital expenditure or additional capitalization being higher or lower than that projected and adjustment of both should be allowed at bank rate.
3. The overall tariff is computed by the Transmission Licensee and approved by the Commission on the basis of total capital expenditure during the year. Since separate tariff is neither computed/approved for the variation in the capital cost on year on year basis, it would be prudent to adopt the overall tariff, which would be a fairly transparent process, for the purpose of the aforesaid provisions and accordingly, the provisions may be modified as under:

   "*10 (8) Where the tariff approved by the Commission on the basis of projected additional capital expenditure exceeds the tariff computed and approved by the Commission on the basis of actual additional capital expenditure incurred on year to year basis by more than 10%, the generating company or the transmission licensee shall refund to the beneficiaries or the long term transmission customers as the case may be, the excess tariff recovered along with interest at the bank rate as prevalent on 1st April of the respective year.*

   10 (9) Where the tariff approved by the Commission on the basis of projected additional capital expenditure falls short of the tariff computed and approved by the Commission on the basis of actual additional capital expenditure incurred by more than 10% on year to year basis, the generating company or the transmission licensee shall recover from the beneficiaries or the long term customers as the case *may be, the shortfall in tariff along with interest at the bank rate as prevalent on 1st April of the respective year.”*

3.8. In-principle Approval in Specific circumstances

Draft CERC Tariff Regulations, 2019

11 – In-principle approval from Commission for undertaking additional capitalization on account of change in law events or force majeure conditions after prior notice to the beneficiaries if the estimated expenditure exceeds 10% of the capital cost of the project or Rs. 100 Cr, whichever is lower.

Our Comments/Suggestions

After commissioning of the project, the Transmission Licensees may require to modify/shift its assets through development of alternate solution by either using multi-circuit towers, raising height of towers or change the course of the line in order to address force majeure conditions of Right of Way (RoW) constraints due to urbanization, change in river course, execution of highway/railway line/other transmission lines in transmission tower route, etc..

The execution of such works are required to be carried out by the Transmission Licensees in a time bound manner.

As per the regulations, a in-principle approval is required to be taken from the Commission for carrying out additional capitalization in such cases after prior notice to the beneficiaries. Since the petition filed by the Transmission Licensee for taking in-principle approval of the Commission shall be sent to the beneficiaries as they shall be the Respondents of the petition, prior notice to them as such is not required.

Therefore, the provision may be modified by deleting this requirement.

4. Chapter 5: Capital Structure

4.1. Reduction in Equity after Useful Life

Draft CERC Tariff Regulations, 2019

17(6). In case of generating station or a transmission system including communication system which has completed its useful life as on or after 1.4.2019, the accumulated depreciation as on the completion of the useful life less cumulative repayment of loan shall be utilized for reduction of the equity and depreciation admissible after the completion of useful life and the balance depreciation, if any, shall be first adjusted against the repayment of balance outstanding loan and thereafter shall be utilized for reduction of equity till the generating station continues to generate and supply electricity to the beneficiaries.

Our Comments/Suggestions

1. The provision in the Draft Regulations proposes reduction of equity by difference of accumulated depreciation as on completion of useful life and cumulative loan repayment, resulting in reduction of equity from 30% of the admitted capital cost to mere 5% after useful life (considering salvage value of 5%). Further, the provision also states that the depreciation admissible after useful life beyond repayment of loan shall be utilized for reduction of equity. These provisions would significantly affect the return allowed to the licensee after useful life and thereby impact the decision of additional capitalization for extension of life/efficient operation of asset after useful life.

2. The investments made out of the equity capital i.e. equity deployment is considered as a risk capital and it is necessary to incentivize the electricity utility to invest equity. The investment in equity is the money blocked by the investor in the project. Without induction of equity, it will not be possible to raise loan from the banks and financial institutions. In other words, the banks and financial institutions insist on the promoters of the transmission system to invest a minimum equity as a pre-condition for lending money for the project. Further, as long as the transmission asset is in use, the equity cannot be taken as repaid or depleted.

3. The Appellate Tribunal of Electricity had passed a judgment dated May 16, 2006, 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 Hon'ble Supreme Court in its Judgment dated February 24, 2016 in Appeal No. 256 of 2007, where the Apex Court had held that – "That there is no depreciation on equity, cannot be disputed".

4. The Transmission Licensee puts all efforts to repair and maintain the transmission assets in appropriate conditions such that the services can be rendered even after

the useful life of the transmission assets. The cost of O&M to maintain the same standard of service beyond the useful life is higher and the same will not be compensated by the O&M recovery allowed.

5. During the initial useful life of the assets, return on 30% equity is provided which has a built-in element to compensate for the services rendered by the utility. When the RoE is given on a reduced base after the useful life, services rendered by the utility by maintaining the assets which have completed the stipulated useful life are not adequately compensated. This may encourage the utilities to discard assets instead of deriving full benefit of the remaining economic value residing in these assets. In a resource scarce economy such as in our county, it would be advantageous to the consumers if the utilities are encouraged to extract maximum benefit out of investments, including through renovation and modernisation, so that the cost of power is reduced. It is, therefore, requested that the Commission may continue with the existing provisions for providing return on equity on full 30% of asset cost.

5. Chapter 6: Computation of Capital Cost

5.1. Exclusions from capital cost

Draft CERC Tariff Regulations, 2019

"18 (5) The following shall be excluded from the capital cost of the existing and new projects:
(a) The assets forming part of the project, but not in use (to be declared at the time of filing tariff petition);
(b) De-capitalisation of Assets after the date of commercial operation on account of replacement or removal on account of obsolescence or shifting from one project to another project;"

21(2) The "uncontrollable factors" shall include but shall not be limited to the following:

- *a. Force Majeure events;*
- *b. Change in law; and*
- *c. Time and cost over-runs on account of land acquisition except where the delay is attributable to the generating company or the transmission licensee;*

23(1) Second Proviso - In case of any replacement of the assets, the additional capitalization shall be worked out after adjusting the gross fixed assets and cumulative depreciation of the assets replaced on account of de-capitalization.

Our Comments/Suggestions

1. Due to rapid urbanization, load demand at different locations are increasing. The only alternative option for meeting the additional load at the respective locations is either through (i) installation of additional new ICTs in the existing substation if there is space for such installation, (ii) construct new substation nearby the existing substation or (iii) augmentation of transformation capacity. It may be appreciated that challenges are being faced in most of the cases for accommodating additional ICTs due to non availability of space in the existing substation. It may also be appreciated that the unit sizes of transformers are discreet and therefore meeting the additional load demand through replacement of existing ICT with higher capacity ICT is a cost effective solution for the planners. Otherwise, setting up a new station (including procurement of land) nearby the existing station would be required to be carried out by the transmission utilities, thus increasing the transmission charges of the beneficiaries.

2. Similarly, with increasing size of the power system, higher capacity Reactors at existing substations are required to contain the over voltage. The transmission utility

can either meet reactive compensation requirement by replacement of existing Reactor with higher capacity Reactors or installing additional Reactors, thus consuming more space.

3. The de-capitalization of existing equipment, which are in healthy condition, is carried out by the Transmission Licensees after the approval is granted by the beneficiaries in Regional Power Committee and Standing Committee Meeting based on the system requirements as stated above.

4. The utilization of the replaced/existing equipment is not in the hands of the Transmission Licensee and depends on the system requirements. Therefore, it is submitted that in case any existing asset or part of the existing asset is required to be replaced due to system requirement, the following methodology may be adopted:

    a. In the event the existing asset is not utilized/usable after its replacement, it is submitted that the Transmission Licensee may be allowed

        i. Additional capitalization of the gross cost of the new assets and

        ii. To recover the balance unrecovered depreciation in one time basis on de-capitalization of the existing assets in its gross block.

    b. In the event the existing/replaced equipment are either shifted to new location or may be utilised as Regional Spare to provide desired services to the system as and when required under contingencies, the Transmission Licensee may be allowed

        i. Additional capitalization of the gross cost of the new assets,

        ii. To recover the carrying cost i.e. Interest on loan, depreciation, ROE and nominal maintenance expenses in respect of replaced asset till the asset is put to use and

        iii. To capitalize the assets in new project where it shall be put to use with its de-capitalized value.

    Generally in a substation, all the reactors/ICTs are replaced with higher values and there may be a time gap of 6 months to 1 year when the existing assets are taken out of service. In such case, the Transmission Licensee needs to undertake truing up exercise multiple times. To avoid this, it is proposed that the decpaitalization of the replaced assets may be allowed during the truing up exercise in the next block.

5. With regard to provision 21(2) it is to mention that Transmission licensee is to face stiff Right of Way problems while constructing transmission lines causing delay in completion. In case of transmission lines, Transmission Licensees are not acquiring the land along the RoW but are paying the damages caused (including diminishing value of land) due to construction of lines. Hon’ble Commission is condoning the

delay due to RoW in tariff petitions. In view of the above, it is submitted that delay due to Right of Way problems may also be included in Uncontrollable factors like delay due to Land acquisition.

5.2. Initial Spares

Draft CERC Tariff Regulations, 2019

22. Initial Spares*: Initial spares shall be capitalised as a percentage of the Plant and Machinery cost upto cut-off date, subject to following ceiling norms:*

(d) Transmission system

(ii) Transmission Sub-station - 4.00%

(vi) Static Synchronous Compensator - 3.50%

………

Our Comments/Suggestions

While going through the Explanatory Memorandum, it is noted that the initial spares for brown field substation have been reduced to 4% (i.e. same of green filed substation) from 6% as provided in Tariff Regulations, 2014. The Table below shows the initial spares procured for brown field substation during the last few years:

List of Brown Field Substations	**Petition No.**	**Initial Spares Claimed (in %)**
Installation of 01 no. 125 MVAR Bus Reactor at Maithon S/S with GIS bays	233/TT/2016	7.53
400kV Circuit-I, of Dehradun-Abdullapur D/C(Quad) line along with associated bays at both ends	56/TT/2017	8.23
400kV Circuit-II, of Dehradun-Abdullapur D/C(Quad) line along with associated bays at both ends	56/TT/2017	9.33
400kV D/C(Quad) Dulhasti-Kishenpur –single circuit strung along with associated bays at kishenpur end	56/TT/2017	10.94
Extension of Dehar 400/220 kV Substation (BBMB)-Installation of 400 kV, 1x63 MVAR Bus reactor I through a single 400 kV hybrid GIS bay	234/TT/2016	12.62
Extension of 220kV Navsari (GIS) Substation: 2 Nos line bays and	365/TT/2018	8.43
Asset 2- Extension of 400kV Vadodara (GIS) substation: 3 nos of bays (2 nos line bays & 1 no. bus reactor bay) including 1x 125 MVAR, 400kV Bus reactor	365/TT/2018	7.22
Extension of Kudankulam APP- Tirunelveli 400kV (Quad) D/C line to Tuticorin pooling station along with associated bays at Tuticorin pooling station	110/TT/2017	5.66
Average		**8.75**

In this regard, it may be mentioned that 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 reinstate initial spare norms for AIS (Brown Field) @6%. Since the capital cost of extension project is less as compared to a new substation, higher percentage of capital cost is required for procuring initial spares.

In case of GIS Substation, up-gradation of the same is carried out normally by the OEMs and difficulties are being faced in getting the spares for the earlier designed systems. The spare norms for GIS system of 5%, as indicated in the draft Tariff Regulation 2019, are therefore not adequate as compared to the spares already procured for the projects which are under commercial operation. Hence, there is a need to specify higher initial spare norms for GIS (Brown Field) @7%-8% separately.

5.3. Ceiling norms for Initial Spares for new technology equipment

Draft CERC Tariff Regulations, 2019

22 – Separate Initial Spare norms for SVC@4% and STATCOM @3.5% provided.

Our Comments/Suggestions

POWERGRID is installing new technology equipment in the Indian power system viz., Fixed Series Compensator, TCSC, Static Var Compensator (SVC) and STATCOM. These equipment are fewer in numbers and are generally manufactured and supplied by foreign manufacturers.

Being imported items, the lead time of procurement of spares is much higher than any onshore equipment. Hence the Transmission Licensee is required to ensure adequate supply of spares to take care of any contingency so that the system does not remain under outage for want of spares. These equipment are generally for enhancing stability of the system and their outage for a prolonged time may comprise the safety and stability of the system.

The initial spares claimed for such type of assets during last few years are reproduced hereinbelow:

List of STATCOM	Petition No.	Initial Spares Claimed (in %)
±300 MVAR STATCOM at 400kV Aurangabad Sub-station	111/TT/2018	5.19
±200 MVAR STATCOM at 400kV Gwalior Sub-station	111/TT/2018	6.35
±300 MVAR STATCOM at 400kV Solapur Sub-station	111/TT/2018	5.20
±300 MVAR STATCOM at Rourkela Substation	173/TT/2018	6.37
±200 MVAR STATCOM at Jeypore Substation	173/TT/2018	6.25
±300 MVAR STATCOM at Ranchi Substation	272/TT/2018	4.17
±200 MVAR STATCOM at Kishanganj Substation	272/TT/2018	4.17
Average		**5.38**

List of Static Var Compensator (SVC)	Petition No.	Initial Spares Claimed (in %)
(+) 600 MVAR / (-) 400 MVAR SVC at 400/220 kV Ludhiana Substation	149/TT/2016	6.45
(+) 400 MVAR / (-) 300 MVAR SVC at 400/220 kV Kankroli Substation	241/TT/2016	6.50
(+) 300 MVAR / (-) 200 MVAR SVC at 400/220 kV New Wanpoh Substation	6/TT/2018	6.79
Average		**6.58**

Hence, there is a need to provide higher initial spares norms of 6% - 7% for new technology equipment viz., Fixed Series Compensator, TCSC, Static Var Compensator (SVC), STATCOM etc.

5.4. Ceiling norms for Initial Spares for Communication System

Draft CERC Tariff Regulations, 2019

22 – Norms for Initial Spares for Communication System @3.5% provided in CERC (Terms and Conditions of Tariff) Regulations, 2019.

Our Comments/Suggestions

The Communication System can be broadly categorized into fibre optic cables (OPGW) and Communication equipment (viz., SCADA and WAMS System, SDH, Multiplexer, NMS and PABX etc.), RTUs, PMUs, DCPS etc.

Though the initial spare @3.5% is adequate for OPGW, the Communication equipment (viz., SCADA and WAMS System, SDH, Multiplexer, NMS and PABX etc.), RTUs, PMUs, DCPS etc. being electronic equipment, requirement of more spares are essential for smooth operation of the system. It has been experienced that spares corresponding to 10% of the plant and machinery cost are generally required.

Hence, there is need to introduce higher initial spares norms of 10% for electronic equipment viz., Communication equipment (viz., SCADA and WAMS System, SDH, Multiplexer, NMS and PABX etc.), RTUs, PMUs, DCPS etc.

5.5. Benchmarking of capital costs – database

Draft CERC Tariff Regulations, 2019

***19(3) Prudence Check of Capital Expenditure**: The generating company or the transmission licensee, as the case may be, shall furnish the package wise capital cost for execution of the existing and new projects as per Annexure-I along with tariff petition for the purpose of creating a database of benchmark capital cost of various components.*

Our Comments/Suggestions

1. Econometric analysis for determination of prudent costs would require database spanning across multiple variables that may influence capital costs.

    a. Captial cost depends upon multiple variables:

        i. *Project specific conditions* such as terrain, length of transmission line, number of bays and weather conditions may lead to different capital costs of similar transmission assets or

        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.

    b. Keeping track of all such factors that may influence discovery of prudent costs, whether project specific or market forces driven, is practically challenging

    c. Results of any econometric model may vary from the actual costs and since the Commission would in any case restrict the same upto actual costs if the model price is higher, the only result of this would be to restrict the actual costs to economectic model, if the actual cost is higher thereby resulting in severe losses for the Transmission Licensee.

2. 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.

3. Since it may not be pratically possible to factor in all the considerations mentioned above in an econometric model, it is therefore suggested that the Hon'ble Commission may carry out such benchmarking exercise for determination of Ex-works supply cost of the equipment subject to periodic updation based on economic conditions, inflation, bank rate etc.

6. Chapter 7:Computation of Additional Capital Expenditure

6.1. Treatment of O&M Additional Capitalization

Draft CERC Tariff Regulations, 2019

24(2) –Provision in CERC (Terms and Conditions of Tariff) Regulations, 2019 for replacement of assets (not equipment forming part of the asset) through additional capitalization.

Our Comments/Suggestions

1. Over the course of operation and maintenance of a transmission system, additional capital expenditure on replacement of items/equipment (not complete assets) specifically the following are required to be undertaken on the existing projects after cut-off date for successful and efficient operation of the transmission assets.

   "Relays, control and instrumentations, computer system, PLCC, batteries, replacement of equipment due to obsolescence of technology or due to increase in fault level, tower strengthening, communication equipment, IT hardware, software, emergency restoration system, insulator cleaning infrastructure, replacement of porcelain insulators with polymer insulators, damaged equipment not covered under insurance and any other expenditure which has become necessary for successful and efficient operation of transmission system."

   This additional expenditure helps in improving plant availability, technological upgradation and may also lead to life extension in case of a plant about to complete its useful life.

2. The proposed regulations have done away with this key clause, thereby denying improved operations of existing depreciated assets and the extension of their useful life, whose benefits can be enjoyed by the beneficiaries.

3. <u>Given the overall economic benefit of improving the performance of the existing assets and continuing the operations of depreciated assets in an efficient manner and prolonging their useful life using additional capitalization, it is suggested that 14(3)(ix) of 2014 regulations should be retained for replacement of items/equipment which are under original scope of work through additional capitalization after cut-off date.</u>

6.2. Treatment of Additional Capitalisation on account of R&M

Draft CERC Tariff Regulations, 2019

26(4) – …… Expenditure incurred or projected to be incurred and admitted by the Commission after prudence check, and after deducting the accumulated depreciation already recovered from the original project cost, shall form the basis for determination of tariff.

Our Comments/Suggestions

1. Renovation and Modernization involves an overhaul of major components of a system. It is a long process involving preparation of Detailed Project Report that includes identification of specific parts to be replaced/repaired, assessing cost involved in R&M, cost-benefit analysis, schedule of completion etc. It may be required to involve specialized agencies or obtain inputs from OEM. Further, the licensee is required to obtain the approval of the Commission before taking up the work.
2. Considering the fact that R&M of existing depreciated assets is beneficial to both the beneficiaries and consumers due to lower tariffs for extended useful life and should be carried out as soon as its requirement is assessed by the operating agency, it is not in the interest of licensee, beneficiaries or consumers to add an extra layer of consent to the process which would only add time to it.
3. Thus, it is requested that the requirement of obtaining consent from the beneficiaries be removed from the final Regulations and the Licensee be allowed to carry out R&M with approval from the Commission.
4. 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 26(4) may be modified to replace ''after deducting the accumulated depreciation already recovered from the original project cost'' by ''*after deducting the accumulated depreciation already recovered from the original asset/equipment cost"*.
5. 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.
6. Further, the provision may be modified to include Communication System also.

7. Chapter 8: Computation of Annual Fixed Cost

7.1. Capital Investment and Return

7.1.1. Maintenance of Existing Rate of Return on Equity

Draft CERC Tariff Regulations, 2019

30 (2) Return on equity shall be computed at the base rate of 15.50% for thermal generating stations, transmission system including communication system…

Our Comments/Suggestions

An attempt has been made to assess the required rate of return for an entity in transmission business based on the return allowed by regulators in other countries, expected return in the Indian market (using CAPM) and return allowed to other regulated sectors in India. The same has been detailed below.

- *RoE based on allowed Return by Regulators in Other Countries*

The transmission business is regulated in most part of the world. Consequently, regulators allow return on the capital invested at a specified rate, based on methodology adopted by them. 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.

In order, to estimate the required rate of return in India, first step is to calculate the business risk premium in the selected country. Thereafter, the business risk for transmission business is India is estimated using the business risk premium in the selected country and the differential country risk premium. The country risk premium is estimated using the default spread based on rating by independent agencies (such as Moody's), adjusted for the additional volatility of equity market. Finally, the business risk for India is added to risk free rate for India to estimate the required rate of return. A step-by-step approach is shown below:

(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 step i:

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 = Country risk premium (India) – Country 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:

Table 1: Calculation for estimation of business risk premium in India

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* (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.

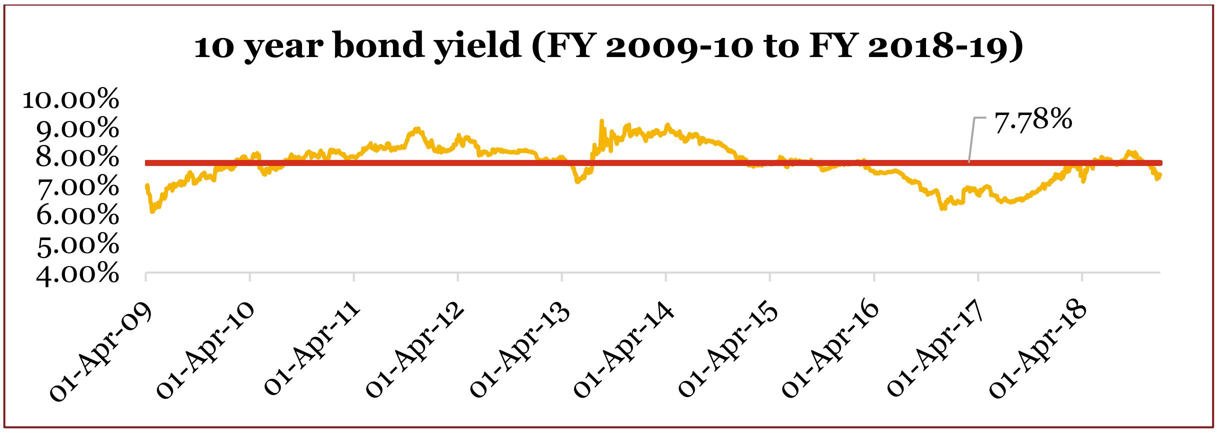
* Country risk premium for India (CRP (India))* = 2.19%

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 10 years[1]. The data has been taken for 10 years to exclude the outlier effect caused by global recession during FY 2008-09.



Thus, the rate of return for transmission business can be estimated at 7.70%+7.78% = 15.48%.

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

- *Expected Rate of RoE based on CAPM for Indian Transmission Entities*

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

$$Ra = Rf + [\beta\, x\, (Rm - Rf)]$$

Where:

Ra = Expected rate of return

Rf = Risk-free rate

β = Beta of the security

Rm = Expected return on market

[1] Data considered from 01.04.2009 to 31.12.2018

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

- **Step 1** •Calculate historical market returns for the past 10 years (2009 – 2018) using BSE Sensex data to determine Rm
- **Step 2** •Calculate risk free rate for similar period of 10 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:

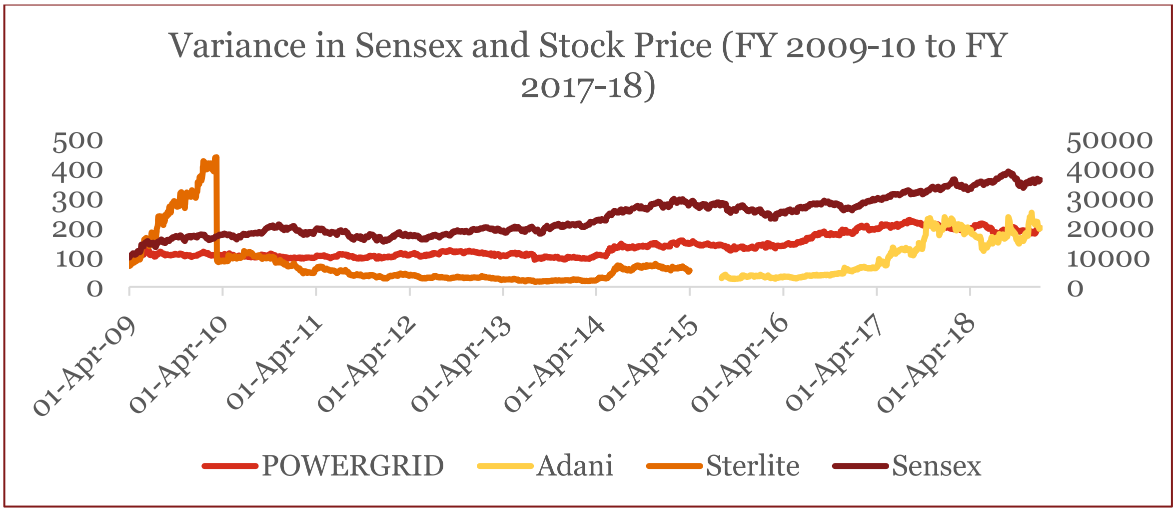
Calculate equity beta for major listed transmission firms and determine average of equity betas → Calculate each firm's financial leverage and determine average of financial leverage → Un-lever the average equity beta using average financial leverage to get average un-levered beta → Re-lever the average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

The unlevered beta is then calculated using the following formula:

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

(i) Calculation of market return

The market return has been estimated based on historical data of returns of BSE Sensex over past 10 years from FY 2009-10 to FY 2018-19[2] (till 31 Dec 2018). The data has been taken for 10 years to exclude the outlier effect caused by global recession during FY 2008-09.

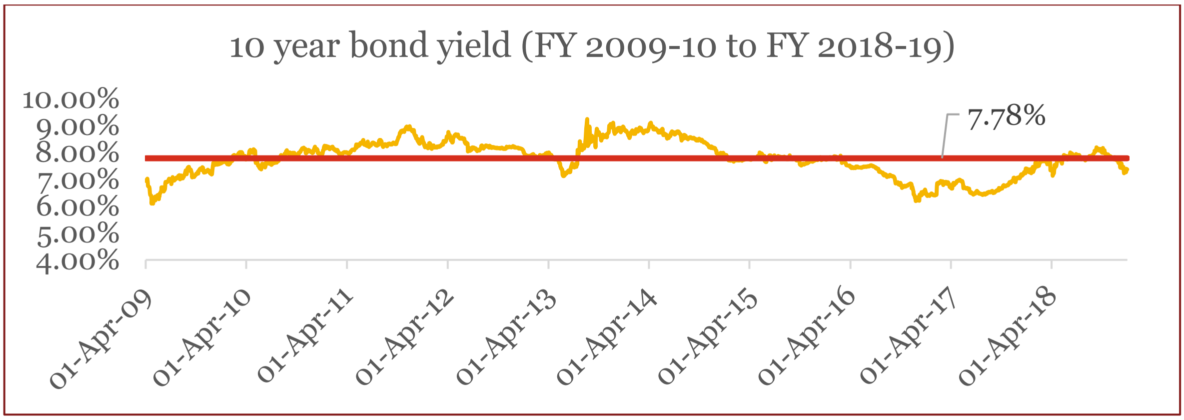


The market return for a period from FY 2009-10 to FY 2018-19 is 15.86%.

[2] Data considered from 01.04.2009 to 31.12.2018

(ii) Risk free rate based on 10-year government bond yields

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



The Risk free rate (Rf) based on 10-year Indian government bond yield from FY 2009-10 to FY 2018-19 (till 31 Dec 2018) works out to be 7.78%.

(iii) Estimation of expected Beta for POWERGRID

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

Table 2: Calculation of un-levered beta for transmission sector

Firm	Equity / Levered Beta	D/E	Tax Rate	Un-levered Beta
Adani Transmission Ltd.	1.61	2.06	21.11%	0.612
POWERGRID	0.68	2.33	20.68%	0.237
Sterlite Technologies Ltd.	1.28	1.40	25.87%	0.627
Overall Average				**0.492**

- 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 – Dec 2018, since it got listed in July 2015
- For POWERGRID, data used from FY 2009-10 to FY 2018-19 (till Dec 2018), consistent with Rf and Rm
- For calculation of tax rate, 3-year average MAT rate has been used

The unlevered beta works out to be 0.492.

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 – MAT Rate) x (Debt/Equity)))
= 0.492 x (1 + (1-0.2068) x (70/30))
= 1.40

Thus, the Beta for calculation for expected return for POWERGRID is estimated at 1.40.

(iv) Estimation of expected Rate of Return for POWERGRID

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

= 7.78% + [1.40 x (15.86% - 7.78%)]

= 19.11%

Thus, it can be observed that using the CAPM method, the expected return works out to be 19.11%, much more than the existing number of 15.50%.

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

(i) Aviation

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

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

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

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

Table 3: Return allowed to private airports in India

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

S.No.	Airport	Allowed RoE	Source
			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 electricity transmissions sector.

(ii) Natural Gas Transmission

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

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

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

Where:

g: gearing

Rd = Cost of debt

Tc = Tax rate

Re: Cost of equity

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

Table 4: Assumptions made for computing return on equity for natural gas transmission

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

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

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

⇨ $Re = 22.66\%$

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

1. It can be observed that using the CAPM method, the expected return works out to be 19.11%, much more than the existing number of 15.50%;
2. Similarly, Regulators world over (e.g. Australia, Netherlands, Philippines, Malaysia etc.) have used CAPM to calculate the expected return on equity for Transmission Players. As can be seen in the analysis above, <u>the current rate of Return on Equity @15.5% is in line with the return allowed by regulators in other countries;</u>
3. Therefore, we would like to allude to the fact that CERC needs to maintain the current rate of return on equity i.e., 15.5% based on the current market expectations.

7.1.2. No Provision for Additional Return on Equity

Draft CERC Tariff Regulations, 2019

No Provision in CERC (Terms and Conditions of Tariff) Regulations, 2019 for additional return on equity for timely completion of projects.

Our Comments/Suggestions

1. The Commission in CERC (Terms and Conditions of Tariff) Regulations, 2009 introduced additional Return on Equity of 0.5% for timely completion of projects. The provision was continued in the Regulations governing the next Control Period – the CERC (Terms and Conditions of Tariff) Regulations, 2014. However, the provision has been discontinued in the Draft Regulations for the Control period FY 2019-20 to FY 2023-24.

2. The provision of additional 0.5% return on equity was appropriate and much desired incentive for the licensees to expedite the projects and ensure timely completion. It also rewarded the licensee for good project management practices, and motivated other companies to adopt the same. The arrangement was beneficial for the entire sector as whole – generation companies benefited from timely availability of transmission facility for evacuation of power, Transmission Licensee received better returns for future investments and the consumers benefitted by lower project cost (lower IDC & IEDC cost) and reliable power supply.

3. Thus, it is suggested to reintroduce the provision including the Completion Timelines as per Tariff Regulations, 2014 and provide additional RoE for timely completion of projects.

4. Furthermore, the projects which have been entitled to additional 0.5% return on equity during the block 2009-14 and 2014-19 should be allowed to retain the additional RoE throughout its useful life as utilities have made additional efforts for early completion.

7.1.3. Reduced Return on Equity on additional capitalization after cut-off date

Draft CERC Tariff Regulations, 2019

30(2)(i) Return on equity in respect of additional capitalization after cut off date within or beyond the original scope shall be computed at the weighted average rate of interest on actual loan portfolio of the generating station or the transmission system

Our Comments/Suggestions

1. The additional capitalization beyond cut-off date may be incurred to meet the liabilities of award of arbitration, change in law, force majeure or replacement of assets deployed under original scope of work as per the proposed Draft Regulations.

2. As it can be noticed, the additional capitalization is carried out either to meet certain obligations / force majeure etc. or for successful and efficient operation of the system. In any condition, this expenditure is an investment towards asset creation and such investments should be allowed to earn a fair rate of return.

3. Therefore, the equity investment on account of additional capitalization cannot be treated any differently from equity investment during construction of asset and should be allowed the same fair rate of return. Further, the return allowed on equity investment cannot be compared with that of debt, which is a fixed income instrument.

4. Thus, it is suggested that the return on the entire equity, invested at any stage of the project should be allowed at the same proposed rate i.e., 15.5%.

7.2. Working Capital

7.2.1. Changes in norms for working capital

Draft CERC Tariff Regulations, 2019

"34. Interest on Working Capital: (1) The working capital shall cover:....................

(c) Hydro generating station (including pumped storage hydro electric generating station) and transmission system:
(i) Receivables equivalent ***to 45 days of annual fixed charges;***
(ii) Maintenance spares @ 15% of operation and maintenance expenses specified in Regulation 35 of these regulations; and
(iii) Operation and maintenance expenses for one month."

Our Comments/Suggestions

With the weakening of financial health of most of the DISCOMs, the payment cycle of most of the beneficiaries has moved from 60 days to 90 days. Considering the same, preponing payment period to 45 days would lead to additional burden of late payment surcharges on these otherwise ailing DISCOMs. It is, therefore, suggested to retain the allowable receivables to 60 days of AFC for working out the Interest on Working Capital.

7.3. Depreciation

7.3.1. Classification & Depreciation Rate for IT equipment and Software

Draft CERC Tariff Regulations, 2019

Appendix – I (Sl. No. p) – Depreciation rate @15% for IT equipment and Software.

Our Comments/Suggestions

a. The IT equipment and Software have no salvage value after they are put into service and therefore Hon'ble Commission has allowed them to be 100% depreciable. Further, rapid technological obsolescence is being faced in telecom/electronic industry.
b. The Transmission Licensees use 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/SAS/PMUs: These devices are installed at the substations and are used to collect 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 and large are electronic equipment 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	: Software
(c) RTU/SAS/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. Central Electricity Regulatory Commission (Fees and Charges of Regional Load Despatch Centre and other related matters) Regulations, 2015 (RLDC Regulation) have provisioned that the software assets are to be depreciated at 30%.

<u>Keeping in view the above, the depreciation rate for software may be provisioned as 30% in line with the RLDC Regulations and accordingly, the depreciation table may be modified as under:</u>

S. No.	**Asset Particulars**	**Depreciation Rate (Salvage Value=5%)**
p.	**IT Equipment including Software**	
(i)	**IT Equipment**	**15%, (salvage value Nil)**
(ii)	**Software**	**30%, (salvage value Nil)**

7.3.2. Treatment of Fibre Optic

Draft CERC Tariff Regulations, 2019

Appendix – I (Sl. No. O(iii)) – Depreciation rate @6.33% for Fibre Optic

Our Comments/Suggestions

With reference to the definition of communication system, Fiber Optic Cable includes OPGW, ADSS, Wrap Type, Approach cable etc. OPGW has earth wire component which can have salvage value after disposal but the ADSS, WRAPP Type, Approach cable etc would not have any salvage value.

It is, therefore, submitted to introduce following two categories to be included under communication system. In line with the above regulation, it is humbly submitted to consider the salvage values of these equipment as zero (except OPGW Fiber cable) as all of them are IT equipment and have zero realizable value upon turning obsolete.

S. No.	Asset Particulars	Depreciation Rate (Salvage Value=5%)
o.	**Communication Equipment**	
(i)	**Radio and high frequency carrier system**	**6.33%, (salvage value Nil)**
…		
(iv)	**Fiber Optic (OPGW)**	**6.33%**
(v)	**Fiber Optic (ADSS, WRAPP Type, Approach cable etc)**	**6.33%, (salvage value Nil)**

7.4. Depreciation of Batteries and Relay

Draft CERC Tariff Regulations, 2019

Appendix – I (Sl. No. h) – Depreciation rate @5.28% for Batteries and no provision for Relays in CERC (Terms and Conditions of Tariff) Regulations, 2019.

Our Comments/Suggestions

The useful life of batteries and relays are short – approx. 5 years, therefore, these items should be allowed to be depreciated at much faster rate. Since salvage value of these items are zero, it is humbly submitted to consider the depreciation rate at 18% and salvage values of these equipment as zero in line with that of IT equipment.

7.5. O&M Norms for Transmission System

Draft CERC Tariff Regulations, 2019

35(3)(a) - The following normative operation and maintenance expenses shall be admissible for the transmission system:

……

Provided further that the O&M expenses norms for HVDC bi-pole line shall be considered as Single Circuit quad AC line.

Provided also that the O&M expenses for the GIS bays and transformers shall be allowed as worked out by multiplying 0.70 of the O&M expenses of the normative O&M expenses for bays and transformers.

Our Comments/Suggestions

1. While studying the calculation of normative operation and maintenance expenses from the Explanatory Memorandum in respect of Tariff Regulation, 2019, it is observed that the O&M norms have been derived by normalization of actual O&M expenses during the last 5 financial years. The normalized O&M expenses were apportioned between sub-stations and transmission lines to arrive at norms per bay, per MVA and per km based on corresponding average assets under operation during the respective financial years.

2. **Treatment of HVDC Bi-Pole**

   a. It is observed that HVDC bi-pole line length has been considered as D/C quad for the purpose of deriving the normative O&M expenses whereas while formulating the Regulation for the recovery of the O&M charges, the same has been considered as Single Circuit quad AC line.

   b. That it is submitted that the HVDC Bi-pole should be considered as double circuit due to the following reasons:

      i. Each pole of HVDC pole is one element and operates independent to each other.

      ii. As per para 1(v) of Appendix – II of Regulation, 2019, HVDC Bi-pole links is defined as :

         "Each pole of HVDC link along with associated equipment at both ends shall be considered as one element."

         As such, each pole of HVDC Bi-pole link is to be treated separately as both are independent to each other.

      iii. It is pertinent to mention that as per para 1(i) of Appendix II of Regulation "each circuit of AC transmission line shall be considered as one element". Accordingly, each circuit in the transmission system is treated as separate individual element.

   c. That the Hon'ble Commission has also rightly considered HVDC Bi-pole line as Double Circuit quad AC line while calculating the normative O&M charges.

   d. In view of the above premises, <u>it is submitted that the O&M expenses norms for HVDC Bipole line be considered as Double Circuit quad AC line</u>.

3. Inclusion of Performance Related Pay

a. While studying the calculation of normative operation and maintenance expenses from the Explanatory Memorandum (Page 174) in respect of Tariff Regulation, 2019, it is observed that Performance Related Pay (PRP) has been excluded from the actual O&M expenses during the respective financial years while arriving at the normarlized O&M expenses.

b. At para 14.5.2 (page 154) of the Explanatory Memorandum, it has been indicated that - “the Commission has been consistently following the principle that such incentives and performance related pay should be paid by the generating company from the increase in revenue due to reduced down time and efficient operations of the generating stations. Therefore, for computing O&M expenses norms, these types of expenses are excluded from the actual O&M expenses.”

c. Following is submitted w.r.t PRP as part of employee cost:

   i. Presently PRP is payable to employees of POWERGRID as per DPE guidelines for pay revision of Board level and below Board level executives of CPSEs, as a part of pay structure since pay revision in 2007and subsequent revision in 2017. Further, PRP is also part of the wage agreement for the non-executives.

   ii. The PRP scheme was formulated as a variable pay component linking the payment to the organization, team as well as individual performance.

   iii. In the report of 2nd Pay Revision Committee (2nd PRC), PRP was envisaged as a variable pay and PRP was made an integral part of overall compensation package.

   iv. The 3rd PRC report, published in Gazette of 09th June, 2016 (Page No. 79-84, Para 3.17) has envisaged the following objectives behind allowing payment of PRP to the employees of CPSEs:-

      - Allowing the PRP for better team performance which will also build a competitive environment within the Company and a motivation to excel as a team.
      - To equip the CPSEs to compete in the emerging domestic and global economic scenario.
      - Inculcating performance oriented culture across the organization.
      - The PRP gives emphasis to the team’s performance to inculcate a team culture and achieve desired productivity levels of CPSEs.
      - The PRC viewed that PRP for team performance is a win-win situation, both for individual executives and the CPSEs.

   It may be seen that the objectives behind allowing PRP is essentially to improve competitiveness, team culture and to raise the CPSEs to global standards. It also opined that the present PRP mechanism is beneficial for the firm as well as the employees.

v. The exact amount of PRP payable to an individual employee is calculated as per the methodology given in DPE circular No. W-02/0028/2017-DPE (WC)-GL-XIII/17, Annexure-IV dated 03rd August, 2017 , which envisaged the following points :-

- Rating of Memorandum of Understanding (MoU) entered between POWERGRID and Ministry of Power for the corresponding year. MoU is a performance measuring tool containing no. of performance parameters along with weightages assigned to each parameter. (Performance parameters enclosed at Annexure-I).
- Profitability of the Company during the corresponding year.
- Incremental profit of the Corporation i,e. increases in profit in comparison to previous year.
- Performance of the Regions in achievements of the company Targets.
- Performance of the Individuals in achievements of the company Targets.

d. It is relevant to mention that the availability based incentive is not included in any of the above points. The contention that, PRP is payable only in case the transmission system achieves normative operational levels or overachieves them, does not hold good in the present scenario as explained above.

e. Moreover, PRP payable may increase at the rate of 3% annually on account of annual increment as per DPE guidelines irrespective of the incentive received.

f. It is also pertinent to note that as per DPE Office Memorandum Dt. 25th Nov 2008 in respect of Revision of Pay w.e.f 01.01.2007, PRP has been envisaged as a component directly linked to the profits of the CPSE [Annex III, (i) of the OM]. It is also mentioned that it has to come out of the profits of the CPSE [Annex III, (i)(a) of the OM]. Whereas in DPE memorandum dt 03.08.2017 in respect of Revision of Pay w.e.f 01.01.2017, it is clearly stated that the revised compensation structure is inclusive of PRP [Annex II(b) & (c) of the OM]. Moreover, due importance is given to PRP in the revised structure to ensure the better team performance and to build a competitive environment within the company. This clearly shows a shift in philosophy and calculation of PRP from the earlier guidelines.

g. From the above, it is clear that PRP is actually an integral and variable part of compensation package of the employees. The PRP scheme was formulated as a variable pay component linking the payment to the organization, team as well as individual performance. PRP is based on overall performance of the organization as measured by its MoU rating as well as appraisal ratings of individual employee. Therefore, the ambit of PRP is much larger and is not akin to a productivity-linked incentive scheme which provides for payment linked to physical parameters such as generation, availability, etc. The PRP as a variable pay component is intended to link the overall employee remuneration to performance as opposed to fixed pay entitlements which are independent of performance. It may also be noted, from the calculation method (Point No. c (v) above) of PRP, that there may be situation where the company has earned less/no incentive but PRP has to be paid to the employees under the present norms of DPE.

h. If the PRP is not added to the O&M expenses, it will affect the profitability of the company by sizable margin and is not in tandem with the philosophy in which PRP is envisaged and impacts the desired return on equity as provided in the provision of the regulations.

i. Therefore, in light of the above, <u>it is submitted that the normalized O&M expenditure for FY 2013-14 to FY 2017-18 may be arrived at by including Performance Related Pay (PRP) as part of employee cost to arrive at the normative O&M norms for 2019-24</u>.

4. **<u>Introduction of factor for Additional Manpower in O&M Norms</u>**

a. POWERGRID is committed towards providing the economic transmission system for its stakeholders. In the same endeavour, POWERGRID keeps on continuously reviewing its procedures. Accordingly, in the year 2014, POWERGRID made a leap in OPEX optimisation through two landmark decisions:

    i. Establishment of NTAMC (National Transmission Asset Management Centre): NTAMC enabled the centralised operation of our O&M substations with reduction in Operation staff at substation level.

    ii. MSH (Maintenance Service Hub) based maintenance planning: The MSH had maintenance staff stationed at a central location, which was responsible for carrying out maintenance at nearby 3-4 substations.

b. Accordingly, the manpower was reduced whereas there was exponential rise in the number of assets under maintenance. However, in subsequent years there were experiences where during failure of substation equipment, the MSH team could not reach the substation timely due to access constraints viz., road blocks, fallen trees, debris etc. This prolonged the restoration activities.

c. With these experiences, POWERGRID realised the practical limitations posed by the centralised O&M and MSH Hub. Thus, in order to ensure timely restoration it was decided to withdraw the MSH philosophy and post maintenance staff at all the substations. Accordingly, POWERGRID has recruited 703 nos. of employees during the FY 2018-19 and another 1006 nos. employees during FY 2019-2020 are being recruited for operation and maintenance of transmission system. The above aspect was submitted to the Commissioning alongwith the O&M data.

d. However, while studying the calculation of normative operation and maintenance expenses from the Explanatory Memorandum in respect of Tariff Regulation, 2019, it is observed that no provision has been accounted for the additional manpower being recruited by POWERGRID. .

e. Since the expenditure on manpower is a considerable portion of the O&M expenses, <u>it is humbly submitted that a markup in lieu of above employee recruitment should be kept on this account while deriving the O&M norms</u>.

5. **<u>Mismatch in the working out the average assets in operations</u>**

a. It is observed from the Explanatory Memorandum that the no. of substation bays and transformation capacity in operation during the financial years are not commensurate with the data provided for the same in Annexure – VA.

b. Further while working out the norms for bays, the total no. of bays (AIS & GIS) have been converted to equivalent 400kV bays with the weightage factors to arrive at per bays norms for AIS bays. However, while formulating the Regulation for the recovery of the O&M norms for GIS bays, the same has been considered to be recovered by multiplying 0.70 to the per bays rates for AIS bays leading the considerable mismatch for recovery. The average equivalent bays (AIS & GIS) have been worked out as under:

i. <u>The average total no. of equivalent 400kV bays in operations are as under:</u>

Average no. of AIS Bays in Operation						**Weight-age Factor**	**Average equivalent 400kV AIS Bays in Operation**				
Type	**13-14**	**14-15**	**15-16**	**16-17**	**17-18**		**13-14**	**14-15**	**15-16**	**16-17**	**17-18**
765 kV	164	257	332.5	374.5	401.5	**1.40**	229.6	359.8	465.5	524.3	562.1
400 kV	1476.5	1630.5	1728	1817.5	1937	**1.00**	1476.5	1630.5	1728	1817.5	1937
220 kV	728	763	782	804.5	838.5	**0.70**	509.6	534.1	547.4	563.15	586.95
Up to 132kV	157	161.5	170.5	177	189	**0.50**	78.5	80.75	85.25	88.5	94.5
Average no. of GIS Bays in Operation						**Weight-age Factor**	**Average equivalent 400kV GIS bays in Operation**				
Type	**13-14**	**14-15**	**15-16**	**16-17**	**17-18**		**13-14**	**14-15**	**15-16**	**16-17**	**17-18**
765 kV	0	3.5	9	29.5	62.5	**0.98**	0.00	3.43	8.82	28.91	61.25
400 kV	51	77	110	159	210.5	**0.70**	35.70	53.90	77.00	111.30	147.35
220 kV	45	61.5	78	93	106.5	**0.49**	22.05	30.14	38.22	45.57	52.19
Up to 132kV	3	5.5	10	12	12	**0.35**	1.05	1.93	3.50	4.20	4.20
Total no. of equivalent 400kV bays (AIS & GIS) in Operation							**2353.0**	**2694.5**	**2953.7**	**3183.4**	**3445.5**

ii. Similarly, the average equivalent Transformation capacity in MVA in operations are as under:

Average Transformation capacity of AC Substation in operation						Weig-htage Factor	Average equivalent Transformation capacity in MVA in operation				
Type	**13-14**	**14-15**	**15-16**	**16-17**	**17-18**		**13-14**	**14-15**	**15-16**	**16-17**	**17-18**
765kV	76015	104895	122645	138395	153637.5	**1.00**	76015.00	104895.00	122645.00	138395.00	153637.50
400kV	80264.5	87467	92899.5	101284	115327.5	**0.73**	58593.09	63850.91	67816.64	73937.32	84189.08
220kV	2180	2180	2440	2700	2800	**0.50**	1090.00	1090.00	1220.00	1350.00	1400.00
132 kV	215	243	283	320	350	**0.50**	107.50	121.50	141.50	160.00	175.00
Average equivalent Transformation capacity in MVA in operation							**135805.59**	**169957.41**	**191823.14**	**213842.32**	**239401.58**

c. It is humbly submitted that the aforesaid figures in the above tables may be taken into consideration while working out per bay and per MVA O&M norms.

6. **O&M norms for ±800kV Biswanath Chairali – Agra HVDC Bi-pole**

a. The ±800kV HVDC Agra – Alipurduar – Biswanath Chariali Bi-pole Link consists of two (2) Bi-poles. One Bi-pole link is Agra-Biswanath Chariali and another Bi-pole link is Agra-Alipurduar.

b. Pole - I of Agra – Biswanath Chariali Bi-pole link was commissioned on 01st November 2015 while Pole – II of this link was commissioned on 02nd September 2016.

c. Further, both the Poles of 2nd Bi-pole link i.e. Agra – Alipurduar was commissioned on 21st September 2017.

d. Accordingly, while submitting the O&M expenses, the expenditure incurred on these link were considered i.e., expenses during FY 2015-16 corresponds to a period of only 5 months on Pole – I of 1st Bi-pole link, FY 2016-17 corresponds to expenses on Pole-I for full year and on Pole – II for 8 months while FY 2017-18 corresponds to expenses on 1st Bi-pole for full year and on 2nd Bi-pole for 7 months.

e. Moreover for most of the time during the aforesaid period, the stations were under warranty coverage and the expenses were borne by the manufacturer/ executing agency. Thus, the expenses does not truly reflects the annual expenses of the System.

f. Though, there are 8 poles operating at 800kV DC voltage level under Agra – Alipurduar – Biswanth Chariali HVDC links, but the O&M expenses proposed in the draft regulation for this HVDC link is even less than that of Balia-Bhiwadi HVDC link, which has only 4 poles operating at 500kV DC voltage level.

g. In CERC (Terms & Conditions of Tariff) Regulations, 2014 following is mentioned at Clause 29 (3)(a):

Quote

"Provided that operation and maintenance expenses for new HVDC bi-pole scheme for a particular year shall be allowed pro-rata on the basis of normative rate of operation and maintenance expense for 2000 MW, Talcher-Kolar HVDC bi-pole scheme for the respective year."

Un-Quote

h. In view of above, it is submitted that O&M expenses for Agra – Alipurduar – Biswanath Chariali HVDC link and for other new HVDC bi-pole link may be considered in line with CERC (Terms & Conditions of Tariff) Regulations, 2014.

7. **O&M norms for HVDC Back to Back (HVDC BTB) Stations**

a. It is observed from the Explanatory Memorandum (Page 182) that while the arriving at the normative O&M expenses of HVDC BTB Stations, the O&M expenses of expenditure of Gazuwaka and Vindhyachal HVDC were not considered since their expenses are not comparable with other HVDC BTB Stations.

b. While the O&M expenses of Vindhyachal HVDC BTB is high due to its ageing, the O&M expenses of Gazuwaka HVDC BTB are consistently higher as compared to other BTB Station due to the following:

i. Technical Uniqueness: The Gazuwaka HVDC BTB Station is unique among all POWERGRID's Back to Back Stations in the sense that the two back to back Stations (2x500MW) are from two different manufacturers viz. Pole 1 from Alstom/GE and Pole 2 from ABB and these Poles were commissioned in two different years 1999 and 2005. This requires two different set of spares to be maintained for both the Poles separately increasing the overall maintenance cost. This is applicable for all equipment viz. HVDC control & Protection, Valve Cooling system, Valve Hall and associated equipment, auxiliary systems, Air Conditioning systems etc. and the maintenance cost increases due to the requirement of two separate set of spares for the station due to difference in the technology/ manufacturers of Pole 1 and Pole 2. This results in almost 2 times the cost of spares and maintenance as compared to any other HVDC BTB Stations of similar type.

ii. Geographic Conditions: The Gazuwaka HVDC BTB Station is only BTB Station very near to sea coast (around 500 meter). This results in saline contamination due to coastal environment resulting in severe corrosion. The severe corrosion requires stringent maintenance practices including regular and frequent painting of equipment, frequent maintenance and requirement of consumables increasing the overall maintenance cost. Further NTPC has an installed capacity of 2000 MW and Hinduja has an installed capacity of 1000 MW in the near vicinity which has resulted in severe pollution in the Station Switchyard area. The power plant pollutants together with the saline environment have an extremely detrimental effect on all the HVDC outside equipment leading to reduced life of equipment. It requires continuous system maintenance and resultant expense on account of spares and services which are very specific to Gazuwaka Station as compared to other HVDC Station. Further this increased pollution has resulted in severe electrical tracking in Gazuwaka Station Switchyard equipment over the years which necessitates the following activities as preventive measure:

- Hot Line/Live Line Washing of equipment on regular basis to avoid any tracking and resulting electrical flashovers.
- RTV Silicon Rubber High Voltage Insulator Coating (HVIC) for all HVDC Switchyard equipment to avoid any tracking and resulting electrical flashovers.
- Cold Line Washing of equipment with additional manpower.
- Replacement of all gantry porcelain insulators with polymer insulators.

The above unique maintenance requirements results in more O&M expense as compared to other similar HVDC Back to Back Stations in a substantial way.

iii. Natural Calamities: The location of Gazuwaka HVDC BTB Station is susceptible to regular natural calamities/severe cyclonic storms including the major ones like HUD HUD, Titli etc resulting in higher than normal requirement of R&M for replacement/ renovation of Plant and Machinery, administrative expenses.

iv. Power System issues exclusive to Gazuwaka HVDC BTB Station: The Gazuwaka Station has historically been connected to weak AC link with Eastern Grid which has resulted in severe voltage instability conditions affecting the Gazuwaka Station equipment detrimentally over the years. The voltage was quite unstable (with both low and high voltage conditions) in addition to the severe pollution and electrical tracking issue resulted in severe stresses on the equipment (both outside and Valve Hall equipment) which has resulted in requirement of replacement of electrical equipment and increased propensity to failures including very costly thyristors also.

All of the above factors have all resulted in higher O&M cost of Gazuwaka Station as compared to other HVDC Back to Back Stations.

c. Therefore, it is submitted that O&M expenses of all HVDC BTB Station should be taken into account while arriving at the normative O&M expenses of HVDC BTB Station due to their respective uniqueness.

8. In view of the foregoing, it is submitted that all of the above aspects may be taken into account while arriving at the normative O&M norms for tariff period 2019-24. Furthermore, it is submitted that there are no GIS transformers in the system. Therefore, word 'Transformers' may be deleted from the last proviso of clause 35(3)(a).

7.6. O&M Norms for Communication System

Draft CERC Tariff Regulations, 2019

35(4) – Separate norms for O&M of Communication System introduced in CERC (Terms and Conditions of Tariff) Regulations, 2019.

Our Comments/Suggestions

1. The O&M norms of Communication System have been derived by the Commission based on the expenditure incurred by POWERGRID for ULDC system and ULDC assets under operation. It is submitted that such expenses mainly consists of manpower, spare parts cost, Band width/fibre hiring charges and AMC (Annual Maintenance Cost) cost. For maintenance of SCADA and communication equipment support of OEM is required due to specialized nature of the work. O&M of all equipment is normally done through OEM as part of AMC.

2. It may be submitted that Communication System of POWERGRID can be broadly categorized as under:

   (i) Scheme implemented under ULDC. These schemes are identified and approved separately. The tariff petitions for these schemes are being filed separately.

   (ii) OPGW and communication equipment are being installed on all new transmission lines and sub-stations and are integral part of the transmission system.

3. It is submitted that no. of assets in 2(ii) above were not separately given in the data submitted to the Hon'ble Commission as O&M charges for these assets are recovered as part of the associated transmission assets.

4. The Central Electricity Regulatory Commission (Communication System for inter-State transmission of electricity) Regulations, 2017, envisages centralized supervision and monitoring for managing communication system, necessitating deployment of resources include 24x7 manning at regional/ national level, which is not presently in place. Once centralized Network Management System (NMS) is established, expenses shall be incurred for the following:

   a. 24x7 manning at regional/ national level.
   b. Centralized NMS

c. Control Center building
d. Auxiliary power supply
e. Video projection system
f. Furniture etc.

5. Therefore, the O&M norms for Communication Systems (limited to only Communication Systems of ULDC schemes and not for those assets under Transmission System) needs to be re-looked and should be allowed on actual limited to 7.5% of the Capital Cost subject to prudence check as per practice being followed in existing ULDC tariff.

7.7. Operation and Maintenance Expenses

Draft CERC Tariff Regulations, 2019

35(4)(c) - The Security Expenses, Capital Spares and Self Insurance Reserve for transmission system and associated communication system shall be allowed separately after prudence check:

Provided that the transmission licensee shall submit the assessment of the security requirement and estimated expenses, the details of year wise actual capital spares consumed and details of self insurance expenditure at the time of truing up with appropriate justification.

Our Comments/Suggestions

1. **Security Expenses, Capital Spares and allocation for Self Insurance Reserves**

   a. As per the Regulations, the Security Expenses, Capital Spares and allocation for Self Insurance Reserves for transmission system and associated communication system shall be allowed separately on normative basis.

   b. Since the nature and purpose of the expenditure on (i) allocation for Self Insurance Reserves and (ii) Security Expenses & Capital Spares are different, the recovery of expenditure on these account should also have different treatment.

   c. Allocation for Self Insurance Reserves – At present POWERGRID is undertaking Self Insurance in respect of AC system assets such as substation equipment and transmission line. The company is setting aside annually 0.12% of the original cost of the assets towards Self Insurance Scheme (SIS) Reserve. Under SIS, the entire risk to transmission assets against any eventuality is taken by the Transmission Licensee and accordingly all losses are being borne by the Transmission Licensee. It may please be appreciated that the rate of 0.12% was decided based on cost of insurance, past experience etc. and actual requirement could vary from year to year. In case the assets are insured with external insurers, the actual premium is permitted for recovery through tariff such as in case of HVDC assets. The risks in such case are borne by the insurance company and not by POWERGRID. In case the Commission seeks to apply prudence check and true up based on actual expenditure for SIS Reserves, all associated risks viz., MBD and business interruption losses etc. due to any insurable risk shall be borne by the beneficiaries on actuals. To avoid disputes in the matter, it would be prudent that the allocation for Self Insurance Reserves @0.12% of original cost of assets may be included in the normalized O&M expenses to arrive at the normative O&M norms for 2019-24.

Alternatively, in case SIS Reserves are excluded from the O&M norms for 2019-24, the Commission may allow insurance expenses @0.12% of the original cost of the assets on an annual basis while giving the Transmission Licensee the flexibility to choose the mode of insurance cover i.e., through SIS or third party insurers. In case of SIS, the actual losses if greater than the amount transferred to SIS shall be permitted to be recovered through tariff.

d. Expenses towards Security and Capital Spares: The expenditure on these account are considerable and to the tune of more than Rs. 250 Cr. The recovery of the same at the time of truing up would adversely impact the financial health of the company. Therefore, the Transmission Licensee be allowed to include the same provisionally based on actual expenditure during 2018-19 subject to truing up. In this regard, it is proposed that the Transmission Licensee shall submit the details of year wise estimated/projected expenses towards Security and Capital Spares based on the actual expenses incurred during FY 2018-19. The same shall be subject to adjustment based on actual expenditure at the time of truing up.

2. **Annuity, Lease and other Statutory Payments**

Transmission Licensees are required to incur expenditure towards forest lease maintenance charges, lease rent on lease hold land, annuity payments to land owners/other authorities as per terms and condition of land acquisition/under provisions of law. Since these expenses are recurring in nature and are to be paid on annual basis based on relevant government notifications, it is suggested that the words ‘annuity, lease and other statutory payments’ may be included in the aforesaid provision - 35(4)(c) to account for the above expenses and allowed on actuals. The modality for recovery may be kept in line with that of Security and Capital Spares as brought out at 1(d) above.

8. Chapter 11:Computation of Capacity Charges and Energy Charges

8.1. Methodology for calculation for transmission system availability

Draft CERC Tariff Regulations, 2019

56(2) & Annexure - II – Provision for monthly availability for recovery of transmission charges in CERC (Terms and Conditions of Tariff) Regulations, 2019.

Our Comments/Suggestions

1. Recovery of transmission charges of ISTS transmission system on monthly basis with progressive availability for the period and finally on annual availability for a year.

    i. In the draft Regulation, the norms for operation of transmission system given as "Normative Annual Transmission System Availability Factor" which is on annual basis. This is average transmission system availability for the whole year and takes care of variation of outages in different periods of the year and the outage of annual maintenance of the elements taken once in a year.

    ii. Preventive maintenance of transmission systems is carried out as per annual maintenance plan. Shutdowns activities are carried out by taking shutdown in a suitable time in a year so that maintenances are carried out smoothly during with minimum shutdown time. Further shutdown of HVDC system takes longer duration and the same is continuous. These shutdown activities for an element is only one month in a year and maintenance activities are planned taking care of weather conditions like rainy season / foggy weathers etc. Hence shutdown of elements for maintenance are not uniform across the years. Further, there are various elements of transmission systems, weightages of which are different, outage of higher weightage elements will have higher impact on the regional availability for the same outage period. Therefore, to nullify impact of non-uniformity of transmission elements, it is desirable to have recovery of transmission charges of ISTS transmission system on annual transmission availability. The annual transmission system availability for recovery of transmission system was followed by CERC in tariff regulation 2001 (applicable for the tariff block 2001-2004) and Tariff Regulation

2004 (applicable for the tariff block 2004-2009). Prior to CERC, Govt. of India vide tariff notifications also implemented annual transmission availability for the tariff blocks 1992-1997 and tariff block 1997-2002.

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

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.

2. The transmission charges (inclusive of incentive) payable for a calendar month for transmission system or part shall be computed for each region on regional availability of transmission systems (AC + HVDC systems in the region) in the region.

3. The transmission system in the grid is an integrated system and all AC and HVDC elements combined provides the desired level of services. Power flow in AC and HVDC elements does not takes place in isolated way. Hence combined performance of the all transmission elements in the region is better indicator of regional performance of all transmission elements in the region. This concept was notified in CERC Regulation 2001 (Terms and Condition of Tariffs) applicable for the tariff period 2001-2004.

8.2. Treatment of availability of Communication System

Draft CERC Tariff Regulations, 2019

56(2) & 56 (4) – Provision for monthly availability for recovery of charges for Communication System introduced in CERC (Terms and Conditions of Tariff) Regulations, 2019.

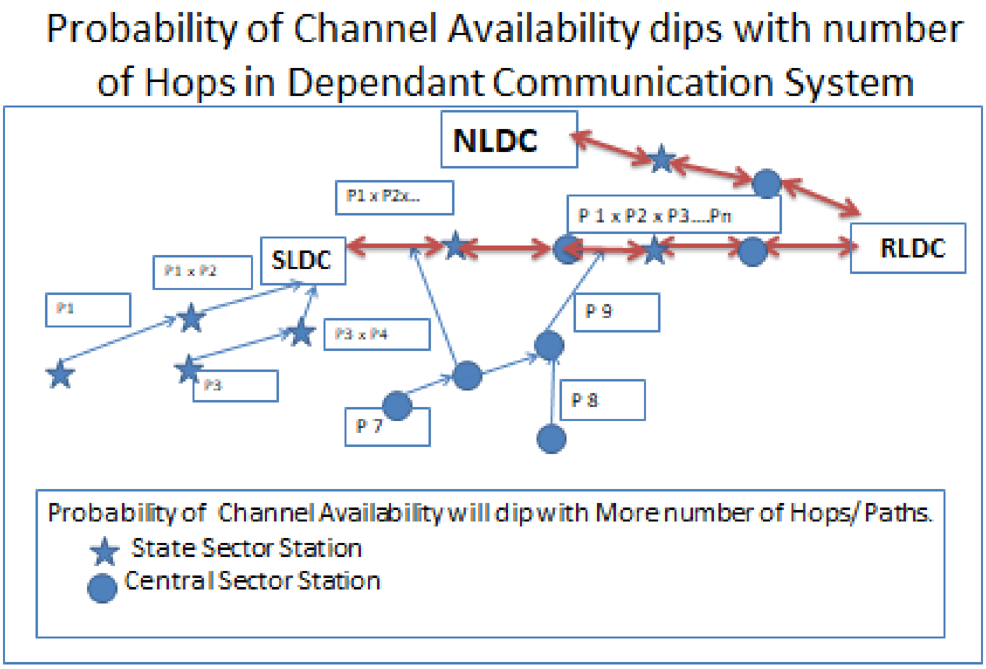
Our Comments/Suggestions

1. The Communication System developed by POWERGRID was for providing voice and data connectivity between/amongst sub-stations and control centres for grid management. These Communication Systems were on piece meal basis and came up in different time frame and are adequately catering to the requirements of Control Centers. Hence, the implemented ISTS communication system has multiple Network Management Systems (NMS) of various makes delivered as part of each project. Thus the evolved communication system including NMS has constraints to support the requirement of availability as envisaged in the Central Electricity Regulatory Commission (Communication System for inter-State transmission of electricity) Regulations, 2017. The existing NMS is limited to following functionalities :

   a. Fault Management
   b. Configuration Management
   c. Accounting Management
   d. Performance Management
   e. Security Management

2. Accordingly, the Central Electricity Regulatory Commission (Communication System for inter-State transmission of electricity) Regulations, 2017 envisages Centralized NMS to take care of the needs of ISTS communication system including availability/performance requirements.

3. Network configuration : As of now most of the communication system catering data and voice connectivity is in linear mode and carries data traffic (in the form of n numbers of channels) from various sub-stations to control centres and also between control centres. Any outage in one link may affect entire data and voice traffic to control centre connected through the said link and will render non-availability of large number of channels.



4. Last mile connectivity : ISTS Communication System caters data and voice connectivity from Central Sector Sub-stations/generating station to Control Centres namely RLDCs and large volume data exchange between control centres(SLDCs, RLDCs, NLDCs). Most of the control centres are not connected through transmission lines hence last mile connectivity is generally provided through underground fiber optic or state distribution network which is prone to disturbance and not very reliable. Any outage in last mile connectivity will affect entire traffic to RLDC/NLDC resulting in non-availability of channels.

5. Dependency: As power system is interconnected and ISTS communication System involves state infrastructure and ISGS/IPPs also for laying OPGW and location of communication equipment in their premises. Hence for maintenance and

restoration of ISTS communication system there is dependence on States and ISGS/IPPs which require access to their premises and may cause delays in restoration and affect availability of communication.

6. Redundancy of communication equipment has not been built in the communication system & thereby suitable provisions needs to be kept for taking care of breakdown of equipment.

7. Presently, Communication system is being considered as an integral part of Transmission System, OPGW being maintained along with the Transmission line & communication equipment/ battery banks etc are being maintained along with Substation Bays and thereby generally no separate shutdown are taken for preventive maintenance of communication system. Preventive maintenance of OPGW includes Re-splicing work in case of high losses, Restringing/ Replacement of OPGW in affected spans (High loss, Clearance problems etc.), Sag Management, Joint box inspection, peak strengthening, fiber Loss rectification etc. shall be addressed under this. Preventive maintenance of Communication Equipment include; Earthing conditions, Alarm Measurement Verification, Updating of Log Records, Tightening of Connectors, updating the patches, upgrading software & hardware, Card Cleaning, Measurement of Earth Resistance.

8. Complexity in Availability Computation: The communication system is managed by NMS (Network Management System). NMS systems supplied by different vendors are proprietary in nature. There are around 20 numbers of NMS systems of various makes (around Seven-7 vendors) managing the Communication system as envisaged. These NMSs have the capability of monitoring the node availability and it generates alarms for each node. The supplied NMSs don't support computation of automatic generation of link/ channel availability. This is computed manually with the help of node-wise alarm reports. The communication network is maintained by the respective vendors in accordance with AMC contract in place along with the original contract. In view of Communication Equipment being common for multiple links there is possibility of failure of multiple links due to equipment failure at a node.

Considering the above, regulation of tariff based on availability of communication system(Channel Availability) for the period 2019-24 shall be premature at this stage as available communication infrastructure (i.e. Technology, redundancy, media, etc) and supporting tools for management of the same are not sufficient to cater.

Hence, it is humbly submitted that the availability of Communication System may be delinked with the recovery of charges during the Tariff Block 2019-24.

9. Chapter 12 : Norms of Operations

9.1. Removal of upper cap of transmission system availability of 99.75% for claiming incentive in tariff.

Draft CERC Tariff Regulations, 2019

61 – Provided further that no incentive shall be payable for availability beyond 99.75%.

Our Comments/Suggestions

1. 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.
2. 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.
3. 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.

4. 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.
5. 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."

6. 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."

7. 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"

8. 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."

9. <u>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</u>.

10. Chapter 13: Scheduling, Accounting and Billing

10.1. Rebate

Draft CERC Tariff Regulations, 2019

*68. **Rebate:** (1) For payment of bills of the generating company and the transmission licensee through letter of credit on presentation or through National Electronic Fund Transfer (NEFT) or Real Time Gross Settlement (RTGS) payment mode within a period of 2 days of presentation of bills by the generating company or the transmission licensee, a rebate of 2% shall be allowed.*

(2) Where payments are made on any day after 2 days and within a period of 30 days of presentation of bills by the generating company or the transmission licensee, a rebate of 1% shall be allowed.

Our Comments/Suggestions

1. The Draft Regulations proposes reduction in the period of receivables from 60 days to 45 days.
2. To have an equitable preposition, the rebate may be reduced from 2% to 1.50% for payments made within 2 days of presentation of bills.

10.2. Late Payment Surcharge

Draft CERC Tariff Regulations, 2019

*69. **Late payment surcharge:** In case the payment of any bill for charges payable under these regulations is delayed by a beneficiary or long term transmission customers as the case may be, beyond a period of 45 days from the date of billing, a late payment surcharge at the rate of 1.25% per month shall be levied by the generating company or the transmission licensee, as the case may be.*

Our Comments/Suggestions

1. The Draft Regulations propose reduction of the Late Payment Surcharge from 1.50% to 1.25% per month. The late payment surcharge, being a penal provision is intended to create a deterrence from defaulting in payments. A signal reducing the same to 1.25% from 1.50% would be seen as moderating the same.
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. Hence, it is proposed that the late payment surcharge should be retained as 1.50% per month. Further, as brought out at para 7.2.1 above, the billing cycle may be retained and late payment surcharge be applicable beyond 60 days in place of 45 days.

11. Chapter 14: Sharing of Benefits

11.1. Sharing of Non – Tariff Income

Draft CERC Tariff Regulations, 2019

72. The non-tariff income in case of generating station and transmission system on account of following shall be shared in the ratio of 50:50 with the beneficiaries and the long term customer on annual basis:

a) Income from rent of land or buildings;
b) Income from sale of scrap;
c) Income from statutory investments;
d) Interest on advances to suppliers or contractors;
e) Rental from staff quarters;
f) Rental from contractors;
g) Income from advertisements;
h) Interest on investments and bank balances;

Provided that the interest or dividend earned from investments made out of Return on Equity corresponding to the regulated business of the Generating Company shall not be included in Non-Tariff Income.

Our Comments/Suggestions

1. **Income from rent of land and building:** POWERGRID, the CTU is in the business of constructing and maintaining the interstate transmission system and uses its transmission assets. The land is specifically procured for implementation of its transmission assets while the buildings are constructed for operational and maintenance of assets including administrative purposes and not for any commercial purpose. Furthermore, the rent recovered, if any, in case the land/building is provided to the working agencies during construction stage of the projects, is adjusted in the capital cost of the project.

2. **Income from sale of Scrap:** The generation of scrap during construction of transmission system projects are negligible. However, the realised value of scrap generated, if any, is passed on to the beneficiaries by crediting the entire amount to capital cost of the project.

   Scrap is generated during operation stage of the transmission system mainly on account of the following:

   i) on discarding the assets on completion of useful life; or
   ii) Replacement of full/part of asset/equipment due to break down or operation failure before its useful life.

In both the cases, the scrap belongs to the Transmission Licensee, since in the former instance it is on account of residual value of the assets i.e 10% value of the asset for which no depreciation is allowed and in the latter case the same is recovered by the insurance company towards the scrap value. Further, in cases of losses on sale of scrap, the same is borne by the Transmission Licensee and not passed on to the beneficiaries.

3. **Income from statutory Investment:** The Transmission licensee is not having any statutory investment other than Bond Redemption Reserve (BRR), which is required as per Companies Act, 2013. The said investment is made from the internal resources generated from transmission tariff /normative repayment of loan. Since the transmission licensee is getting interest on loan on normative basis, i.e to the extent depreciation allowed in the tariff is treated as deemed redemption of the loan. However the actual repayment schedule of loan is quite different to deemed repayment schedule and the licensee is bearing the interest cost from the deemed repayment date to schedule repayment date on its own. Thus there is no rational to its benefit as the entire cost is to the account of the licensee.

4. **Interest on advances to suppliers and contractors:** Advances to suppliers and contractors are given by the Transmission Licensee against contracts awarded for construction of transmission system. The entire interest is recovered in line with the provision of contracts and adjusted in the capital cost of the project. In other words, the project cost is reduced to the extent of interest recovered from the suppliers and contractors.

5. **Rental from staff quarters:** The entire amounts of receipts towards sale of tender, training and recruitment, guest house and transit camps, power charges etc. are passed on to the beneficiaries by reducing from the cost of administrative and general expenses of the Transmission License. Rent recovered from staff quarters is booked in other income. However, the amount recovered under rent from staff quarters is not very substantial in comparison to the income passed to the beneficiaries in different heads, as stated above.

6. **Rental from contractors:** The entire rental income along with other recoveries from contractor are credited to project cost through IEDC. Rental income, if any, during O&M stage is nominal.

7. **Income from Advertisement:** The Transmission Licensee does not derive any income from advertisement by using its transmission assets/facilities.

8. **Interest on investment and bank balances:** Investments and bank balances of a licensee can arise out of return on equity or surpluses arising out of operations. It would be well neigh impossible for determination of source of such investment as to whether they are made out of Return on Equity or from other sources. Therefore, it is submitted that the provisions of the draft regulations would be difficult to implement and are a potential source of dispute as the beneficiaries would claim all

interest/dividend income as due for refund whereas the Transmission Licensees are likely to contest such claims. Further, there is no rationale for the proposed sharing of interest income since the investments generating such interest/dividend are not arising out of any amount due to the transmission beneficiaries.

The major components of interest income from interest and bank balances in case of POWERGRID is as under :

a. **Interest income on Loans given to Subsidiaries and Joint Ventures:** POWERGRID is raising debt from domestic bond market and financial institutions for debt financing of subsidiaries created under TBCB mechanism. The interest accrued to lenders on such loans is booked as an expense while the corresponding interest recoverable from the subsidiaries is accounted as "other income" as per the applicable accounting principles. Hence, there is no surplus generated from the interest income on loans to subsidiaries, which can be claimed by the beneficiaries.
b. **Interest earned from Indian Banks on Statutory Investment for debt redemption:** Such interest arises from amount invested under Companies Act towards bond redemptions due in the next financial year as explained in point no. 3 above.
c. **Interest earned from Indian Banks on Loans drawn kept in Short Term Depository Receipts (STDR) (during the period before utilization for capital expenditure):** POWERGRID is drawing loans from Bond market based on the prospective monthly/bi-monthly/quarterly debt funding requirement. The loans drawn are kept in STDR in scheduled banks till the period they are utilised for capital expenditure. The interest income earned on such deposit is adjusted against the interest cost capitalised (IDC) in the projects in which the loan funds are deployed.
d. **Balance Interest earned from Indian Banks:** Other investments if any, are mainly from RoE and revenue from Telecom and Consultancy businesses.

9. <u>In view of the foregoing, the provisions for sharing of non-tariff income may kindly be deleted in case of Transmission Licensees.</u>

12. Chapter 15: Miscellaneous Provisions

12.1. Deferred Tax liability with respect to previous tariff period

Draft CERC Tariff Regulations, 2019

77 - Deferred tax liabilities for the period upto 31st March, 2009 whenever they materialise shall be recoverable directly by the generating companies or transmission licensees from the then beneficiaries or long term transmission customers/DICs, as the case may be. Deferred tax liabilities for the past periods, if any shall not be recoverable from the beneficiaries or the long term transmission customers/DICs, as the case may be.

Our Comments/Suggestions

The provision provides for recovery of Deferred Tax Liability directly by the Transmission Licensees from the then beneficiaries for the period upto 31st March, 2009. However, it is stated that Deferred Tax Liability for the past period, if any, shall not be recoverable from the beneficiaries. The meaning of the word ‘past period’ is ambiguous. In order to make the provision clearer, it is requested to specify the word ‘past period’ as ‘from 01.04.2009 to 31.03.2019’.

13. Appendix - II: Procedure for Calculation of Transmission System Availability Factor for a Month

13.1. Treatment of Outages

Draft CERC Tariff Regulations, 2019

5 - The transmission elements under outage due to following reasons shall be deemed to be available:

i. Shut down availed for maintenance or construction of elements of another transmission scheme. If the other transmission scheme belongs to the transmission licensee, the Member-Secretary, RPC may restrict the deemed availability period to that considered reasonable by him for the work involved.

ii. Switching off of a transmission line to restrict over voltage and manual tripping of switched reactors as per the directions of RLDC.

Our Comments/Suggestions

The Transmission Licensee are required to take outages for carrying out works related to Additional Capitalization/R&M already approved by the Commission and RPC for effective operation of the System, which are beyond the control of the Transmission Licensees. It is, therefore, suggested that the following may be added as Sl. No. 5(iii) for treating the outage as deemed available for calculation of transmission system availability in the aforesaid provision:

"The outage on account of the work related to Additional Capitalization and R&M."

13.2. Treatment in case of disputes

Draft CERC Tariff Regulations, 2019

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;*

ii) Outage caused by grid incident/disturbance not attributable to the transmission licensee, e.g. faults in substation or bays owned by other agency causing outage of the transmission licensee's elements, and tripping of lines, ICTs, HVDC, etc. due to grid disturbance. However, if the element is not restored on receipt of direction from RLDC while normalizing the system following grid incident/disturbance within reasonable time, the element will be considered not available for the period of outage after issuance of RLDC"s direction for restoration.

Our Comments/Suggestions

Dispute resolution in the aforesaid provision may be provided as a fair practice. Accordingly, following may be added as Sl. No. 6(iii):

"In case of outage of elements due to acts of God and force majeure events beyond the control of the transmission licensee, till the finalization of the failure report, the availability certificate to be given as per normative availability. Based on the failure investigation report, availability certificate shall be revised. In case of any clarification/ dispute regarding availability, the case to be referred to Chairperson CEA, whose decision will be treated as final."

14. Annexure I (Part – III): Tariff Filing Forms for Determination of Tariff

14.1. Tariff Forms

Our Comments/Suggestions

Observations on various forms are brought-out hereunder:

Tariff Form No.	Observations
FORM-1	• Since there is no separate treatment for depreciation upto cutoff date and beyond cutoff date, point 1.1 & 1.2 should be combined. • Clarity on point no. 1.5 i.e. RoE on add capitalization. It should be RoE on add. Capitalization beyond cut off date.
FORM-2	Switchable Line Reactor should also be included along with Line Reactor under Transmission Lines
FORM-3	Clarification is required in point no. i.e. it should be Base Rate of RoE upto cutoff date and Base Rate of RoE on add cap after cutoff date.
FORM- 4	No Comments
FORM- 4A	No Comments
FORM- 4B	No Comments
FORM- 4C	No Comments
FORM-5	No Comments
FORM-5A	No Comments
FORM-5B	No Comments
FORM- 6	No Comments
FORM- 7	No Comments
FORM- 7A	No Comments
FORM- 7B	No Comments
FORM- 8	Mentioned below heads should be added • Additional head for "Notional Equity on add cap upto Cut off Date". • Point 1.6 should be "RoE on add cap after cutoff date" • Additional head for "RoE on add cap after useful life"
FORM-8A	No Comments
FORM-9	No Comments
FORM-9A	No Comments
FORM-9B	No Comments
FORM-9C	No Comments
FORM-9D	No Comments

Tariff Form No.	Observations
FORM-9E	No Comments
FORM- 10	No Comments
FORM- 10A	Since there is no separate treatment for depreciation upto cutoff date and beyond cutoff date, the instant form should be removed
FORM- 10B	No Comments
FORM-10C	No Comments
FORM- 11	No Comments
FORM- 12	Modifications needed • Point 2 : "Forest proposal submission, clearance and tree cutting" • Point 3: "Land Acquisition" • Point 4 & 13: since there is no planning for RoW, these activities should be removed from the head. • Point 9 should be clubbed with tower supply
FORM- 12A	No Comments
FORM- 12B	No Comments
FORM- 13	**Total Cost –** it should be Total Cost excluding IDC and IEDC.
FORM- 14	No Comments
FORM- 15	Already considered in the comments on the draft regulation.
FORM-16	No Comments
FORM-17	NA for Transmission System
FORM-18	No Comments

Further, the Tariff Forms need to be modified based on the comments/suggestion made against the respective regulations.

Comments on CERC Draft (Terms and Conditions of Tariff) Regulations, 2019

Regulatory Cell
POWERGRID