No.L-1/144/2013/CERC
Central Electricity Regulatory Commission
New Delhi

Coram : Shri Gireesh B. Pradhan, Chairperson
Shri M. Deena Dayalan, Member
Shri A. K. Singhal, Member

Date: 24.4.2014

In the matter of

Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2014

Statement of Reasons

1. Introduction

1.1 The Central Electricity Regulatory Commission, exercising the powers under the Electricity Act, 2003 (hereinafter referred to as "the Act"), has notified the Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2014. Sub-section (1) of Section 79 of the Act assigns the following tariff related functions to the Central Electricity Regulatory Commission (hereinafter referred to as the "Commission" or "CERC"), among others:

a) to regulate the tariff of generating companies owned or controlled by the Central Government;
b) to regulate the tariff of generating companies other than those owned or controlled by the Central Government specified in Clause (a), if such generating companies enter into or otherwise have a composite scheme for generation and sale of electricity in more than one State;
c) to regulate the inter-State transmission of electricity;
d) to determine tariff for inter-State transmission of electricity.

1.2 Section 61 of the Act empowers the Commission to specify, by regulations, the terms and conditions for determination of tariff in accordance with the provisions of the said section and guided by the National Electricity Policy and Tariff Policy, 2006. In terms of clause (s) of sub-section (2) of Section 178 of the Act, the Commission has been vested with the powers to notify regulations on the terms and conditions of tariff under Section 61. As per sub-section (3) of Section 178 of the Act, the Commission is required to make previous publication before finalizing any regulation under the Act. Thus, as per the provisions of the Act, the Commission is mandated to specify, through notification, the terms and conditions of tariff of the generating companies and inter-State transmission systems covered under clauses (a), (b), and (c) of sub-section (1) of Section 79 of the Act after previous publication.

1.3 The Commission initiated the process of framing the Tariff Regulations for the Tariff Period from April 1, 2014 to March 31, 2019 (hereafter referred to as "2014-19") by writing to Central Electricity Authority (CEA) seeking recommendations on operational norms for the thermal and hydro generating stations. In parallel, the Commission also issued a suo motu order on 7.6.2013 inviting detailed operational and performance data including operation and maintenance expenses from the regulated entities namely CPSUs, IPPs and other State Utilities and private sector projects in the specified formats, in respect to their generating stations and Inter-State Transmission systems. The Commission also issued a detailed Approach Paper on 21st June, 2013 soliciting comments of stakeholders on the basis and assumptions to be considered while framing the new terms and conditions of Tariff Regulations. The Commission received comments from 77 stakeholders including the State Governments, State Electricity Regulatory Commissions (SERCs), Central Sector Utilities, State Sector Utilities, private sector utilities, Financial Institutions, other organizations, individual experts and interested persons. During the process, the Commission also consulted Central Advisory Committee on 7th October, 2013 and received comments from the members of the Central Advisory Committee on various issues.

1.4 In exercise of the powers vested under Section 61 and clause (s) of sub-section (2) of Section 178 of the Act and all other enabling powers and in compliance of the requirement under sub-section (3) of Section 178 of the Act, the Commission, vide Public Notice no. L-1/144/2013/CERC dated 6th December, 2013, issued a draft of Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2014 for the tariff period from 1.4.2014 to 31.3.2019 (hereinafter referred to as the 'draft Regulations') along with Explanatory Memorandum for inviting comments/suggestions/objections thereon. The Commission received comments/suggestions on the draft Regulations from 85 stakeholders (**Annex-1**). The Public Hearing on the draft Regulations was held at SCOPE Complex, New Delhi on 15th and 16th January, 2014 to facilitate oral submissions by desirous stakeholders. Many stakeholders have preferred submission in the presentation/written format which have been uploaded on the Commission's website on 17th January, 2014. The list of participants in the public hearing held on 15th and 16th January, 2014 is enclosed at **Annex-2**. The Commission has received recommendation of CEA on operational norms. The Commission had also published CEA recommendations on operational norms on 16.1.2014 seeking comments/suggestions of the stakeholders by 22.1.2014 which was subsequently extended to 29.1.2014 on the request of some of the stakeholders. The Commission has also received reply of CEA to the representation made by NTPC on certain aspects of their recommendations vide their letter dated 24.1.2014. The Commission notified Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2014 (hereinafter referred to as "Tariff Regulations, 2014"), on February 21, 2014 in due consideration of CEA recommendations, their subsequent letter dated 11.2.2014 and comments/suggestions of stakeholders on the draft Regulations. This Statement of Objects and Reasons (SOR) has been issued with the intent of explaining the rationale and objective behind Tariff Regulations, 2014. However, in case of any deviation/discrepancy in the SOR with respect to Tariff Regulations, 2014, the provisions of Tariff Regulations, 2014 shall be applicable.

2. Views of Stakeholders

2.1 The Commission has considered the comments and suggestions of the stakeholders on the various provisions of the draft Regulations and additional suggestions in response to notice dated 6th December, 2013, views of the participants in the Public Hearing held on 15th and 16th January, 2014, comments and suggestions on the recommendation of the Central Electricity Authority on operational norms in response to notice dated 16th January,2014, as well as their written submissions received during and after the Public Hearing. The Commission has taken all written and oral submission on record. The final Regulations have been made by the Commission after due consideration of the responses of the stakeholders, the provisions of the Act, the National Electricity Policy, Tariff Policy , current scenario of the electricity industry and recommendations of the Central Electricity Authority. The issue-wise comments/suggestions of the stakeholders, the Commission's analysis of the issues, and findings of the Commission thereon have been discussed in the subsequent paragraphs.

2.2 The major comments and views expressed by the stakeholders through their written submissions as well as during the Public Hearing and the Commission's views thereon have been summarized and discussed in the following paragraphs. It may be noted that all the responses on record given by the stakeholders have been considered, and the Commission has attempted to elaborate these responses/comments/suggestions, and arrived at a conclusion in this "Statement of Objects and Reasons". However, in case any suggestion is not specifically elaborated, it does not mean that the same has not been considered. Further, some stakeholders have suggested changes in regard to syntax/phrase/addition of word(s)/rewording related changes, which have been suitably incorporated, wherever found necessary.

3. Overview of Power Situation in the Country

3.1 India, since its independence, has made significant progress in terms of capacity addition. The installed capacity of the country has increased from 1362 MW in 1947 to 237743 MW as at the end of February, 2014. Coal based generation contributes around 59% of the total installed capacity. The details of source-wise installed capacity of India are as shown in the table below:

Table 1: Installed Capacity of India as on February , 2014

Ownership / Sector	Thermal (MW)				Nuclear (MW)	Hydro (Renewable) (MW)	RES *(MW)	Total (MW)
	Coal	Gas	Diesel	Total				
State	53078	6548	603	60229	0	27482	3727	91438
Private	41720	7768	597	50086	0	2694	25736	78515
Central	45925	7066	0	52991	4780	10019	0	67790
Total	140723	21382	1200	163305	4780	40195	29463	**237743**

Source: Central Electricity Authority

- RES Renewable Energy Source

Power Supply Position of India

3.2 The summary of peak demand, peak met and peak deficit for the country during the period FY 2001-02 to FY 2013-14 is pictorially depicted below:

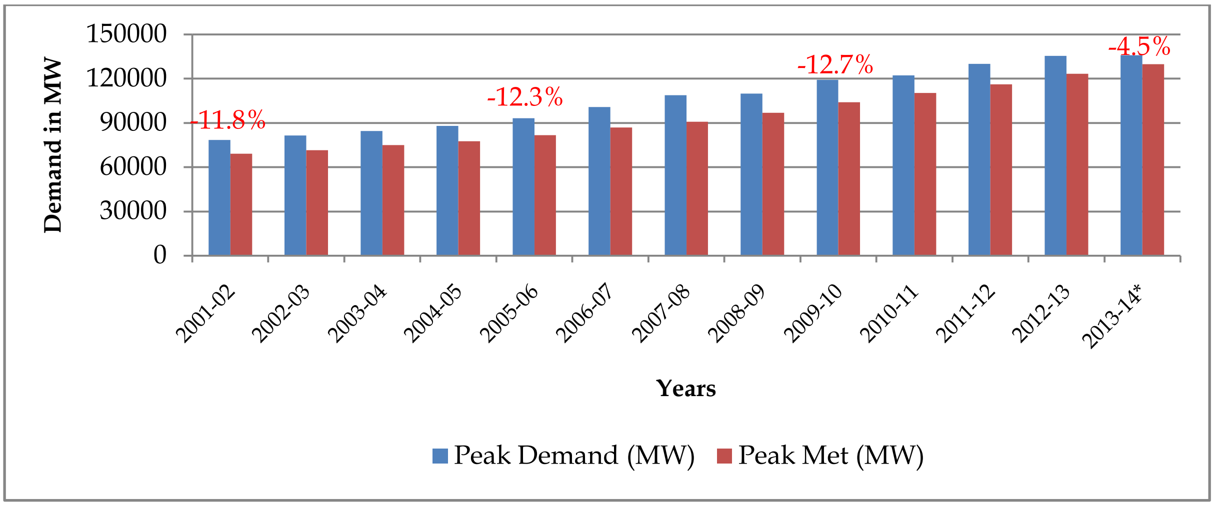

Figure 1: Summary of Peak Demand and Peak Met

*Source: Central Electricity Authority * Data for Peak demand and peak met for FY 2013-14 is provisional.*

3.3 The peak deficit for the country for FY 2001-02 was around 11.8%, which increased to around 12.7% in FY 2009-10. However, in FY 2013-14, the country faced peak deficit (provisional) of around 4.5%.

3.4 The summary of energy requirement, energy availability and energy shortage for the country during the period FY 2001-02 to FY 2013-14 is pictorially depicted below:

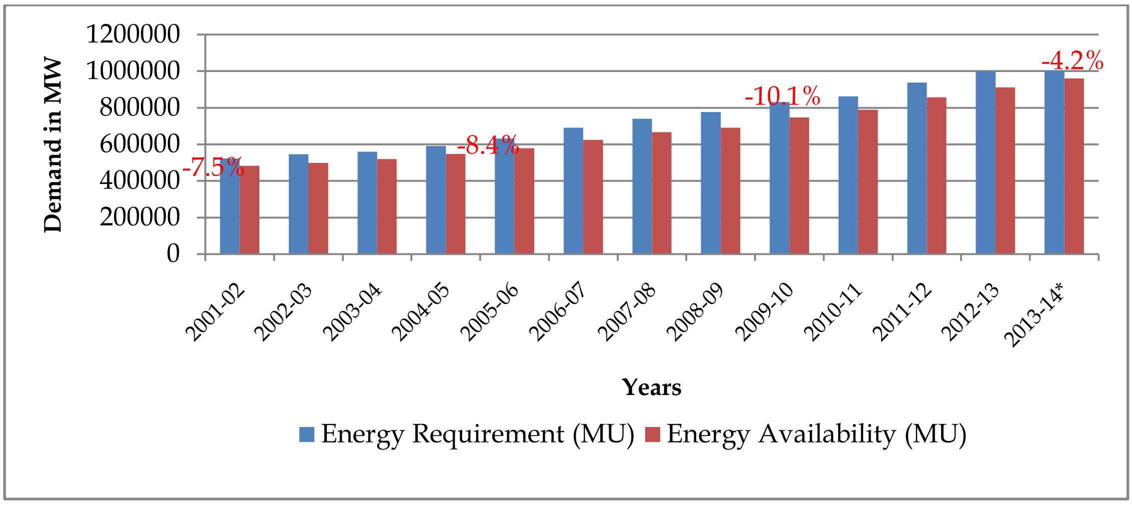

Figure 2: Summary of Energy Requirement and Energy Availability
Source: Central Electricity Authority** Data for Energy Requirement and Energy Availability for FY 2013-14 is provisional.*

3.5 It is observed that the peak deficit for the country has decreased in last five years. The provisional peak deficit and energy shortage for FY 2013-14 has been around 4.5% and 4.2%, respectively, which is comparatively much lower than the peak deficit and energy shortage of 9% and 8.7% for FY 2012-13, respectively.

Year Wise Capacity Addition in last 5 Years

3.6 The summary of year-wise capacity addition during last five years is as shown in table below:

Table 2: Summary of Year Wise Capacity Addition (in MW)

Year	Thermal	Nuclear	Hydro	RES	Total
2008-09	1818	0	969	2117	4904
2009-10	8729	440	0	2279	11448
2010-11	10370	220	704	2934	14228
2011-12	18779	0	1423	6049	26251
2012-13	19928	0	501	3038	23467
Total	**59624**	**660**	**3597**	**16417**	**80298**

Source: Central Electricity Authority Annual Report

3.7 As can be observed from the above table, the cumulative capacity addition in the last five years has been around 80000 MW out of this thermal capacity addition is close to 60000 MW.

Decreasing Trend of Plant Load Factor for Thermal Generating Stations

3.8 Though, significant capacity addition has been achieved during last five years,, the Plant Load Factor of thermal generating stations has reduced, as presented below:

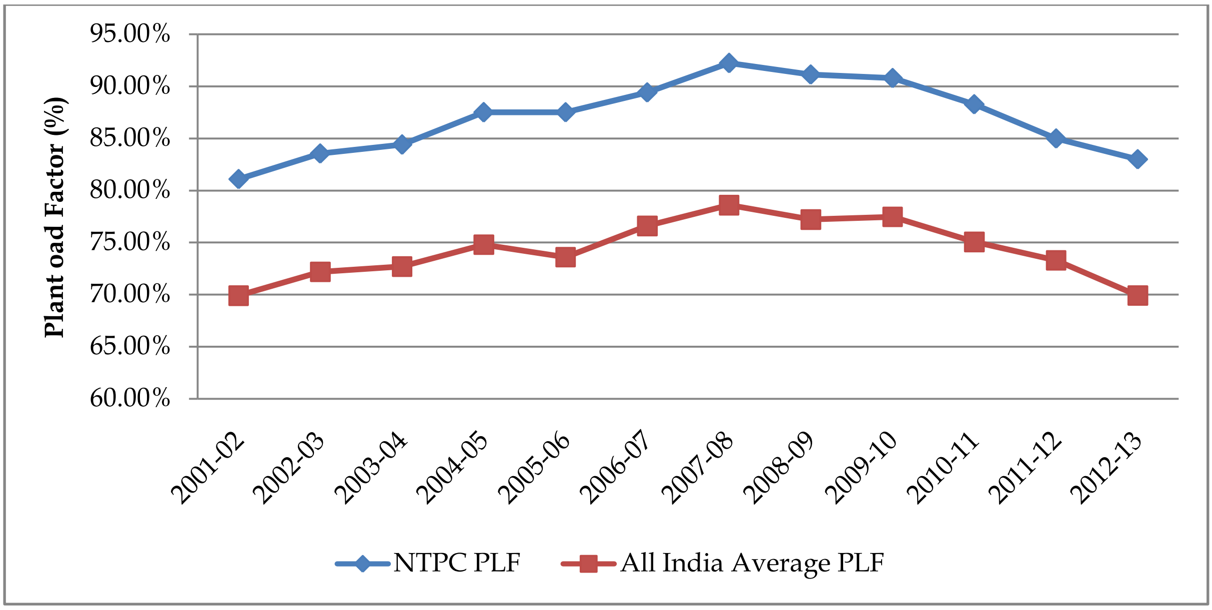

Figure 3: Plant Load Factor for Thermal Generating Stations
Source: NTPC and Central Electricity Authority

3.9 The reduction in PLF of thermal generating stations is observed mainly due to the shortage in domestic fuel availability, capacity addition, increase in cost of imported coal and consequent increase in the price of electricity pushing the growth in demand to a lower side.. A.

3.10 The Commission, taking into consideration the overall scenario of power sector in the country and the challenges being faced by the sector, has framed the Tariff Regulations ,2014 with the following broad objectives:

- Regulatory Certainty.
- Simplification of Tariff Determination Process.
- Fostering fresh Investments in the sector and achieving the desired projections for addition of capacity in the 12th Plan period.
- Promoting higher efficiency and optimization of cost of production and Transmission of electricity.
- Balancing the interest of the consumers and reasonable recovery of cost by the generators and the investors.

4. Scope and Extent of Application {Regulation 2(2)}

4.1 In the draft Regulations, the extent of application of these Regulations has been specified. It was proposed that the draft Regulations would be applicable in all cases where tariff is required to be determined by the Commission under Section 62 of the Act read with Section 79 thereof. The draft Regulation 2(2)(a) provides that *"these Regulations shall not apply for determination of tariff in case of the following: (a) Generating stations or inter-State transmission systems whose tariff has been discovered through tariff based competitive bidding in accordance with the guidelines issued by the Central Government under Section 63 of the Act;"*

Stakeholders' Comments/Suggestions

4.2 Some of the stakeholders submitted that the Legal Opinion given by the Learned Attorney General of India clearly emphasized that the Electricity Regulatory Commissions have the power to revise the tariff adopted under Section 63 of the Act. Therefore, Regulations may also be made applicable for revision of tariff adopted under Section 63 of the Act in specific cases with supply to multiple States. In view of this, it was suggested to delete clause 2(2)(a) of the draft Regulations.

Commission's Views

4.3 Section 63 of the Act clearly stipulates that *"Notwithstanding anything contained in section 62, the Appropriate Commission shall adopt the tariff if such tariff has been determined through transparent process of bidding in accordance with the guidelines issued by the Central Government."* As per the opinion of the Learned Attorney General of India, relief to be granted to Power Purchase Agreements executed under Section 63 of the Act, is a matter to be considered by the Appropriate Commission in the light of its powers, functions, roles and duties under the Electricity Act, 2003. Therefore, the Commission is of the view that these Regulations, which specify the terms and conditions for determination of tariff under Section 62, cannot be applied for revision of tariff adopted under Section 63 of the Act as this will defeat the purpose of the Act which provides for two distinct processes for determination of tariff. Further, such modification to the draft Regulations may vitiate the sanctity of the bidding process and may allow most of the generating companies to approach the Commission for modification of tariff adopted under Section 63 of the Act, which may also be against the commercial interest of the procurers. The Commission has, therefore, decided not to modify this provision of the draft Regulations.

5. Definitions and Interpretations (Regulation 3)

5.1 Additional Capitalisation {Regulation 3 (2)}

5.1.1 Clause 3(2) of the draft Regulations defines additional capitalisation as the capital expenditure incurred or projected to be incurred after the date of commercial operation of the project and admitted by the Commission after prudence check.

Stakeholders' Comments/Suggestions

5.1.2 Some of the beneficiaries submitted that the tariff claim based on projected capital expenditure needs to be dispensed with and capital cost should be determined based on actual expenditure incurred as on COD.

Commission's Views

5.1.3 The Commission is of the view that the tariff claim based on projected capital expenditure will have following added advantages apart from meeting the intended objective of certainty of tariff and minimal retrospective adjustments:

a) The beneficiaries would be aware of the intended additional capitalization in advance and would be able to submit their observations before the Commission about the reasonableness and necessity of additional capitalisation before the actual expenditure is made by the generating companies/transmission licensees.
b) The generating companies/transmission licensees would be assured of the admittance of expenditure before incurring the expenditure, once accepted by the Commission in the capital cost.
c) Sufficient incentives and disincentives have been built in to ensure that the generating companies and transmission licensees make their projections in such a manner that the difference between projected expenditure and actual expenditure is minimized.

5.1.4 Thus, the proposed definition of additional capitalization on the basis of projected capital expenditure in addition to the actual expenditure incurred as on COD, is in line with the objective of multi-year tariff principles, and hence, the Commission is not in agreement with the suggestion to change the definition of additional capitalization to consider only actual capital expenditure incurred. The Commission has, therefore, decided not to modify this provision of the draft Regulations.

5.2 Auxiliary Energy Consumption {Regulation 3 (3)}

5.2.1 Clause 3(3) of the draft Regulations defines the Auxiliary Energy Consumption in case of a generating station, as the quantum of energy consumed by auxiliary equipment of the generating station, such as the equipment being used for the purpose of operating plant and machinery including switchyard of the generating stations and transformer losses within the generating station, expressed as a percentage of the sum of gross energy generated at the generator terminals of all the Units of the generating station. In the definition of Auxiliary Energy Consumption, a specific exclusion was proposed for supply of power to housing colony and other facilities at the generating stations and the power consumed for construction works at the generating station.

Stakeholders' Comments/Suggestions

5.2.2 Some of the generating companies and the Developers submitted that 'Auxiliary Energy Consumption' or 'AUX' in relation to a generating company should include energy consumed for supply of electricity to housing colony and other facilities at the generating station and the power consumed for construction works at the generating station. Further, some stakeholders requested clarification on how and under what head shall the energy consumed for supply of power to housing colony and other facilities at the generating station be accounted.

5.2.3 Some of the beneficiaries submitted that power supply to housing colony and other such facilities, other than machine auxiliaries of Generating Stations should not be part of Auxiliary Energy Consumption of the stations. TANGEDCO submitted that the method to account for the Auxiliary Energy Consumption from the gross Generation may also be provided.

5.2.4 The Power Company of Karnataka Limited (PCKL) submitted that some of the generating plants have installed Flue Gas Desulphurization Unit, desalination units, dedicated Jetty for handling of coal, water pump house, etc., which are being used for the purpose of operating plant and machinery and some of these are situated beyond the plant premises. In such cases, the specified Auxiliary Energy Consumption needs to be reduced and so the definition may be suitably modified.

Commission's Views

5.2.5 Some of the generating companies have argued that as per the Electricity (Removal of Difficulty) (fourth) order, 2005, the supply of electricity by a generating company to its housing colonies or township housing of the operating staff of the generating stations is deemed to be an integral part of the activity of generating electricity and therefore, consumption by the housing colony also form part of the auxiliary consumption of the generating station. In this connection, the Commission would like to clarify that under the Act, license is required to supply power to the consumers. In this context, generating stations faced difficulty due to uncertainty over the requirement of license for supplying power to their colonies. In that context, the Removal of Difficulty order was issued which provided that the generating companies shall not be required to obtain license under the Act for supply of electricity. Thus, the housing colony is treated as integral part of generating station for all practical purpose. The said order does not provide that the electricity supplied to the housing colonies and township shall be accounted for as part of the auxiliary consumption of the generating station. , However the fuel expenses corresponding to electricity supply to the colony from the station net of revenues from employees for the consumption of power are accounted for in the operation and maintenance expenses of the generating station while framing norms for the operation and maintenance expenses. Therefore, if the housing colony consumption is included in the auxiliary energy consumption norm of the generating stations then it would tantamount to double charging of the same from the beneficiaries. Therefore, consumption of electricity in housing colony, though integral part of the generating station, cannot be included in the auxiliary energy consumption norm. In the light of the above, the Commission is of the view that the electricity consumption of housing colony shall not form a part of Auxiliary Energy Consumption.

As regards the suggestion to include power consumption of construction activities as a part of Auxiliary Energy Consumption, the Commission is of the view that such expense during construction period should ideally form a part of the capital cost of the Unit under construction. This will be essential to restrict cross subsidization of expenses if the beneficiaries of the two Units/Stages are different and therefore, charging expenses of one Unit to other is not justified. Hence, the Commission concludes that the consumption of power due to construction activities should be accounted for separately.

5.2.6 As regards the comment regarding specifying the method to account for Auxiliary Energy Consumption from gross generation, the Commission is of the view that the proposed definition of Auxiliary Energy Consumption is clear as it mentions consumption corresponding to plant auxiliaries in operation excluding housing colony consumption and is to be measured on the basis of energy meters installed for each generating Unit.

5.2.7 As regards the suggestion received from stakeholders regarding treatment of Auxiliary Energy Consumption for auxiliaries located outside the plant premises, the Commission has dealt with the matter appropriately at Para 37.75 of the Statement of Objects and Reasons. The Commission has, therefore, decided not to modify this provision of the draft Regulations.

5.3 Auditor {Regulation 3(4)}

5.3.1 Clause 3(4) of the draft Regulations defines Auditor as an auditor appointed by a generating company or a transmission licensee in accordance with the provisions of Sections 224, 233B and 619 of the Companies Act, 1956 (1 of 1956), as amended from time to time or any other law for the time being in force.

<u>Stakeholders' Comments/Suggestions</u>

5.3.2 Some generating companies submitted that the data can be certified by practicing Chartered Accountants / Cost Accountants holding a valid certificate of practice from the Institute of Chartered Accountants of India/Institute of Cost

Accountants of India. Some of the beneficiaries submitted that Section 233B of the Companies Act, 1956 provides for appointment of Cost Auditor, and the furnishing of the Cost Audit Report at the time of filing of true up petition may be made mandatory.

Commission's Views

5.3.3 The Commission is of the view that for tariff purposes, data is taken from the audited Balance Sheets of the project and annual reports of the company, which are audited by the statutory auditors, and auditor certificate is also considered for the purpose of tariff. With regard to modification in the definition of Auditor as proposed by some of the stakeholders, the Commission is of the view that the definition proposed in the Draft Regulation is appropriate. However, since the Companies Act, 2013 has been enacted recently, the Commission has decided to modify the definition to include auditors appointed under the Companies Act, 2013 as under:

> *"'**Auditor**' means an auditor appointed by a generating company or a transmission licensee, as the case may be, in accordance with the provisions of sections 224, 233B and 619 of the Companies Act, 1956 (1 of 1956)], as amended from time to time or Chapter X of the Companies Act, 2013 (18 of 2013) or any other law for the time being in force;"*

As regards submission of the Cost Audit Report, the Commission accepts the suggestions to call for the Cost Audit Report as an additional check, and the Cost Audit Report along with Cost Accounting Records should be submitted by the generating Company or the transmission licensee to the Commission only in sealed cover being confidential documents along with the information and documents to be submitted under specified Tariff Filing Forms.

5.4 Bank Rate {Regulation 3(5)}

5.4.1 Clause 3(5) of the draft Regulations defines Bank Rate as the Base Rate of interest specified by the State Bank of India (SBI) from time to time or any replacement thereof for the time being in effect, plus 350 basis points.

Stakeholders' Comments/Suggestions

5.4.2 NTPC submitted that the provisions for adjustment along with interest at the Bank Rate plus 350 basis points may be incorporated in the Regulations to take care of the difference between provisional and final bills. Some beneficiaries suggested keeping the Bank Rate as Base Rate plus 150 or 200 basis points. CSPGCL submitted that as on date, the benchmark Prime Lending Rate (PLR) of SBI has a spread of 475 basis points over Base Rate, hence, the spread should remain consistent with the prevailing banking practice to match the current economic scenario.

5.4.3 Some beneficiaries have also suggested that there should be a ceiling limit, with Bank Rate being trued up at the end of the Tariff Period, and added that SBI Base Rate w.e.f. 07.11.2013 is 10% and so current Bank Rate works out to 13.50%.

Commission's Views

5.4.4 The SBI PLR has ranged between 300-400 basis points over the Base Rate, which varies on account of several factors and financial scenarios. On the other hand, Bank Rate is applicable on under recovery or over recovery on account of true up, which can either be applicable to generating company/transmission licensee or beneficiaries/long-term customers as the case may be. The Commission has observed that Bank Rate specified is not discriminatory either to a generating Company or beneficiaries and is in line with current financial scenario. Hence, the definition of Bank Rate as specified in the Regulations is appropriate and the Commission has, therefore, decided not to modify this provision of the draft Regulations. The Commission's intent while framing the regulations and as also specified in Tariff Policy has been to adopt normative approach for most of the aspects except where the Commission in the Regulations has specifically provided for carrying out the truing up and hence it will not be practical to adjust the interest rate on actual basis.

5.5 Beneficiary {Regulation 3(6)}

5.5.1 Clause 3(6) of the draft Regulations defines Beneficiary in relation to a generating station as a distribution licensee who is purchasing electricity generated at such generating station through a long-term Power Purchase Agreement either directly or through a trading licensee on payment of fixed charges and by scheduling in accordance with the Grid Code.

Stakeholders' Comments/Suggestions

5.5.2 NTPC submitted that the entities such as GUVNL, GRIDCO, MP Trade Co, UPPCL, and HPPC, should also be included as beneficiaries. Some of the generating companies submitted that *"fixed charges"* may be replaced with *"total tariff and trading margin in case of trader"*. Jaiprakash Power submitted that term *'long term Power Purchase Agreement'* should be defined. GRIDCO submitted that in addition to distribution licensee, the Bulk Supplier (i.e., the Apex State Power Purchase Entity) which purchases power on behalf of the State for supply to DISCOMs should also be included. Further, GRIDCO also proposed to include the term *"Supply Licensee"* in view of the proposed upcoming amendment to the Electricity Act, 2003.

5.5.3 SRPC submitted that power from the generating station is allocated not only to distribution licensee but also to transmission licensee (HVDC stations), generating stations, NLC mines, etc. Therefore, the term 'distribution licensee' in the definition may be replaced with 'a person who has a share in a generating company'.

Commission's Views

5.5.4 The Commission is of the view that as the Apex State Power Purchase Entities in some of the States are purchasing electricity on behalf of Distribution Licensees, hence, the beneficiaries, for availing power from generating stations, are distribution licensees. Further, the Act does not define the Bulk Supplier. The Commission is of the view that 'long term' needs to be deleted from the Regulations considering the fact that some of the Distribution Licensees may enter into a Power Purchase Agreement on 'medium-term' basis. The Commission has also noted that Power Purchase Agreements on short-term basis are on single part tariff basis and commercial arrangement is not on the basis of declaration of availability and despatch schedule, hence, the definition will not be applicable for purchasing electricity on short-term basis.

5.5.5 As regards the comments of GRIDCO regarding inclusion of supply licensee (in view of the upcoming amendment of Electricity Act, 2003), the Commission is of the view that without there being provisions for these entities in the Act, it will not be possible to recognize these entities for the purpose of tariff in the tariff regulations. In any case, these entities are discharging the functions akin to the traders in the chain of supply of power from a generating company to a distribution licensee which has been recognized in the definition of beneficiary. The Commission, considering the suggestion that the beneficiary shall also include the person who has allocation in generating stations,has included the same in definition of Beneficiary.

5.5.6 After careful consideration, the Commission has decided to modify the proposed definition as under:

> *"'**Beneficiary**' in relation to a generating station covered under clauses (a) and (b) of sub-section 1 of section 79 of the Act, means a distribution licensee who is purchasing electricity generated at such generating station through a Power Purchase Agreement either directly or through a trading licensee on payment of fixed charges and by scheduling in accordance with the Grid Code:*
>
> *Provided that where the distribution licensee is procuring power through a trading licensee, the arrangement should be secured through back to back power purchase agreement and power sale agreement:*
>
> *Provided further that beneficiary shall also include any person who has allocation in inter State Generating Stations;"*

5.6 Block {Regulation 3(7)}

5.6.1 Clause 3(7) of the draft Regulations defines Block in relation to a combined cycle thermal generating station as including combustion turbine-generator, associated waste heat recovery boiler, connected steam turbine- generator and auxiliaries.

<u>Stakeholders' Comments/Suggestions</u>

5.6.2 Wartsila India Limited submitted that Internal Combustion (IC) Engine should also be included in the definition.

Commission's Views

5.6.3 The Commission notes that presently there is no generating station based on IC Engine for which the tariff is being determined by the Commission under Section 62 of the Act. Thus, at present, the Commission is not inclined to include IC engine based generating station in the definition. However, the same may be dealt on case to case basis if distribution licensees enter into a PPA with a generating company for supply of power from its generating station based on IC Engine subject to the condition that such a generating station is eligible for tariff determination under clauses (a) or (b) of sub-section (1) of Section 79 of the Electricity Act, 2003. The Commission has, therefore, decided not to modify this provision of the draft Regulations.

5.7 Capital Cost {Regulation 3 (8)}

5.7.1 Clause 3(8) of the draft Regulations defines Capital Cost as the capital cost determined in accordance with Regulation 9 of the draft Regulations.

Stakeholders' Comments/Suggestions

5.7.2 One stakeholder submitted that the definition of Capital Cost in the draft Regulations is not proper, and must be made as per the 1992 Notification of Government of India.

Commission's Views

5.7.3 The Commission is of the view that the definition refers to the relevant provision of Regulation, which comprehensively deals with the various components included under the capital cost for the purpose of tariff determination by the Commission and hence, no change is required in the definition of Capital Cost.

5.8 Change in Law {Regulation 3(9)}

5.8.1 Clause 3(9) of the draft Regulations defines Change in Law as occurrence of any of the events like (a) enactment, bringing into effect or promulgation of any new Indian law; or (b) adoption, amendment, modification, repeal or re-enactment of any existing Indian law; or (c) change in interpretation or application of any Indian law by a competent court, Tribunal or Indian Governmental Instrumentality which is the final authority under law for such interpretation or application; or (d) change by any competent statutory authority in any consent or clearances of covenants, approval or licence available or obtained for the project.

Stakeholders' Comments/Suggestions

5.8.2 NHPC submitted that the hydro power projects are being developed on rivers that span international boundaries. The definition of 'change in law' should therefore, be modified to include 'change in international law affecting execution of hydro power projects'. Some of the generating companies submitted that definition of 'change in law' may not be restricted to Indian Laws. They also submitted that Change in Law due to change in foreign laws has been taken into consideration by the Commission in its recent Orders. Some stakeholders suggested that the definition should include 'any other change in law' defined in bid documents issued by the Government of India (GoI) under Section 63 of the EA 2003.

5.8.3 Some stakeholders suggested that in Clause (d) of the definition, the phrase "consent or clearances or covenants, approval" should be replaced with "condition or covenant of any consent or clearances or approval".

Commission's Views

5.8.4 As regards the inclusion of change in laws of other countries in the definition of Change in Law, the Commission is of the view that change in law envisaged in Standard Bidding Document issued by Government of India for Tariff Based Competitive Bidding is meant for matters to be dealt with under those documents, i.e., competitively bid projects, whereas the proposed definition is intended to cover matters to be dealt under the proposed Tariff Regulations, i.e., projects subjected to regulated tariff determination. Moreover, change in law in other countries and the consequential impact on projects in India would have to be considered by the Commission on a case to case basis, and no blanket dispensation can be provided in the Tariff Regulations. However, the Commission has decided that any bilateral or multilateral agreement/treaty between the Government of India and any other Sovereign Government having implication for the generating station or the transmission system regulated under these Regulations shall be covered under Change in Law. Further, the Commission has accepted the suggestion regarding clause (d) of the definition.

5.8.5 Accordingly, the Commission has decided to rephrase the clause 3(9)(d) of the draft Regulations and include a new clause (9)(e) as under:

> *"(d) Change by any competent statutory authority in any condition or covenant of any consent or clearances or approval or license, available or obtained for the project; or*
> *(e) coming into force or change in any bilateral or multilateral agreement/treaty between the Government of India and any other Sovereign Government having implication for the generating station or the transmission system regulated under these Regulations."*

5.9 Communication System {Regulation 3 (11)}

5.9.1 Clause 3(11) of the draft Regulations specifies that the Communication System includes communication system of Power Grid Corporation of India Limited covered under Unified Load Dispatch and Communication (ULD&C) scheme, SCADA, Wide Area Measurement (WAMS), Optical Fibre, etc., used for inter-State transmission of electricity.

<u>Stakeholders' Comments/Suggestions</u>

5.9.2 POWERGRID submitted that the draft Regulation may be modified as:

> *"………Wide Area Measurement (WAMS), Optical Fiber, Fiber Optic Communication Equipment, RTU/PMU, PLCC, PABX, Radio Communication System and Auxiliary Power Supply System etc. used for inter-state transmission of electricity;"*

<u>Commission's Views</u>

5.9.3 The Commission has considered the suggestions of POWERGRID to include additional items like RTU, PABX, Radio communication system, and auxiliary power supply system associated with such communication system used for managing inter-State transmission of electricity, etc. The communication system, which is part of ULD&C scheme and meant for communicating real time data/speech data to RLDC/SLDC, etc., is to be covered under the scope of the communication system. However, the general communication system used for office administration purpose, etc., shall be excluded.

5.9.4 Accordingly, the Commission has decided to modify the definition of communication system as under:

> *"'**Communication System'** includes communication system of Power Grid Corporation of India Ltd. covered under Unified Load Dispatch and Communication (ULD&C) scheme, SCADA, Wide Area Measurement (WAMS), Fibre Optic Communication system, Remote Terminal Unit, Private Automatic Branch Exchange, Radio Communication System and auxiliary power supply system etc. used for managing inter-state transmission of electricity;"*

5.10 Competitive Bidding {Regulation 3(12)}

5.10.1 Clause 3(12) of the draft Regulations defines Competitive Bidding as a transparent process for procurement of equipment, services and works in which bids are invited by the project developer by open advertisement covering the scope and specifications of the equipment, services and works required for the project and the terms and conditions of the proposed contract as well as the criteria by which bids shall be evaluated, and shall include domestic competitive bidding and international competitive bidding.

Stakeholders' Comments/Suggestions

5.10.2 Some of the stakeholders submitted that International Competitive Bidding (ICB) should be made mandatory with assured quality of equipment. Some stakeholders submitted that there may be few packages for which domestic or International Competitive Bidding may not be feasible.

Commission's Views

5.10.3 The Commission has already dealt with the issue of mandatory International Competitive Bidding (ICB) in the Explanatory Memorandum to the draft Regulations. The Commission is of the view that it would be impractical to make ICB mandatory for award of all the packages particularly when the project is being executed by awarding multiple packages, since, it may not be possible to attract international suppliers for some of the packages. It is desirable that major technology intensive packages for the projects should be procured through international competitive bidding for efficient price discovery. However, it may not be economically and technically practical to adopt ICB route for all the packages. The expenses should be incurred in a prudent manner to achieve cost efficiency and hence, competitive bidding is desirable. It is left to the prudent business practice of the generating company or transmission licensee to decide which packages are to be procured through ICB and which packages are to be procured through Domestic Competitive Bidding (DCB). Accordingly, the Commission is of the view that the proposed definition is appropriate and no change is required.

5.11 Cut-off Date {Regulation 3 (13)}

5.11.1 Clause 3(13) of the draft Regulations defines Cut-off Date as 31st March of the year closing after two years of the year of commercial operation of whole or part of the project.

Stakeholders' Comments/Suggestions

5.11.2 NTPC submitted that the term 'whole or part of the project' may be removed from definition of Cut-off date. CSPGCL submitted that the whole concept of 'Cut-off Date' may be reconsidered. Some stakeholders suggested that Cut-off Date should be one year only from the COD. Some of the stakeholders suggested for longer period for cut off date.

Commission's Views

5.11.3 The definition of the cut-off date was modified during the Tariff Period 2009-14, which provides that in case the date of commercial operation falls in the last quarter of the financial year, the cut-off date shall be the financial year closing after three years of the year of commercial operation of the generating station or the transmission system. The Commission is of the view that this provision provides sufficient time to the project developer for completion of balance works and for payment of liabilities after achieving COD in the last quarter.

5.11.4 As regards the suggestion to remove the words 'whole or part of the project', it is observed that there is a large time gap between COD of Units or phases or stages of the project and hence, it is appropriate to retain the words 'whole or part of the project'.

5.11.5 As regards extending the period of "Cut-off Date", the Commission is of the view that in certain instances, it may not be possible for the project developer to capitalise certain costs at the time of COD or within one year of COD, for reasons beyond the control of the project developer and hence, such provision has been made in the Regulation. The Commission is of the view that the definition of cut-off date addresses the project requirements appropriately and enables the project developer to capitalize the expenses in a reasonable time period, and hence, the definition proposed in the draft Regulations is retained without any change.

5.12 Declared Capacity {Regulation 3 (15)}

5.12.1 Clause 3(15) of the draft Regulations defines Declared Capacity in relation to a generating station as the capability to deliver ex-bus electricity in MW declared by such generating station duly taking into account the availability of fuel or water, and subject to further qualification in the relevant Regulations.

Stakeholders' Comments/Suggestions

5.12.2 Some private sector project developers and Associations submitted that the availability of thermal power plants is likely to be impacted adversely due to non-availability of fuel for reasons beyond the control of the developer. Therefore, the following proviso may be included in the above definition:

> *"Provided that in case of fuel shortage in a thermal generating station, the generating company may propose to deliver a higher MW during peak-load hours by saving fuel during off-peak hours. The declared capacity (DCi) for the purpose of computation of availability in such an event shall be considered equal to the maximum peak hour ex-power plant declared."*

5.12.3 Some private sector project developers and Associations submitted that the hydro power generator should be allowed to declare capacity based on machine availability as availability of water is not under the control of the generator. As such, the provision as existing under CERC Tariff Regulations, 2004 should be reinstated.

Commission's Views

5.12.4 The Commission has examined the suggestion (in case of fuel shortage) of project developers to consider ex-power plant declared capacity based on maximum peak hour declared capacity. A provision similar to the one sought by private developers was existing in 2009-14 in Regulation 21(4) of Tariff Regulations 2009 but was rendered ineffective due to absence of consensus amongst the stakeholders. This was therefore, not provided in the proposed Draft Regulations. For the same reason we are not inclined to provide the same now in this regulation.

5.12.5 The Commission is of the view that the responsibility for arrangement of fuel lies with the generator and any failure to arrange the fuel should be to the account of the generator. In case of a hydro generating station, the concept of Capacity Index prevailing during Tariff Regulation 2004 was done away with in the next tariff period of 2009-14 in Tariff Regulation 2009 , thereby, providing for hydrology risk to be borne by the Generator. The Commission is not inclined to make any change in the approach. In view of the above, the Commission is not in agreement with the suggestions to declare availability on the basis of machine availability without considering the fuel and water availability. The Commission has, therefore, decided not to modify this provision of the draft Regulations.

5.13 **De-capitalisation**

5.13.1 Considering the views of the stakeholders and in order to have clarification on the issue of de-capitalisation, the Commission has decided to include the definition of De-capitalisation in the Regulations as under:

> *"'**De-capitalisation**' for the purpose of the tariff under these regulations, means reduction in Gross Fixed Assets of the project corresponding to the removal/deletion of assets as admitted by the Commission;"*

5.14 De-commissioning {Regulation 3 (16)}

5.14.1 Clause 3(16) of the draft Regulations defines de-commissioning as removal from service of a generating station or transmission system, after it is certified by the Central Electricity Authority or any other authorized agency, either on its own or on an application made by the project developer or the beneficiaries or both, that the project cannot be operated due to non performance of the assets on account of technological obsolescence or uneconomic operation or a combination of these factors.

Stakeholders' Comments/Suggestions

5.14.2 NTPC submitted that the right to apply for decommissioning should be only with the project developer and a certificate from CEA/any other authority may not be insisted upon. POWERGRID submitted that the draft Regulation may be modified as under:

> *".......Central Electricity Authority or any other authorized agency, on an application made by the generating company or transmission licensee, as the case may be that the project cannot be operated........."*

Commission's Views

Decommissioning has a consequential impact on the tariff to be determined under cost plus tariff mechanism and the Commission felt the need to bring clarity in terms of circumstances, timing, etc., of decommissioning while issuing the draft Regulations. The Commission is of the view that under the cost plus tariff mechanism, where the cost of asset is recovered through tariffs, some checks need to be applied and accordingly, proposed the definition of de-commissioning in the draft Regulations, which provides for certification by CEA or any other authorized agency, under the specified circumstances, for de-commissioning. In response to the comments of NTPC regarding the right to apply for decommissioning, the Commission would like to clarify that the definition of decommissioning does not intend to take away the rights of the project developer in accordance with Law/PPA to decommissioning of the asset. It is intended to bring more clarity in addressing the de-commissioning stage of project and hence, the Commission is of the view that the apprehension of NTPC expressing concerns over their sole right to apply for decommissioning is unfounded. The proposed definition has been retained without any change.

5.15 Design Energy {Regulation 3 (17)}

5.15.1 Clause 3(17) of the draft Regulations defines Design Energy as the quantum of energy, which can be generated in a 90% dependable year with 95% installed capacity of the hydro generating station.

Stakeholders' Comments/Suggestions

5.15.2 THDC India Limited submitted that the phrase 'energy generated out of natural flow of water' should be added in the definition.

Commission's Views

5.15.3 As regards the suggestion of THDC to add the phrase 'energy generated out of natural flow of water', the Commission is of the view that since the term 'natural flow of water' is not defined in these Regulations, adding the same in the definition of design energy will result in subjective assessment and consequent differences between the project developer and the beneficiaries. Moreover, the same definition was there in 2009 Tariff Regulations and no instance has been brought to our notice that the project developer has encountered any problem on account of that definition. Hence, the Commission is of the view that the definition is appropriate and does not require any more detailing, and has retained the proposed definition without any change.

5.16 **Element**

5.16.1 The Commission used the term "Element" consistently throughout the draft Regulations, however, the same was not defined in the draft Regulations. The Commission, in order to provide more clarity as to what constitutes an Element of a transmission system, has defined the same in the Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2014 (hereafter referred to as "Tariff Regulations, 2014") as under:

> *"(21)'**Element**' in respect of a transmission system shall mean an asset which has been distinctively defined under the scope of the project in the Investment Approval;"*

5.17 Force Majeure {Regulation 3(25)}

5.17.1 The term "Force Majeure" has been used in several places in the draft regulations. Suggestions have been received from stakeholders to define the term from the purpose of clarity and certainty. Considering the views of the stakeholders, the Commission has decided to include definition of Force Majeure as under:

> *"**'Force Majeure'** for the purpose of these regulations means the event or circumstance or combination of events or circumstances including those stated below which partly or fully prevents the generating company or transmission licensee to complete the project within the time specified in the Investment Approval, and only if such events or circumstances are not within the control the generating company or transmission licensee and could not have been avoided, had the generating company or transmission licensee taken reasonable care or complied with prudent utility practices:*
>
> > *a) Act of God including lightning, drought, fire and explosion, earthquake, volcanic eruption, landslide, flood, cyclone, typhoon, tornado, geological surprises, or exceptionally adverse weather conditions which are in excess of the statistical measures for the last hundred years; or*
> >
> > *(b) Any act of war, invasion, armed conflict or act of foreign enemy, blockade, embargo, revolution, riot, insurrection, terrorist or military action; or*
> >
> > *(c) Industry wide strikes and labour disturbances having a nationwide impact in India;"*

5.18 Generating Unit {Regulation 3 (23)}

5.18.1 Clause 3(23) of the draft Regulations defines generating Unit in relation to a thermal generating station other than combined cycle thermal generating station to mean steam generator, turbine-generator and auxiliaries, or in relation to a combined cycle thermal generating station, to mean turbine-generator and auxiliaries; and in relation to a hydro generating station, to mean turbine-generator and its auxiliaries.

Stakeholders' Comments/Suggestions

5.18.2 Some generating companies submitted that in relation to a combined cycle thermal generating station, the definition should also include "Waste heat recovery boiler and connected steam turbine-generator".

Commission's Views

5.18.3 The Commission has examined the suggestions of the generating companies. The suggestions are aimed to bring more clarity about the scope of equipment to be included under the generating Unit. The Commission notes that the existing definition separately identifies a thermal generating station and a combined cycle thermal generating station. The Commission is of the view that the definition is designed for the purpose of tariff determination and its interpretation is to be done accordingly. Hence, the definition of generating Unit is retained without any change. However, the Commission has decided to define the Generating Station separately as per provisions of the Act to have more clarity, as discussed in Para 4.20.4 and 4.20.5.

5.19 Indian Government Instrumentality {Regulation 3 (23A)}

5.19.1 Clause 3(23A) of the draft Regulations defines Indian Government Instrumentality as the Government of India, Governments of State(s) and any ministry.

Stakeholders' Comments/Suggestions

5.19.2 Some Independent Power Producers (IPPs) submitted that the Central/State Government or Commissions form temporary/regular committee of experts to take certain decisions. Such Committees may also be included in the list of Indian Government Instrumentality.

Commission's Views

5.19.3 The Commission is of the view that Committees of Experts is usually formed for the purpose of providing assistance on certain aspects to the Government or Commission and hence, the recommendations of the Committees are not binding in nature. The Commission is of the view that Indian Government Instrumentality cover the Central and State Governments (where the project is located), respective ministries/Department/agency/regulatory/quasi-judicial under the respective

Governments and accordingly, the Commission has decided to modify the definition as under:

> *"**'Indian Governmental Instrumentality'** means the Government of India, Governments of State (where the project is located) and any ministry or department or board or agency or other regulatory or quasi judicial authority controlled by Government of India or Government of State, where the project is located."*

5.20 Hydro Generating Stations {Regulation 3 (27)}

5.20.1 Clause 3(27) of the draft Regulations defines hydro generating stations as generating station or a Unit thereof that generates electricity by water power and includes penstock, head and tail works, main and regulating reservoirs, dams and other hydraulic works, but does not include substation.

Stakeholders' Comments/Suggestions

5.20.2 NHPC submitted that the definition may be modified as under:

> *"...........regulating reservoirs, dams and other hydraulic works, including any building and plant with step-up transformer, switchgear, cables, switch yard/ pothead yard or other appurtenant equipment, but does not include sub-station; if any, used for that purpose and the site thereof; a site intended to be used for a generating station, and any building used for housing the operating staff of a generating station"*

5.20.3 Some stakeholders submitted that the definition of hydro project should also include any building and plant with step-up transformer, switchgear, switch yard, cables or other appurtenant equipment and the site; a site intended to be used for the project, and any building used for housing the operating staff of the project. THDC India Limited submitted that term "etc." should be added after "dams and other hydraulic works" in the definition.

Commission's Views

5.20.4 The Commission has received comments and suggestions from many stakeholders on the definition of a hydro generating station. These suggestions seek to include additional equipment/assets in the definition of hydro generating station. The Commission has observed that the term "generating station" has been comprehensively defined in section 2(30) of the Act and specifically includes electricity generated by water-power. It is noted that the definitions as specified in the Act are automatically applicable for the interpretations of Regulations specified by the Commission.. Accordingly, the Commission is of the view that the term "generating station" should be defined in accordance with the provisions of the Act. The Commission felt that inclusion of the definition of 'Generating Station' as per Electricity Act, 2003 is more meaningful as it defines both thermal and hydro generating stations.

5.20.5 Accordingly, the Commission has decided to replace the current definition of hydro generating station by the definition of generating station as defined under the Act. Therefore, the proposed Regulation 3(27) is modified as under :

> *"'**Generating Station**' means any station for generating electricity, including any building and plant with step-up transformer, switch-gear, switch yard, cables or other appurtenant equipment, if any, used for that purpose and the site thereof; a site intended to be used for a generating station, and any building used for housing the operating staff of a generating station, and where electricity is generated by water-power, includes penstocks, head and tail works, main and regulating reservoirs, dams and other hydraulic works, but does not in any case include any sub-station;"*

5.21 Installed Capacity {Regulation 3 (29)}

5.21.1 Clause3 (29) of the draft Regulations defines the Installed Capacity as the summation of the name plate capacities of all the Units of the generating station or the capacity of the generating station reckoned at generator terminals. In the draft Regulations, a proviso was proposed that installed capacity in case of thermal generating stations before declaration of COD shall be as per schedule given by RLDC or SLDC as the case may be.

Stakeholders' Comments/Suggestions

5.21.2 SRPC submitted that the schedule by RLDC/SLDC is at ex-bus periphery. Therefore, the definition may include clause 'computed based on normative Aux % at generator's end'. NHPC submitted that the technical features such as Installed Capacity, Design Energy, dam, penstocks, etc., are approved by CEA based on detailed DPR. The Authority can upgrade/degrade or revise the technical features. Therefore, the definition may include "Authority".

5.21.3 Some private sector developers and Associations submitted that the applicability of the provision is unclear as energy generated prior to COD is infirm in nature and infirm power is not scheduled by RLDC or SLDC. Further, as per the definition, the Installed Capacity is determined only for the generating station and not for the Units.

5.21.4 Suggestions were also received to link the installed capacity of a generating station with the capacity demonstrated by successful trial run and to continue with the existing definition and delete the proposed proviso to clause 3(29) of the draft Regulations.

5.21.5 One stakeholder suggested that the following proviso may be added in the definition:

> *"Provided that on the conclusion of performance test, uprated or derated capacity shall be declared by the generating company based on performance test and it shall not be less than that determined by Performance test. Installed capacity shall then be reckoned based on declared uprated or derated capacity. In case of derating (or uprating), annual fixed charges as determined by the Commission shall be altered in proportion of derated (or uprated) capacity to the capacity considered by the Commission and shall not exceed from that determined for name plate rating."*

Commission's Views

5.21.6 The Commission is of the view that the impact of uprating and derating of the capacity has to be considered on a case to case basis and cannot be addressed through the Regulations. The Commission will consider the certificate issued by the Authority on uprating and derating of the capacity on case to case basis. Considering the suggestions of stakeholders, the Commission has decided to delete the proviso *"provided that installed capacity in case of thermal generating stations before declaration of COD shall be schedule given by RLDC or SLDC as the case may be"* to the definition.

5.22 Implementation Agreement {Regulation 3 (30)}

5.22.1 Clause 3(30) of the draft Regulations defines Implementation Agreement as the agreement, contract or MoU, or any such covenant entered into (i) between transmission licensee and generating station or (ii) between transmission licensee and developer of the associated transmission system, for the execution of project in coordinated manner.

Stakeholders' Comments/Suggestions

5.22.2 One of the private sector utility submitted that the definition may include long-term transmission customer/DIC instead of generating station.

Commission's Views

5.22.3 The Commission is of the view that the Implementation Agreement considered for the purpose of this Regulation is between generating station/developer of associated transmission system and transmission licensee. There is no role of DICs in Implementation Agreement of project of generating station and transmission system. The purpose of the definition is that the generating company and the transmission licensee should provide for the development of the generating station and transmission line in a coordinated manner so that mismatch between the commissioning of the generating station and the transmission system are avoided. Moreover, the implementation agreement should provide for the liability of the generating company or the transmission licensee for the delay of the execution of their respective project. Till the beneficiaries are not identified, the generating stations are deemed long-term transmission customers for the payment of transmission charges, hence, the proposed definition does not require any modification.

5.23 Investment Approval {Regulation 3 (32)}

5.23.1 Clause 3(32) of the draft Regulations defines Investment Approval as approval by the Board of the generating company or the transmission licensee or any other competent authority conveying administrative sanction for the project including funding of the project and the timeline for the implementation of the project. In the draft Regulations, a proviso was proposed that the date of investment approval shall be reckoned from the date of the resolution/minutes of the Board/competent authority or fifteen days from the date of sanction by the Board/competent authority, whichever is earlier.

Stakeholders' Comments/Suggestions

5.23.2 NTPC submitted that exceptions such as extended investment approval pending certain clearances should be allowed. The suggestion was also received to add the following in the definition of 'Investment Approval'.

> *"However, in case of Independent Power Producers, the date of financial closure shall be considered for the investment approval purpose."*

5.23.3 Some of the stakeholders suggested that Scheduled COD should be linked to SCOD indicated in the lender's appraisal documents as per the Common Loan Agreement and finalization of the Loan/Facility Agreement. Further, there should also be a provision to revise scheduled COD and start/zero date for reasons not attributable to the generator.

Commission's Views

5.23.4 It is noted that the investment approval signifies the decision to take up implementation of the project and inter-alia defines scope of the project, its broad features, estimated cost and estimated time of completion duly taking into account various general as well as project specific factors. Investment Approval requires proper identification of SCOD so as to assess reasonability of time over-run and cost over-run, if any. Therefore, the investment approval should clearly specify the SCOD. As regards the suggestion of IPPs to link the Investment Approval with financial closure, the Commission is of the view that uniformity of approach should be maintained and the Board of the IPP, should while taking the decision, lay down the timeline for execution of the project. In case of certain companies particularly hydro generating companies in the Central Sector, their Board of Directors are not authorised to take decision on Investment Approval which is vested in CCEA. The requirement of CCEA approval was covered under "any other competent authority" in the draft regulations. However, for the purpose of clarity, the approval of CCEA has been included in the definition of Investment approval. Accordingly, the Commission has modified the definition as follows:

> *"'**Investment Approval**' means approval by the Board of the generating company or the transmission licensee or Cabinet Committee on Economic Affairs (CCEA) or any other competent authority conveying administrative sanction for the project*

including funding of the project and the timeline for the implementation of the project.

Provided that the date of Investment Approval shall reckon from the date of the resolution/minutes of the Board/approval by competent authority"

5.24 Long Term Transmission Customer {Regulation 3 (34)}

5.24.1 Clause 3(34) of the draft Regulations defines long term transmission customer as a person having a transmission service agreement with the transmission licensee including deemed transmission licensee for use of inter-State transmission system.

Stakeholders' Comments/Suggestions

5.24.2 NTPC submitted that the words "Long term transmission Customer" may be replaced with "Long term Customer" and "Long term Customer" should be defined as per CERC (Grant of Connectivity, Long-term Access and Medium-term Open Access in inter-State Transmission and related matters) Regulations, 2009.

Commission's Views

5.24.3 The Commission is of the view that the proposed definition is intended to address the customers availing transmission services and hence, the inclusion of the word "transmission" in the definition will ensure that the meaning is restricted to transmission only. Further, the context of use of the term 'long-term transmission customer' justifies the intent in the Regulation and hence, no change is required.

5.25 Original Project Cost {Regulation 3 (39)}

5.25.1 Clause 3(39) of the draft Regulations defines original project cost as capital expenditure incurred by the generating company or the transmission licensee within the original scope of the project upto cut-off date as admitted by the Commission.

Stakeholders' Comments/Suggestions

5.25.2 NEEPCO proposed that 'Original Project Cost' may be replaced by 'Project Cost' and be defined as under:

"Project cost means the capital expenditure incurred by the generating company or the transmission licensee, as the case may be, within the original scope as well within

the revised scope of works of the project as per the latest approved cost up to the cut-off date as well as beyond cut off date or as admitted by the Commission."

Commission's Views

5.25.3 The Commission has gone through the suggestions of the stakeholders and is of the view that the purpose of original project cost is to ensure that all the necessary expenditure are made within the original scope, within specific period and any expenditure beyond this period means that this was not necessary for the project. Similarly, initial spares if brought after two years need to be distinguished and shall not per se qualify for capitalization as initial spares. Therefore, the definition of original project cost needs to be viewed in the context in which the term has been used in the Regulations, and hence, no change is required.

5.26 Plant Availability Factor {Regulation 3 (40)}

5.26.1 Clause 3(40) of the draft Regulations defines Plant Availability Factor (PAF) for any period as the average of the daily declared capacities (DCs) for all the days during that period expressed as a percentage of the installed capacity in MW reduced by the normative Auxiliary Energy Consumption.

Stakeholders' Comments/Suggestions

5.26.2 THDC India Limited submitted that the definition may be modified as follows:

> *"'Plant Availability Factor (PAF)' in relation to a generating station means the declared capacities (DCs) for the days expressed as a percentage of the installed capacity in MW reduced by the normative auxiliary energy consumption."*

5.26.3 One beneficiary submitted that in case of non-availability of fuel or water, the plant should not be considered available as it is the responsibility of the generator (except where it is committed by beneficiary) to provide the same. Accordingly, the definition may be amended. The availability of the plant needs to be considered only if there is a consent given by beneficiaries for the use of alternate fuel. NLC submitted that the definition may include the clause at the end *"....and further reduced by the normative consumption by linked Mines/Internal schemes"*

Commission's Views

5.26.4 The suggestions of the stakeholders are mainly to consider the factors like non-availability of water or fuel and normative consumption by linked mines/internal schemes. The Plant Availability Factor is to be arrived based on average of daily declared capacities. As per definition of Declared Capacity, the availability of fuel or water is to be ensured by the generating station. The Commission is of the view that the issue of availability of fuel or water as raised by the stakeholders has been addressed in the definition of declared capacity and hence, the definition of Plant Availability Factor does not require any changes. As regards the suggestion of NLC to consider the normative consumption of linked mines, the Commission is of the view that the same should be accounted for in transfer pricing of coal or lignite from the linked mine.

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5.27 Plant Load Factor {Regulation 3 (41)}

5.27.1 Clause 3(41) of the draft Regulations defines Plant Load Factor (PLF) for a given period as the total sent out energy corresponding to scheduled generation during the period, expressed as a percentage of sent out energy corresponding to installed capacity in that period, which shall be computed in accordance with a formula specified in the Regulations.

Stakeholders' Comments/Suggestions

5.27.2 MPERC and few other stakeholders submitted that Scheduled Generation in MW (SGi) is figured for the i^{th} time block of the period. There is no need to mention 'k' in the formula. THDC submitted that the definition may include clause *"in relation to a thermal generating station"*. NLC submitted that the formula for computation of the PLF should factor in the normative consumption of the linked Mines/Internal schemes.

5.27.3 Some of the generating companies submitted that as per the formula, the PLF can be calculated at the station level and not at the Unit level, and hence, Installed Capacity (IC) considered in the definition of PLF, may be modified as:
'IC = Installed Capacity of the generating station or generating unit in MW'.

5.27.4 NTPC submitted that to avoid confusion with the existing definition of PLF, the new definition should be renamed as Scheduled PLF (SPLF) instead of PLF.

<u>Commission's Views</u>

5.27.5 The Commission is of the view that since the definition of Plant Load Factor is for a thermal generating station, it is pertinent to mention so in the Regulation. Therefore, the Commission has decided that it is appropriate to qualify the definition with the words *"in relation to thermal generating station or unit"* in the Regulations. Further, the term 'k' was appearing inadvertently in the formula and the same has been removed. The definition of PLF specified herein is for the purpose of Tariff Regulations and is linked to Scheduled Generation, and hence, there is no need to rename it as Scheduled PLF. The IC considered in the definition of PLF has been modified to include Unit also. As regards the suggestion of NLC to consider the normative consumption of linked mines, the Commission is of the view that the same should be accounted for in transfer pricing.

5.27.6 Accordingly, the modified Regulation is as under:

*"'**Plant Load Factor or '(PLF)**' in relation to thermal generating station or unit, for a given period means the total sent out energy corresponding to scheduled generation during the period, expressed as a percentage of sent out energy corresponding to installed capacity in that period and shall be computed in accordance with the following formula:*

$$PLF = 10000 \times \sum_{i=1}^{N} SG_i \,/\, \{N \times IC \times (100 - AUX_n)\}\%$$

Where,

IC = Installed Capacity of the generating station or unit in MW,

SG_i= Scheduled Generation in MW for the i^{th} time block of the period,

N = Number of time blocks during the period, and

AUX_n = Normative Auxiliary Energy Consumption as a percentage of gross energy generation"

5.28 Definition of Prudence Check

5.28.1 Considering the suggestions of stakeholders, the Commission has decided to include the definition of Prudence Check as under:

> *"**'Prudence Check'** means scrutiny of reasonableness of capital expenditure incurred or proposed to be incurred, financing plan, use of efficient technology, cost and time over-run and such other factors as may be considered appropriate by the Commission for determination of tariff. While carrying out the Prudence Check, the Commission shall look into whether the generating company or transmission licensee has been careful in its judgments and decisions for executing the project or has been careful and vigilant in executing the project; "*

5.29 Regular Service {Regulation 3 (48)}

5.29.1 Clause 3(48) of the draft Regulations defines Regular Service as putting into use a transmission system or element thereof after successful testing and charging for which it has been installed and a certificate to that effect has been issued by the concerned Regional Power Committee. In the draft Regulations, a proviso was made for the transmission system or the element thereof after being put into regular service to demonstrate availability of not less than the normative availability in the month following the date of declaration of commercial operation.

<u>Stakeholders' Comments/Suggestions</u>

5.29.2 SRPC submitted that the role of Regional Power Committee should be specifically defined to indicate whether it covers successful trial run or covers the requirement that the transmission element has met the normative availability in the month following the COD. Some stakeholders suggested that a proviso may be added to mandate RPC to issue Commissioning Certificate within 48 hours. Further, in case transmission system is not able to demonstrate the normative availability, the same shall get captured in cumulative availability and revenue to that effect shall get reduced. Hence, the first and second provisos to clause 3(48) of the draft Regulations may be deleted.

5.29.3 POWERGRID submitted that the clause 3(48) of the draft Regulations may be modified as under:

> *"'regular service' means putting into use a transmission system or element thereof after <u>successful trial operation</u> and a certificate to that effect has been issued by the <u>concerned Regional Load Despatch Centre after trial operation</u>:*

……………not less than the normative availability, as provided in CERC (Standards of Performance of Inter-State Transmission Licensees) Regulations, 2012, in the month following the date of declaration of commercial operation

……………to demonstrate normative availability, as provided in CERC (Standards of Performance of Inter-State Transmission Licensees) Regulations, 2012, except for the reasons beyond the control of the transmission licensee and also as defined in Appendix III of the Regulation under "Procedure for calculation of transmission system availability factor for a month under clause 5(i) & (ii) and 6 (i) &(ii)", such transmission system or the element is said to be put into regular service from the date of demonstrating normative availability for a month;"

Commission's Views

5.29.4 The condition of normative availability was proposed with a view to ensure the minimum availability of the transmission system and for that, the transmission licensee was expected to complete all relevant works prior to declaration of COD. Suggestions have been made to remove the 1st and 2nd provisos to the clause (48) linking regular service with failure to demonstrate normative availability on the premise that reduction of normative availability has been taken care in recovery of annual fixed cost, the Commission has reviewed the proposed definition. The condition of demonstrating normative availability was proposed with a view to ensure that the transmission licensee completes all relevant works prior to declaration of COD. The Commission has has considered the matter and is of the view that the transmission licensee does not recover full fixed charges if it fails to achieve normative target availability. Therefore, the first and second provisos to the clause 3(48) of the draft Regulations have been deleted.

5.29.5 Considering the views of stakeholders, the Commission has decided to link the definition of regular service to trial operation and accordingly, the definition is modified as under:

"'Regular Service' means putting into use a transmission system or element thereof after successful trial operation and a certificate to that effect has been issued by the concerned Regional Load Dispatch Centre."

5.30 Scheduled Commercial Operation Date {Regulation 3 (49)}

5.30.1 Clause 3(49) of the draft Regulations defines SCOD as the date(s) of commercial operation of a generation or transmission project as indicated in the investment approval or as agreed in power purchase agreement or transmission service agreement as the case may be, whichever is earlier.

Stakeholders' Comments/Suggestions

5.30.2 THDC India Limited submitted that the draft Regulation may be modified as under:

> *"Scheduled commercial operation date or SCOD shall mean the date(s) of commercial operation of a generation or transmission project or a unit thereof on the completion of 3 months after the scheduled commissioning as indicated in the investment approval or as agreed in power purchase agreement or transmission service agreement as the case may be, whichever is earlier;"*

5.30.3 SJVNL submitted that reasons beyond the control of generator in the Hydro projects lead to time extension for completion of the project as scheduled. Therefore, SCOD may be considered as date of commercial operation as defined in draft Regulation 4. Some of the stakeholders suggested that draft Regulation may be modified as under :

> *"Scheduled commercial operation date or SCOD shall mean the date(s) of commercial operation of a generation <u>station or generating unit or block thereof or transmission system or element</u> as indicated in the investment approval or as agreed in power purchase agreement or transmission service agreement as the case may be, whichever is earlier;"*

5.30.4 NHPC submitted that the delay in Land Acquisition, extra ordinary geological surprises, law and order problems, stoppage of work due to local unrest / employment issues, legal hurdles, inter-State dispute and international disputes should be considered as uncontrollable factors. Therefore, clause 3(49) of the draft Regulations may be modified as follows:

> *"Scheduled commercial operation date or SCOD shall mean the <u>last day of quarter in which the</u> date(s) of <u>commissioning</u> of a generation or transmission project as*

indicated in the investment approval falls or as agreed in power purchase agreement or transmission service agreement as the case may be, whichever is earlier;

Provided that where delay in commercial operation is on account of uncontrollable factors, the date(s) of commercial operation after taking into account delay on account of uncontrollable factors shall be considered as SCOD."

Commission's Views

5.30.5 The suggestions of stakeholders are mainly to deal with the situation where delay is occurring due to various controllable and uncontrollable factors. The purpose of SCOD is to ensure that the project developer prescribes a firm time schedule for implementation of the generation or transmission project in the investment approval or in the power purchase agreement in case of generation project and Transmission Service Agreement in case of transmission system. It was provided in the draft Regulation that the date in the investment approval or the date in the PPA/TSA whichever is earlier should be reckoned as SCOD. The same was proposed keeping in view the interest of the consumers as the consumers should be required to pay less IDC if the project is implemented within the shortest possible time. As regards the suggestion of THDC to allow a cushion of three months for the purpose of stabilization or testing of the unit between the date of commissioning and date of commercial operation, the Commission is of the view that the Board of the generating Company should factor in all such events while prescribing the time schedule for implementation of the project and there is no requirement to allow additional time beyond the time approved in the investment approval or PPA. As regards the suggestion of NHPC to take into account the delay due to uncontrollable factors for the purpose of deciding SCOD, it is clarified that SCOD prescribes the assessed time line within which the project is required to be implemented. In case, implementation of the project exceeds the SCOD due to certain uncontrollable factors, the same has been taken care of in the Regulation dealing with the Capital cost of the project. As regards the suggestion of SJVNL, the Commission is of the view that in case the unit or block of the generating station and elements of the transmission system have a different time schedule for implementation, the same need to be reflected in the definition SCOD. Accordingly, the definition of SCOD is modified as under :

(54) **'Scheduled Commercial Operation Date or SCOD'** shall mean the date(s) of commercial operation of a generating station or generating unit or block thereof or transmission system or element thereof as indicated in the Investment Approval or as agreed in power purchase agreement or transmission service agreement as the case may be, whichever is earlier;

5.31 Scheduled Generation {Regulation 3 (50)}

5.31.1 Clause 3(50) of the draft Regulations defines scheduled generation as schedule of ex-bus generation in MW or MWh, given by the concerned Load Despatch Centre.

Stakeholders' Comments/Suggestions

5.31.2 NTPC submitted that in case of gas stations, correction in Scheduled Generation may be provided below 50.0 Hz. Some stakeholders requested to initiate the process to determine the technical minimum of various plants in the country regulated by the Commission, and include suitable proviso in this definition. In the meantime, till such technical limits are established, they suggested that the technical limits be fixed at a level of 60% of the installed capacity. In case the installed capacity is shared by more than one beneficiary, then each beneficiary should be restricted from going down below 60% of its contracted capacity in the plant.

Commission's Views

5.31.3 The Commission has gone through the comments and suggestions. The suggestion of NTPC to provide for correction in scheduled generation below 50.00 Hz with regard to gas based generating stations, the Commission is of the view that up to 49.52 Hz, the gas based generating station will provide stable output and hence, the definition proposed in the draft Regulations is appropriate and does not require any change. As regards the technical minimum limit, the Commission is already aware of the issue and shall appropriately address the same separately.

5.32 Start Date or Zero Date {Regulation 3 (52)}

5.32.1 Clause 3(52) of the draft Regulations defines the Start Date as the date indicated in the investment approval from which the implementation of the project has commenced or is deemed to have been commenced.

Stakeholders' Comments/Suggestions

5.32.2 NTPC submitted that this definition of start date/zero date may be applied for projects, which will be cleared for approval in this Tariff Period only. Some generating companies submitted that the 'start date or zero date' should be linked to the grant of Environmental and Forest Clearance by MoEF or other major approval/clearances or acquisition of land, which is essential for establishment of the Project, whichever is later, and not with the investment approval.

Commission's Views

5.32.3 As regards the applicability of Regulations for existing projects commissioned prior to 31.3.2014, the proviso to Regulation 1 shall be applicable. The Tariff Regulations, 2014 shall be in operation for five years from 1.4.2014 to 31.3.2019 and shall be applicable to existing projects which were commissioned prior to 1.4.2014 and new projects which are commissioned on or after 1.4.2014. The zero date or start date shall be applicable to the project which are commissioned during the period from 1.4.2014 till 31.3.2019 irrespective of the clearance of the project. Where the zero date or start date has not been specified in the investment approval, the date of investment approval shall be deemed to be the start date or zero date. For the projects cleared for approval in the Tariff Period 2009-14 but commissioned in the Tariff Period 2014-19, the provision of Tariff Regulations, 2014 will be applicable irrespective of the period when the project was cleared. Accordingly, the definition has been modified as under ::

> *"'**Start Date or Zero Date**' means the date indicated in the Investment Approval for commencement of implementation of the project and where no date has been indicated, the date of investment approval shall be deemed to be Start Date or Zero Date;"*

5.32.4 Since the start date or zero date is important from the point of view of assessment of time over run, the generating Company or transmission licensee shall invariably ensure that the investment approval contain the zero date or start date without any caveats or conditionality.

5.33 Trial Run or Trial Operation {Regulation 3 (55)}

5.33.1 Clause 3(55) of the draft Regulations defines Trial Run in relation to transmission system as having the same meaning as specified in Regulation 5 of the draft Regulations.

<u>Stakeholders' Comments/Suggestions</u>

5.33.2 THDC India Limited submitted that the clause 'in relation to transmission system' may be removed from the definition. Some stakeholders suggested that the definition may also include generating station.

<u>Commission's Views</u>

5.33.3 The Commission is of the view that as the Regulations are for generation and transmission, there is a need to include generating station also in the definition. Accordingly, the modified Regulation is as under:

> *"**'Trial Run' or 'Trial Operation'** in relation to transmission system or a generating station shall have the same meaning as specified in Regulation 5 of these regulations;"*

5.34 Useful Life {Regulation 3 (60)}

5.34.1 Clause 3(60) of the draft Regulations defines Useful Life in relation to a unit of a generating station and transmission system from the COD.

<u>Stakeholders' Comments/Suggestions</u>

5.34.2 NTPC submitted that the useful life of communication system should be reduced to 4-5 years. Some of the stakeholders submitted that there is no rationale for increasing useful life of AC/DC Sub stations from 25 to 35 years. Therefore, it is suggested to continue 25 years of Useful Life for AC/DC Substations. GRIDCO submitted that in view of the modern upgraded technology including the present performance, the useful life of the different types of Generating Stations may be enhanced by 5 years. Some of the stakeholders submitted that the proposal of increasing useful life of AC and DC substations to 35 years is justified. POWERGRID has proposed useful life of communication system as 15 years.

5.34.3 POWERGRID submitted that substation equipment are failing much before completion of the existing useful life due to various reasons such as heavily stressed Indian grid conditions, international practices, non-availability of spares, absence of adequate protection in downstream systems of utilities, high loading in case of HVDC systems, frequency of operation, etc., and therefore, the useful life of substation equipments cannot be more than 25 years. For establishing life of 25 years, it cited examples of transmission system for which useful life have been allowed by the Commission in tariff for replacement of equipment through additional capitalization after completion of 25 years of service life.

5.34.4 POWERGRID submitted that the investment decision for the existing assets was based on the life of assets to be around 25 years. It submitted that design criteria plays a great role in the longevity of the equipment. It is likely that all the equipment supplied by the manufacturers are designed considering the criteria 'to give life of not less than 25 years' in order to optimize the cost. Hence, old equipment has no reliability of continuing operations up to 35 years. Further, for introduction of 35 years of useful life for new equipment, vendor /product development has to be done with satisfactory test result for 35 years, which will take considerable time.

5.34.5 Adani Power Ltd. submitted that the Explanatory Memorandum did not provide the firm basis for increasing the useful life to 35 years. It submitted that existing systems' useful life cannot be increased to 35 years since, they have been designed for 25 years. It cited other reasons such as design criteria, frequent replacement of protection system, and insulation degradation, and submitted that if newer system is to serve for 35 years it shall involve additional capital cost.

Commission's Views

5.34.6 As regards submission of POWERGRID that sub-station equipments operating under the Indian grid conditions are heavily stressed, it is noted that keeping in view the future load growth and right of way problem, high capacity transmission systems are being developed. So, during the initial operational period, equipment may not get fully loaded.

5.34.7 The Commission, during the Tariff Period 2009-14, had also approved tariff for various spare transformers, reactors, converter transformers and additional capitalization for upgradation and replacements of the equipment before the end of their useful life under relevant provisions of additional capitalization. With the availability of these spares, it is possible to take out existing equipments for various tests and if the value of technical parameters is not satisfactory as compared to values specified in the Technical Standards (national/international), it can be repaired either on site or at vendor site. Also, the Commission is aware that in case of certain technological obsolescence and non-availability of spares/vendor support, it is sometimes necessary to replace some of the bay equipment like CT/PT/LA/CB, if found necessary, after testing and exploring all alternatives.

5.34.8 As regards the deficiency pointed out by the POWERGRID in the down stream intra-State Transmission System of State utilities, the Commission, on the basis of protection audit report, has already initiated action and directed the State Utilities to correct the deficiencies in case of repeated fault at a particular State substation. The Commission has taken several measures to maintain grid discipline like automatic demand disconnection, protection audit, etc., which are expected to improve operation of intra-State transmission system. As regards high loading of Talcher-Kolar HVDC system, additional loading is allowed only for six hours and additional capital investment for this purpose has been allowed. Further, an analysis of the outage data given by POWERGRID brings out that the availability of all HVDC and AC systems is continuously increasing; the availability of even Rihand-Dadri HVDC system has increased substantially as the performance of converter transformers has improved and incident of failure of converter transformers is substantialy reduced not there at present. Also, spare converter transformer sets are available in all HVDC stations.

5.34.9 Considering the long-term interest of the consumers, the Commission is encouraging promotion of new technologies to increase the useful life of the equipment, thereby reducing the total life cycle cost of the equipment and improving the quality of service to the consumers. The Commission will continue to support adoption of new technology by the utilities. New technologies such as superconductor, etc., may also be explored in future and any pilot project based on this may also be considered. The above measures will enhance the expected life of operation of equipment. The Commission has consciously decided to increase the life of AC and DC sub-stations.

5.34.10 The Commission is of the view that useful life of the equipment may be higher than design life if it is properly maintained, routine tests are carried out regularly, and the use of IT based asset management systems are adopted.

5.34.11 As regards useful life of the substation, it is clarified that useful life of 35 years was proposed in the draft Regulations based on international practices. In view of the stakeholders' suggestion that the useful life of the existing systems may not be increased to 35 years, since the existing substation equipment has been designed to give life of at least 25 years, the Commission has decided to retain the useful life of existing AC and DC substations as 25 years. Further, the useful life of Gas Insulated Sub-stations has also been specifically mentioned.

5.34.12 In this context, the Commission has noted the following:

a. The CIGRE Committee B3-103, in its published paper on 'Substation life cycle cost management supported by Stochastic optimization algorithm' has assumed lifetime for all substation components as 40 years.

b. Based on Sinclair Knight Merz (SKM) experience of more than 15 years of transmission asset valuations and detailed understanding of factors affecting the economic life of transmission assets in a number of countries worldwide, it has estimated the typical economic life span of major high voltage electrical equipment to fall within the following range:

- Substation Switch bays : 45-50 years
- Substation Establishment : 50 - 60 years
- Power Transformers : 45 - 50 years
- Capacitors : 40 years
- Circuit Breakers : 45 years

- Current Transformers : 45 years
- Voltage Transformers : 45 years
- Control & Protection Schemes : 15 - 30 years
- SCADA Systems : 15 years

c. M/s. ABB in its paper CIRED 2009, Paper 0764 states that primary equipment in substations has a typical life span of 30 to 50 years, and upgrades on the secondary equipment have often been forced to follow almost the same cycle.

d. The Asset life applicable to new assets as proposed by Transgrid before the Australian Energy Regulator is as under:
   - Transmission Lines and Cables : 50 years
   - Substations : 40 years
   - Secondary Systems : 35 years
   - Communications : 35 years

   Asset life applicable to replacement assets as proposed by Transgrid before the Regulator is as under:
   - Transmission Lines and Cables : 26 years
   - Substations : 40 years
   - Secondary Systems : 35 years
   - Communications : 35 years

e. Office of Gas and Electricity Markets (Ofgem), the regulator for the electricity and downstream natural gas markets in the Great Britain, in its decision ruled that all new assets will be depreciated over 45 years but existing electricity transmission assets will continue to be depreciated over 20 years.

f. Republic of Ireland (Electricity Transmission 2011-15) – re-iterated asset life of 50 years for high voltage network assets. This had been extended to 50 years (from 40 years) under the price control 2005-2010.

5.34.13 Taking note of the above mentioned technical documents, study papers, and international reports available in the public domain, the Commission is of the view that the life expectancy of substation equipments is between 35 to 50 years. The Commission has noted that few stakeholders have also agreed to the proposal to consider enhanced life of 35 years for the purpose of tariff. However, taking cognizance of the plea of other stakeholders to consider useful life of existing substations as 25 years, the Commission has decided that the useful life of the existing substations shall be considered as 25 years. However, the useful life of the substations for which Notice Inviting Tender is floated on or after 01.04.2014 shall be considered as 35 years. The Commission has considered the suggestions regarding useful life of communication system and finds it appropriate to retain useful life of the Communication system as 15 years as proposed in the draft Regulations. Accordingly, the modified Regulation is as under:

"'Useful life' in relation to a unit of a generating station and transmission system from the COD shall mean the following, namely:-

(a)	*Coal/Lignite based thermal generating station*	*25 years*
(b)	*Gas/Liquid fuel based thermal generating station*	*25 years*
(c)	*AC and DC sub-station*	*25 years*
(d)	*Gas Insulated Substation (GIS)*	*25 years*
(e)	*Hydro generating station including pumped Storage hydro generating stations*	*35 years*
(f)	*Transmission line (including HVAC & HVDC)*	*35 years*
(g)	*Communication system*	*15 years*

Provided that the useful life for AC and DC substations and GIS for which Notice Inviting Tender is floated on or after 01.04.2014 shall be considered as 35 years.

Provided further that the extension of life of the projects beyond the completion of their useful life shall be decided by the Commission;"

5.34.14 In view of the Commission's decision to consider the useful life of 35 years for the new equipment, the Commission would like to suggest following :

i) POWERGRID/Transmission Licensee may initiate action for vendor development, R&D and international technology transfer to achieve, develop, and design for substation equipments corresponding to useful life of 35 years. In this context, transmission licensees should take guidance from their experience of approving design of vendors, tested and approved by the reputed agencies including CPRI.

ii) In case of substations for which Notice Inviting Tender shall be issued on or after 01.04.2014, minimum time of 18 to 24 months is considered to be sufficient for introduction of substation equipments with useful life of 35 years, which may be based on new technology, if necessary. The Commission is of the view that POWERGRID, which is operating and maintaining a very large asset base of high voltage equipment shall take a lead in this respect and help in developing equipment with longer useful life.

5.35 **Other Suggestions on Definitions and Interpretation {Regulation 3}**

5.35.1 GUVNL submitted that definitions of change in law, Government Instrumentality and Competitive bids, etc., have been used in the draft Regulations. However, these definitions/terms are relevant for adoption of tariff under Section 63 of Electricity Act 2003, whereas the Tariff Regulations are framed for tariff determination under Section 62 of the Electricity Act, 2003. Therefore, these definitions may be removed. THDC India Limited submitted that the definition of 'Commissioning' may be added after clause 3(10) of the draft Regulations as follows:

"The term 'Commissioning' may be defined in similar line as communicated by MOP, GoI vide their Order no. 3/2/2007-P&P dated 12.08.2008."

Commission's Views

4.35.1.2 The Commission is of the view that the definitions of Change in law, Government Instrumentality and Competitive Bidding are relevant for tariff determination. "Change in Law" has been applied by the Commission as one of the reasons for admitting additional capital expenditure claims made by the generators/transmission licensees. In the present Regulation, the "Change in Law" has been used for prudence check of capital expenditure, additional capital expenditure and at the time of truing up exercise involving operational and financial parameters. "Government Instrumentality" which has been used in Change in Law has been defined for the purpose of clarity. The term, "Competitive Bidding" has been used in this regulation in the context of procurement process to be adopted by the generating Company or Transmission licensee for procurement of various packages which is different from the selection of project developer or transmission service provider.

4.35.1.3 As regard the suggestion of THDC to define the term "Commissioning, the Commission is of the view that the said term has not been independently used in the regulations and therefore there is no need to define the term.

5.35.2 Some stakeholders suggested that the definition of 'Controllable factors' and 'Un controllable factors' may be added. One beneficiary suggested that "Due date of Payment" should be defined in the Regulations because the generating companies sometimes consider due date as two days from the bill date and some time as 30 days from the bill date. The Commission clarifies that the term "controllable" and "un-controllable" are self-explanatory and the factors covered under these terms have been enumerated in Regulation 12 and hence there is no need to specifically include a definition for the same. As regards definition of "Due date of payment", it is clarified that 'Due date of payment' has not been used in Regulation 44 and Regulation 45 which deals with the mechanism for the rebate and late payment surcharge and therefore specific definition for "Due date of payment" is not required.

5.35.3 POWERGRID submitted that the following terms should be defined in Final Tariff Regulations: Decapitalization, Assets not in use, Effective Commercial operation date, Consolidated petition combining all the assets to be commissioned. POWERGRID also submitted that the following terms need to be incorporated:

- Tariff for POC billing
- Stranded asset treatment

POWERGRID has submitted that in case of stranded assets, the Commission may provide Return on the blocked investment from the originally scheduled commercial operation date and provide appropriate relief in the Regulations on these accounts. Compensatory tariff in such cases to address the debt servicing obligations and the equity returns should at the least be provided for in the Regulations.

Commission views

5.35.4 As regards the suggestions to define additional terms, the Commission appreciates that the stakeholders desire more clarity in respect of use of these terms. In this regard, it is clarified that wherever it is felt necessary, particular terms have been stated clearly and in other cases the terms have been explained in the respective regulations.The purpose and usage of terms, viz. decapitalization, effective commercial operation date, controllable and uncontrollable factors have been provided in the Regulations. As regards due date of payment, it is self explanatory. Further, separate definition of 'assets not in use' and 'consolidated petitions' is not required. The assets not in use are the assets, which are not providing intended services of transmission or generation as the case may be. The Commission is of the view that the terms are already discussed in various clauses of the Regulations and therefore, there is no need to define these separately.

5.35.5 MPPMCL submitted that a new definition under clause 3(35A) may be added to define 'Month' to mean 30/31 days, as the case may be, to provide clear interpretation of third proviso to clause 4(1) of the draft Regulations.

5.35.6 Some stakeholders submitted that the term Renovation & Modernisation needs to be precisely defined and should cover only instances of use of modern technology, up-gradation, energy-saving, cost-saving and environment-friendly technology and machinery.

5.35.7 Some stakeholders suggested that the definitions of 'Prudence Check' and 'Tariff' should be provided in the Tariff Regulations and the term 'Working Capital' should be defined in the context of the electrical industry.

Commission's Views

5.35.8 In the Regulations, third proviso to the clause 4(1) of the draft Regulations has been modified and hence, the Commission is of the view that definition of month is not required. The term Renovation and Modernization has already been dealt with in detail in clause 15 and same needs no further clarification. The Commission has considered the suggestion to define the term prudence check and concluded that generic definition of term 'prudence check' should be included as the same has been used at many places in the Regulations. The term 'tariff' has been covered in the Chapter-5 and does not need further explanation. Further, Working Capital has been dealt in detail in clause 28 and hence, there is no need to specifically define the same.

6. Date of Commercial Operation {Regulation 4}

6.1 The first proviso of clauses 4(1) and 4(2) of the draft Regulations proposed that the trial run shall commence after seven days notice by the generating company to the beneficiaries and scheduling shall commence from 0000 Hr after acceptance of the test results by the beneficiaries or within 48 hours after the trial run, whichever is earlier. The second proviso to Clauses 4(1) and 4(2) of the draft Regulations proposed that it shall be mandatory for the generating company to obtain a certificate from Central Electricity Authority or any agency designated by Authority to the effect that the generating station meets all the technical standards of Central Electricity Authority (Technical Standards for Construction of Electrical plants and electric lines) Regulations, 2010 and the Grid Code. Further, the third proviso of clause 4(1) of the draft Regulations proposed that the generating station or Unit after commercial operation shall demonstrate the plant availability of not less than the normative plant availability in the month following the date of declaration of commercial operation. If the generating station or Unit thereof is not able to demonstrate normative availability, except for the reasons beyond the control of the generating company, such generating station or Unit is said to be put into commercial service from the month of normative availability.

6.2 For hydro stations, the third proviso to clause 4(2) of the draft Regulations specified that in case a hydro generating station with pondage or storage is not able to demonstrate peaking capability corresponding to the installed capacity for the reasons of insufficient reservoir or pond level, the date of commercial operation of the last Unit of the generating station shall be considered as the date of commercial operation of the generating station as a whole, and it will be mandatory for such hydro generating station to demonstrate peaking capability equivalent to installed capacity of the generating Unit or the generating station as and when such reservoir/pond level is achieved. Similarly, the fourth proviso to clause 4(2) of the draft Regulations states that if a purely run-of-river hydro generating station or a generating unit thereof is declared under commercial operation during lean inflows period when the water inflow is insufficient for such demonstration of peaking capability, it shall be mandatory for such hydro generating station or generating Unit to demonstrate peaking capability equivalent to installed capacity as and when sufficient water inflow is available.

6.3 Clause 4(3) of the draft Regulations specified that the date of commercial operation in relation to a transmission system shall mean the date declared by the transmission licensee from 0000 Hr of which an element of the transmission system is in regular service after successful charging and trial operation for transmitting electricity and communication signal from sending end to receiving end.

Stakeholders' Comments/Suggestions

6.4 One Generating Company commented on the first proviso of clause 4(1) of the draft Regulations and submitted that 7 days period for notice is too long and may be changed to 3-4 days.

6.5 Several suggestions from the stakeholders were received on the second proviso to Clauses 4(1) and 4(2) of the draft Regulations related to obtaining a certificate from CEA or any agency designated by the Authority. Most of the Generating Companies submitted that requirement of certification by CEA may delay COD of Units with financial implications thereby delaying supply of electricity to beneficiaries. They mentioned that statutory inspections by electrical inspector, boiler inspector, etc., are already applicable and hence, CEA certification may not be made mandatory. SRPC submitted that the provisions of Central Electricity Authority (Technical Standards for connectivity to grid) Regulations, 2007 and Central Electricity Authority (Grid Standards) Regulations, 2010 should also be met. SRPC also submitted that Certificate of meeting the normative plant availability could be issued by the Member Secretary, RPC. A suggestion was also received that CEA should be required to certify only those provisions, which relate directly to the commercial operation of the asset and once a COD or DOCO is declared by owner of the asset, it should be subject to subsequent cross checking and verification by CEA. In case there are deficiencies, then the date when the deficiencies are removed and are verified by CEA shall be considered as DOCO. NLC submitted that for projects under construction, obtaining certificate from CEA for reckoning the date of commercial operation is not possible. Further, CEA in its report submitted as follows:

As per the Electricity Act 2003, "*Any generating company may establish, operate and maintain a generating station without obtaining a licence under this Act if it complies with the technical standards relating to connectivity with the grid referred to in clause (b) of section 73*" (Sec-7 of the Act)

6.6 CEA further submitted that it is not feasible to conceive any process of detailed examination and certification of compliance to the Regulations before allowing commercial operation of such large number of Units.

6.7 On the third proviso of clause 4(1) of the draft Regulations, NTPC submitted that annulment of COD on a subsequent date due to lower availability will have issues of billing, accounting, etc., and in any case, generator will be losing fixed charges. Therefore, requirement of demonstration of target availability in next month should be dispensed with. Some other Generating Companies also expressed similar views that the third proviso to clause 4(1) of the draft Regulations may be deleted.

6.8 Some IPPs submitted that for plants with part capacity tied up under CERC Regulations and balance capacity to be tied up under Case-1 bidding, this provision will impose restriction on declaring COD since the normative availability cannot be demonstrated with only part of the capacity tied up. Therefore, the provision should be clarified.

6.9 Some stakeholders also suggested that the Commission may allow a stabilization period of minimum 6 months after COD with relaxed norms applicable during the stabilization period to fulfil the specified condition for demonstrating the normative availability. Some beneficiaries submitted that the Regulation may also include concerned RLDC and RPC and also the term 'commercial service' may be replaced by 'commercial operation'.

6.10 NHPC submitted that distinction should be made between definition of Trial Run in case of a hydro generating station and thermal generating station in line with the revised definition of commissioning issued by the Ministry of Power (MoP). JVVNL submitted that the draft Regulations do not appear to be reasonable as the total risk in case of hydro generating stations is proposed to be covered by the beneficiaries and in turn by the end consumers. There should be a time limit prescribed, say one year, to cover all the seasons for demonstrating the peaking capability.

6.11 APDCL submitted that there may be time frame of one month during which the transmission licensee must ensure that:

a. Regular service without any shut down for reasons attributable to the licensee
b. Ability to cater to the requirement of scheduled demand of Beneficiaries depending on the availability of the associated Generating Station and network capacity in between the generating Station and receiving substation of the Beneficiary State.
c. Other associated services like communication service, etc.

6.12 SRPC submitted that the clause 4(3) of the draft Regulations may be modified as follows:

> *"(3) Date of commercial operation in relation to a transmission system shall mean the date declared by the transmission licensee from 0000 hour first day of next calendar month in which an element of the transmission system is in regular service after successful charging and trial operation for transmitting electricity and communication signal from sending end to receiving end: …………………."*

6.13 SRPC also submitted that a new proviso may be inserted as under:

> *"Provided that the transmission company shall obtain a Certificate from Central Electricity Authority or any agency designated by the Authority to the effect that the transmission elements in place meet the technical standards of Central Electricity Authority (Technical Standards for Construction of Electrical plants and electric lines) Regulations, 2010, Central Electricity Authority (Technical Standards for Connectivity to Grid) Regulations, 2007, Central Electricity Authority (Grid Standards) Regulations, 2010 and IEGC Regulations as amended from time to time or any subsequent re-enactment thereof."*

6.14 POWERGRID submitted that clause 4(3) of the draft Regulations may be modified as follows:

> *"Date of commercial operation in relation to a transmission system or element thereof shall mean the date declared by the transmission licensee from 0000 hour of which a transmission system or element is in regular service after successful charging and trial operation for the purpose of transmitting electricity along with voice and data and communication signal from sending end to receiving end:*
> *......."*

Commission's Views

6.15 In the second proviso to clause 4(1) of the draft Regulations, the Commission, with the intent to prevent the declaration of COD by the generating stations without meeting requisite technical standards, proposed requirement for obtaining certificate from CEA or any agency designated by the Authority. CEA, in its recommendations, has submitted that certain key operational parameters should be ensured by the generator before declaring COD.

6.16 Considering the views of stakeholders as well as recommendation of CEA, the Commission is of the view that in order to avoid any unnecessary delays, instead of certification from CEA, self certification prior to declaration of CoD by the generating company to the effect that all key provisions as specified in Appendix VI of technical standards have been ensured, will meet the required intent. The issuance of such certificate shall be approved by the Board of Directors of the company and signed by an authority not below the CMD/CEO & MD of the Company. However, the Commission in order to restrict false declaration of COD has included a proviso that the generating station should submit copy of certificate to the Member Secretary (concerned RPC) and concerned RLDC before declaration of COD. The intent of self certification and submission to Member Secretary is to ensure that the developer observe certain standards prior to COD. Hence, in the event of any deficiency with reference to self-certification, the Commission may, on receipt of report from Member Secretary or filing of petition by beneficiary, initiate action for non-compliance of provisions of Tariff Regulations/technical standards of CEA in accordance with law.

6.17 As regards the third proviso to the clause 4(1) of the draft Regulations relating to the demonstration of plant availability of not less than normative availability in the month following the date of declaration of commercial operation, the Commission has, keeping in view the fact that a disincentive is already in place if a generating station fails to achieve the target availability, decided to dispense with the proposed proviso.

6.18 Considering the suggestions of stakeholders, the clause 4(1) of the Regulations is modified as under:

> *"(1) Date of commercial operation in case of a generating unit or block of the thermal generating station shall mean the date declared by the generating company after demonstrating the maximum continuous rating (MCR) or the installed capacity (IC) through a successful trial run after notice to the beneficiaries if any, and in case of the generating station as a whole, the date of commercial operation of the last generating unit or block of the generating station:*
>
> *Provided that*
>
> *(i) where the beneficiaries have been tied up for purchasing power from the generating station, the trial run shall commence after seven days notice by the generating company to the beneficiaries and scheduling shall commence from 0000 hr after completion of the trial run:*
>
> *(ii) the generating company shall certify to the effect that the generating station meets the key provisions of the technical standards of Central Electricity Authority (Technical Standards for Construction of Electrical plants and electric lines) Regulations, 2010 and Grid Code:*
>
> *(iii) the certificate shall be signed by CMD/CEO/MD of the company subsequent to its approval by the Board of Directors in the format enclosed at Appendix VI and a copy of the certificate shall be submitted to the Member Secretary, (concerned Regional Power Committee) and concerned RLDC before declaration of COD:"*

6.19 In similar manner, the provisos to clause 4(2) of the Regulations are modified as under:

> *Provided that:*
>
> *(i) where beneficiaries have been tied up for purchasing power from generating station, scheduling process for a generating unit of the generating station or demonstration of peaking capability corresponding to installed capacity of the*

generating station through a successful trial run shall commence after seven days notice by the generating company to the beneficiaries and scheduling shall commence from 0000 hr after completion of trial run:

(ii) the generating company shall certify to the effect that the generating station meets key provisions of the technical standards of Central Electricity Authority (Technical Standards for Construction of Electrical plants and electric lines) Regulations, 2010 and Grid code:

(iii) the certificate shall be signed by CMD/CEO/MD of the company subsequent to its approval by the Board of Directors in the format enclosed at Appendix VI and a copy of the certificate shall be submitted to the Member Secretary, (concerned Regional Power Committee) and concerned RLDC before declaration of COD:"

6.20 As regards the stabilisation period and relaxed norms during the same, even the CERC Tariff Regulations, 2009, do not specify any relaxed parameters during the stabilisation period for thermal power plants, and hence, the Commission did not consider it appropriate to propose relaxed norms in the draft Tariff Regulations for the next Tariff Period.

6.21 As regards the comments on notice period for commencement of trial run, the Commission disagrees with the views of the stakeholders that notice period of 7 days is long, and has, therefore, decided not to modify this provision of the draft Regulations.

7. Trial Run and Trial Operation {Regulation 5}

7.1 Clause 5(1) of the draft Regulations specified that Trial Run in relation to generating station shall mean the successful running of the generating station or Unit thereof at maximum continuous rating or installed capacity for continuous period of 72 hours. The first proviso to clause 5(1) of the draft Regulations specified that the generating company shall obtain a certificate from Central Electricity Authority or any agency designated by the Authority to the effect that the generating station has all the auxiliaries in place to meet the technical standards of Central Electricity Authority (Technical Standards for Construction of Electrical plants and electric lines) Regulations, 2010 and Grid code.

7.2 Clause 5(2) of the draft Regulations states that trial operation in relation to a transmission system or an element thereof shall mean successful charging of the transmission system or an element thereof for 24 hours at continuous flow of active power, and communication signal from sending end to receiving end and with requisite metering system, telemetry and protection system in service enclosing certificate to that effect from concerned Regional Load Dispatch Centre.

Stakeholders' Comments/Suggestions

7.3 NHPC and some other generating companies submitted that continuous running of station at MCR for 72 hours during trial run should not be made mandatory for hydro generators. Trial run for units of hydro projects should be limited to 12 hours. THDC submitted that the proviso to clause 5(1) of the draft Regulations may include the following clause:

> *"(except tripping due to fault on account of transmission system which is beyond the control of generating station) for which the generating company shall give notice for clear three days to the beneficiaries. Trial run in relation to Pumped Storage Plant or unit thereof shall mean the successful running of the generating station or unit thereof in pumping and turbine modes as per the manufacturer's specifications and availability of pumping energy and water."*

7.4 NLC submitted that the period of 72 hours of trial operation may not be sufficient enough to verify all the parameters of technical standards, since the operation of the Unit itself needs to get stabilized and it also requires time to install special instruments to conduct all the tests. NLC also submitted that stipulating COD through trial run, which is defined as 72 hours continuous running at rated installed capacity contravenes the CEA definition of COD. Tata Power Delhi Distribution Limited submitted that the Regulation may clarify whether continuous period of 72 hours is on hourly basis or based on 15 minute block which is used by SLDC for Scheduling & Despatch of power. CSPGCL submitted that the objective of the draft Regulation is sufficiently covered if the condition is modified to the extent that during the trial run period of continuous 72 hours, the average PLF should be 85% and in minimum 10% time blocks of 15 minutes each, the Unit should achieve

100% MCR. Accordingly, the Regulation may be revisited. Some stakeholders suggested modifying the draft Regulation stipulating Trial Run in line with the Model PPA for UMPP.

7.5 Some stakeholders submitted that dispatch of power during the trial run may be affected due to grid restrictions/variation in power demand of beneficiaries during the day/season. Such conditions are beyond the control of the power plant developer and therefore, backing down of the power plant generation during the trial runs should be allowed as deemed generation and in such an event, deemed COD should be permitted. They further argued that alternatively, it should be made mandatory for RLDCs or SLDCs to schedule the power projects undertaking trial run or commissioning test on full load basis during the period and such plants should be considered as "Must Run". It should be a deemed completion of Trial Run at full load for 72 hours if plant has operated according to the dispatch instructions (with deemed generation for backing down period).

7.6 Some of the stakeholders submitted that the requirement of obtaining a certificate from CEA may be reviewed or dispensed with or the Commission may dispense with the condition of obtaining a Certificate from CEA for adherence to Technical Standards at least for the plants under construction/Commissioning.

7.7 POWERGRID submitted as under:

a. The requirement of active flow of power needs to be removed, since, once the transmission elements are successfully charged, the elements are immediately available for transmission of power @100% of its rated capacity. Actual power flow through any AC element is dependent on grid condition along with demand and supply situation of the grid, which is beyond the control of POWERGRID.

b. "Continuous flow of active power" may also be deleted on account of the fact that there are elements like Reactor, SVC, series compensator where no active power flow takes place.

c. Moreover, the metering arrangement is to be done by CTU only and is not covered in the scope of the transmission licensee. So for the completion of the trial operation of a transmission element, completion of metering arrangement should also not be imposed. There cannot be a COD without metering in place and transmission licensee other than POWERGRID may suitably take up with CTU for timely implementation of metering.

Commission's Views

7.8 The Commission has gone through the comments and suggestions of various stakeholders on this Regulation. The Commission is of the view that the in case of hydro generating stations, continuous operation for 72 hours may not be appropriate as the continuous run will depend upon the water inflow, which is not in the control of the generator. NHPC has suggested a trial run period of 12 hours. The Commission is of the view that trial run in respect of a hydro generating station should be successful running of the generating station for continuous period of 12 hours at Maximum Continuous Rating (MCR), which should be sufficient to demonstrate the reliability of the plant.

7.9 Further, for reasons already discussed earlier, the certification from CEA has been removed and the Commission has included the provision of self certification to be given by generating company before declaration of COD. Further, the Commission has decided to include a proviso to clause 5(1) of the Regulations specifying the time period of seven days to generating station for notice to the beneficiaries about the trial run.

7.10 The Commission considered the submissions and agree with the suggestions of POWERGRID that for reactors, active power flow will not be applicable; hence, the word 'active' is deleted. Further, metering requirement is also important and transmission licensee shall coordinate with CTU to implement metering, as required and hence the Regulation is accordingly modified.

7.11 As regards the suggestion to specify PLF or deemed generation provisions for trial run and trial operation, the Commission clarifies that the objective of specifying provisions related to trial run and trial operation is to ensure that the generating station or Unit is capable of reliably operating at normative levels. Moreover, there is already a provision of disincentive in place if a generating station fails to achieve the target availability.

8. Tariff Determination {Regulation 6}

8.1 In clause 6 of the draft Regulations, it was proposed that the Tariff in respect of a generating station may be determined for the whole of the generating station or stage or generating unit or block thereof, and tariff in respect of a transmission system may be determined for the whole of the transmission system or transmission line or sub-station or communication system forming part of transmission system. The second proviso to clause 6(1) of the draft Regulations specified that the generating company or transmission licensee shall file a consolidated petition combining all the units of generating station or all elements of transmission system, which are likely to be commissioned during next six months from the date of application.

8.2 Clause 6(2) of the draft Regulations proposed that for the purpose of determination of tariff, the capital cost of a project may be broken up into stages, distinct blocks, units, transmission lines and sub-systems forming part of the project, if required. The first proviso to clause 6(2) of the draft Regulations proposed that where the cost incurred on common facilities have not been proportionately apportioned between the units or elements of the project, the cost in respect of such common facilities shall be apportioned on the basis of the installed capacity of the units or line length and number of bays, as the case may be.

Stakeholders' Comments/Suggestions

8.3 Some stakeholders submitted that the second proviso to clause 6(1) of the draft Regulations specifies that the generating station can file the tariff determination petition for units of Generating Station likely to be commissioned during next six months from the date of application, while as per clause 7(1) of the draft Regulations, the time line mentioned for tariff petition is 120 days from anticipated date of commercial operation. These provisions need to be reconciled.

8.4 NHPC submitted that the time period for filing of tariff petition for new projects should be kept up to 6 months before anticipated date of commercial operation. One of the generating company with regard to unit-wise tariff determination, suggested that the Commission should also incorporate cases wherein only a part capacity of a particular unit is tied up under long term PPA and tariff for such part of unit should be allowed to be determined as per the Tariff Regulations. Some stakeholders, with regard to unit-wise tariff determination, submitted that where more than one unit is commissioned, tariff for billing purposes may be specified as weighted average of tariff (fixed as well as variable charges) determined based on normative availability of each unit.

8.5 THDC India Limited submitted that the first proviso to clause 6(2) of the draft Regulations may be modified as follows:

> *"……; Interest During Construction (IDC) for the apportioned amount of the common facilities' cost for subsequent units needs to be allowed on normative basis. However, in exceptional cases, considering the technical necessity of the power generating station the common facilities cost may be allowed along with the first unit of the project."*

8.6 NTPC submitted that the cost of common facilities should be allowed to the extent capitalised, except where such assets are clearly not in use by the unit(s) under commercial operation. Some stakeholders submitted that the cost of common facilities cannot be evenly distributed as being proposed. Further, in case partial plant/transmission assets are commissioned and the Tariff petition is filed the common expenses like IDC, Financing charges are not proportionate to the IC/line length ratio. These common expenses would be incurred more on the commissioned unit/asset rather than balance plant/transmission asset. Hence, proportion has to be worked out and considered on case to case basis considering specific features of power plant /transmission asset.

Commission's Views

8.7 As regards the comments received for reconciliation of Clause 6(1) of the draft Regulations and Clause 7(1) of the draft Regulations, the Commission has already amended Clause 7(1) of the Regulations and the time period for filing tariff petition has been revised to 180 days from the anticipated date of commercial operation.

8.8 Further, in Clause 6(2) of the Regulations, the Commission has decided to replace the term sub-system with substations as it is more appropriate and precise. Clause 6(1) of the Regulations enables determination of tariff, Unit wise, Stage wise or for the Station as a whole and hence, no modifications are required in this regard. Further, Clause 6(5) of the Regulations adequately covers the issue related to part capacity tied up for supplying power to beneficiaries. On the issue of common facilities, the Commission has modified the provisions by considering the suggestions/responses of stakeholders. Accordingly, the modified clause 6(2) of the Regulations is as under:

> *"(2) For the purpose of determination of tariff, the capital cost of a project may be broken up into stages, blocks, units, transmission lines and sub-stations, forming part of the project, if required:*
>
> *Provided that where break-up of the capital cost of the project for different stages or units or blocks and for transmission lines or sub-stations is not available and in case of on-going projects, the common facilities shall be apportioned on the basis of the installed capacity of the units, line length and number of bays:*
>
> *Provided further that in relation to multi-purpose hydro schemes, with irrigation, flood control and power components, the capital cost chargeable to the power component of the scheme only shall be considered for determination of tariff."*

9. Application for Determination of Tariff {Regulation 7}

9.1 The draft Regulation 7 covers the following five aspects:

<u>Time Period for making an application</u>

9.2 The Commission in the draft Regulations proposed that in case of new generating station or unit, the generating company may make an application for determination of tariff within 120 days of the anticipated date of commercial operation and in case of new transmission system or element, the transmission licensee may make an application for determination of tariff for transmission system or element anticipated to be commissioned minimum 180 days from the date of filing of the petition. For existing generating station or transmission system, the time period specified for making application for determination of tariff is 120 days from the date of notification of these Regulations.

<u>Stakeholders' Comments/Suggestions</u>

9.3 Some stakeholders suggested that the time frame for submission of application may be changed to 180 days. Some stakeholders suggested that there should be a provision of time limit within which the petition for the existing assets has to be filed and new tariff is awarded.

9.4 APDCL submitted that in case of delay in issue of any tariff order for any reasons attributable to the petitioner, the Commission should issue tariff order of its own within the time period stipulated in the Act. Further, any carrying cost accrued during the delayed period should not be allowed to be recovered from the beneficiaries.

9.5 Some stakeholders submitted that the clause 7(2) of the draft Regulations may include the term 'within' as given below:

> *"…transmission system or elements thereof anticipated to be commissioned <u>within</u> minimum 180 days from the date of filing the petition"*

9.6 POWERGRID submitted that clause 7(2) of the draft Regulations may include the following proviso:

> *"Provided that where the application for POC billing of a Transmission system or element thereof, as the case may be, has been filed based on anticipated COD, the transmission licensee shall file an application as per Annexure-I of these Regulations for determination of Tariff within 180 days of the commercial operation of the Transmission system or an element thereof"*

9.7 Some of the stakeholders suggested that the time frame for making an application may be changed to 180 or 240 days. Some of the beneficiaries submitted that the limit of 120 days needs to be revised considering the time period required by Respondents to submit their submissions on the Petitions.

9.8 NHPC submitted that the next tariff period starts from 01.04.2014 and therefore linking of timeline for filing of tariff petition from date of notification is not appropriate, and timeline for filing of tariff petition should be linked with start date of tariff period, i.e., 01.04.2014. Secondly, in existing Tariff Regulations (clause 6(2) of Tariff Regulations, 2009) 31.10.2014 is specified as the last date by which the petition for truing up of capital expenditure of 2009-14 should be filed.

Commission's Views

9.9 The Commission has considered the suggestion of stakeholders to review the time period of 120 days and has decided to change the proposed time period of 120 days to 180 days in clause 7(1) of the Regulations. Accordingly, clause 7(1) of the Regulations is modified as under:

> *"The generating company may make an application for determination of tariff for new generating station or unit thereof in accordance with the Procedure Regulations, in respect of the generating station or generating units thereof within 180 days of the anticipated date of commercial operation."*

9.10 The Commission has decided to include the term 'within' in clause 7(2) of the Regulations. Accordingly, clause 7(2) of the Regulations is modified as under:

> *"The transmission licensee may make an application for determination of tariff for new transmission system including communication system or element thereof as the case may be in accordance with the Procedure Regulations, in respect of the transmission system or elements thereof anticipated to be commissioned within 180 days from the date of filing of the petition."*

9.11 In view of the change of time period from 120 days to 180 days, clause 7(3) of the Regulations is modified as under:

> *"In case of an existing generating station or transmission system including communication system or element thereof, the application shall be made not later than 180 days from the date of notification of these regulations based on admitted capital cost including any additional capital expenditure already admitted up to 31.3.2014 (either based on actual or projected additional capital expenditure) and estimated additional capital expenditure for the respective years of the tariff period 2014-15 to 2018-19:"*

Projected Capital Expenditure

9.12 In case of existing generating station or transmission system, the draft Regulations provided for making application for determination of tariff based on admitted capital cost upto 31.3.2014 and estimated additional capital expenditure for the respective years of the Tariff Period 2014-19. For new generating stations or transmission system, the draft Regulations provided for making an application for determination of tariff based on capital expenditure incurred duly certified by the auditors or projected to be incurred upto date of commercial operation and additional capital expenditure projected to be incurred during the tariff period.

Stakeholders' Comments/Suggestions

9.13 Most of the generating companies and transmission licensees have requested to continue with the existing approach of making an application based on projected/estimated capital expenditure. On the other hand, some of the beneficiaries and consumer organizations suggested that the petition should be filed based on actual expenditure as per audited accounts and the estimated /projected additional capital expenditure for the Tariff Period 2014-19 should not be included. Once the project is commissioned, the capital expenditure incurred thereafter may be taken care through a petition as an additional capital expenditure. It has also been suggested that initially, an ad-hoc tariff may be agreed to with the beneficiaries at the RPC level and the provisional tariff may be decided or agreed to on the basis of actual capital expenditure or latest approved capital cost, which is applicable particularly in case of CPSU's/Government companies.

Commission's Views

9.14 The Commission has considered the views of various stakeholders. The Commission is of the view that apart from meeting the intended objective of certainty of tariff and minimal retrospective adjustments, the provision on consideration of the projected Capital expenditure would have following additional advantages:

(a) The beneficiaries would be aware of the intended additional capitalization in advance and be able to raise their observations before the Commission about the reasonableness and necessity of additional capitalisation before the actual expenditure is incurred by the generating companies/transmission licensees.

(b) The generating companies/transmission licensees would be assured of the admittance of expenditure once accepted by the Commission in the capital cost before incurring the actual expenditure.

Moreover, the beneficiaries are being compensated for the excess tariff, if any claimed after truing up of capital expenditure. As the tariff fixation based on projected capital expenditure was commenced first time from 1.4.2009, the truing up of projected capital expenditure is yet to be done for the most of the projects. The Commission has observed in the Explanatory Memorandum that the project developers have gained experience of projecting capital cost during the period of 2009-13 and it is expected to have a further improvement after completion of truing up exercise under CERC Tariff Regulations, 2009. As the tariff fixation based on projected capital expenditure avoids retrospective revision of the tariff of beneficiaries, it is beneficial to the consumers. The tariff determination based on projected capital expenditure is advantageous for beneficiaries and long term transmission customers/DICs and generating companies and transmission licensees. In order to ensure that the gap between projected capital expenditure and actual capital expenditure is minimum, safeguards have been provided in the Regulations for higher interest rates for refund for over-projection and lower interest for recovery for under-projection of capital expenditure. Therefore, the Commission has decided to continue with the provisions for determination of tariff based on the capital expenditure incurred duly certified by the auditors and the capital expenditure projected to be incurred for the different years of the tariff period.

Inadequacy of the Tariff Application

9.15 The draft Regulations provided for returning the tariff application if it is inadequate in any respect for re-submission within one month after rectifying the deficiencies.

Stakeholders' Comments/Suggestions

9.16 NHDC and NEEPCO submitted that the time limit for re-submission of deficient petition may be enhanced to 'two months' from the proposed 'one month'. NHPC submitted that time limit should be included in the Regulation itself for returning the petition for any deficiency. Further, the condition of serving the petition to respondents/beneficiaries, before filing the petition, should be exempted till the petition is found technically correct and accepted by the Commission.

Commission's Views

9.17 The Commission is of the view that one month time provided in the draft Regulations to file a fresh application for determination of tariff after rectifying the deficiencies is appropriate and does not require any change.

Delay in Commercial Operation

9.18 On the issue of delay in date of commercial operation, the second proviso to clause 7(7) of the draft Regulations proposed as under:

> *"Provided that if the date of commercial operation is delayed beyond 180 days from the date of issue of tariff order in terms of clause (6) of this Regulation, the tariff granted shall be deemed to have been withdrawn and the generating company or the transmission licensee shall be required to file a fresh application for determination of tariff after the date of commercial operation of the project"*

Stakeholders' Comments/Suggestions

9.19 NLC submitted that filing fees for re-filing of tariff application for delayed CoD of more than 180 days from issue of tariff order on the basis of anticipated CoD may be exempted. A suggestion was received that the generating company or the transmission licensee may be allowed to file a fresh application one month or 15 days prior to anticipated COD so that some provisional tariff is given till final tariff order is issued. Some stakeholders submitted that the provisional tariff should not be withdrawn in case the delay is due to reasons beyond the control of generators. A suggestion was also received that in case the generating company or transmission licensee is required to file tariff application again because of delay beyond 180 days, then the fees for tariff processing may be borne by the petitioner.

Commission's Views

9.20 As regards filing of fresh application if the date of commercial operation is delayed beyond 180 days, it has been clarified in the Explanatory Memorandum to draft Regulations that in case the project gets delayed, the Capital Cost as on COD varies substantially due to various reasons such as increase in price variation, IDC, IEDC, etc., and hence, it becomes imperative to carry out prudence check of the Capital Cost once again based on actual Capital Cost as on COD. Accordingly, it has been provided that in case of delay in commercial operation by more than six months from the date of issue of tariff order, the tariff shall be withdrawn and the generating company or transmission licensee should file a fresh petition after the commercial operation. It is expected that the generating company or transmission licensee makes a realistic assessment of the date of commercial operation before approaching the Commission for tariff. The Commission does not find any requirement to make any changes in this provision. As regards the fees, the same is payable in terms of MW in case of generating station or a percentage of annual transmission charges in case of transmission assets and re-filing of petitions after rectification of defects or revision of capital cost will not affect the fee liability of generating company or transmission licensees. However, it is clarified that the generating company or transmission licensees shall pay the fee applicable for Miscellaneous Petitions while re-filing the tariff petition and the fees on this account shall not be reimbursable.

9.21 Difficulties have been expressed regarding the determination of tariff for inclusion in PoC charges. Since the transmission charges should be available at least two months in advance before start of the "application period" under the PoC Regulations, there is a need to provide for special dispensation in case of transmission assets. To address the issue of transmission tariff for the purpose of inclusion in POC charges, the Commission has included the proviso in Clause 7 of Regulations as follows:

"Provided that
(i) the Commission may grant tariff up to 90% of the annual fixed charges claimed in respect of the transmission system or element thereof based on the management certificate regarding the capital cost for the purpose of inclusion in the POC charges in accordance with the CERC (Sharing of Inter State Transmission charges and losses), Regulation, 2010 as amended from time to time:"

Variation in Actual vs. Projected/Estimated Additional Expenditure

9.22 In order to control the wide variation between projected and actual capital expenditure, the Commission in the draft Regulations proposed a mechanism for refund of excess tariff along with interest at 1.2 times the Bank Rate if the projected capital cost or projected additional capital expenditure exceeds the actual capital cost of actual additional capital expenditure by 5%. Similarly, the draft Regulations provides for recovery of shortfall in tariff along with interest at 0.8 times of the Bank Rate if the projected capital cost or projected additional capital expenditure falls short of actual capital cost or actual additional capital expenditure by 5%.

Stakeholders' Comments/Suggestions

9.23 Some of the Generating Companies submitted that either the existing provision in CERC Tariff Regulations, 2009 may be continued or the second proviso and third proviso to clause 7(7) of the draft Regulations may be modified to either 1.2 times of the Bank Rate or 0.8 times of the Bank Rate, i.e., same in both the cases. Some of the Generating Companies also suggested for refund and recovery with interest at Bank Rate. Some stakeholders suggested that the provision of 5% should be reduced to 2% in case the projected capital cost or projected additional capital expenditure exceeds the actual capital cost incurred, while some Generating Companies suggested to increase the band of 5% to 10%.

9.24 NLC submitted that stipulation of penal interest of 1.2 / 0.8 times Bank Rate for settlement of tariff difference for +/-5% variation of the projected capital expenditure vis-a-vis the actual capital cost is contradictory with the provision stated in clause 8(9) of the draft Regulations, which specifies only simple interest at Bank Rate for regularization of tariff based on actual capital cost after truing up. The same analogy may be followed even if capital projection differs by +/- 5% and the penal interest should be dispensed with.

9.25 NLC also submitted that tariff based on actual capital cost for new projects and actual capital expenditure for existing projects will be known only at the time of truing up and hence, regularization of tariff based on actual capital cost is possible only after 31.10.2019. Hence, clause 7(7) and 7(8) of the draft Regulations concerning interest rate cannot be applied to regularization of provisional billing.

9.26 NHPC submitted that the normal allowed deviation on year to year basis should be at least 25% from the allowed expenditure. Irrespective of the year to year deviation, overall deviation of up to 20% should be allowed over the period of 5 years. Further, interest rate should be same. POWERGRID suggested that the 3rd and 4th provisos to clause 7(8) of the draft Regulations may be deleted and should be replaced by the following proviso:

> *"Provided that where the Transmission charges billed as per tariff approved by the Commission and applicable as on 31.03.2014 exceeds or falls short of the tariff approved by the Commission under these regulations, the transmission licensee shall refund to or recover from the beneficiaries or the transmission customers, as the case may be, within six months along with bank rate for the period from the date of first billing to the date of issue of the final tariff order of the Commission."*

9.27 NHDC submitted that though the Commission has introduced such provisions with a view to reduce the burden of carrying cost on the consumer, such kind of inequitable provisions will induce apprehension, especially amongst the generating utilities, in making realistic projections. Thus, such inequitable provisions in the draft Regulations may be dispensed with and the existing provisions of Tariff Regulations, 2009 may be continued.

9.28 NTPC submitted that provisions for adjustment along with interest at the Bank Rate plus 350 basis points may be incorporated in the Regulations to take care of the difference between provisional and final bills. The principle of recovery and refund in case of deviation should be applicable in a balanced and equitable manner. NTPC also submitted that the deviation margin of 5% is too low and the limit may be increased to at least 25% of projected Capex for payment of additional interest.

The percentage of variation for the purpose of interest payment should not be calculated on year to year basis and should be for the entire period.

<u>Commission's Views</u>

9.29 As discussed in the Explanatory Memorandum, based on the analysis of actual data, there is wide variation between the projected capital expenditure and actual capital expenditure as on COD for new projects as well as between estimated additional capital expenditure and actual additional capital expenditure for existing projects. In case the actual capital expenditure varies substantially with respect to the projected/estimated capital expenditure, the impact of the same needs to be allowed at the time of truing up with interest. It is important that the wide variation between projected and actual capital expenditure is controlled. In order to have more accurate projections with regard to capital expenditure and in order to limit the impact on consumers in terms of carrying cost of under recovered or over recovered tariff on account of variation between projected and actual capital expenditure, the Commission has proposed differential interest rates for refund and recovery as the generating or transmission company is in the best position to make realistic projections of capital expenditure. The Commission is of the view that the band of 5% variation between actual capital cost and capital cost considered for tariff is adequate as the projections made by the utilities are based on remaining works to be carried out in case of new projects. Further, the Commission would like to clarify that proviso (ii) and (iii) to clause 7(8) of the draft Regulations shall be applicable for variation in actual Capital Cost or Additional Expenditure with respect to capital cost or additional expenditure considered in tariff. The provisions related to truing up of Capital expenditure including additional capital expenditure subject to prudence check shall be applicable as per Regulation 8 (Truing Up).

10. Truing Up {Regulation 8}

10.1 Clause 8(1) of the draft Regulations specified that the Commission shall carry out truing up exercise along with the tariff petition filed for the next Tariff Period, with respect to the capital expenditure including additional capital expenditure incurred up to 31.3.2019. The first and second proviso to clause 8(1) of the draft Regulations provide for the filing of application for interim true up of capital expenditure within 180 days of the commercial operation of the new project and for filing of application for revision of tariff at the discretion of the generating company or transmission licensee one more time prior to 31st March, 2019 for revision of tariff.

10.2 Clause 8(2) of the draft Regulations provided for truing up of tariff of generating stations based on the controllable and uncontrollable parameters and specifies the controllable and uncontrollable factors. Clause 8(3) of the draft Regulations 8 provided for the sharing of the financial gains by a generating company on account of controllable parameters between generating company and the beneficiaries on monthly basis, in the ratio of 3:1.

Stakeholders' Comments/Suggestions

10.3 Some of the beneficiaries and other stakeholders suggested that there is a need for mid-term review/truing up after 3 years and some stakeholders even suggested annual truing up. Some stakeholders also suggested that the scope of truing up may not be limited to Capital Cost and should include other aspects such as O&M expenses, Non Tariff Income, Interest on Working Capital, etc.

10.4 Some of the generating companies suggested that the variation in heat rate due to backing down and part loading, frequent start/stop instructions of Load Despatch Centre also be included in truing up. Further, a normalization factor may be devised to take care of effect of SHR and AEC variation. Some generating companies opined that SHR, SFOC and AEC cannot be considered as controllable factors.

10.5 Some of the stakeholders submitted that the draft Regulations do not provide for treatment of loss on account of controllable factors by generating company and some of the generating companies suggested that similar to financial gain, there has to be provision for sharing of financial losses also.

10.6 NTPC submitted that the provision of truing up of operational parameters such as Heat Rate, Secondary Oil Consumption, Auxiliary Energy Consumption will be too complicated to implement without any substantial tangible benefits and should be dropped.

10.7 Some of the beneficiaries and other stakeholders suggested to have sharing ratio with maximum benefits to be passed on to beneficiaries on account of controllable factors as the norms are relaxed norms and not stringent base norms. Most of the generating companies suggested that instead of monthly basis, the sharing of net financial gains may be done on annual basis. PSPCL submitted that for truing up exercise to be practically successful, the determination of GCV of coal should be done jointly between generator and beneficiaries.

10.8 NHPC submitted that net gain is proposed to be calculated on the basis of scheduled generation; however, this includes free power to the home State, which should not be included. Therefore, Scheduled Generation may be replaced with Scheduled Generation (net of free power). Also, the income tax on the financial gains shared with the beneficiaries, should be borne by the beneficiaries.

10.9 Some generating companies submitted that the financial gains should not be shared with the beneficiaries and any efficiency gain in the Energy Charges due to better operational performance by the Generating Station w.r.t. the norms should be rewarded in line with the Tariff Policy.

Commission's Views

10.10 Considering the suggestions of various stakeholders, the Commission is of the view that in order to streamline the tariff and to control any variation between the actual and approved tariff, it will be more appropriate to have mandatory provision for interim truing up of capital expenditure including additional capital expenditure during the Tariff Period for new as well as existing projects. Accordingly, the proviso to clause 8(1) of the Regulations has been modified as follows:

> *"Provided that the generating company or the transmission licensee, as the case may be, shall make an application for interim truing up of capital expenditure including additional capital expenditure in FY 2016-17."*

10.11 As regards the controllable and uncontrollable factors, the Commission is of the view that the performance parameters are controllable factors and accordingly the sharing of financial gains on account of controllable factors was proposed in the draft Regulations. As regards the suggestion that sharing of gains on account of performance parameters will be complicated, the Commission in the Regulation has specified the specific formula and further the truing up of performance parameters for generating stations is being done by State Electricity Regulatory Commissions in some of the States. The Commission is of the view that saving on interest due to re-financing of loan is also a controllable factor and therefore, should be included in the Regulations as controllable factor.

10.12 The provisions of the Regulations allow the generating companies operating at the normative performance parameters to pass through all the prudent costs incurred by them. Further, the Commission has specified uniform normative performance parameters throughout the Tariff Period and has not specified any trajectory for performance improvement. It is expected that the generating companies would endeavour to improve their performance during the Tariff Period, which would result in significant cost saving, which should be shared with the beneficiaries. On the other hand, losses would imply that the generating companies have not put in adequate efforts to sustain even at the normative performance parameters specified by the Commission contrary to the expected improvement. Passing on such losses on account of the lapse of the generating companies would not be appropriate and would discourage improvement in efficiency by the generating companies. Hence, no sharing of losses is being considered for the generating companies.

10.13 As regards the sharing ratio of gains on account of controllable factors, the Commission is of the view that the sharing ratio needs to be specified considering the fact that operational norms have been specified in the Regulations based on actual performance with some margin. Considering the suggestions of various stakeholders including the discussions held in the meeting of the Forum of Regulators held on 17th January, 2014 at Chandigarh, the Commission has considered it appropriate to modify the sharing ratio to 60:40 between the generating company/transmission licensee and beneficiaries respectively.

10.14 The Commission agrees with the views of some of the stakeholders that the monthly figures would vary widely depending upon the seasonal changes, maintenance schedule of the Units and the load that is maintained depending on the prevailing conditions. Therefore, the Commission has decided to include the provision of annual reconciliation with respect to sharing of gains. As regards considering the variation in heat rate due to backing down and part loading, frequent start/stop, etc., the Commission as discussed in subsequent sections has provided some margin while specifying the norms of operation and the same along with annual reconciliation will take care of these aspects.

10.15 Further, the Commission is of the view that the reconciliation of controllable parameters shall be carried out by the generating company or transmission licensee on regular basis, while the truing up of uncontrollable parameters shall be carried out by the Commission as a part of interim truing up or final truing up.

10.16 Accordingly, clauses 8(2) to 8(6) of the Regulations have been modified as under:

"(2) The generating station shall carry out truing up of tariff of generating station based on the performance of following Controllable parameters:

a) Controllable Parameters:

i) Station Heat Rate;
ii) Secondary Fuel Oil Consumption;
iii) Auxiliary Energy Consumption; and
iv) Re-financing of Loan.

(3) The Commission shall carry out truing up of tariff of generating station based on the performance of following Uncontrollable parameters:

i) Force Majeure;
ii) Change in Law: and
iii) Primary Fuel Cost.

(4) The Transmission licensee shall carry out truing up of tariff of transmission system based on the controllable parameter of Re-Financing of Loans:

(5) The Commission shall carry out truing up of tariff of transmission licensee based on the performance of following Uncontrollable parameters.

(i) Force Majeure; and
(ii) Change in Law

(6) The financial gains by a generating company or the transmission licensee, as the case may be on account of controllable parameters shall be shared between generating company/transmission licensee and the beneficiaries on monthly basis with annual reconciliation. The financial gains computed as per following formulae in case of generating station on account of operational parameters as shown in clause 2(a) (i) to (iii) of this Regulation shall be shared in the ratio of 60:40 between generating station and beneficiaries:

Net Gain = (ECR_N– ECR_A) X Scheduled Generation
Where,
ECR_N – Normative Energy Charge Rate computed on the basis of norms specified for Station Heat Rate, Auxiliary Consumption and Secondary Fuel Oil Consumption.
ECR_A – Actual Energy Charge Rate computed on the basis of actual SHR, Auxiliary Consumption and Secondary Fuel Oil Consumption for the month

Provided that in case of financial gains on account of Clause 2 (a)(iv) and Clause 4 of this Regulation shall be shared in accordance with Clause 7 of Regulation 26 of these regulations."

11. Capital Cost {Regulation 9}

11.1 Clause 9(1) of the draft Regulations specified that the Capital Cost determined by the Commission after prudence check shall form the basis of determination of tariff for existing and new projects. Clause 9(2) of the draft Regulations specified that the Capital Cost should include expenditure incurred or projected to be incurred up to the date of commercial operation of the project, interest during construction, financing charges, FERV, capitalised initial spares, etc. Sub-clause (f) of clause 9(2) of the draft Regulations provided for adjustment of revenue due to sale of infirm power prior to scheduled commissioning. Clause 9(3) of the draft Regulations provided that the Capital Cost of the existing project shall include the capital cost admitted by the Commission prior to April 1, 2014 after true-up, additional capitalisation & decapitalisation and expenditure on account of renovation and modernisation. Clause 9(4) of the draft Regulations provided that the Capital Cost shall also include the cost of approved R&R and cost of developer's 10% contribution towards RGGVY. Clause 9(5) of the draft Regulations provided that the capital cost with respect to thermal generating station, incurred or projected to be incurred on account of PAT scheme will be considered on case to case basis.

11.2 Clause 9(6) of the draft Regulations provides that the following shall be excluded or removed from the capital cost of the existing and new project:

(a) The assets forming part of the project, but not in use;
(b) Any grant received from the Central or State Government or any statutory body or authority for the execution of the project which does not carry any liability of repayment;
(c) Decapitalisation of Asset; and
(d) Any expenditure incurred or committed to be incurred by a project developer for getting the project site allotted by the State government by following a two stage transparent process of bidding.

Stakeholders' Comments/Suggestions

11.3 Some of the beneficiaries and other stakeholders submitted that the Capital Cost of a project may be fixed as per projected capital expenditure arrived at based on the benchmarks of capital cost.

11.4 Some generating companies suggested that sub-clause (f) of clause 9(2) of the draft Regulations should be related to actual commissioning date instead of scheduled commissioning. NTPC submitted that due to adjustment of revenue prior to scheduled commissioning, in case a project is delayed, the developer will find it very difficult to carry out the commissioning and trial operation as there will be no adjustment of revenue for this period.

11.5 Some beneficiaries suggested that the construction period must be standardized as per the Appendix-2 of CERC Tariff Regulations, 2009 and the Capital Cost for tariff purposes should be actual cost as on date of COD, and all anticipated additional costs, after prudence check by the Commission, may be allowed during the truing up process.

11.6 Some stakeholders submitted that the actual cost of developer's contribution may be included subject to a ceiling of 10%, and the Commission may include existing / new thermal generating stations also in clause 9(4) of the draft Regulations to cover the R&R expenses in these projects.

11.7 Some stakeholders submitted that carrying out PAT is required under the provisions of BEE, which is a statutory body created under the Energy Conservation Act, 2001 and hence, it is a mandatory requirement. Therefore, the cost of capital expenditure on account of PAT may be allowed as a pass through subject to prudence check. Further, as the capital cost is a pass through, benefits accruing due to implementation of PAT should accrue to the beneficiary, even if the developer is not able to demonstrate achievement of performance parameters as per PAT. As the impact of the PAT scheme implementation will be reflected in terms of improved SHR and AEC, it is necessary to clarify whether gains/losses on account of availing E-certificates and selling in the market and penalty due to non-achievement of PAT target will also be shared. Some beneficiaries submitted that the results achieved on account of capital expenditure incurred by the Generator for implementation of PAT scheme, may be shared in the ratio of 75:25 between the beneficiary and the generator.

11.8 Some of the beneficiaries submitted that sub-clause (b) of clause 9(6) of the draft Regulations may include contribution by customers towards capital cost (in the form of depreciation) in excess of loan repayment amount. As regards the removal of the cost of the assets forming part of the project but not in use, some of the stakeholders submitted that a provision for loss on write off of such asset may be incorporated by way of deferred recovery over balance useful life of the project. NHPC submitted that there are assets, which are not allowed by the Commission for the purpose of tariff such as minor assets, furniture & fixtures, tools & tackles, capital spares, etc. However, such assets remain part of gross block in the Balance Sheet of the respective generating station. Therefore, such assets which were part of capital cost when decapitalised should be excluded from capital cost for the purpose of tariff.

11.9 As regards sub-clause (d) of clause 9(6) of the draft Regulations, it was suggested that the actual expenses/costs for awarding the project (certified by the Government) should be allowed as pass through in tariff. Moreover, the State Governments such as the Government of Arunachal Pradesh ask for monitoring fee

@ 0.1 % of project cost from the developers. The same should also be considered as part of the capital cost of the Project. Moreover, expenses / costs incurred as per the terms of the Implementation Agreement with the concerned State Government for award of the Project should be allowed as part of the capital cost of the Project.

11.10 Some stakeholders submitted that depreciation is meant for replacement of assets after its useful life and if the grant received from any Authority shall not be recovered, then accumulated depreciation shall not be up to the level of 90%. Therefore, the grant should be considered as a part of capital cost, however, the same may be treated as normative loan and only depreciation and applicable interest rate should be allowed. The grant amount shall be excluded for calculation of ROE, only. Therefore, the sub-clause (b) of clause 9(6) of the draft Regulations may be deleted.

11.11 Some generating companies submitted that while calculating the Capital Cost of a project, since many of the replacements are not granted/considered by the Commission, the capital cost approved as per Regulations should be kept unchanged. The need for decapitalisation of assets arises due to technological upgradation, operational requirement and unexpected failures, which are beyond the control of the Generator. Therefore, decapitalisation of assets should be removed from clause 9(6) the draft Regulations. Further, the expenditure on common offices is legitimate and prudent and has been incurred to reduce the overall cost. The benefits of such expenditure have already been passed on the beneficiaries. Therefore, servicing of corresponding equity needs to be considered in tariff.

Commission's Views

11.12 As regards fixing the Capital Cost based on benchmark norms, the Commission is of the view that the projects do not have same features and site conditions, and the cost varies based on project specific or site specific features and hence, it may not be appropriate to consider the benchmark capital cost for determination of tariff. However, while admitting projected capital expenditure as on COD, prudence check of Capital Cost shall be carried out based on the applicable benchmark norms, published separately by the Commission from time to time. Further, clause 10(1) of the Regulation on truing up of capital cost provides that the prudence check of capital cost may be carried out taking into consideration the benchmark norms.

11.13 On the issue of standardization of construction period, as elaborated in the Explanatory Memorandum, the Commission is of the view that it may not be appropriate to specify the standard construction period as the time schedule for executing the project varies substantially across the projects due to various reasons such as execution philosophy, site conditions, etc. However, the Commission has, in the Regulations, specified the appropriate mechanism towards treatment of increase in cost on account of delay due to controllable and uncontrollable factors.

11.14 The Commission is of the view that due to certain reasons, the cost under various contract packages may increase, which also needs to be approved by the Commission based on prudence check. Accordingly the Commission has decided to include 'increase in cost in contract packages as approved by the Commission' in Clause 9(2) of the Regulations, as under:

> *"(2) The Capital Cost of a new project shall include the following:*
>
> *(a)...*
>
> *(b)...*
>
> *(c) Increase in cost in contract packages as approved by the Commission;"*

11.15 The Commission is of the view that the term 'scheduled commissioning' in draft sub-clause (f) of clause 9(2) of the draft Regulations, i.e., on adjustment of revenue due to sale of infirm power, should be replaced with the term 'COD' as the Capital cost as on COD of the project will be considered for tariff determination purpose. Further, with the intent to provide more clarity towards the adjustment of revenue due to sale of infirm power, the Commission has decided to modify the draft Regulations. The Commission is also of the view that any revenue earned by the transmission licensee by using the assets before COD needs to be adjusted from the Capital Cost. Hence, the Commission has decided to modify the provisions of adjustment of revenue before COD from Capital Cost as follows:

> *"(2)………*
>
> *…..*
>
> *(g) adjustment of revenue due to sale of infirm power in excess of fuel cost prior to the CoD as specified under regulation 18 of these Regulations.*

(h) adjustment of any revenue earned by the transmission licensee by using the assets before COD."

11.16 As regards cost of capital expenditure on account of PAT Scheme to be allowed as a pass through along with sharing of benefits, the Commission is of the view that the capital expenditure on account of PAT scheme needs to be examined in detail and hence the Commission will consider the same on case to case basis.

11.17 The Commission has gone through the other suggestions on Capital Cost and is of the view that some of these suggestions relates to the detailed prudence check to be carried out by the Commission while approving the Capital Cost.

11.18 As regards the elements to be excluded from the Capital Cost, the Commission in the draft Regulations proposed to exclude the grant received from the Capital Cost. However, there are certain normative expenses, which are linked to Capital Cost and if grant is reduced from the Capital Cost, it will have effect on normative expenses linked to the Capital Cost. Therefore, the Commission has decided to modify the provision in the draft Regulations related to the grant and specified that any grant received for the execution of project which does not carry any liability of repayment will be excluded from the Capital Cost for the purpose of computation of interest on loan, return on equity and depreciation.

11.19 As regards the asset which are not in use due to change in technology or is not expected to be used for the purpose for which it was originally created the Commission is of the view that those assets which are not in use should be written-off from the balance sheet and thus no Capex related benefit should be provided for the same and which is specified in Clause (6) of Regulation 9 that capital cost shall not include the decapitalisation of asset. Thus the Commission to this extent has not made any modification in the draft Regulation. Further, the Commission is of the view that the proportionate cost of land, which is being used for generating power from generating station based on renewable energy, needs to be excluded from the capital cost while determining the tariff of generating station as the generating station will earn the revenue from power generated through renewable energy. The Commission has accordingly modified the Clause 9(6) of the Regulations, as follows:

"(6) The following shall be excluded or removed from the capital cost of the existing and new project:

(a) The assets forming part of the project, but not in use;

(b) De-capitalisation of Asset;

(c) In case of hydro generating station any expenditure incurred or committed to be incurred by a project developer for getting the project site allotted by the State government by following a two stage transparent process of bidding; and

(d) the proportionate cost of land which is being used for generating power from generating station based on renewable energy:

Provided that any grant received from the Central or State Government or any statutory body or authority for the execution of the project which does not carry any liability of repayment shall be excluded from the Capital Cost for the purpose of computation of interest on loan, return on equity and depreciation;"

12. Prudence Check of Capital Expenditure {Regulation 10}

12.1 Clause 10 of the draft Regulations provided that in case of thermal generating station and the transmission system, prudence check of capital cost may be carried out taking into consideration the benchmark norms specified/to be specified by the Commission from time to time

<u>Stakeholders' Comments/Suggestions</u>

12.2 Some generating companies submitted that the benchmark norms provide general idea about the cost of the project, however, the cost of the project may substantially vary depending upon site conditions, terrain, technology and configuration and prevailing market conditions, and hence, it may not be appropriate to limit the Capital Cost to the benchmark norms. Some stakeholders submitted that there is a need for re-assessment of benchmark norms based on current scenario and thereafter, on a regular basis. Further, there is no benchmark for thermal generation capacities below 500 MW and this anomaly is required to be removed by specifying benchmark norms for generating stations below 500 MW.

12.3 Some of the beneficiaries submitted that the capital cost of thermal stations may be vetted by CEA or independent expert body of technical experts. Some of the beneficiaries suggested that the Capital Cost should be limited to benchmark cost and in no case capital cost exceeding the benchmark norms should be allowed. POWERGRID submitted that linking the Capital Cost with benchmark norms is not justified and cost should not be restricted.

12.4 On the issue of competitive bidding for procurement, some generating companies suggested that competitive bidding for procurement of Main Plant or BTG Packages only be considered.

12.5 On the issue of vetting of capital cost of hydro-electric projects by independent agency or an expert, some of the hydro generators submitted that generally the completed cost of a hydroelectric project of a State controlled or owned company is approved by the Government of India on the basis of report/recommendations of the CEA and the Standing Committee on time & cost over-run. Therefore, it is not required to get the capital cost vetted by an independent agency as it will lead to duplication of work and such provision may be restricted only for the hydro power stations, whose capital cost is not approved by appropriate government authority.

Commission's Views

12.6 The Regulations specify that the prudence check of capital cost may be carried out taking into consideration the benchmark norms and second proviso to clause 10(1) of the Regulations requires the generating company or transmission licensee to submit the reasons in case of variation of capital cost from benchmark norms. As regards revision in benchmark norms, the Commission, as and when considered appropriate, will separately take up the matter. In case of the transmission system, element wise cost shall be compared with the benchmark cost and hence, even if transmission project, where the transmission element is part, is not completed, the capital cost benchmark data for the element shall be submitted along with the tariff petition.

12.7 The Commission does not agree with the views of some of the stakeholders that the capital cost of thermal stations may be vetted by CEA or independent expert body of technical experts as the Commission while approving the capital cost carries out the detailed scrutiny of capital cost. Further, vetting of capital cost of thermal power stations is not a function of CEA as per the provisions of the Act. Further, the Act has done away with the requirement of concurrence of CEA (except for the hydro generating stations involving capital expenditure exceeding the sum as fixed by the Central Government) and hence, any such provision towards approval of capital cost for all the projects by CEA would be contrary to the provisions of the Act.

12.8 On the issue of competitive bidding for procurement, the Commission is of the view that in a cost plus tariff mechanism, wherein the tariff is determined based on the cost incurred, it is necessary that all the expenses are incurred in a prudent manner. This can be ensured by procuring the equipment/services on competitive bidding basis, with reference to the guidelines/manuals prescribed by the organisation.

13. Interest during construction (IDC) and Incidental Expenditure during Construction (IEDC) {Regulation 11}

13.1 Clause 11(A) of the draft Regulations deals with the computation of IDC corresponding to the loan from the date of infusion of funds or date of financial closure, whichever is later, and after taking into account the prudent phasing of funds upto SCOD. Further, clause 11(B) of the draft Regulations specified that IEDC shall be computed from the zero date and after taking into account pre-operative expenses upto SCOD.

13.2 Sub-clause (2) of Clauses 11(A) and 11(B) of the draft Regulations specified that in case of additional costs on account of IDC and IEDC due to delays in achieving the date of commercial operation or SCOD, the generating company or the transmission licensee as the case may be, shall be required to furnish detailed justifications with supporting documents for such delay including prudent phasing of funds and the details of incidental expenditure during delay period and liquidated damages recovered or recoverable corresponding to the delay.

Stakeholders' Comments/Suggestions

13.3 MPERC submitted that clarification may be provided as to how the debt can be infused before the date of financial closure and any infusion of funds before the date of financial closure may be through equity only. NLC submitted that the proposed change of computation of IDC corresponding to loan from date of infusion or financial closure, whichever is later, may not be specified and if necessary, the same may be made applicable to the projects sanctioned after 01.04.2014 only.

13.4 Some of the generating companies submitted that there is generally a significant time gap between the award of hydro project and actual date of financial closure. IDC for the amount invested during this period may be allowed on notional debt: equity ratio of 70:30 irrespective of actual source of funding. NHPC submitted that the cost of various activities like survey, preparation of DPR, etc., is capitalized before the project is sanctioned to NHPC and therefore, NHPC should not be deprived of IDC and as such there is no concept of financial closure for hydro projects of NHPC.

13.5 Some beneficiaries submitted that IDC must be capped up to the scheduled construction time period and cost of delay should not be passed on to consumers. Some of the beneficiaries submitted that the construction period of thermal and gas projects and transmission projects should be standardized and no IDC/IEDC should be allowed for the period of time overrun. On the other hand, most of the generating companies and transmission licensees submitted that IDC should be allowed till actual COD and not till scheduled COD.

13.6 POWERGRID submitted that in their case, funds are deployed to the projects from common pool of loans and no separate account is maintained for each project exclusively. Income, if any on the surplus common pool loans are credited to the project cost through IEDC/IDC. Therefore, the term 'infusion of fund or date of financial closure, whichever is later' should be replaced with term 'drawal of funds'.

13.7 Some of the generating companies submitted that the developer may infuse funds prior to the date of financial closure so as to expedite the implementation of the project and therefore, he should not be penalized for this by disallowance of the IDC for the period from the date of infusion of funds to the date of financial closure. NTPC submitted that the IDC of works, which are in original scope of works but not completed up to cut-off date, should be allowed to be serviced and therefore, Regulations may allow IDC up to cut-off date with respect to SCOD.

13.8 Some developers submitted that IEDC incurred before the Zero date for obtaining consents/approvals, statutory clearances, arranging finances, and other expenses for development of the Project up to Zero date should also be allowed as part of the capital cost.

13.9 Some developers and generating companies submitted that if delay in commissioning of project is found beyond control of the developer, then, in addition to the IDC on actual loan, IDC on normative loan (viz. Equity investment in excess of 30%) too should be allowed as part of Capital Cost. Further, equity infusion beyond the prescribed debt: equity ratio should be treated as normative debt and interest on such normative debt should be considered as IDC.

13.10 POWERGRID requested clarification on the provisions of IDC to be allowed on the normative loan (in case equity deployment is higher than 30% of the project cost) and suggested to add following proviso in sub-clause (2) of clause 11(A) of the draft Regulations:

> *"Provided that in case the actual equity deployment is more than 30%, the excess equity will be treated as normative loan and normative IDC shall be allowed on such equity invested by the generation or transmission company as the case may be."*

13.11 Some of the beneficiaries also suggested for sharing of IDC and IEDC in case of time over-run. Some stakeholders suggested that for new stations where investment approval has been granted under previous Regulations, the IDC and IEDC should be governed by the provisions of CERC Tariff Regulations, 2009.

Commission's Views

13.12 The Commission would like to clarify that as per the provisions of the Regulations, in case of additional costs on account of IDC and IEDC due to delay in achieving COD, the generating company or transmission licensee shall be required to furnish detailed justification with supporting documents and the Commission will take an appropriate view after due prudence check. The Commission is of the view that it may not be practical to limit the IDC and IEDC only till SCOD as suggested by some of the beneficiaries and it shall be appropriate to carry out the prudence check for assessing the reasons for delay in achieving COD. Thus, the IDC and IEDC is not only limited up to scheduled COD but actual IDC and IEDC beyond SCOD and up to actual COD may be allowed subject to prudence check.

13.13 On the issue of allowing IDC for the equity infusion above the desired level, the Commission would like to refer to the Tariff Policy issued by the Government of India, which states that all the new power projects would be financed in the debt-equity ratio of 70:30 and the investors are free to infuse equity more than the 30% level with a condition that equity infusion above the threshold limit of 30% would be considered as normative loan. The Commission is of the view that any investment deployed either in the form of equity or debt has a cost to be serviced. The investments made in the form of equity are risk capital carrying higher rate of return and have perpetual flow of return up to the end of the life of the plant. However, the loan capital does not enjoy the aforesaid perpetual and higher rate of return. As the equity in excess of 30% of capital cost has been considered as notional loan for the purpose of tariff, the Commission is of the view that the equity capital equivalent to notional loan shall also be entitled for interest during construction.

13.14 As regards the expenses incurred before the Zero date for obtaining consents/approvals, statutory clearances, arranging finances, and other expenses for development of the Project up to Zero date, the same are to be treated as part of Project Development expenses while approving the Capital Cost based on prudence check. As regards the interest on works which are in original scope of work but not completed as on COD, will be considered on case to case basis based on prudence check while approving the additional capitalisation.

13.15 As regards the date from which the IDC is to be computed, the Commission is of the view that it will be more appropriate that interest should be computed from the date of the infusion of debt fund and the date of financial closure should not be considered. Accordingly, the sub-clause (1) of clause (A) of Regulation 11 is modified as under:

> *"(1) Interest during construction, shall be computed corresponding to the loan from the date of infusion of debt fund, and after taking into account the prudent phasing of funds up to SCOD."*

This modification to the Regulation will take care of the concerns raised by some of the stakeholders including the cases in which the loans are availed for funding the projects on common pool basis.

13.16 As regards the funds invested before infusion of debt, the Commission is of the view that as per the prudent industry practice, any project is funded in the following pattern:

i. Certain proportion of upfront Equity (30% or 50%)
ii. Similar proportion of upfront Debt
iii. Debt and Equity in proportion to Debt: Equity ratio

Therefore, typically the debt funding to the project starts once upfront equity is infused in the Project and hence, it will not be appropriate to provide IDC on equity funded for meeting the initial expenses prior to infusion of debt fund.

14. Controllable and Uncontrollable Factors {Regulation 12}

14.1 Clause 12 of the draft Regulations deals with the controllable and uncontrollable factors leading to cost escalation impacting IDC and IEDC. The first proviso provides that no additional impact of time overrun or cost overrun shall be allowed on account of non-commissioning of the generating station or associated transmission system by SCOD, as the same should be recovered through Indemnification Agreement between the generating company and the transmission licensee. The second proviso provided that if the generating station is not commissioned on the SCOD of the associated transmission system, the generating company shall bear the IDC or transmission charges if the transmission system is declared under commercial operation. The third proviso specified that if the transmission system is not commissioned on SCOD of the generating station, the transmission licensee shall arrange the evacuation from the generating station at its own arrangement and cost till the associated transmission system is commissioned.

Stakeholders' Comments/Suggestions

14.2 Most of the generating companies and transmission licensees submitted that delay in land acquisition may be considered as uncontrollable factor or delay in Land Acquisition be assessed on case to case basis and if found that the delay was on account of the developer then it should be treated as controllable, else it should be classified as uncontrollable. Some stakeholders also submitted that the uncontrollable parameters should also include 'geological surprises' in case of hydro projects. Some stakeholders submitted that the statutory clearances, court proceedings, Right of Way issues, etc., may not be considered as controllable factors. Further, some stakeholders submitted that delay due to the contractor, supplier or any agency of the generating company may be shifted under the category 'uncontrollable factors". Some beneficiaries suggested that the cost overrun and time over run during construction may raise a dispute and hence, there may be a capping on the allowable expenditure.

14.3 Some hydro project developers submitted that there should be a provision to enable special dispensation in terms of cost overrun/time overrun in case of hydro power projects located in north eastern region, particularly when land acquisition and project clearances are treated as 'controllable factors'. Further, force majeure events like earth quake, land-slide, etc., may also be categorised as uncontrollable factors.

14.4 SRPC submitted that in case of a dedicated line, there may be no evacuation possible and in some cases some capacity may be stranded due to partial development of transmission system. Therefore, following clause may be added to second and third provisos to clause 12(2) of the draft Regulations:

> *"………cost till the associated transmission system is commissioned. And if transmission company is not able to make such arrangement and cost it shall bear the*

IDC or fixed charges for stranded capacity if the generating station/unit is declared under commercial operation by the Commission in accordance with second provision of regulation 4(1) & 4(2) of these regulations till the transmission system is commissioned or there is no stranded capacity."

Commission's Views

14.5 The Commission is of the view that for the purpose of IDC computation, it may not be appropriate to consider the delay in land acquisition and associated activities as uncontrollable factor as the IDC is to be computed from the date of infusion of debt funds and typically the land is acquired before the financial closure or before the infusion of debt funds. In fact, the acquisition of land is also one of the pre-disbursement conditions by Lenders for disbursement of debt funds.

14.6 As regards the treatment of delay in execution of project on account of contractor, supplier or agency of the generating company or transmission licensee as uncontrollable factor, the Commission is of the view that all such events cannot be categorised as uncontrollable factors, and it is the responsibility of the Project Developer to ensure adequate provisions with respect to delay in contracts with contractor, supplier or any other agency. On the Force Majeure events, the Regulations already cover natural calamities and hence, there is no need to specifically mention some of the natural calamities such as earthquake, etc.

14.7 As regards delay on account of land acquisition, arising out of Uncontrollable Factors as specified in Regulation 12 of these Regulations, the generating company or the transmission licensee may approach the Commission on case to case basis with proper documentary proof.

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14.8 On the issue of capping the IDC and IEDC, the Commission is of the view that the Regulations detail the controllable and uncontrollable factors, which shall be considered leading to cost escalation impacting IDC and IEDC subject to prudence check and hence, the capping is not required in the Regulations. Further, some of the issues raised by the stakeholders are related to detailed prudence check, which will be examined by the Commission while carrying out the prudence check.

14.9 The Commission is of the view that due to certain reasons, the cost under various contract packages may increase, which also needs to be considered as approved by the Commission based on prudence check. Accordingly, the Commission has decided to include the clause 'contract prices' as under:

> *"12. Controllable and Uncontrollable factors: The following shall be considered as controllable and uncontrollable factors leading to cost escalation impacting Contract Prices, IDC and IEDC of the project:"*

14.10 The proviso under Clause 4(3) specifies that the transmission licensee can approach the Commission for approval of COD if asset is completed but the asset is not being put into use due to reasons not attributable to the licensee.

14.11 In the Tariff Regulations 2014-19, provisions have been incorporated so that beneficiaries of transmission projects should not be affected by the delay in the commissioning of generating station or associated transmission system., The generating company and the transmission licensee should provide for meeting such situations in the form of appropriate agreements. The issue of COD of transmission system in case of delay in commissioning of generating station was analysed in detail. In this regard, submissions of beneficiaries of transmission system, views of transmission licensees and various decisions of the Commission and their implications on all affected parties were studied. In most of the cases, the implementation or indemnification agreement between generating companies and transmission licensee was taken into consideration.

14.12 On one side, beneficiaries have PPA with the generating companies in which it is agreed between generating company that generating company is selling power at its bus bar and it shall be the responsibility of buyers to make arrangement for transfer of power. Then there is agreement between transmission licensee and beneficiaries for construction of transmission system and agreement for payment of transmission charges. Also, there is a legacy arrangement between generating companies of Central Power Sector Utilities (CPSU) and POWERGRID in which liability for payment of six month IDC by generating companies to transmission companies in case of generating station delay and for 35% of IDC of generating company by transmission company in case of delay in transmission system, is agreed. This liability is subject to the condition that it is payable only in case of revenue loss. The provision of Zero date is also provided, which can be shifted based on mutual agreement. In this arrangement, beneficiaries are not a party.

14.13 This system is workable if the generating station since inception has identified beneficiaries for 100% power and if the delay in commissioning of generating station is limited to only six months. However, if the delay is more than 6 months, then the issue of who should bear the implication for this delay has to be addressed. While the beneficiary of the transmission system takes the plea that because POWERGRID is also a Central Transmission Utility, it should coordinate development of transmission system with the generating stations thereby avoiding levy of transmission charges before the line is charged.. POWERGRID has argued that due to contractual issues relating to the project implemenation, declaration of COD beyond a particular limit would be not practicable. .

14.14 For example consider a case where generating station is delayed by 18 months and transmission system is completed. In this case if transmission company requests COD immediately then the tariff of this system is to be borne by beneficiaries, without any power flow.

14.15 On the other hand, if COD is not granted till the generation comes up, the transmission license who has invested the money is not getting any return for 18 months and as per Regulation, IDC shall be paid by the generating company for 6 months as per Indemnity Agreement. For the remaining 12 months, IDC implication is built into approved capital cost, which is to be paid by the beneficiaries.

14.16 After implementation of Sharing Regulations, a model Transmission Service Agreement was approved by the Commission, which is to be signed by every DIC including generating stations. In accordance with said Regulation 8(c), it is provided that before COD of the generating station, the generating company shall be responsible for payment of transmission charges. This was formulated with the concept that transmission company may be given COD from its project completion. After COD of generating station, its beneficiaries shall pay transmission charges. However, it was informed that central generating companies have not signed the said TSA so far.

14.17 Keeping in view the objective that in case of delay in commissioning of generating stations, all implications thereof should be recovered through implementation agreement between generating company and transmission licensee, following provisos have been included in Regulation 12(2):

> *"Provided that no additional impact of time overrun or cost over-run shall be allowed on account of non-commissioning of the generating station or associated transmission system by SCOD, as the same should be recovered through Implementation Agreement between the generating company and the transmission licensee:*
>
> *Provided further that if the generating station is not commissioned on the SCOD of the associated transmission system, the generating company shall bear the IDC or transmission charges if the transmission system is declared under commercial operation by the Commission in accordance with second proviso of Clause 3 of Regulation 4 of these regulations till the generating station is commissioned:"*

14.18 If at the time of tariff determination of the generating stations by the Commission, it is found that delay in the commissioning of generating station was not controllable, the implication due to above provisos may be treated as part of capital cost.

15. Initial Spares {Regulation 13}

15.1 It was observed that typically the initial spares are procured from the OEM suppliers and it may not be appropriate to consider the cost of initial spares as percentage of the total capital cost. Accordingly, the Commission proposed that initial spares shall be capitalised as a percentage of the Plant and Machinery cost upto cut-off date, subject to the ceiling norms.

Stakeholders' Comments/Suggestions

15.2 Most of the generating companies and transmission licensees urged to retain the existing provision of allowing initial spares as percentage of total Project Cost. They further suggested that if the initial spares are to be allowed as a percentage of Plant and Machinery Cost, the percentage as specified in draft Regulations needs to be increased. On the other hand, some of the beneficiaries and other stakeholders appreciated the concept of allowing initial spares as percentage of Plant & Machinery cost.

15.3 SJVNL submitted that for hydro stations, Plant & Machinery cost is approximately 20% to 25% of the total Project cost. Therefore, considering 4% of Plant & Machinery Cost will be only approx. 0.8% to 1.0% of Project Cost, and hence, initial Capital Spares may be retained as 1.5 % of project capital cost as per Tariff Regulations, 2009. NHPC submitted that the proposed limit for initial spares of hydro generating stations including pumped storage hydro generating station may be increased to 6% of cost of plant and machinery.

15.4 POWERGRID submitted that since the benchmark norms are required for only prudence check, initial spares should not be restricted as per benchmark norms and the percentage of initial spares be increased. It further submitted that if the cost of initial spares calculated as percentage of plant and machinery cost of projects based on the cost submitted to the Commission along with the Petition, the average percentage of initial spares comes out to be much higher than the percentage indicated in the draft Regulations. It submitted that as GIS equipments are imported items and lead time of procurement is much higher, therefore, more spares may be allowed for smooth operation of the system. It further submitted that ceiling percentage spares for extension of substation other than new substation may be prescribed separately, as the same are much higher and non-acceptance of the same by the Commission shall have financial impact. POWERGRID submitted that spares norms are being changed in every Tariff Period and transmission licensees are facing difficulty as norms do not differentiate between new projects and projects with extension of substation, small projects and large projects. It further submitted that the list of spares along with the quantity is available with the Commission and the same may be considered for the purpose of initial spares and there will no need of review in every Tariff Period.

15.5 NTPC submitted that for coal stations of capacity up to 500 MW and gas stations, initial spares norm may be fixed at 4% of Plant and Machinery cost. For coal stations of capacity more than 500 MW capacity (i.e. 660 MW, 800 MW), the norm may be fixed at 5% considering interchangeability and adoption of new technology.

15.6 Some of the stakeholders submitted that in case of HVDC stations, proposed ceiling limit of 4.5% is on higher side and capitalization of converter transformer (spare) is also being allowed separately, which is not justified. They submitted that the higher figure of 4.5% should cover the cost of spare converter transformer also.

15.7 M/s Adani Power Ltd. submitted that for HVDC system, initial spares should be considered on actual case to case basis.

Commission's Views

15.8 The Capital Cost for the project, in addition to plant and machinery cost, includes various other components such as cost of land, cost for site development, IDC, Financing Charges, establishment expenses, etc., and such cost depends on various other factors. It is noted that in case of two similar projects having same Plant and Machinery cost, the total Capital Cost may vary substantially because of other components of Capital Cost and if Initial Spares are allowed as percentage of Capital Cost, the amount allowed towards Initial Spares for two projects with identical plant and machinery cost may vary substantially for the same quantity and quality of spares.

15.9 As regards generating stations, the Commission has considered the following stations while approving the norms of Initial Spares**.**

Table 3: Initial Spares as a percentage of Plant and Machinery Cost

Station	**Initial spares as % of plant & machinery cost**
Udupi Power Project	3.15%
Sipat-II	5.49%
Vindhyachal-III	3.60%
Dadri Stage-II	3.76%
Kahalgaon Stage-II	4.17%
Gas Based Stations	
ONGC Tripura CCGT , Palatana	5.69%
Sugen CCPP of Torrent Power Limited	5.89%
Uno Sugen	2.94%
Hydro Stations	
Uri-II	3.80%

Teesta Low Dam Stg- III	4.00%

15.10 In view of the above data and NTPC's submissions, the Commission is of the view that for coal and gas based stations, the ceiling limit of 4% is appropriate. As regards new gas based stations, the general trend is to go for long-term service and maintenance contracts, which also includes cost of spares and hence, higher initial spares may not be required. In case, there are no long-term service and maintenance contracts, the above ceilings shall apply.

15.11 Further, in case of hydro generating stations, the norm of 4% based on recently commissioned units is sufficient and accordingly, the Commission has retained the same.

15.12 In response to the proposed limit of initial spares, the suggestions were mainly on the ceiling limit proposed by the Commission. Many stakeholders have suggested increasing proposed ceiling limit of initial spares. POWERGRID has suggested working out the spares on the basis of list of initial spares. The Commission has carefully examined the ceiling limit. In view of various suggestions, in order to fix ceiling limit of initial spares for transmission system, the Commission decided to review the proposed ceiling limit on the basis of the information regarding initial spares submitted by various transmission licensees during the Tariff Period 2009-14.

15.13 As regards suggestion for consideration of the list of spares along with the quantity, the Commission felt that the information regarding initial spares filed by various transmission licensees on affidavit should be considered to work out the ceiling limit. It is clarified that as per the proforma along with list of spares, item-wise indicative cost was also required to be furnished. The same was not made available by POWERGRID and in the absence of such an important detail, the option of specifying initial spares in terms of the list of spares could not be explored completely. In view of various suggestions, in order to fix ceiling limit of initial spares for transmission system, the Commission analysed a number of petitions received during the Tariff Period 2009-14 and observed as under:

a) Around 86% of the transmission lines assets have initial spares upto 1% of Plant and Machinery cost, accordingly, it is considered appropriate to fix the ceiling limit of initial spares as 1% of plant and machinery cost as proposed in the draft Regulations.

b) Initial spares have been claimed only for certain number of substation assets. It is observed that the though the expenses claimed were higher than the norms, the same were restricted by the Commission based on the norms. It is further observed that due to higher scale of procurement, per unit cost of spares is less in case of new substations. The Commission considered it appropriate to segregate total substation assets under analysis into greenfield and brownfield substation assets.

   In case of greenfield substation assets, it is observed that around 86% of the assets are having initial spares up to 4% of plant & machinery cost. Accordingly, it is considered appropriate to fix the ceiling limit of initial spares as 4% of plant and machinery cost. In case of brownfield substation assets, the average claim towards initial spares for majority of assets is found to be around 6% of the plant and machinery cost. Therefore, it is considered appropriate to fix the ceiling limit as 6% in case of Transmission Sub-stations (brownfield).

c) The average claim of initial spares of fixed series compensation substation assets were found to be around 4%. Accordingly, it is considered appropriate to fix the ceiling limit at 4% instead of 4.50% proposed in the draft Regulations.

d) In case of HVDC sub-stations, the average claim of initial spares as a percentage of plant and machinery cost of assets is found to be around 4%. Accordingly, it is considered appropriate to fix the ceiling limit at 4% instead of 4.50% proposed in the draft Regulations. In response to the suggestions of stakeholders, it is clarified that the cost of spare transformer is excluded while fixing the ceiling limit.

e) The claim of initial spares in case of GIS assets is found to be in the range of 3.5% - 5.51% with average being 5.12%. Accordingly, it is considered appropriate to fix the ceiling limit at 5% instead of 4.50% proposed in the draft Regulations.

f) Rate of initial spares for PLCC shall be considered in line with respective transmission sub-station.

15.14 Thus, the Commission has specified the following ceiling limits:

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

(a) Coal-based/lignite-fired thermal generating stations	*- 4.0%*
(b) Gas Turbine/Combined Cycle thermal generating stations	*- 4.0%*
(c) Hydro generating stations including pumped storage hydro generating system	*- 4.0%*
(d) Transmission system	
(i) Transmission line	*- 1.00%*
(ii) Transmission Sub-station (Green Field)	*- 4.00%*
(iii) Transmission Sub-station (Brown Field)	*- 6.00%*
(iv) Series Compensation devices and HVDC Station	*- 4.00%*
(v) Gas Insulated Sub-station (GIS)	*- 5.00%*
(vi) Communication system	*- 3.5%*

Provided that:

i. where the benchmark norms for initial spares have been published as part of the benchmark norms for capital cost by the Commission, such norms shall apply to the exclusion of the norms specified above:

ii. where the generating station has any transmission equipment forming part of the generation project, the ceiling norms for initial spares for such equipments shall be as per the ceiling norms specified for transmission system under these regulations:

iii. once the transmission project is commissioned, the cost of initial spares shall be restricted on the basis of plant and machinery cost corresponding to the transmission project at the time of truing up:

iv. for the purpose of computing the cost of initial spares, plant and machinery cost shall be considered as project cost as on cut-off date excluding IDC, IEDC, Land Cost and cost of civil works. The transmission licensee shall submit the break up of head wise IDC & IEDC in its tariff application."

15.15 For assessing the requirement of spares, POWERGRID stated during the public hearing that OEMs do not specify the percentage spare figures, but it is based on experience. Purchase of spares is required to be optimized. We direct all transmission licensees to maintain annual record of utilization of spares. POWERGRID with its PAN-India presence shall endeavour to optimize procurement of spares based on hub and spoke concept in management of O&M activities.

15.16 At the time of finalization of tariff of individual assets, percentage figures of apportioned approved cost of assets or actual, whichever is lower and as covered in the Petition shall be taken. However, to arrive at percentage for the whole project, the transmission licensee can submit details of spares at the time of truing up.

16. Additional Capitalisation and De-capitalisation {Regulation 14}

16.1 Clause 14 of the draft Regulations specified that the additional capital expenditure in respect of the new project or an existing project incurred or projected to be incurred under certain heads within the original scope of work, after the date of commercial operation and up to the cut-off date may be admitted by the Commission, subject to prudence check. Clause 14(2) of the draft Regulations refers to capital expenditure incurred/projected to be incurred under certain heads within original scope of work after cut-off date, which may be allowed by the Commission after prudence check. Clause 14(3) of the draft Regulations specified that the additional capital expenditure in respect of existing generating station or the transmission system including communication system, incurred or projected to be incurred under certain heads after the cut-off date may, at its discretion, be admitted by the Commission, subject to technical scrutiny and prudence check.

<u>Stakeholders' Comments/Suggestions</u>

16.2 Some of the beneficiaries suggested that the additional capitalisation after the cut-off date may not be allowed and the generators or the transmission licensees may be allowed to claim the compensation allowance as per clause 17 of the draft Regulations to account for the additional capitalization if any, after the cut-off date. Some beneficiaries and other stakeholders submitted that the words 'or compliance of any existing law' may be deleted in sub-clause (v) of clause 14(1) of the draft Regulations.

16.3 Some of the generating companies submitted that the cost of creating infrastructure for supply of power to rural households within 5 km radius of power station if the generator does not intend to meet such expenditure as part of CSR, was included as part of 'Additional Capitalization' under CERC Tariff Regulations, 2009 and the same should be reinstated. Some of the stakeholders suggested that the additional capital expenditure incurred towards security and safety should be allowed as part of additional capital expenditure.

16.4 NTPC submitted that if the provisions of cut-off date are relaxed, the generator will plan the capital expenditure for new generating stations on the basis of priority, which will reduce the capital expenditure, thereby reducing the front loading of fixed charges in tariff. Accordingly, the provision for Cut-off Date may be reviewed. Further, any expenditure incurred to sustain operational performance and reliability of the machine may also be admitted for coal based stations based on justification. NTPC also submitted that due to rapid change of technology, C&I systems such as DDC MIS, Data Acquisition System, SOE and PLC become obsolete in around 5-7 years, and are necessarily replaced to take care of the availability of equipments and improve reliability of operation. The current provisions of the Compensatory Allowance do not cover expenses on such heads. Hence, any expenditure on account of replacement of C&I systems due to obsolescence should be allowed to be capitalised. Further, a proviso for allowing additional capital expenditure for compliance of existing laws may be added along with change in law provision (sub-clause (ii) of clause (3) of draft Regulation 14) as allowed for new projects.

16.5 NHPC submitted that the following new clause in case of new projects may be inserted in clause 14(2) of the draft Regulations:

"(v) In case of hydro generating stations, any expenditure which has become necessary on account of damage caused by natural calamities (but not due to flooding of power house attributable to the negligence of the generating company) including due to geological reasons after adjusting for proceeds from any insurance scheme, and expenditure incurred due to any additional work which has become necessary for successful and efficient plant operation;"

16.6 Some of the beneficiaries submitted that as regards clause 14(3)(ix) of the draft Regulations, the beneficiaries/Discoms are the parties sourcing the power. It may be possible that in the present situation, certain DISCOM may not require scheduling any power with additional cost due to prevailing surplus position in the State and therefore, prior approval of such DISCOM is required.

16.7 Some of the beneficiaries submitted that in case of de-capitalisation of assets, the depreciation for the asset ceases from that time, however, as per the draft Regulations, the equity on that asset would continue although the asset does not exist, hence, 30% of asset de-capitalisation should be reduced from equity as well. Also, in case the asset is decapitalised before the usable period and the loan related to such asset is still outstanding, then the loan amount also needs to be reduced for calculation of interest.

Commission's Views

16.8 The Commission is of the view that the Regulations specify the details of various heads on which additional capital expenditure may be admitted by the Commission after prudence check. The Commission observed that some of the suggestions received are related to prudence check of the additional capital expenditure and the same will be examined by the Commission while carrying out the prudence check.

16.9 On the issue of additional capital expenditure towards security and safety, the Commission is of the view that any capital expenditure on account of need for internal security of the plant needs to be included in the Regulations. Accordingly, the Commission has included the following sub-clause (iii) of clause 14(3) of the Regulations:

> *"Any expenses to be incurred on account of need for higher security and safety of the plant as advised or directed by appropriate Government Agencies or statutory authorities responsible for national security/internal security;"*

16.10 Further, the Commission has included a new sub-clause 14 (3)(vi) to cover the expenditure on account of liability for works admitted by the Commission after the cut-off date as under:

> *"(vi)Any liability for works admitted by the Commission after the cut-off date to the extent of discharge of such liabilities by actual payments;"*

16.11 Further, the Commission has decided to include expenditure incurred with respect to tower strengthening and communication equipment in the Regulations. Accordingly, the modified Regulation is as under:

> *"(ix)In case of transmission system any additional expenditure on items such as relays, control and instrumentation, computer system, power line carrier communication, DC batteries, replacement due to obsolescence of technology, replacement of switchyard equipment due to increase of fault level, tower strengthening, communication equipment, emergency restoration system, insulators cleaning infrastructure, replacement of porcelain insulator with polymer insulators, replacement of damaged equipment not covered by insurance and any other expenditure which has become necessary for successful and efficient operation of transmission system; and"*

16.12 As regards the suggestion of not considering capital expenditure towards compliance to existing law from the additional capital expenditure, the Commission is of the view that the generating company or transmission licensee may have to incur some additional capital expenditure for compliance with existing laws, which was not originally planned and hence, it will be appropriate to consider the same. In any case, the additional capital expenditure shall be admitted by the Commission, as per the provisions of Regulations, subject to prudence check.

16.13 Regarding provisions related to de-capitalisation and treatment of corresponding loan and equity, in order to have more clarity, the Commission has modified clause 14(4) of the Regulations as under:

> *"(4) In case of de-capitalisation of assets of a generating company or the transmission licensee, as the case may be, the original cost of such asset as on the date of de-capitalisation shall be deducted from the value of gross fixed asset and corresponding loan as well as equity shall be deducted from outstanding loan and the equity respectively in the year such de-capitalisation takes place, duly taking into consideration the year in which it was capitalised."*

17. Renovation and Modernisation and Special Allowance for coal based/lignite fired Thermal Generating Stations {Regulations 15 and 16}

17.1 Clause 15(1) of the draft Regulations specified the details of application to be made for approval of renovation and modernization for the purpose of the extension of life beyond the useful life of the generating station or a Unit thereof or a transmission system or an element thereof. Clause 15(2) of the draft Regulations specified that when the generating company or the transmission licensee makes an application for approval of its proposal for renovation and modernisation, the approval shall be granted after due consideration of reasonableness of the cost estimates and such other factors as may be considered relevant by the Commission.

17.2 Clause 16(1) of the draft Regulations provided for a 'special allowance', as compensation for meeting the requirement of expenses including renovation and modernisation beyond the useful life of the generating station in case of coal-based/lignite fired thermal generating station. In clause 16(2) of the draft Regulations, the Special Allowance is specified as ₹ 7.5 lakh/MW/year for the year 2014-15 and thereafter escalated @ 6.35% every year during the Tariff Period 2014-19, unit-wise from the next financial year from the respective date of the completion of useful life with reference to the date of commercial operation of the respective unit of generating station.

<u>Stakeholders' Comments/Suggestions</u>

17.3 Some beneficiates and stakeholders submitted that before making an application to the Commission regarding the proposed renovation and modernization, the concerned generator or transmission licensee should discuss and obtain consent from the beneficiaries of the project. In case of renovation and modernization of gas power plant, renovation and modernization should be allowed only if corresponding quantity of extra APM gas is arranged by the generator. Some stakeholders submitted that a standard Renovation and Modernization Policy may be developed in consultation with CEA, if feasible. Renovation and modernization activities should be considered after proper scrutiny of cost benefit analysis by taking into consideration the improvement in the operational parameters including the reduction in Gross Station Heat Rate of the Plant and renovation and modernization should be allowed only if the assets have outlived their useful life or else the required capital expenditure, if any, should be covered under regular O&M expenses.

17.4 Some stakeholders suggested that the parameters such as plan for post renovation and modernization monitoring of performance and liquidated damages to be claimed from the generating company in case of non-performance or non-improvement of the operating norms may also be considered by the Commission while granting approval.

17.5 NEEPCO suggested to reduce the period from 25 years of operation to 15 years of operation for renovation of gas turbines. Some other generating companies submitted that the expenditure incurred on Gas Turbine overhaul after every 12000 hrs/ 24000 hrs/ 48000 hrs (Equivalent Operating Hours (EOH)) be considered as capital expenditure/R&M expenditure as they are mandatory for life extension of Gas Turbines. Such expenses should not be treated as O&M expenses. NTPC submitted that renovation and modernization of gas turbines after 15 years of operation from COD may be continued (as per Second Amendment of CERC Tariff Regulations, 2009) as existing gas based plants were conceived and planned considering life of the plant as 15 years.

17.6 Some beneficiaries submitted that the accumulated depreciation should be deducted to arrive at the net capital base for the purpose of tariff determination during the extended period of useful life of the asset and in case generator does not opt for renovation and modernization and claims special allowance, then in such case the Regulations should also specify about how accumulated depreciation shall be utilized.

17.7 Some beneficiaries and other stakeholders submitted that the concept of special allowance for coal based thermal generating station may be removed, and if special allowance is allowed to a generator, then extension of plant life should also be made mandatory. They also suggested that the details of utilisation of special allowance should be submitted to the Commission at the time of truing up. Some beneficiaries also commented that the special allowance provided in draft

Regulations is on higher side as compared to the special rate and escalation rate provided in Tariff Regulations 2009-14.

17.8 Some of the hydro power plant companies submitted that a special allowance for hydro stations may be allowed in line with renovation and modernization for Coal/ lignite based thermal stations on completion of 25 years. Further, servicing of renovation and modernization expenditure at the fag end of the useful life of station shall extend the useful life so that the project cost can be recovered through depreciation. A benchmark norm may be fixed for renovation and modernization expenses with minimum life extension of 10 years for hydro generators.

Commission's Views

17.9 The Commission is of the view that the draft Regulations provides the detailed mechanism for making an application for approval of Renovation & Modernisation and various aspects to be considered by the Commission for approval of renovation and modernization expenditure. The Commission observed that some of the suggestions received are related to prudence check of renovation and modernization expenditure. As regards the suggestion of obtaining consent from the beneficiaries before submitting an application, the Commission is of the view that it may not be practical to implement this suggestion and in any case, the Commission approves the renovation and modernization expenditure after detailed prudence check.

17.10 For gas/liquid fuel based open/combined cycle thermal generating stations, the useful life of such stations is specified as 25 years and hence, the renovation and modernization expenditure can be considered after 25 years of operation. Further, the expenditure incurred after every overhaul is a regular expenditure and the same cannot be considered as part of renovation and modernization expenditure.

17.11 Clause 15(4) of the Regulations adequately provides for the treatment of accumulated depreciation in case of renovation and modernization of the project.

17.12 The Commission has already stated the purpose behind allowing special allowance in the Explanatory Memorandum to the draft Regulations in case of coal/lignite based generating stations. As regards the amount allowed as special allowance, the Commission has already stated in the Explanatory Memorandum that considering the increase in R&M cost over a period of time, the Special Allowance is being increased to ₹ 7.5 Lakh/MW. As regards the submission of details of utilisation of Special Allowance, Clause 16(3) of the Regulations adequately provides for the submission of relevant information.

18. Compensation Allowance {Regulation 17}

18.1 Clause 17(1) of the draft Regulations provided for a separate Compensation Allowance in case of coal-based or lignite-fired thermal generating station that shall be admissible to meet expenses on new assets of capital nature (including in the nature of minor assets) of the generating station. Clause 17(2) of the draft Regulations specified the manner for allowing the Compensation Allowance from the year following the year of completion of 10, 15, or 20 years of useful life.

Stakeholders' Comments/Suggestions

18.2 NTPC submitted that compensation allowance of ₹ 0.30 lakh/ MW may be allowed between 5–10 years and compensation allowance in other slabs should be increased. Some generating companies suggested that the provision of compensatory allowance available to coal based stations needs to be extended beyond 25 years as expenses for which compensation allowance is given would also continue to be required after renovation & modernisation. They further suggested that the compensation allowance may be escalated on year to year basis commensurate with the actual inflation rate.

18.3 Some of the beneficiaries and other stakeholders suggested that the compensation allowance may be withdrawn. PPCL submitted that such provision may also be made applicable for Gas based Power plants. NHDC submitted that hydro generating stations may also be included in the ambit of this Regulation and a suitable Compensation Allowance be allowed after 10 years of CoD.

Commission's Views

18.4 The Commission is of the view that the objective of allowing Compensation Allowance is to take care of expenses on new assets of capital nature including minor assets and as the requirement of such assets may arise after certain years of operation, the Compensation Allowance has been provided from eleventh year of operation. After completion of the useful life of the thermal generating station, the generating company can either opt for Renovation & Modernisation or opt for Special Allowance and hence, the Compensation Allowance has been provided upto 25 years only. As regards the escalation of compensation allowance based on actual inflation rate, the Commission is of the view that when this allowance is being permitted on normative basis irrespective of expenditure incurred, it may not be appropriate to consider the escalation on the same. For gas based stations, clause 14(3)(vii) provides for successful operation of the plant. Further, present day advanced class GTs are having long-term service/maintenance agreement with the OEM to achieve guaranteed operational performance. In view of this, further loading of cost on beneficiaries on account of compensation allowance would be unjustified.

18.5 As regards the compensation allowance for hydro generating stations, the Commission in its Statement of Objects and Reasons on Central Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2009 deliberated on this aspect and included a specific provision related to capital expenditure for hydro generating stations which has been retained in the Regulations.

19. Sale of Infirm Power {Regulation 18}

19.1 Clause 18 of the draft Regulations proposed that supply of infirm power shall be accounted as Unscheduled Interchange (UI) and paid for from the regional or State UI pool accounts. Proviso to clause 18 of the draft Regulations specified that any revenue earned by the generating company from supply of infirm power after accounting for the fuel expenses shall be applied in adjusting the capital cost accordingly.

Stakeholders' Comments/Suggestions

19.2 SRPC submitted that the draft Regulation may be modified as follows:

"Sale of Infirm Power: Supply of infirm power shall be accounted in accordance with the Central Electricity Regulatory Commission (Deviation Settlement Mechanism

and related matters) Regulations, 2013, as amended from time to time or any subsequent re-enactment thereof:......."

19.3 Some of the generating companies submitted that the Regulations should also allow capitalisation of any loss incurred on sale of infirm power. NHPC submitted that sale of infirm power should be adjusted after accounting for the water charges.

Commission's Views

19.4 The Commission agrees with the suggestions of SRPC and has modified the Regulation as under:

"18. Sale of Infirm Power: Supply of infirm power shall be accounted as deviation and shall be paid for from the regional deviation settlement fund accounts in accordance with the Central Electricity Regulatory Commission (Deviation Settlement Mechanism and Related matters) Regulations, 2014, as amended from time to time or any subsequent re-enactment thereof:"

19.5 The other issues raised on this aspect relates to detailed prudence check, which will be examined by the Commission while carrying out the prudence check.

20. Debt- Equity Ratio {Regulation 19}

20.1 Clause 19 of the draft Regulations proposed the normative debt-equity ratio of 70:30 for new projects with the proviso that if the equity actually deployed in a project is more than 30%, equity in excess of 30% shall be considered as normative loan. However, where equity deployed is less than 30%, it is proposed to consider actual equity for determination of tariff. In respect of the existing projects, the Commission proposed to retain the same debt-equity ratio as was specified by the Commission in tariff determination for the period ending 31.3.2014. Thus, the Commission intended that the investors should be free to invest funds in the form of equity as per their own investment plans, even beyond 30%. It was further proposed that the expenditure on additional capital expenditure and renovation and modernization would be serviced in the debt-equity ratio of 70:30. Further, the Commission proposed that the resolution of the Board of the company for infusion of fund from internal resources should be submitted by the generating station or the transmission system. Also, any grant obtained for the execution of the project shall not be considered as a part of capital structure for the purpose of tariff determination.

Stakeholders' Comments/Suggestions

20.2 Some of the beneficiaries and other stakeholders proposed that the debt-equity ratio may be modified to 80:20 as some of the private players are already adopting debt-equity ratio of 75:25 or 80:20. POWER GRID suggested that grant should be considered as a part of capital cost, however, the same may be treated as normative loan and only depreciation and applicable interest rate should be allowed. The grant amount should be excluded for calculation of ROE, IoWC and Incentive.

20.3 The Commission received number of suggestions regarding modification in the provisions related to Board Resolution. THDC India Ltd. has proposed not to specify separate Board Resolution as a requirement in case of projects, which are approved by Govt. of India. Jaiprakash Power Ventures Ltd. has proposed that the developer may provide an authenticated document signed by CMD/MD instead of the Board Resolution of the company. POWERGRID and NHPC have proposed that the provision of Board approval for deployment of equity should be deleted. Alternatively, NHPC has proposed that the resolution of Board of the Company noting the actual infusion of funds from internal resources may require to be provided by the generator after the completion of the project.

20.4 The summary of suggestions received on the provisions of submission of Board Resolution for infusion of fund from internal resources are as follows:

i. Board Resolution may not be submitted in case of projects approved by the Government of India

ii. Developer may provide an authenticated document signed by the CMD/MD instead of the resolution of the Board of the company

iii. Board Resolution may not be required for Projects for which PIB/CCEA approval of project has been accorded

iv. Capital expenditure is incurred after approval of budget from competent authority as per delegation of power (DOP). Approval from board of the company will only delay the execution of capital expenditure projected

Commission's Views

20.5 Regarding debt-equity ratio of 70:30, the Commission in the Explanatory Memorandum to the draft Regulations observed that keeping in mind the existing uncertainties of debt market such as rising trend of increase in interest rate and uncertainties in debt market, it would not be prudent to revise the existing debt: equity ratio. Further, the Commission had also taken into consideration the growth in the Bank Credit to infrastructure and observed that there has been significant growth in bank credit to infrastructure projects in which the power sector has a major share. Given these realities and due regard to the sentiments of the stakeholders, the Commission is of the view that existing debt-equity ratio of 70:30 may be continued for the next Tariff Period, as the investors might have planned investments taking into consideration the existing debt-equity ratio and change in debt-equity ratio may indicate regulatory uncertainty.

20.6 As regards suggestion of considering grant as part of capital cost for providing normative loan and depreciation, the Commission is of the view that it may not be appropriate to consider grant component in the project cost and treating the same as normative loan. Further, as discussed earlier, the Commission has modified the provisions related to grant and has specified that the grant shall be excluded from the Capital Cost for the purpose of computation of interest on loan, return on equity and depreciation.

20.7 The Commission is of the view that in order to have sanctity of equity investments out of internal resources, it will be appropriate to have the Board Resolution to verify that the funds from internal sources have been utilised to meet the capital expenditure of the generating station or the transmission system. Considering the suggestions of stakeholders, the Commission is of the view that for projects which have received CCEA approval, the CCEA approval can be considered as supporting document regarding infusion of funds from internal resources and accordingly, the Commission has decided to include the approval from CCEA also in the Regulations.

21. Components of Tariff {Regulation 20}

21.1 Clause 20 of the draft Regulations provided for the Tariff Components (capacity and energy charges) for supply of electricity from a thermal and hydro generating station and for transmission charges (annual fixed cost).

<u>Stakeholders' Comments/Suggestions</u>

21.2 Some of the stakeholders submitted that the word "and Secondary Fuel Cost" may also be inserted as part of energy charges.

<u>Commission's Views</u>

21.3 The cost of secondary fuel consumption is already included as part of the energy charges in clause 22, and accordingly, the Commission has included the word "and Secondary Fuel Cost" in clause 20 (1). The modified clause 20 (1) is as under:

> *"(1) The tariff for supply of electricity from a thermal generating station shall comprise two parts, namely, capacity charge (for recovery of annual fixed cost consisting of the components specified in Regulation 21 of these Regulations) and energy charge (for recovery of primary and secondary fuel cost and limestone cost where applicable)."*

22. Capacity Charges and Energy Charges {Regulations 21 and 22}

22.1 Clause 21 of the draft Regulations provided that the Capacity Charges shall be derived on the basis of annual fixed cost and specified the components of Annual Fixed Cost (AFC) of a generating station or a transmission system including communication system. Clause 22 of the draft Regulations provided that the Energy Charges shall be derived on the basis of the landed fuel cost (LFC) of a generating station (excluding hydro) and shall consist of certain costs.

<u>Stakeholders' Comments/Suggestions</u>

22.2 Some of the stakeholders suggested that the Secondary Fuel Consumption should be kept in Fixed Charges only. Some of the beneficiaries supported shifting of cost of secondary fuel oil consumption from Annual Fixed Charges to Energy Charges. NTPC submitted that the Water Charges and other levy of taxes, and duties payable to statutory authorities, which have not been made part of the O&M Expenses are to be passed through separately based on actual payment made by the generating company.

22.3 PPCL submitted that the provision may also include the clause *"arising out of less scheduling or lower supply of fuel less than minimum guaranteed offtake (MGO) or ship or pay charges or imbalance charges or any other charges levied by supplier and transporter shall be fully recoverable from the beneficiaries in the proportion to their share of allocation of power."*

22.4 One stakeholder submitted that the provisions related to normative transit and handling loss as contained in clause 30(7) of the draft Regulations is contradictory to the provisions in clause 22 of the draft Regulations.

Commission's Views

22.5 The Commission would like to clarify that as per the provisions of clause 21, the recovery of special allowance and compensation allowance is allowed separately in accordance with clause 17 of the draft Regulations, but not included as a part of Annual fixed cost for recovery of tariff, with a view to exclude it for computation of working capital.

22.6 The secondary fuel oil consumption is a part of fuel cost, which will primarily depend on the generation of electricity and is variable in nature, and hence, the Commission disagrees with suggestions of stakeholders to include it as a part of capacity charges.

22.7 The recovery of water charges is allowed separately as detailed in the clause on O&M expenses.

22.8 As regards the contradiction in the provisions of regulations with respect to normative transit and handling loss, it is clarified that the Clause 22 only states that the landed fuel cost shall consist of landed fuel cost of primary fuel and cost of secondary fuel oil consumption, while the Regulation 30 (8) elaborates in detail the landed cost of fuel for the month to be considered for computation of energy charges and hence there is no contradiction. The provisions related to lower supply of fuel and use of alternative source of fuel supply has been dealt in Clause 30 of the Regulations.

23. Landed Fuel Cost for Tariff Determination {Regulation 23}

23.1 Clause 23 of the draft Regulations provided that the landed fuel cost of primary and secondary fuel for tariff determination shall be based on actual of the weighted average cost of primary fuel and secondary fuel of the three preceding months and in the absence of landed costs for the three preceding months, latest procurement price of primary fuel and secondary fuel for the generating station, before the start of the year.

Stakeholders' Comments/Suggestions

23.2 TANGEDCO submitted that in accordance with the draft Regulations, the cost of coal, GCV of coal and oil of the three-preceding months before COD has been considered in energy charges on weighted average basis. However, the billing is done based on the weighted average cost and GCV of coal and oil during the month. Therefore, this procedure is not correct. The generator has to furnish quantity, cost of coal, GCV of coal and oil every month along with their bills to check the correctness of the claim including the weighted average GCV and cost claimed in their invoices.

Commission's Views

23.3 In response to the suggestions of stakeholders, the Commission would like to clarify that clause 23 of the draft Regulations has already dealt with this aspect. It provides for the landed cost of fuel to be considered for tariff determination, however, the billing shall be governed by the provisions of Clauses 30(5) and 30(6), which specify that *"The energy charge shall cover the primary and secondary fuel cost and limestone consumption cost (where applicable), and shall be payable by every beneficiary for the total energy scheduled to be supplied to such beneficiary during the calendar month on ex-power plant basis, at the energy charge rate of the month (with fuel and limestone price adjustment)"*. The cost of coal, GCV of coal and oil consumption of three preceding months has been considered to work out the base energy charges, which gives indicative energy charges, however, energy charges for billing is to be computed on monthly basis based on landed cost and GCV of fuel in the month in accordance with clause 30.

24. Rate of Return on Equity {Regulation 24}

24.1 In the draft Regulations, the Commission proposed to continue with the existing base rate of return on equity of 15.5% for thermal generating stations, transmission system including communication system and run of the river hydro generating station, and the base rate of 16.50% for the storage type generating stations including pumped storage hydro generating stations and run of river generating station with pondage with the additional 0.5% return on equity for timely completion of projects. Further, the Commission proposed reduction of 1% in RoE, if the generating station or transmission system declares commercial operation without commissioning of RGMO/FGMO, data telemetry and communication system up to load dispatch centre and protection system.

Stakeholders' Comments/Suggestions

24.2 Most of the generating companies and transmission licensees suggested that rate of return on equity should be allowed higher than 15.5% proposed in the draft Regulations. NTPC has proposed higher RoE of around 18-20% supported by a broad calculations used for computation of cost of equity under Capital Asset Pricing Model (CAPM). For computation of cost of equity under CAPM, NTPC has considered a risk free return of 8.0%, Beta in today's scenario of 1.21 and risk premium of 10%, thereby working out the cost of equity of around 20%.

24.3 Some of the hydro project developers submitted that the Return on Equity for hydro projects may be specified at higher level considering the risks involved in hydro projects, and proposed RoE of at least 19.5%.

24.4 On the other hand, some beneficiaries and other stakeholders suggested to reduce the Return on Equity from 15.5% to 14%. Some beneficiaries submitted that as under cost plus regime, all the costs are allowed as pass through, Return on Equity may be limited to risk free rate plus 2%. Some beneficiaries submitted that it is well established fact that equivalent rate of return on equity is inversely proportional to the life of the equipment. The draft Regulations provides for 16.5% ROE for storage type HEP including pumped storage HEP and run of the river with pondage, while for others like Thermal Power Station and Transmission System it is

15.5%. The life of HEP and Transmission system is 35 years whereas life of Thermal Power Stations is 25 years. Therefore, ROE of hydro electric plant and transmission system may be specified lower than that of thermal power plants (15.5%).

24.5 Some of the generating companies submitted that the installation of telemetry and communication network at the RLDC/CTU end of the transmission network is beyond the scope of the generator and delay in installation of data telemetry and communication infrastructure at the RLDC/NLDC/SLDC/CTU end of the transmission network may not be linked to declaration of COD of the generating station and should not result in lowering of ROE for the generators.

24.6 Some of the beneficiaries suggested that additional RoE for timely completion of projects may be limited to 0.1% instead of 0.5%. Some of the stakeholders submitted that once the debt repayment is over, the depreciation should be reduced from equity component for computing return on equity.

Commission's Views

24.7 Section 61(d) of the Electricity Act, 2003 provides that the Commission, while specifying the terms and conditions for determination of tariff, shall be guided by the principle of '*safeguarding of consumers interest and at the same time, recovery of cost of electricity in a reasonable manner*'.

24.8 Section 5.3(a) of the Tariff Policy stipulates that while laying down the rate of return, the Commission shall maintain balance between the interests of consumers and the need for investments. CERC would notify, from time to time, the rate of return on equity for generation and transmission projects keeping in view the assessment of overall risk and the prevalent cost of capital, which shall be followed by the SERCs also. The rate of return notified by CERC for transmission may be adopted by the SERCs for distribution with appropriate modification taking into view the higher risks involved.

24.9 The Commission is of the view that while specifying the norms for generation and transmission utilities, it should also take into consideration the impact of the same on the consumers, since the rate of return decided by the Commission for transmission may be adopted by SERCs for distribution. Further, the cost of power purchase from Central Utilities is a significant contributor to the distribution cost and hence, the retail tariff. The Commission is fully cognisant of the financial health of distribution companies in India and the kind of challenges they are faced with in the present scenario.

24.10 Giving due regard to the suggestion of various stakeholders for determining cost of equity using scientific model, the Commission has endeavoured to determine the cost of equity using CAPM Model as suggested by various stakeholders. The Commission has analysed the various scientific models such as Dividend Growth Model/Discounted Cash Flow Model, Price/Earning Ratio Method, Risk Premium Approach, Capital Asset Pricing Model (CAPM). However, the Commission observed that CAPM Model is more suitable for determining cost of equity for investments in the Indian power sector. Further, CAPM is also the most popular and widely accepted method for determining the cost of equity. This risk-return model has been in use the longest and is still the standard method adopted across the world.

24.11 The Commission is aware of the fact that although Government securities do not have a default risk, they are still susceptible to reinvestment risk and inflation risk. To eliminate reinvestment risk, zero coupon securities has been considered. However, inflation risk is still not effectively mitigated. Due to the lack of any better measure of risk free rate, the Commission has considered the yield on zero coupon Government securities as Risk Free Rate. The Risk Free rate has been considered as average of the yield on 10-year zero coupon bonds for the period January, 2012 to June, 2013, i.e., 7.99%.

24.12 In order to compute the Market Risk Premium (R_m), the expected return provided by the market has been estimated by assuming that the past returns provided by the equity market mirrors the expectations of the investors. For determining the market return, the Commission has considered the returns provided by the BSE Sensex over the period January 1992 to September 2013, as a proxy for the historical returns provided by the Indian equity market. The average annual growth rate of the BSE Sensex over the period 1992 – 2013 works out to around 16.47% as shown in the graph below:

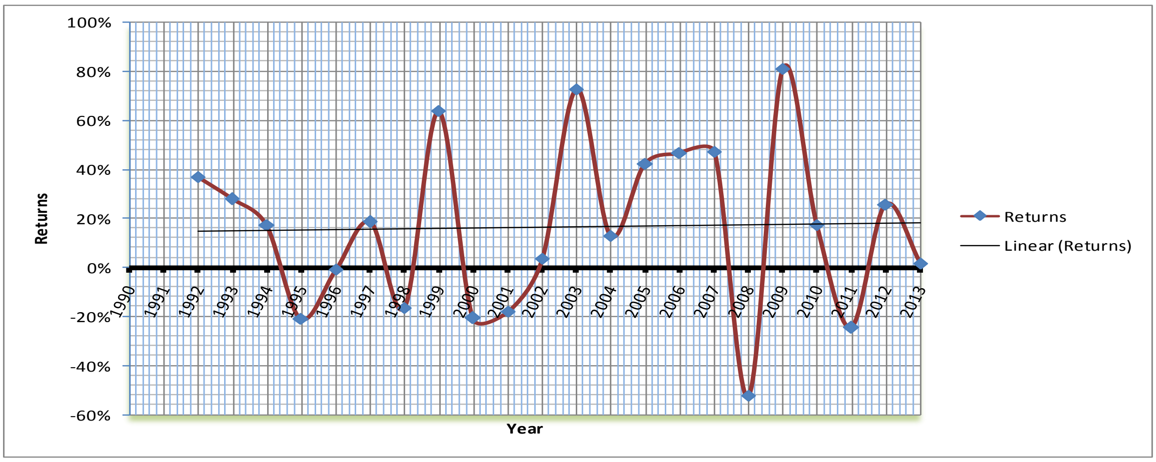

Figure 4: Average annual growth rate of the BSE Sensex over the period 1992 – 2013

24.13 For computing the β in the first step, the levered Beta is estimated for all major power sector companies in the business of power generation and transmission listed in the BSE. Then the levered Beta is converted to unlevered Beta considering the actual debt: equity ratio and effective tax rate to gauge the business risk. In the next step, the Composite Beta based on the weighted average of market capitalization separately for Regulated entities and IPPs have been computed to estimate the business risk of the concerned companies. For computing the levered Beta, it has been considered that the actual debt- equity till now will remain same in the future. It is observed that in the initial years, debt-equity ratio is normative close to normative debt: equity ratio of 70:30 and this high debt-equity ratio during the construction phase means higher risk for the equity holders during this period and hence, the expected returns are higher. However, once the plant is operational, the debt-equity ratio will reduce due to debt repayments made during the term of the loan and hence, lower the risk for the equity holder. Once all the debt is repaid, the financial risk is reduced to that of servicing only working capital requirements. As the risk profile reduces over the life of the project, the Commission is of the view that actual debt-equity ratio of the companies is a good reflector of the financial risk involved through the life of the project. To calculate the cost of equity, the Commission has considered the actual debt-equity ratio over the life of the Project. On the basis of this approach, the cost of equity for regulated entities works out to be in the range of 13-15% with few exceptions. Thus, the Commission is of the view that the cost of equity arrived at using CAPM model is in line with the existing return on equity during the Tariff Period and proposed in the draft Regulations, i.e., 15.50%. In view of the above, the Commission does not find any merit in increasing the rate of return of equity.

24.14 The Commission also explored the option of fixing the rate of return on equity by linking to an appropriate benchmark like RBI Bank Rate, SBI Base Rate, 10 year G-Securities Rate, etc., with an appropriate mark up. However, it is observed that the debt market is not mature enough and interest rates have also witnessed significant fluctuation in the recent past as shown in the graph below:

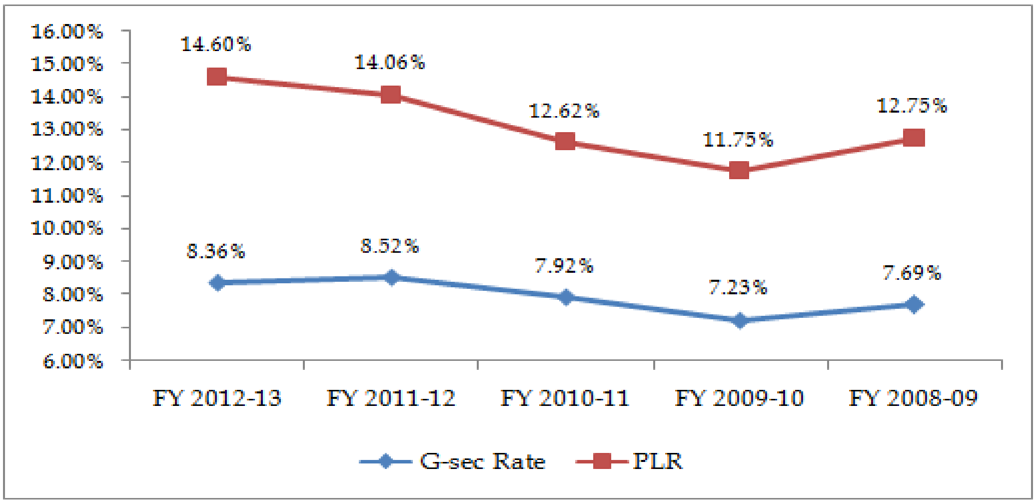

Figure 5: Trend of G-sec Rate and PLR

24.15 It can be observed from the above graph that interest rates have varied from 11.75% to 14.60% and G-sec rate has varied from 7.23% to 8.52% for the period FY 2008-09 to FY 2012-13. Hence, the Commission proposes that unless the debt market stabilises, it may not be appropriate to link the rate of return to any benchmark rate with mark up. The Commission after considering the views and suggestions of various stakeholders, does not find any merit to revise the rate of return on equity and has decided to keep rate of return on equity as proposed in the draft Regulations.

24.16 As regards the various suggestions received on modification of the provisions related to reduction in the rate of return for new projects in case of declaration of commercial operation without commissioning of RGMO/FGMO, data telemetry and communication system up to load dispatch centre and protection system, the Commission would like to clarify that commissioning of RGMO/FGMO is of prime importance for maintaining grid stability and thus, no relaxation may be extended in declaring COD without commissioning of RGMO/FGMO. Further, the Commission clarifies that in case of lack of any of the above requirement based on the report submitted by RLDC, the RoE will be reduced by 1% for the period the deficiency in the system continues.

24.17 The Commission would like to clarify that additional RoE of 0.50% shall be allowed if any element of the transmission project is completed within the specified timeline and it is certified by the Regional Power Committee/National Power Committee that commissioning of the particular element will benefit the system operation in the regional/national grid. Further, the Commission clarifies that provision for additional ROE will not be applicable for transmission line having length of less than 50 km.

24.18 Regarding the suggestion for higher Return on Equity for hydro projects, the Commission in draft Regulations has already proposed 1% higher Return on Equity for storage type generating stations including pumped storage hydro generating stations and run of river generating stations with pondage and the Commission is continuing with the same.

24.19 On the issue of reduction of additional RoE from 0.5% to 0.1% for timely completion of the projects, the Commission is of the view that the incentive for timely completion for the Project has to be adequate enough to incentivise the project developers for making the efforts to ensure timely completion of the project.

24.20 As regards reduction in equity base after debt repayment period is over, the Commission in the Explanatory Memorandum to draft Regulations has discussed the merits and de-merits of Return on Equity Approach and Return on Capital Employed Approach. As elaborated in the Explanatory Memorandum to draft Regulations, the Commission is following the Gross Fixed Asset approach for computing the fixed charges. The Commission is of the view that under Net Fixed Asset approach, the return on equity will reduce significantly. The Commission is also aware of the fact that investors have made investments based on GFA approach and changing the methodology of the existing projects will have detrimental effect on the returns on the investments. The approach suggested by some of the stakeholders of reducing the depreciation from the equity after loan repayment is over, is a hybrid approach. After considering all aspects in this regard, with a view to provide the regulatory certainty to the investors who have made investments in the sector on the basis of the Return on Equity approach linked to Gross Fixed Assets, the Commission has decided to continue with the existing method of Return on Equity.

24.21 Accordingly, clause 24 has been modified as follows:

"24. Return on Equity: (1) Return on equity shall be computed in rupee terms, on the equity base determined in accordance with regulation 19.

(2) Return on equity shall be computed at the base rate of 15.50% for thermal generating stations, transmission system including communication system and run of the river hydro generating station, and at the base rate of 16.50% for the storage type hydro generating stations including pumped storage hydro generating stations and run of river generating station with pondage:

Provided that:

i. *in case of projects commissioned on or after 1st April, 2014, an additional return of **0.50 %** shall be allowed, if such projects are completed within the timeline specified in **Appendix-I**:*
ii. *the additional return of 0.5% shall not be admissible if the project is not completed within the timeline specified above for reasons whatsoever:*
iii. *additional RoE of 0.50% may be allowed if any element of the transmission project is completed within the specified timeline and it is certified by the Regional Power Committee/National Power Committee that commissioning of the particular element will benefit the system operation in the regional/national grid:*
iv. *the rate of return of a new project shall be reduced by 1% for such period as may be decided by the Commission, if the generating station or transmission system is found to be declared under commercial operation without commissioning of any of the Restricted Governor Mode Operation (RGMO)/ Free Governor Mode Operation (FGMO), data telemetry, communication system up to load dispatch centre or protection system:*
v. *as and when any of the above requirements are found lacking in a generating station based on the report submitted by the respective RLDC, RoE shall be reduced by 1% for the period for which the deficiency continues:*
vi. *additional RoE shall not be admissible for transmission line having length of less than 50 kilometres."*

25. Tax on Return on Equity {Regulation 25}

25.1 In the draft Regulations, the Commission proposed to modify the existing provision of pre-tax RoE being grossed up with the Tax Rate, to post tax RoE with income tax to be recovered on actual basis to the extent of return on equity only. Further, the Commission incorporated the provision stipulating that in case the profit before tax for a particular year is higher than the effective income tax on Return on Equity, then the Income Tax on Return on Equity shall be as follows:

$$\text{Income Tax to be recovered from beneficiaries} = \frac{\text{Total Income Tax Paid} \times \text{RoE approved by the Commission}}{\text{Profit before Tax}}$$

25.2 On the other hand, if the Profit before Tax for a particular year is lower than the tax on Return on Equity, then the actual Income Tax paid by the Generating Company or Transmission Licensee shall be recovered from beneficiaries or the long term transmission customers/DICs.

<u>Stakeholders' Comments/Suggestions</u>

25.3 Most of the generating companies and transmission licensees were in favour of continuing the existing Regulations of pre-tax ROE. Several generation and transmission companies have expressed their interest in retaining existing Regulations and retaining grossing up of RoE by effective tax rate as was provided in Tariff Regulations, 2009. Further they are of the view that all the costs pertaining to tax on income from non-core business including incentive, efficiency gain, income on UI, PAT, CDM, late payment surcharge, etc., should be passed on to the beneficiaries. On the other hand, beneficiaries have stated that the generation and transmission companies should pay the income tax from the profit being earned by them and it should not be recoverable from beneficiaries. They further suggested that tax holiday benefit under section 80-IA availed by the generators and transmission licensees should be passed to the beneficiaries.

25.4 POWER GRID further suggested that the annual adjustment of under-recovery/over-recovery shall not be possible as the assessment will be completed after three years from the end of the Financial Year. Therefore, the annual adjustment provision needs to be modified accordingly.

Commission's Views

25.5 The Commission in the Explanatory Memorandum to the draft Regulations discussed the need for shifting from pre-tax return on equity approach to post-tax return on equity approach with income tax to be recovered on actual basis to the extent of return on equity only. Accordingly, in the draft Regulations, the Commission proposed post – tax return on equity with income tax to be recovered separately only on the RoE component.

25.6 The Commission observed that various stakeholders have suggested to retain the existing pre-tax return on equity approach. On the other hand beneficiaries have suggested that utilities should recover income tax from their profit and not separately from the beneficiaries. The Commission has analysed the suggestions and observations received from various stakeholders and observed that both the approaches have their own merits and demerits. However, the major disadvantage, which the Commission envisages in implementation of post-tax approach is the incremental effect of income tax liability, which will arise as the reimbursement of income tax shall again be considered as income in the hands of the generator/licensee and the same will defeat the entire purpose of adopting this approach. Thus, with due regard to the suggestions of the stakeholders and the complexities involved in computing income tax liability, it will be appropriate to retain the existing pre-tax rate of return approach. In order to pass on the benefits and concessions available in income tax, the income tax rate to be considered for grossing up purpose shall be Minimum Alternate Tax (MAT) rate, if the generating company, generating station or the transmission licensee is paying MAT, or the effective Tax Rate, if the generating company or the transmission licensee is paying income tax at corporate tax rate. Accordingly, the Commission has decided to allow pre-tax rate of return on equity which shall be grossed up with the effective tax rate of the financial year or MAT rate and the tax on other income stream will not be considered for the calculation of the effective tax rate.

25.7 Accordingly, clause 25 has been modified as follows:

"25. Tax on Return on Equity:

(1) The base rate of return on equity as allowed by the Commission under Regulation 24 shall be grossed up with the effective tax rate of the respective financial year. For this purpose, the effective tax rate shall be considered on the basis of actual tax paid in the respect of the financial year in line with the provisions of the relevant Finance Acts by the concerned generating company or the transmission licensee, as the case may be. The actual tax income on other income stream (i.e., income of non generation or non transmission business, as the case may be) shall not be considered for the calculation of "effective tax rate".

(2) Rate of return on equity shall be rounded off to three decimal places and shall be computed as per the formula given below:

Rate of pre-tax return on equity = Base rate / (1-t)

Where "t" is the effective tax rate in accordance with Clause (1) of this regulation and

shall be calculated at the beginning of every financial year based on the estimated profit and tax to be paid estimated in line with the provisions of the relevant Finance Act applicable for that financial year to the company on pro-rata basis by excluding the income of non generation or non transmission business, as the case may be, and the corresponding tax thereon. In case of generating company or transmission licensee paying Minimum Alternate Tax (MAT), "t" shall be considered as MAT rate including surcharge and cess.

Illustration:

(i) In case of the generating company or the transmission licensee paying Minimum Alternate Tax (MAT) @ 20.96% including surcharge and cess:

Rate of return on equity = 15.50/ (1-0.2096) = 19.61%

(ii) In case of generating company or the transmission licensee paying normal corporate tax including surcharge and cess:

(a) Estimated Gross Income from generation or transmission business for FY 2014-15 is Rs 1000 crore.

(b) Estimated Advance Tax for the year on above is Rs 240 crore.

(c) Effective Tax Rate for the year 2014-15 = Rs 240 Crore/Rs 1000 Crore = 24%
(d) Rate of return on equity = 15.50/ (1-0.24) = 20.395%

(3) The generating company or the transmission licensee, as the case may be, shall true up the grossed up rate of return on equity at the end of every financial year based on actual tax paid together with any additional tax demand including interest thereon, duly adjusted for any refund of tax including interest received from the income tax authorities pertaining to the tariff period 2014-15 to 2018-19 on actual gross income of any financial year. However, penalty, if any, arising on account of delay in deposit or short deposit of tax amount shall not be claimed by the generating company or the transmission licensee as the case may be. Any under-recovery or over-recovery of grossed up rate on return on equity after truing up, shall be recovered or refunded to beneficiaries or the long term transmission customers/DICs as the case may be on year to year basis."

24.8 The term 'Effective Tax Rate' has been introduced to compute the tax rate at which the base ROE is to be grossed up and is expected to be lower than the corporate tax rate. The Regulation provides for the computation of effective tax rate. The effective tax rate will be computed by the generating company or transmission licensee on the basis of estimated tax payable and estimated gross income from generation and transmission business, which refers the estimated gross profit before tax. The effective tax rate will be applied on the extent of return on equity admitted by the Commission for tariff purposes.

26. Interest on Loan Capital {Regulation 26}

26.1 It was proposed in the draft Regulations that the loan computed on the basis of debt-equity ratio to be determined as per the provision of clause 19 of the draft Regulations, would be considered as gross normative loan for the purpose of calculation of interest on loan. It was proposed that the normative loan outstanding as on 1.4.2014 would be worked out by deducting the cumulative repayment admitted by the Commission up to 31.3.2014. The repayment for each year shall be deemed to be equal to the depreciation allowed for the corresponding year. In case of de-capitalization of assets, the repayment shall be adjusted by taking into account cumulative repayment made to the extent of de-capitalization. The interest on loan would be calculated on the normative average loan by applying weighted average rate of interest, to be worked out on the basis of actual loan portfolio of the generating company or transmission licensee. In the absence of actual loan portfolio in a particular year, the last weighted average rate of interest and in the absence of any loan, the weighted average rate of interest of the generating company or transmission licensee as a whole, would be taken into account. The draft Regulations further provided for refinancing of loan and sharing of benefits with the beneficiaries in the ratio of 2:1.

Stakeholders' Comments/Suggestions

26.2 NHPC has proposed that for the projects where actual loan has been repaid, the depreciation pertaining to additional capitalization only should be considered as repayment of loan rather than full amount of depreciation during the year. It is also equitable, as normative loan arising during the year is on account of additional capitalization. THDC India Ltd. suggested that the cumulative depreciation of de-capitalized assets should be reduced from cumulative repayment of loan and has no relation with current year repayment of loan.

26.3 POWERGRID proposed that in case of additional capitalization, the interest on loan on additional capitalisation may be considered additionally. POWER GRID further suggested to consider the rate of interest on the basis of overall interest liability of the company for the actual loan portfolio.

26.4 As regards sharing of gains on refinancing of loans, some beneficiaries proposed that the cost of the refinancing should also be shared between beneficiaries and generating/transmission company in the ratio of 2:l

26.5 KSEB suggested that the Commission may incorporate appropriate mandatory provisions in the Regulations that all the generators and transmission licensees shall take every effort to refinance the high cost loans at the cost of the beneficiaries and to share the savings with the beneficiaries.

Commission's Views

26.6 The Commission has examined the suggestion provided by the stakeholder for linking depreciation to repayment of debt raised for additional capitalisation. The linking of depreciation to the additional capitalization only will require separate stream of depreciation. The basic premise for providing higher depreciation in the initial years is to provide sufficient liquidity to the utility for repayment of loan, however, there may be variation in actual repayment and depreciation on year to year basis and in case actual repayment is higher than the depreciation allowed in initial years, then the utility will be able to recover higher interest as compared to actual interest in initial years. In the event of linking depreciation with additional capitalization, there will be implication on early or later recovery of depreciation, however, there will be no commercial implication. If the suggestion of stakeholder is accepted, the depreciation could be limited to the extent of additional capitalisation after repayment of project loans will be complex as the depreciation is to be computed in separate stream for additional capitalization. The interest rate of additional capitalisation will also be considered based on actual loan component for the additional capitalisation of the project. The approach proposed in the draft Regulations is simplified and balanced. In view of above, the Commission does not find it appropriate to consider the suggestion of stakeholder to link depreciation with repayment towards additional capitalisation as the interest on loan from first year of operation is being computed by considering the repayment equal to depreciation instead of actual repayment.

26.7 Few stakeholders have suggested to share the benefit on account of re-financing of loan. Keeping in view the balancing between generator/transmission licensee and beneficiaries/long term customers, the Commission is of the view that re-financing should be undertaken only if it is beneficial to the consumers and major portion of the benefits should be passed on to beneficiaries while allowing the utilities to retain one-third for the initiative taken by them to refinance the loan. Therefore, any cost incurred in such refinancing will be borne by the beneficiaries and the net savings will be shared in the ratio of 2:l between beneficiaries and the generating company or the transmission licensee, as the case may be.

26.8 THDC India Ltd has suggested to reduce the cumulative repayment of loan in case of de-capitalization of assets. The Commission clarifies that in case of de-capitalisation of assets, the repayment will be adjusted by taking into account cumulative repayment made to the extent of de-capitalization on a pro-rata basis and the adjustment should not exceed cumulative depreciation recovered upto the date of de-capitalisation of such asset.

26.9 Accordingly, the Clause 26(3) of the Regulations has been modified as follows:

> *"(3) The repayment for each of the year of the tariff period 2014-19 shall be deemed to be equal to the depreciation allowed for the corresponding year/period. In case of de-capitalization of assets, the repayment shall be adjusted by taking into account cumulative repayment on a pro rata basis and the adjustment should not exceed cumulative depreciation recovered up to the date of decapitalisation of such asset."*

27. Depreciation {Regulation 27}

27.1 It was proposed in the draft Regulations that Depreciation will be computed from the date of commercial operation of generating station or unit thereof or transmissions system including communication system or element thereof. In case of the tariff of all the units of generating station or all elements of transmission system including communication system for which a single tariff needs to be determined, the depreciation will be computed from the effective date of commercial operation taking into consideration the depreciation of individual units or elements thereof and the effective date of commercial operation will be worked out by considering the date of commercial operation and installed capacity of all the units of generating station or capital cost of all elements of transmission system, for which single tariff needs to be determined.

27.2 Further in the draft Regulations, it was proposed that for the purpose of computing depreciation, the value base of the asset will be considered the project cost admitted by the Commission. In case of multiple units in a generating station, weighted average life for the station will be applied. Depreciation will be chargeable from the first year of commercial operation and in case of commercial operation of the asset for part of the year, depreciation will be charged on pro rata basis. Further, the salvage value of the asset will be considered as 10% and depreciation will be allowed up to maximum of 90% of the capital cost of the asset. Further land other than the land held under lease and the land for reservoir in case of hydro generating station will not be a depreciable asset and its cost will be excluded from the capital cost while computing depreciable value of the asset. In case of de-capitalization of assets in respect of generating station or unit thereof or transmission system or element thereof, the depreciation shall be adjusted by taking into account the cumulative depreciation to the extent of de-capitalization.

Stakeholders' Comments/Suggestions

27.3 NTPC Ltd. suggested that the useful life of taken over projects such as Tanda, Badarpur, Talcher TPS, etc., may be considered as approved in the 2009-14 tariff orders. Further, NTPC Ltd., Neyveli Lignite Corporation (NLC) and MSPGCL have proposed to allow the unrecovered depreciation due to lower availability at the end of the useful life. On the other hand, some of the beneficiaries submitted that if there is under recovery of fixed charges (including depreciation) due to non achievement of target availability, this shortfall in depreciation should not be allowed to be recovered/recouped at later stage of project since it would be against the principle and concept of normative approach.

27.4 Some generating companies proposed higher depreciation rate for initial 8-12 years. Some of the generating companies proposed to allow Advance against Depreciation (AAD) as was allowed in the 2004-09 Tariff Regulations. CSPGCL proposed to extend the computation of depreciation at specified rates from 12 years to 15 years.

27.5 The Narmada Hydroelectric Development Corporation (NHDC) submitted that as land held for reservoir has no salvage value, 100% depreciation on land held for reservoir may be allowed. THDC further submitted that the draft Regulation provides depreciation towards cost of land coming under submergence of Reservoir and the depreciation allowed on this account, does not qualify to be deductible under Income Tax Rules. Thus, the burden of tax on such depreciation, disallowed under Income Tax Rules, may allowed to be recovered additionally from the beneficiary.. NTPC Ltd. and THDC India Ltd. proposed separate depreciation rate for software elements. THDC India Ltd. proposed depreciation @25% on computers and its peripherals, laptop, etc.

27.6 Kerala State Electricity Board (KSEB) proposed to re-assess the useful life of the assets with the newly added assets. Depreciation on the old assets may be allowed based on the 'original useful life' without any asset addition. However, depreciation on the newly added assets only should be allowed based on the extended useful life of the assets.

Commission's Views

27.7 The Commission in the Explanatory Memorandum to the draft Regulations has categorically mentioned that if the costs disallowed in particular years on account of non-achievement of performance parameters are allowed to be recovered in subsequent years, then the entire purpose of specifying norms will be defeated. The Commission is of the view that the normative performance parameters are determined after detailed deliberation and analysis and thus, compliance of the same by the utilities is of paramount importance. Further, the Commission is of the view that in case of non-compliance of performance parameters by the utility, ultimately the burden has to be borne by end consumer by paying higher cost of power purchase procured from short-term market. It is the responsibility of the Commission to maintain a balance so that the generators and transmission licensee are entitled to legitimate fixed charges and at the same time the end consumer is not burdened with unnecessary cost. Thus, the Commission does not find any merit in the suggestion of allowing recovery of unrecovered depreciation at the end of useful life of the project.

27.8 As regards allowing higher depreciation rate to meet the repayment obligations or providing Advance Against Depreciation, the Commission during finalisation of Tariff Regulations for the Tariff Period 2009-14 has discussed in detail the basis of considering average depreciation rate as 5.28% for initial 12 years and thereafter, spreading the remaining depreciable value over the useful life of the assets. The Commission has fixed the average depreciation rate considering normative debt:equity ratio of 70:30 and the normative loan repayment as 12 years. Further, under most loan agreements, there is a moratorium period of one to two years or more for repayment of loans, hence, the effective period for repayment of loans would amount to 13 to 14 years, and the cumulative depreciation allowed under Tariff Regulations would enable repayment of loans within this effective period. Further, some of the Financial Institutions have started providing longer tenure loans to the power sector. In view of the above, the Commission is of the view that no modification is required to this Clause on this account.

27.9 As regards useful life of Talacher, Badarpur and Tanda stations are concerned, it is clarified that life of these stations were extended in consideration of Renovation and modernisation undertaken and done at that point of time. With further, Renovation and modernisation of other stages/units, Commission would take a view on the further extension of life on case to case basis.

27.10 As regards re-assessment of the useful life of the assets based on additional capital expenditure, the Commission in the draft Regulations has already provided that for any capital expenditure to be added during the fag end of the project, the generating company or the transmission license, as the case may be, shall submit the details of proposed capital expenditure during the fag end of the project along with justification and proposed life extension.

27.11 As regards the capital expenditure during the fag end of the project, the Commission clarifies that the generating company or the transmission license will envisage the capital expenditure and accordingly submit the details to the Commission for capital expenditure proposed during last five years before the completion of useful life of the project.

27.12 As regards depreciation on land held for reservoir and allowing income tax burden for the same, the Commission is of the view that allowing the additional tax burden arising on this account may not be appropriate.

27.13 As regards suggestion of providing depreciation rate for software, the depreciation rate for software has been specified as 15%.

27.14 Accordingly, the clause 27(7) of the Regulations has been modified as follows:

> *"(7) The generating company or the transmission license, as the case may be, shall submit the details of proposed capital expenditure during the fag end of the project (five years before the useful life) along with justification and proposed life extension. The Commission based on prudence check of such submissions shall approve the depreciation on capital expenditure during the fag end of the project."*

28. Interest on Working Capital (IoWC) (Regulation 28)

28.1 Clause 28 of the draft Regulations specified various components to be considered for computation of the working capital requirement for coal based/lignite fired thermal generating stations, open cycle gas turbine/combined cycle thermal generating stations, hydro generating stations and transmission system. Clause 28(2) of the draft Regulations provided that the cost of fuel for coal based/lignite fired thermal generating stations and open cycle gas turbine/combined cycle thermal generating stations shall be based on the landed cost incurred by the generating company and GCV of the fuel as per actual for the three months preceding the first month for which tariff is to be determined and no fuel price escalation shall be provided during the Tariff Period.

Stakeholders' Comments/Suggestions

28.2 MPERC submitted that clause 17(1) of the draft Regulations specified that the compensation allowance shall be included in the annual fixed cost and clause 21 of the draft Regulations specified that the special allowances/or separate compensation allowances shall not be considered for computation of working capital. On the other hand, clause 28(a)(v) of the draft Regulations interprets that the working capital shall cover the receivables equivalent to two months capacity charges, which includes compensation allowance. Therefore, the clause 28(a)(v) of the draft Regulations should be reviewed with reference to clauses 17(1) and 21 of the draft Regulations.

28.3 MPERC and some other stakeholders submitted that Para 11.5.5 of the Explanatory Memorandum emphasises that *"The Commission proposes to not include RoE as the component of receivables for arriving at normative working capital as no working capital is required to fund the Return on Equity."* Therefore, any item, which is not considered for computation of working capital should be mentioned clearly in clause 28(a)(v).

28.4 Some of the beneficiaries submitted that the statements under clause 28(1)(a) (i) and (ii) of the draft Regulations are contradictory in so far as the pit head coal/lignite and limestone stations are concerned. Some of the beneficiaries submitted that the creditors for goods and services may be reduced to determine working capital as this is in line with accounting and banking principles and therefore, point (ii), i.e., *'Cost of coal or lignite and limestone for 30 days for generation, corresponding to the normative annual plant availability factor'* may be deleted from the components of working capital.

28.5 Some of the beneficiaries submitted that the stock of coal may be allowed corresponding to the normative plant availability factor or the maximum coal storage capacity, whichever is lower. The beneficiaries also submitted that most of the generating plants are maintaining the fuel stock for less than 15 days during last few years, irrespective of the fact that whether it may be a pithead or non-pithead station. It is, therefore, proposed to reduce the cost of coal to 15 days for calculation of interest on working capital.

28.6 Some beneficiaries submitted that secondary fuel oil stock should be reduced from proposed two months to 15 days for the purpose of calculation of IOWC. A beneficiary further submitted that in respect of secondary fuel oil, the Commission may limit inventory to 30 days stock as each thermal station is linked to a particular agency (IOCL/BPCL, etc.) and it is always possible to get the secondary fuel oil at short notice, say 7 days. A beneficiary further submitted that the generators may be directed to declare the storage capacity of coal and oil available in their power stations so that the limitation of inventory level under working capital requirement is monitored.

28.7 Some beneficiaries suggested that the truing up of interest on working capital should also be done, particularly, when true up of operational parameters, viz., SHR, AUX, SFC, is done, the true up should also be done for fuel stock actually maintained as against fuel stock required to be maintained and in case of reduced fuel stock, the deduction of interest on working capital may be done.

28.8 A beneficiary submitted that as the O&M cost is included in the two months receivables, there is no rationale in providing one month O&M costs again as part of the working capital. A beneficiary further submitted that instead of adopting two months receivables based on NAPLF, past two months receivables based on the actual schedule may be adopted for assessing the working capital requirement.

28.9 Some generating companies suggested that RoE should be kept part of the receivables as per existing Tariff Regulations 2009 and the present operating norms for interest on working capital may continue.

28.10 Some of the stakeholders submitted that 60 days stock may be allowed for non-pit head coal based generating stations due to unpredictability of coal supply from CIL. It further submitted that the receivables should be re-determined considering the actual days taken by the beneficiaries to make payment.

28.11 Some generating companies submitted that working capital requirement depends on variety of factors such as credit rating of individual company, risk associated with sector, cash flow, security available, etc., and such loans are normally available at higher rates. Hence, the rate of interest on working capital may be increased from (Base Rate + 350 basis points) to (Base Rate + 450 basis points).

28.12 One of the stakeholders submitted that in case of CCGT power station, as per Para 5.2.16 of National Electricity Policy, these should have shifted from costlier liquid fuel to RLNG within 5 years. Hence, there should be no provision for liquid fuel stock in the working capital requirement of gas power stations.

28.13 NTPC submitted as under:

a. Limiting of coal stock to storage capacity may not be considered as in any case generator is penalized through under recovery of capacity charges because of loss of generation due to fuel shortage. Further, lesser storage capacity results in lower land acquisition whose benefits are already available to beneficiaries. Therefore, existing provisions may be retained.
b. For computation of 2 months receivables, Special Allowance and Compensation Allowance should be included in working capital. Since these allowances form part of the monthly billing to beneficiary and realization of payments may take 2 months time, it is not appropriate to exclude these payments for working capital purposes and may be considered in the computation of Working capital.
c. Water charges and other taxes, cess and duties which are to be billed directly to the customers, may also be included in the receivables and working capital should be provided on these items also.

28.14 NHPC submitted that the State of J&K is levying water usage charges. Bills of water usage charges are raised by J&K State Water Authority half yearly and are paid within 15 days. NHPC raises bills within the month for reimbursement from beneficiaries, which beneficiaries pay within 2 months. As water charges are not included in working capital formula, NHPC is incurring a loss. Therefore, a fourth component should be introduced in the formula for working capital, i.e., "(iv) 2 months water usage charges, if applicable".

28.15 NTPC Limited submitted that considering sharp rise in fuel price in recent years, fuel price escalation should be allowed for working out interest on working capital. NTPC further submitted that escalation of 9% may be considered for fuel expenses. NLC submitted that fuel price escalation should be allowed annually during the Tariff Period. NLC further submitted that the actual primary fuel and secondary fuel cost of the respective year may be considered in the computation of working capital involving lignite/coal and oil, i.e., allowing fuel price escalation during the Tariff Period instead of considering the weighted average price of the fuel three months preceding the first month for which tariff is determined.

28.16 WBSEDCL submitted that the Bank Rate is different for different banks and so, the bank rate may be made specific. GRIDCO submitted that the Bank Rate may be considered as 150 basis points above SBI Base Rate. Some of the generating companies submitted that SBI Base Rate changes according to market conditions, therefore, it is suggested that appropriate provision may be incorporated in the Regulations to align rate of interest on working capital with market conditions. For instance, rate of interest on working capital may be specified as the average Bank Rate prevalent during first six months of the year previous to the relevant year.

Commission's Views

28.17 Clause 21 of the draft Regulations specified that the Special Allowance in lieu of Renovation & Modernisation and/or Compensation Allowance shall not be considered for computation of working capital. The Commission has modified clause 17 to further clarify this aspect.

28.18 As regards the submission that the statements under clause 28(1)(a) (i) and (ii) of the draft Regulations are contradictory in so far as the pit head coal/lignite and limestone stations are concerned, the Commission would like to clarify that under the existing as well as previous Regulations, there was single provision towards cost of primary fuel and cost towards maintaining primary fuel stock. The relevant provision of Tariff Regulations, 2009 was *"Cost of coal or lignite and limestone, if applicable, for 1½ months for pithead generating stations and two months for non-pit-head generating stations, for generation corresponding to the normative annual plant availability factor"*. Thus, in the Tariff Regulations, 2009, the cost of coal or lignite for thermal generating stations includes one month fuel cost and cost of fuel towards 15 days of stock for pit head stations and 30 days of stock for non pit head stations. As elaborated in the Explanatory Memorandum to the draft Regulations, the Commission based on the analysis of actual fuel stock position and fuel storage capacity proposed that the cost of fuel towards fuel stock shall be considered as 15 days for pit-head stations and 30 days for non pit-head stations subject to maximum storage capacity. As the Commission decided to limit the fuel stock subject to maximum storage capacity, the Commission made two separate provisions in the draft Regulations, one for fuel stock and other for fuel cost.

28.19 Most of the generating companies have requested to increase the fuel stock, while on the other hand, most of the beneficiaries have suggested to reduce the fuel stock considering the actual fuel stock position. The Commission, in the Explanatory Memorandum to draft Regulations observed that in almost all the stations, the average fuel stock maintained was well below the normative 15 days for pit head stations and 30 days for non pit head stations allowed and the average coal stock at most of the generating stations was in the range of around 10-15 days. The Commission further observed that very few generating stations even have the coal storage capacity of more than 30 days and in most of the cases, the maximum storage capacity of fuel is around 15-30 days. Therefore, the Commission is of the view that there is no merit in increasing the fuel stock, while at the same time, it would be appropriate to allow reasonable fuel stock to ensure smooth operation of the plant duly keeping in mind the contingencies affecting supply of coal to power stations. Therefore, the Commission has decided to continue to include cost of fuel towards fuel stock as 15 days for pit-head stations and 30 days for non pit-head stations subject to maximum storage capacity, as part of working capital.

28.20 Some of the stakeholders suggested that the truing up of working capital shall be carried out considering the actual fuel prices, interest rate, etc. In this regard, the Commission is of the view that the interest on working capital is allowed on normative basis, irrespective of whether the loan has been availed for working capital or not. In case truing up of interest on working capital or adjustment to interest on working capital is to be carried out based on actual fuel prices, fuel price escalation, movement in interest rates, liquid fuel stock, the objective of providing interest on working capital on normative basis will be defeated and the further the entire exercise of adjustments to interest on working capital will be complicated exercise resulting in frequent revision in tariff. Further, there are several sources of obtaining working capital finance and the rate of interest on such working capital depends on the operational performance and profitability of operations, hence, the regulated entities shall be able to source funds at cheaper rate of interest, depending on their performance.

28.21 Regarding inclusion of one month of O&M expenses as a part of the working capital requirement, the Commission is of the view that O&M expenses incurred for a given month are recoverable along with the tariff in the next month and therefore, the same needs to be a part of working capital. Further, exclusion of the same may also have impact on the liquidity position of the utilities. The Commission has therefore, decided to continue with provision of one month of O&M expenses as a part of working capital requirement.

28.22 The Commission has considered the concerns of the beneficiaries on reduction of receivables. The Regulations provides for a rebate of 1% if the payment is made within 30 days and a late payment surcharge of 1.5% in case the payment is delayed beyond 60 days. As the payments are to be made by the beneficiaries without surcharge within a period of 60 days, it is imperative that working capital towards 60 days receivables is provided.

28.23 As regards reduction in depreciation and RoE component from receivables for computation of working capital requirement, the Commission is of the view that though depreciation is not a cash expense, depreciation is utilised to meet the repayment obligations and hence, it will not be appropriate to exclude the depreciation as part of receivables for arriving at normative working capital. Further, there may be some variation in loan repayment and depreciation allowed and as the advance against depreciation is not being allowed now, under such case, the generating company or transmission licensee may utilise RoE to meet the variation in depreciation and repayment. Therefore, the Commission has decided to continue with provisions of entire receivables as part of working capital requirement.

29. Operation and Maintenance Expenses {Regulation 29}

O&M Expenses for Thermal Generating Stations {Regulation 29(1)}

29.1 The draft Regulations specified separate set of norms for the coal/lignite based stations depending upon unit size without distinguishing between new and existing stations. In respect of some of the coal/lignite based stations namely Talcher, Tanda and Badarpur TPS Unit 1 to 3 of NTPC, Chandrapura TPS Unit 1 to 3 and Durgapur TPS Unit 1 of DVC, and NLC's TPS I, relaxed norms were specified. For gas/liquid fuel based combined cycle stations, separate norms for small gas turbines and other than small gas turbines were specified. Further, separate norms for Agartala GPS of NEEPCO and Advance F Class Machines were specified. Apart from these, O&M norms for the generating stations based on coal rejects were introduced in line with the norms as approved for 125 MW lignite fired stations.

29.2 The Commission in its Explanatory Memorandum to the draft Regulations discussed the approach considered for arriving at O&M expenses for various generating stations, which was based on the actual O&M expenses for the period from FY 2008-09 to FY 2012-13.

Stakeholders' Comments and Suggestions

29.3 NTPC submitted as under:

a. Performance Related Pay (PRP) should be considered while fixing the O&M norms.
b. Any abnormal increase in any cost element has been normalised. As such, averaging out the data of 5 years should effectively normalise any abnormality and further normalization should not be done.
c. The escalation rate to be used for escalating the O&M expenses should be based on the actual inflation indices rather than normative.
d. Based on the established practice of using WPI/CPI of last 5 years, the escalation factor for working out the base O&M expenses for 2014-19 works out to 8.62%, instead of the 6.35%.

e. For considering the impact of pay revision, actual share of pay revision should be considered instead of the normative level of 40%.
f. O&M expenses norm of gas plants should be calculated based on their own historical data and Dadri Gas plant should be excluded while computing O&M norms, as it is abnormally low due to the hybrid nature of the station.
g. Relaxation in O&M Cost for Badarpur and TTPS should be provided to avoid occurrence of under-recovery in these stations.

29.4 Some of the beneficiaries submitted that the lower of the actual pay revision as per GOI guidelines and percentage of O&M expenses given in the draft Regulations, may be considered as impact of wage revision in O&M. Some stakeholders submitted that percentage for employee cost as part of O&M expenses in case of hydro generating stations and transmission system may be considered as 40% and 35%, respectively. Other stakeholders submitted that the automatic pass through of wage revision charges is not appropriate as increase in wages is directly linked with incentive. The additional impact of wage revision should be funded out of incentives. Some beneficiaries submitted that the installed capacity, outsourcing of work and vintage of the plant should be considered while deciding the percentage of employee cost. Some of the stakeholders submitted that the methodology for wage revision is different for private players, and hence, there should be different methodology for allowing impact of wage revision for IPPs/private sector projects. Some other stakeholders submitted that the applicability of provision for impact on wage revision for private generating stations may be clarified and similar provision for wage/salary revision to private sector should be considered. NHPC submitted that approved employee cost has been considered at 62% of O&M expenses during current Tariff Period (2009-14) for calculating impact of wage revision, however, the actual was 74% during FY2008-09 to FY 2012-13. Therefore, the norm for employee cost (as a % of O&M expenses) for wage revision needs to be revised accordingly.

29.5 NLC submitted as under:

a. Enhancement of base O&M expenses may be considered to accommodate pay revision of non executives with effect from 01.01.2012.
b. For allowing pay revision due from 01.01.2017 as per DPE guidelines, salary and wages component for NLC should be considered as at least 60% of the

O&M cost instead of 40%, considering the high ratio of employee cost in the actual O&M of NLC.

c. Expenditure incurred on PRP, incentive, ex-gratia, etc., should be considered while fixing the norms for O&M expenses.
d. Reduced O&M expenses for the NLC Barsingsar TPS to be reviewed for enhancement, as lesser expenditure in 2013-14 was mainly on account of lesser expenditure on repair and maintenance and stores and spares as the plant was under warranty.
e. In respect of the vintage plant TPS-I with lower sized Units, O&M norm may be fixed considering the actual O&M incurred during 2013-14 and adopting the annual escalation factor of 6.35%for deriving O&M expenses for 2014-15 and 8.35% thereafter in 2014-19.
f. Not to implement the proposed restriction in the allocation of corporate expenses but to allow the actual allocated amount.

29.6 Some beneficiaries and other stakeholders submitted that keeping in view the O&M norms specified by RERC, the O&M norms for 2014–15 (base year) needs to be reduced. Further, the norms of ₹ 36.68 Lakh/MW of Tanda TPS (in base year2014–15) is very high and not justified in view of the huge expenditure on Renovation & Modernisation and additional capitalization done in previous years. It should be reduced to at least ₹ 29.12 Lakh/MW in 2014–15 as allowed for lignite fired generating station of 125 MW. They further submitted that the O&M norms for coal based thermal power station as approved by RERC are lower than even the existing norms of CERC, as shown below:

(₹ in lakh/MW/Year)

Period	CERC Norm		RERC	
	200 MW	500 MW	Upto 250 MW	500 MW
FY 2014-15	24.07	20.19	16.3	14.69
FY 2015-16 onwards	By escalation of 6.35%			

29.7 Some stakeholders submitted that normative O&M expenses proposed for all generating stations appear to be very high and it is suggested to consider a reduction of at least 10%. Some other stakeholders submitted that the normative O&M expenses proposed in the draft Regulations are exorbitantly high and should be restricted to a ceiling of ₹ 10 Lakh/MW/year subject to prudence check and true up.

29.8 Some beneficiaries submitted that prudence check may be applied before deciding O&M expenses as it seems to be on higher side and also includes performance based incentive paid to employees, which is to be borne by generating stations or transmission licensees out of their extra earnings due to higher performance.

29.9 MSEDCL submitted that the water charges may be included in the O&M expenses. PPCL submitted that the plants using sewage water should be allowed to reimburse all the expenses of primary water treatment. TANGEDCO submitted that while an escalation is allowed over the previous years, the need for excluding water charges need justification. One stakeholder submitted that any land lease charges levied by State Government should also be allowed separately.

29.10 Suggestions were received from stakeholders stating that the proposed O&M norms for Advance F Class Machines are extraordinarily high and the O&M expenditure data for the advance F Class Machines of Sugen Power Project of Torrent Power for the period 2009 to 2013 may be used for fixing the norms of Advance F Class Machines.

29.11 One stakeholder submitted that the O&M expenses should be partly normative and partly based on actual according to controllable and non-controllable items, wherein controllable items should be normative based on actual trend of escalation and uncontrollable items should be allowed as per actuals. The stakeholder also submitted that next pay revision in public sector will be effective during the next Tariff Period, so additional escalation factor should be considered while determining norms.

29.12 One stakeholder submitted that the hybrid system (ESP and Fabric Filter) requires additional O&M expenses of ₹ 0.458 Cr/MW/Year. Hence, O&M Expenses of ₹ 15.14 lakh/MW may be considered for generators using hybrid system. In addition, the same may be escalated @ 6.35%.

29.13 Some stakeholders submitted that in case a thermal project earns revenue from sale of ash/fly ash, this revenue should be utilized to reduce the O&M charges to be recovered through tariff. One of the stakeholders also submitted that for thermal stations having chinese equipment, the O&M expenses may be reduced to about 90% of the norms with other equipment.

29.14 One stakeholder submitted that for projects with extra ordinary factors (long length of railway siding, transmission line or water pipeline, etc.), higher O&M should also be considered, subject to approval by the Commission. It further submitted that separate norms for chemicals may also be considered.

29.15 Some of the stakeholders submitted that for 600 MW, as technology services are sourced from overseas OEMs in initial few years, the norms same as 500 MW station may be allowed for 600 MW and above series for the Tariff Period 2014-19. The same can be re-examined when the historical 5-year actual O&M cost data is available for review. MSPGCL submitted that the mid-term review of normative O&M cost is essential. MSPGCL also submitted that the normative O&M expenses prescribed for new stations in the MERC MYT Regulations, 2011 are far below the normative O&M expenses allowed by CERC Tariff Regulations, 2009, as shown in the Table below:

(₹ Lakh/MW)

Year	**200/210/250 MW Sets**		**500 MW and above sets**	
	CERC	**MERC**	**CERC**	**MERC**
2011-12	20.34	14.81	14.53	13.32
2012-13	21.51	15.66	15.36	14.08
2013-14	22.74	16.55	16.24	14.89

29.16 One stakeholder requested to include provision for IC Engine Technology in the Regulations, immediately after the table for clause 29(c), as under:

"In commissions view O&M charges of IC Engine based power generating stations are similar to that of gas turbine based generating stations. If any modifications to the norms for IC Engine based generating stations are required, the same shall be approved on case to case basis on receipt of application."

29.17 One stakeholder submitted that considering the ratio of WPI:CPI as 70:30, the CAGR (inflation) in the last five years is more than 8.25% and the same may be considered for escalation of O&M expenses. Some stakeholders submitted that it would be prudent to link the annual escalation of normative O&M expenses with the actual inflation rate instead of taking the normative O&M expenses of the previous years as the base for escalation. One stakeholder requested to escalate the FY 2013-14 normative O&M expenses by 8.35% and maintain the same escalation for the subsequent years, considering the current inflation rate with respect to the WPI/CPI indices. One stakeholder submitted that in view of the general trend of inflation, the escalation rate should be revised to at least 8-9% as against the proposed 6.35%. Some stakeholders submitted that appropriate annual escalation may be provided for FY 2014-15 as the proposed O&M Expenses indicates a different rate of escalation for the different generating stations for the first year. One stakeholder submitted that the computation of escalation rate for O&M expenses does not take into account the expected variation in the inflation rate in the coming years. It suggested that if there is a difference of more than 0.5% from the approved rate of 6.35%, then the same may be considered and arrears to be recovered by the generating stations in the next Tariff Period may be allowed.

29.18 Some of the beneficiaries submitted that in case of Talcher TPS (TTPS), the figure of O&M expenses for FY 2014-15 is higher than the figures of FY 2013-14 escalated at the rate of escalation @ 6.35%. This discrepancy may be removed. GRIDCO submitted that in case of TTPS, there should not be any separate relaxed norms. One stakeholder submitted that the O&M charges for Talcher TPS are on higher side and needs downward revision. Some stakeholders submitted that for Talcher, Tanda, Badarpur and Chandrapura, the expenses may be restricted to a ceiling of ₹ 12 Lakh/MW/year and in all cases the expenses should be subject to prudence check. Various stakeholders submitted that for Gas turbine/combined cycle generation stations, O&M expenses may be restricted to a ceiling of ₹ 5 Lakh/MW/year, and O&M expenses may be restricted to a ceiling of ₹ 10 lakh/MW/year for lignite fired generating stations, and the expenses should be subject to prudence check.

29.19 NEEPCO submitted that for AGBPP and AGTPP, the following normative O&M expenses may be specified:

(₹ in Lakh)

Station	Year				
	2014-15	2015-16	2016-17	2017-18	2018-19
AGBPP	38.71	41.17	43.78	46.56	49.52
AGTPP	49.55	52.70	56.04	59.60	63.39

29.20 Some stakeholders submitted that as GCV and the quality of rejects would be very low, the O&M expenses are not sufficient and should be revised to at least ₹ 42 lakh/MW for coal reject based plants, given the higher maintenance for generators based on coal rejects. Some stakeholders submitted that the O&M expenses may be calibrated against the capacity of the reject based plants. Some other stakeholders submitted that coal reject generating plants may be allowed O&M expenses @ ₹ 12 Lakh/MW/year. One stakeholder submitted that introduction of O&M expenses for thermal power plants based on coal rejects is not desirable as this is purely a technical matter and should be controlled by the generating station authorities.

Commission's Views

29.21 In response to the suggestion that the O&M expenses should be partly normative and partly on the basis of actual according to controllable and uncontrollable items, the Commission observes that O&M expenses are controllable in nature and a generating station is expected to limit these expenses within the norms specified. Further, the Commission has already provided for payment of water charges, which is determined by the State agencies and over which generator has no direct control. In case there is an impact on such expenses on account of Force Majeure events as defined in the Tariff Regulations, 2014, the Commission may consider such events on being approached by the generating company or transmission licensee. Therefore, the Commission is of the view that the approach followed for determining the O&M norm is appropriate and doesn't need any review.

29.22 Most of the generators have suggested that the performance related pay, productivity linked incentive, ex-gratia, and incentives should be considered while determining the norms for generating station. In this regard, it has been clarified in the Explanatory Memorandum that the expenses like ex-gratia, incentives, productivity linked incentives and performance related pay are the expenses that are linked to efficient operation and high performance level of generating station and are payable only in case the plant achieves or overachieves vis-à-vis normative operational levels. The incentives and performance related pay are supposed to be paid only if the plant benefits from such efficient and high performance and therefore, the same should be paid by the generating company from the revenue gains due to reduced down time and efficient plant operations. Therefore, the Commission disagrees with the suggestions and reiterates that such expenses should be met through the incentives that the generating stations earn on account of increased generation and reduced generation expenses. The Commission has made a provision for incentives on generation above the target plant load factor and for better plant performance. Therefore, the Commission is of the view that such expenses should be funded through the incentives and profit earned by the generating stations on account of better plant performance. The Commission has therefore, not considered such expenses while determining the O&M norms for the station.

29.23 As regards the suggestion to include abnormal expenses while determining the norm on the premise that such expenses get normalised when averaged over five years, the Commission is of the view that abnormal expenses are specific to the particular year, generating station and on account of specific reasons. The consideration of abnormal expenses to decide the norms will distort the result. The norms should be based on normal expenses that a generating station shall incur towards day to day upkeep of the plant and any abnormal expenses arising out of any exigencies or on account of various other factors that may not be certain to occur in future should not be factored in the norms to be specified, else it shall lead to unnecessarily burdening the consumers. The Commission therefore, disagrees with the suggestion to include abnormal expenses in the norms.

29.24 Most of the generating companies have suggested that the actual inflation rate as derived on the basis of WPI and CPI should be used for escalation while determining the O&M expense norms for FY 2014-19. As regards the escalation rate, the Commission has already clarified its approach in the Explanatory Memorandum, which was based on the actual increase in the normalised O&M expenses. Further, the Commission is of the view that average CPI and WPI indices are at best an indicator of inflation, however, the average increase in actual of normalised O&M expenses for most of the stations is lower than the rate of 8.35% derived on the basis of CPI:WPI indices. Therefore, for the purpose of escalation till FY 2013-14, the Commission proposed to consider the escalation rate of 5.72%, 6.19% and 6.04% for coal, gas and hydro generating stations, respectively. The Commission, in the Explanatory Memorandum observed that the average increase in actual annual normalised O&M expenses for generating stations is around 6.0%, which is approximately 2.35% lower than the prevailing rate of inflation during the same period. The proposed escalation in the draft Regulations was to meet the actual O&M expenditure of generating station during the Tariff Period 2014-19. Keeping in view the interest of the consumers, the Commission decided to fix escalation rate during the next Tariff Period as 6.35%, which is higher than average increase in actual O&M expenses, i.e., 6.0% and lower than inflation rate by 2.0% for all generating stations.

29.25 As regards the escalation factor to be considered till FY 2013-14, the Commission reiterates its views that the same escalation rate should be considered as determined on the basis of normalised O&M expenses as the same truly reflects the actual rate of inflation for the type of generating stations. However, as regards bracketing all types of generating stations to a common escalation rate of 6.35% for the next Tariff Period, the Commission has reviewed the methodology for uniformity purpose. The Commission, while proposing the norms in the draft Regulations, had considered same escalation rate for FY 2014-19 for different types of generating stations. To have a uniform approach towards allowing a margin for different types of generating stations, the Commission is of the view that a margin of 10% over and above the actual increase derived on the basis of normalised O&M expenses should be considered. Therefore, for coal/lignite based and gas based stations, the Commission has considered an annual escalation rate of 6.29% and 6.81%, respectively, for escalating the norm during the Tariff Period 2014-19.

29.26 Some of the generating stations have suggested that the impact of pay revision should be allowed on the basis of actual share of pay revision instead of normative 40% and one generating company suggested that the same should be considered as 60%. In the draft Regulations, the Commission had provided for a normative percentage of employee cost to total O&M expenses for different type of generating stations with an intention to provide a ceiling limit so that it does not lead to any exorbitant increase in the O&M expenses resulting in spike in tariff. The Commission would however, like to review the same considering the macro economics involved as these norms are also applicable for private generating stations. In order to ensure that such increase in employee expenses on account of pay revision in case of central generating stations and private generating stations are considered appropriately, the Commission is of the view that it shall be examined on case to case basis, balancing the interest of generating stations and consumers.

29.27 NTPC has submitted that the O&M norm for gas based generating stations should be determined based on the station's historical data. On the other hand, it has suggested that while determining the norm for gas based stations, Dadri station should be excluded as the O&M expense of the station is lower on account of hybrid nature of the station. The Commission, while determining the norm for gas based generating stations, is of the view that most of these stations are based on similar technology and therefore, giving separate norms for each station is not required and norm based on consolidated historical data of all such generating stations shall give a more appropriate norm on account of large sample size. Therefore, the Commission is of the view that there is no merit in having station-wise norm for the same. Further, the contention that the Dadri station should not be considered while determining the norm on the premise that O&M expenses for the station are lower on account of hybrid nature of the station doesn't hold good, as the Commission while determining O&M norm has also considered O&M expenses of Anta GPS, which is having O&M expenses considerably higher than other gas stations. The only exclusion considered are the O&M expenses for Kayamkulam station (360 MW) as the O&M expenses of the station is abnormally high, totally off the trend and requires man power rationalisation as it was observed that the number of executives employed for the station is almost equal to stations like Gandhar (657 MW) and Auraiya (663 MW). In view of above consideration, the Commission is not inclined to agree with the suggestion of NTPC regarding exclusion of Dadri station and for considering historical data of individual gas based generating station for specifying O&M norms.

29.28 NTPC has suggested that the O&M norm for Badarpur and Talcher Stations needs relaxation. The Commission, while determining the norms for FY 2009-14 has stated in the Statement of Reasons that these stations need manpower rationalisation as the Man:MW ratio of these stations were almost double when compared to other stations, leading to abnormal O&M cost. As per the employees data submitted for these stations, it has been observed that in case of Badarpur, there has been no man power rationalisation in the executives employed by it during the period FY 2008-09 to FY 2012-13 and it has registered reduction of executives from 349 to 341 only. However, the number of non executives has reduced from 977 to 565. It is also observed that the station has 341 executives for 705 MW of generation capacity having five units whereas Talcher Kaniha station with 3000 MW with six units has 488 executives. The Commission is, therefore, of the view that the burden of the high employee cost cannot be allowed any further and BTPS should undertake manpower rationalisation and limit its O&M expenses. The Commission has however, provided relaxed norms for the smaller Units of Badarpur station as allowed for Tanda station. However, for 210 MW units of BTPS, the Commission is of the view that no relaxed norms should be allowed as ample time has been provided to the generating station for manpower rationalisation and the consumer cannot be burdened for failure on the part of the generator in this regard.

29.29 As regards Talcher station, the Commission has already determined the norms on the basis of actual expenses incurred during FY 2008-09 to FY 2012-13 after normalisation and the norm provided for the station is higher than the norm specified for FY 2013-14. The Commission has already considered relaxed norms on the premise of smaller sized Units of the station. The Commission observes that the station should carry out man power rationalisation, especially with regard to number of executives employed by it.

29.30 On the suggestion for reducing the norms for Tanda station on account of considerable Renovation & Modernisation expenses incurred in the past, the Commission would like to reiterate that the norms for the stations have been based on the actual data submitted for FY 2008-09 to FY 2012-13 and only after carrying out normalisation of such expenses. On the suggestion that the O&M expenses of the station should be limited to the O&M expenses allowed for 125 MW lignite stations, the Commission is of the view that such arbitrary approach for allowing O&M expenses is not appropriate and therefore, the Commission has decided to continue with the proposed approach to determine the norms for the Tanda station.

29.31 As regards the comment that the O&M expenses have been approved on the basis of escalating past years expenses though water charges are now being allowed separately, the Commission would like to clarify that the water charges for 2008-09 to 2012-13 have not been considered as a part of O&M expenses while determining the norms for O&M expenses for 2014-19.

29.32 NLC suggested that the norms for Barsingsar TPS are not sufficient to cater to the O&M expenses of the stations as the plant was under warranty and therefore, the Repair &Maintenance expenses for the station was lower. The Commission has examined the data submitted for the station. As per data submitted, it has been observed that NLC has incurred around ₹ 13.69 Crore towards Repairs & Maintenance and consumption of stores for the station which works out to ₹ 5.48 lakh/MW, which in case of NLC TPS-II is ₹ 4.72 lakh/MW for FY 2012-13. These data indicate that there is substantial consumption of stores and at the same time, significant expenses have been incurred towards Repairs & Maintenance of Barsingsar TPS. Therefore, the contention of the generating station doesn't hold merit and hence, the Commission is of the view that there is no case for relaxation on the above premise.

29.33 As regards NLC's suggestion that the norms for TPS-I should be based on the actual expenses incurred by the generating station, it is clarified that norms have been determined on the basis of actual normalised O&M expenses and the norm so determined for FY 2014-15 is higher than the norms already specified for FY 2013-14. Further, the Commission is of the view that the Man:MW ratio of 2.62/MW in FY 2012-13 for the station is on the higher side, which indicates scope for reduction of O&M expenses through man power rationalisation, and the generating station is expected to rationalise its manpower by at least 25-30% during the Tariff Period 2014-19. Further, the station has very high heat rate and is in the process of being phased out, and the Commission is not inclined to incentivise such plants.

29.34 NLC has further submitted that the Commission should not restrict its corporate expenses and should allow the actual corporate expenses. In this context, it has been observed in the Explanatory Memorandum to the draft Regulations that the corporate expenses allocated to its generating station is very high, to the tune of around ₹ 8 lakh/MW for TPS-I owing to considerably higher manpower employed. Keeping in view the interest of the consumers, the Commission is of the view that actual corporate expenses in this case cannot be allowed and the methodology as adopted in the draft Regulations is justified, and the generating company should meticulously carry out manpower rationalisation to bring such expenses to normal levels.

29.35 As regards the suggestion received from some of the stakeholders for deducting the amount of revenue collected from sale of fly ash, the Commission has not deducted the same from the O&M expenses because as per the direction of Ministry of Environment and Forests, revenue collected from sale of fly ash needs to be utilised for betterment of environment. The Commission, after taking cognizance of the direction of Ministry of Environment and Forests, has not considered revenue collected from sale of fly ash as well as the expenses under the head 'ash utilisation expenses' to be charged to O&M expenses.

29.36 On the suggestion of approval of norms for advanced F Class machines based on the O&M expenses of Sugen power plant, the Commission in the draft Regulations had proposed norms on the basis of actual O&M expenses of Sugen Power Plant as it provides optimum efficiency. Since, RGPPL station is also based on the same technology and the O&M expenses of the two stations are comparable, the same has also been considered while arriving at the final norms for advanced F class machines. The Commission has accordingly reviewed the norms specified for such machines by considering the average O&M expenses for Sugen and RGPPL.

29.37 The beneficiaries and one of the generating companies have suggested that the O&M norms proposed in the draft Regulations are much higher than the norms specified by the State Electricity Regulatory Commissions for the State generating stations and therefore, there is a need for reduction in the O&M expenses approved by the Commission. In this regard, the Commission would like to clarify that the Commission has determined the norms on the basis of actual expenses after adjusting any abnormal expenses and further normalisation has been carried out so that no unjust expenses are being allowed as a part of the norm. Further, factors like wage structure at the State and Central level come into play. The approach adopted by the Commission is intended to balance the interest of the generators as it reflects cost plus approach and at the same time, the efficiency has been allowed to be passed through to the consumers.

29.38 Some of the stakeholders have suggested that the Commission should reduce the present norms to 90% for stations having chinese equipment, whereas some stakeholders have suggested to limit the O&M expenses to ₹10-12 lakh/MW. The Commission is of the view that this aspect is already addressed as the proposed approach is based on actual data submitted, which will automatically factor in any reduction of norms on these counts.

29.39 Some of the generating stations have suggested that site specific factors should be taken into account and additional O&M expenses should be allowed. The Commission is of the view that the site specific norms in case of thermal generating stations may not serve much purpose as there is a set of advantages and disadvantages associated with every site, which average out, and the proposed norms are also based on multiple stations with wide geographical spread and therefore, such aspects are already factored in the norms.

29.40 Some of the generating stations have suggested that since the supercritical technology is new, the R&M cost is higher on account of technology services sourced from overseas OEMs. The Commission is of the view that supercritical technology enjoys economies of scale, i.e., 800 MW Unit size is 60% higher in capacity as compared to 500 MW Unit size and the O&M cost allowed for the same on aggregate basis shall be much higher when compared to 500 MW. The Commission has however, considered 90% of the O&M expenses specified for 500 MW for unit size of 600 MW and above units, which in the view of the Commission should be sufficient to cater to the O&M expenses required for efficient plant operations.

29.41 As regards the suggestion that power plants based on IC engine technology should be bracketed with gas turbine based generating stations and the O&M expenses should be allowed accordingly, the Commission is of the view that the stakeholder has not substantiated its claims with actual data and therefore, the Commission is of the view that in case such IC engine based power plant falls under Section 79(1)(a) and (b) of the Act and tariff needs to be determined by the Commission, the same shall be done on a case to case basis.

29.42 Some of the stakeholders have urged for more relaxed norms for O&M expenses for power plants based on coal rejects. However, the same has not been substantiated with any justification and empirical study. The Commission is of the view that the proposed norm for coal reject based plants is appropriate and has therefore, retained the norms specified in the draft Regulations.

29.43 Further, the Commission has reviewed the norms proposed in the draft Regulations in view of the fact that some of the Central Generating Companies including NTPC and NHPC have booked expenses under the heads "Capital Spares" and "Expenditure of Capital nature as per accounting practice not claimed/disallowed in capital cost". The Commission, while deriving the norms, had not considered "Expenditure of Capital nature as per accounting practice not claimed/disallowed in capital cost". After repeated communications from the Commission for submitting the breakup of such expenses incurred, NTPC submitted capital spares data at a very late stage. The Commission prima facie observed that the capital spares data submitted needs detailed scrutiny before being approved. NHPC did not submit the required data in this regard. The Commission has therefore, not included such expenses as a part of O&M expenses. The Commission shall, however, consider the same separately at the time of truing up after prudence check of actual data. The generating stations should submit the details of the year-wise capital spares consumed substantiating that the same has not been funded through either compensatory allowance or special allowance and has not booked such expenses as additional capitalisation or as a part of repair and maintenance expenses and consumption of stores and spares as applicable for thermal and hydro generating stations.

29.44 The Commission has accordingly specified the norms for thermal generating stations as follows:

(1) Normative Operation and Maintenance expenses of thermal generating stations shall be as follows:

(a) Coal based and lignite fired (including those based on CFBC technology) generating stations, other than the generating stations/units referred to in clauses (b) and (d):

(₹ in Lakh/ MW)

Year	200/210/250 MW Sets	300/330/350 MW Sets	500 MW Sets	600 MW Sets and above
FY 2014-15	23.90	19.95	16.00	14.40
FY 2015-16	25.40	21.21	17.01	15.31
FY 2016-17	27.00	22.54	18.08	16.27

Year	200/210/250 MW Sets	300/330/350 MW Sets	500 MW Sets	600 MW Sets and above
FY 2017-18	28.70	23.96	19.22	17.30
FY 2018-19	30.51	25.47	20.43	18.38

Provided that the norms shall be multiplied by the following factors for arriving at norms of O&M expenses for additional units in respective unit sizes for the units whose COD occurs on or after 1.4.2014 in the same station:

200/210/250 MW	Additional 5th& 6th units	0.90
1.1.1	Additional 7th& more units	0.85
300/330/350 MW	Additional 4th& 5th units	0.90
1.1.2	Additional 6th& more units	0.85
500 MW and above	Additional 3rd& 4th units	0.90
1.1.3	Additional 5th& above units	0.85

(b) Talcher Thermal Power Station (TTPS), Tanda TPS, Badarpur TPS Unit 1 to 3of NTPC and Chandrapura TPS Unit 1 to 3 and Durgapur TPS Unit 1 of DVC:

(₹ in Lakh/MW)

Year	Talcher TPS	Chandrapura TPS (Units 1 to 3), Tanda TPS, Badarpur (Unit 1 to 3) , Durgapur TPS (Unit 1)
2014-15	43.16	35.88
2015-16	45.87	38.14
2016-17	48.76	40.54
2017-18	51.83	43.09
2018-19	55.09	45.80

(c) Open Cycle Gas Turbine/Combined Cycle generating stations:

(₹ in Lakh/MW)

Year	Gas Turbine/ Combined Cycle generating stations other than small gas turbine power generating stations	Small gas turbine power generating stations	Agartala GPS	Advance F Class Machines
2014-15	14.67	33.43	41.32	26.55
2015-16	15.59	35.70	44.14	28.36
2016-17	16.57	38.13	47.14	30.29
2017-18	17.61	40.73	50.35	32.35
2018-19	18.72	43.50	53.78	34.56

(d) Lignite-fired generating stations:

(₹ in Lakh/MW)

Year	125 MW Sets	TPS-I of NLC
2014-15	29.10	38.12
2015-16	30.94	40.52
2016-17	32.88	43.07
2017-18	34.95	45.78
2018-19	37.15	48.66

(e) Generating Stations based on coal rejects:

Year	O&M Expenses (₹ in Lakh/MW)
2014-15	29.10
2015-16	30.94
2016-17	32.88
2017-18	34.95
2018-19	37.15

<u>O&M Expenses for Hydro Generating Stations {Regulation 29(2)}</u>

30.1 The draft Regulations proposed separate O&M norms for the hydro generating stations, which have been in operation for three years or more and hydro generating stations, which have not been in operation for three years as on 01.04.2013. The draft Regulations also proposed separate provisions for hydro generating stations declared under commercial operation on or after 01.04.2014.

<u>Stakeholders' Comments/Suggestions</u>

30.2 The submissions of the stakeholders are as summarized below:

30.3 NHPC submitted as under:

(i) Expenses such as prior period expenses, arrears, provisions, loss from store, incentives, VRS, PLI, PRP and ex-gratia, corresponds to 6.73% of total O&M expenses incurred by NHPC and should not be reduced while arriving at the norms.

(ii) NHPC submitted that escalation rate of 6.35% has been fixed below the average CPI and WPI inflation of 8.35%in previous years, considering the increase in normalized expenses during FY 2009-13. The methodology followed for calculation of the escalation rate seems to be inconsistent. The Commission has disregarded the fact that the actual increase in O&M expenses will never be equal to the normative escalation factor derived for the period using the CPI and WPI indexes. The data used for calculation of escalation factor may be provided. Lowering of escalation rate by 2% from 8.35% seems arbitrary.

(iii) The escalation rate should be uniform and two different escalation rates should not be used for arriving at normative O&M expenses for FY 2013-14 (6.04%) and for projecting O&M expenses for each year of the next Tariff Period (6.35%).

(iv) O&M expenses should be trued up at the end of the Tariff Period on account of variation in escalation factor by 10% of the approved escalation factor, unplanned maintenance activities of plants, and revision on the government policies impacting the O&M expenses of the company.

(v) NHPC proposed the following O&M norms for new hydro stations in 2014-19:

Installed Capacity	**O&M Expenses as % of Capital Cost**
Less than 200 MW	4.0%
Between 200 MW & 600 MW	3.0%
Between 600 MW and 1200 MW	2.0%
More than 1200 MW	1.5%

30.4 DVC submitted that in the absence of specific norms of O&M expenditure for DVC's hydel stations in the draft Regulations, it has calculated following normative O&M expenditure for its hydel stations according to the principle adopted by the Commission while computing normative O&M for other hydel stations:

Station	2008-09	2009-10	2010-11	2011-12	2012-13	2012-13	2014-15	2015-16	2016-17	2017-18	2018-19
	Actual					Derived	Projected				
Panchet	12.32	15.76	18.16	17.79	20.71	18.87	21.28	22.63	24.07	25.60	27.22
Maithon	17.96	26.19	27.24	32.32	36.96	31.16	35.14	37.37	39.74	42.27	44.95
Tilyaia	110.38	100.45	162.23	162.64	188.57	160.56	181.07	192.57	204.79	217.8	231.63

30.5 OHPC submitted that for existing hydro power stations beyond 3 years as shown in the table at clause 29(2)(a) of the draft Regulations, the head of power stations, technology used, type of power station, and years of operation of the power stations may also be indicated in the Regulations.

30.6 THDC submitted as under:

(i) Inflation rate @ 8.35% considering the WPI and CPI may be considered for escalation purposes.

(ii) Clause "excluding the cost of rehabilitation & re-settlement works" may be removed and O&M expenses may be fixed at 3.5% of the original project cost, and escalation factor may be increased to 8.35%.

(iii) In case of Tehri HPP, the O&M expenses as submitted for 2013-14 (based on the Commission's Tariff Order dated 16.04.13 for the period 2006-09) is ₹ 232.70 crore. As per the draft Regulations, the O&M expense for FY 2014-15 is proposed as ₹ 211.20 crore, which is lower than the O&M expense for 2013-14, which is not logical. To remove the anomaly, the modified figures of O&M Expense for Tehri HPP taking into account the escalation factor of 8.35% may be considered as below:

(₹ in lakh/MW)

Station	FY 14-15	FY 15-16	FY 16-17	FY 17-18	FY 18-19
THDC	26.83	29.07	31.50	34.13	36.98

30.7 SJVNL submitted that O&M expenses may be calculated after considering the following facts and as would be finalized in the Commission's Order on NJHPS petition for the period 2009-14, with higher percentage incremental:

(i) O&M charges of NJHPS as proposed would not be sufficient for meeting the various expenditures required for the project.
(ii) Insurance cost has increased manifold times due to the Uttarakhand disaster as well as down time of NJHPS machine due to flash floods, lake formation at upstream of project, and flooding.
(iii) No other hydro project of SJVN is under execution after commissioning of RHEP, and all corporate expenses would be booked against NJHPS and RHEP under O&M. Final implication in this regard cannot be envisaged at present, however, O&M charges are likely to be increased by ₹ 40 to 50 Crore every year on this account.
(iv) As per DPE guidelines, pension scheme is applicable to all CPSEs from 01.01.2007. This scheme has been approved for SJVN recently, however, employer contribution is still not finalised. This will also enhance the O&M cost.

30.8 NEEPCO submitted as under:

(i) For RHEP & DHEP per MW normative O&M expenses may be fixed as follows:

(₹ in lakh)

Station	14-15	15-16	16-17	17-18	18-19
RHEP	32.59	34.66	36.86	39.20	41.69
DHEP	59.02	62.77	66.76	71.00	75.51

(ii) Normative O&M expenses per MW can be approved for Kopili Stage II HEP for the period 2014-19 same as that proposed for Khandong HEP.

(iii) Draft Regulations may provide provision for allowing the generating companies to recover additional expenses relating to salary and wages due to pay revision, if any, for their employees during the period of 2014-19.

(iv) The generating companies should be allowed to recover the impact of salary and wages for pay revision, if any, including share of Corporate Office expenses, from their beneficiaries.

30.9 NHDC submitted that any O&M expenses after truing up may lead to reduction of return on equity particularly when the Manpower/MW ratio is 0.38(ISP) and 0.32(OSP) as against standard of 2/MW. NHDC submitted that it may, therefore, be allowed to recover any under-recovery on this account in truing up. Some of the stakeholders submitted that while computing O&M expenses for new hydro generating station capital cost should included R&R expenses.

30.10 Some beneficiaries submitted that the methodology of arriving at the figure of O&M for NHPC, THDC, SJVNL and NEEPCO HEPs may be intimated along with the relevant figures. Stakeholders submitted that for hydro stations with less than 3 years operation, O&M may be fixed at 2% of the cost of plant and machinery instead of 2% of the project cost. One stakeholder submitted that the O&M norms for base year, i.e., 2014-15 needs to be reduced and truing up needs to be undertaken each year to obtain the actual O&M expense u/s 61(d) of Electricity Act, 2003. It further submitted that the norms provided for Loktak (NHPC) is very high and needs reduction to a reasonable limit. APDCL submitted that O&M norm for Loktak Power Station is the highest. This should be reviewed and re-fixed keeping parity with the similar hydro plants of NHPC and also taking into consideration the reports of WAPCOS. Various other stakeholders submitted that expenses must be restricted to a ceiling of ₹ 10 Lakh/MW/year for hydro generating stations.

<u>Commission's Views</u>

30.11 The Commission, while proposing the norms for hydro stations in the draft Regulations, had proposed norms in ₹ lakh/MW similar to that of thermal generating stations. It was observed that representing norms for hydro stations in ₹ lakh/MW is not appropriate as there are various other factors that have a bearing on the O&M expenses like number of Units in the station. Even in case of thermal generating stations, different norms were proposed for different Unit sizes. Further, unlike thermal generating stations where Unit sizes are standardised, Unit sizes of hydro generating stations differ vastly and therefore, representing O&M expenses in ₹ lakh/MW is not appropriate. For example, a station with higher capacity Unit sizes shall have the benefit of economies of scale and O&M expenses in ₹ lakh/MW for such station would be lower. However, for a smaller sized Unit, the number of employees required may not differ by much but O&M expenses in ₹ lakh/MW for such stations would be higher. The Commission has, therefore, reviewed its approach and instead of specifying the O&M expenses norms on the basis of ₹ lakh/MW, has specified the O&M expenses norms in ₹ lakh for hydro stations.

30.12 Most of the generating stations have suggested that prior period expenses, arrears, provisions, loss from store, incentives, VRS, PLI, PRP and ex-gratia should be considered while approving the O&M expenses. The Commission has already expressed its views as regards exclusion of PRP, PLI, ex-gratia, and incentives from O&M expenses and discussed at length in the previous section that such expenses cannot form part of O&M expenses. As regards exclusion of prior period expenses and arrears, the Commission has made it clear in the Explanatory Memorandum that these expenses were non-recurring, which also holds true for provisions, and since these expenses are one-time expenses, hence, the same cannot form part of norms. As regards loss from store, the same cannot be factored in the norms as the same has to be reduced to zero, and cannot be recovered from the beneficiaries.

30.13 As regards suggestions received from various stakeholders to consider higher escalation rate of 8.35% while determining the norms, the Commission has already discussed the issue at length in the previous section. As regards the escalation factor to be considered till FY 2013-14, the Commission reiterates its views that the same escalation rate should be considered as determined on the basis of normalised O&M expenses as the same truly reflects the actual rate of inflation for the type of generating stations. The Commission however, as regards bracketing all types of generating stations to a common escalation rate of 6.35% for the next Tariff Period, has decided to review the methodology to maintain uniformity. The Commission, while proposing the norms in the draft Regulations, had considered same escalation rate for 2014-19 for different types of generating stations. To have a uniform approach towards allowing a margin for different types of generating stations, the Commission is of the view that a margin of 10%over and above the actual escalation rate derived on the basis of normalised O&M expenses should be considered. Therefore, for hydro stations, the Commission has considered an escalation rate of 6.64% for escalating the norm during 2014-19.

30.14 Further, as regards the suggestion of truing up of escalation factor in case the variation in actual escalation factor and approved escalation factor is more than 10% of the approved value, the Commission is of the view that as per the actual normalised expenses, the generating stations have been able to manage their escalation in O&M expenses efficiently when compared to the actual escalation rate. Therefore, the same should continue, and allowing actual escalation rate or having a provision of truing up of escalation rate will come in way of prudent management of such expenses. Further, the Commission is of the view that norms should be fixed and not subject to change on account of various reasons as the same will otherwise lose significance. Therefore, the Commission does not agree with the suggestions for truing up of normative O&M expenses on the basis of variation in escalation rate.

30.15 NHPC has suggested to increase the normative O&M expenses from 2% of the project cost to 4% of the project cost for stations with installed capacity less than 200 MW, to 3% for stations with installed capacity between 200 MW to 600 MW, to 2.50% for stations with installed capacity between 600 to 1200 MW, and 2% for stations above 1200 MW. However, some of the stakeholders have suggested that the present norms of 2% of the project cost should be changed to 2% of Plant and Machinery cost. Further, some of the should include R&R expenses. The generating companies have submitted the actual data to substantiate the same and the same is reproduced below:

Table 4: Actual O&M expenses as a percentage of Capital Cost

Sl. No	Power Station	Installed Capacity (in MW)	Capital Cost on CoD excl. R&R (₹ in Lakh)	Actual O&M expenses (first full year after CoD) (₹ in Lakh)	O&M expenses as % of Capital Cost
Installed Capacity (IC)< 200 MW					
1	Rangit	60	47,585	2,091	4.39%
2	Sewa-II	120	98,268	6,762	6.88%
	Overall		145,853	8,853	6.07%
600 MW<Installed Capacity>200 MW					
3	Dhauliganga	280	162,907	4,271	2.62%
4	Chamera-II	300	195,208	4,592	2.35%
5	Dulhasti	390	507,849	9,124	1.80%

6	Teesta V	510	2,48,389	7,452	3.00%
Overall			11,14,353	25,440	2.28%
Overall(excluding Dulhasti)			6,06,504	16,316	2.69%

30.16 Having analyzed the above data, the Commission is of the view that there is a case for relaxation of normative O&M expenses of hydro stations having installed capacity of less than 200 MW. Accordingly, the norms provided in the draft Regulations have been revised to 4% for stations having installed capacity upto200 MW, and 2.50% for stations having installed capacity of more than 200 MW. As regards the suggestion received for linking O&M expenses with plant and machinery cost, the Commission is of the view that O&M expenses also include expenses towards dam/reservoir and therefore, the same cannot be limited to plant and machinery cost as suggested by the stakeholder. Further, as regards the suggestion to include R&R cost in the project cost while computing O&M expenses, the Commission is of the view that no asset is associated with such expenses that needs to be maintained by the generator on regular basis, therefore, such expenses should not be included in the project cost while computing O&M expenses.

30.17 As regards the suggestion received from THDC to increase the O&M expenses norm for Tehri Station, the Commission observes that both Indira Sagar Station of NHDC and Tehri are multi-purpose hydro projects having large storage capacity with installed capacity of 1000 MW. While Tehri HPS has 4 generating Units of 250 MW each, Indira Sagar HPS has to maintain 8 Units each with 125 MW capacity. Further, both the projects have experienced rehabilitation & resettlement problems during and after construction. Though these stations are common in most of the aspects, it is observed that the O&M expenses for FY 2012-13 as submitted for Indira Sagar are ₹ 86.22 Crore as compared to ₹ 243.64 crore submitted for Tehri. One of the major causes for this disparity is that the total number of employees is 218 in Indira Sagar and 938 in Tehri. In fact the number of employees in case of NJHPS having an installed capacity of 1500 MW is 773. The Commission is therefore, of the view that there is ample scope for man power rationalisation for Tehri HPS. Further, it is observed that the repair and maintenance cost submitted for Tehri is around ₹ 50 Crore and corporate office allocation is around ₹ 51 Crore for FY 2012-13, which is very high and needs detailed scrutiny. The Commission is therefore, not specifying the O&M expenses norms for Tehri Station in the Regulations. However, the

Commission would approve the same after detailed scrutiny along with the tariff determination for FY 2014-19.

30.18 In response to the suggestions of the generators to recover additional impact of pay revisions on actual basis, it is clarified that the Commission in the draft Regulations had provided a normative percentage of employee cost to total O&M expenses for different type of generating stations with an intention to provide a ceiling limit so that the same should not lead to any exorbitant increase in the O&M expenses resulting in spike in tariff. The Commission, however, would like to review the same considering the macro economics involved as these norms are also applicable for private generating stations. In order to ensure that such increase in employee expenses on account of pay revision in case of central generating stations and private generating stations is justified, the Commission is of the view that it shall examine the increase on case to case basis and shall consider the same if found appropriate to ensure that overall impact at the macro level is sustainable and justified.

30.19 As regards the suggestions of the stakeholders to fix a ceiling limit of ₹ 10 lakh/MW for hydro generating stations, it is clarified that the norms have been decided on the basis of actual data after due examination and therefore, there is no need to specify any ceiling limit.

30.20 SJVN Ltd. has submitted that O&M charges of NJHPS as proposed in the draft Regulations would not be sufficient for meeting the various expenditures required for the project, due to increase in the insurance cost on account of various natural calamities. SJVN Ltd. has further submitted that as no other hydro project of SJVN is under execution after commissioning of Rampur HEP (RHEP), O&M charges are likely to increase by ₹ 40 to ₹ 50 Crore on account of booking all corporate expenses against NJHPS and RHEP under O&M. Further, the recently approved pension scheme will also enhance the O&M cost. The Commission has gone through the suggestions of SJVN Ltd. and is aware of the fact that considerable amount of expenses have been incurred by the station towards repairs/replacement of parts due to abnormal silt conditions in certain years after COD of the station, which has resulted in higher O&M expenses. The Commission is of the view that the same needs to be rationalised after detailed scrutiny and before finally approving the

O&M norm of NJHPS. The Commission is therefore, not specifying the norms for NJHPS in the Regulations, which shall be considered after detailed scrutiny on being approached by the generating company for tariff determination for 2014-19.

30.21 While proposing the O&M expenses for NHPC stations in the draft Regulations the Commission had not deducted the PRP expenses included in corporate expenses and regional office expenses and the same has now been deducted. Further, the Commission observed that the approved O&M expenses for SEWA II for FY 2013-14 were around ₹24.57 Crore, however, the norm proposed for FY 2014-15 in the draft Regulations were ₹ 66.53 crore. The Commission has reviewed the same and observed that the Man:MW ratio for most of the stations is very high. Though NHPC has reduced its manpower in the past, there is further scope for manpower rationalisation. Therefore, the Commission has reviewed the O&M expenses of these stations and has further carried out normalisation in employee expenses wherever there was an abrupt increase in these expenses. The Commission has accordingly normalised the actual O&M expenses for NHPC stations as follows:

Table 5: Normalised O&M expenses for FY 2008-09 to FY 2012-13 (₹ in Lakh)

Name of Station	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13
Bairasiul	6,266.98	6,126.83	6,824.55	7,744.62	7,334.41
Loktak	6,744.63	7,275.05	7,964.68	8,854.60	7,223.83
Salal	9,785.15	10,125.68	11,097.44	12,363.27	13,765.37
Tanakpur	4,746.15	4,788.48	5,309.59	6,382.90	6,950.05
Chamera – I	7,943.18	7,710.52	7,853.64	8,864.04	9,687.04
Uri	4,694.58	5,277.23	6,051.68	6,462.43	6,918.74
Rangit	3,507.68	3,296.67	3,723.73	3,520.90	3,947.95
Chamera – II	4,312.23	4,977.32	6,355.98	6,447.42	6,713.46
Dhauliganga	4,690.86	5,306.90	6,033.01	6,171.92	6,166.97
Dulhasti	6,118.71	10,809.92	10,988.42	12,909.63	14,110.39
Teesta- V	5,752.47	5,671.25	6,555.96	6,877.57	7,985.77
Sewa-II	-	-	4,248.20	5,386.46	5,846.50

30.22 The Commission, on the basis of the revised actual normalised expenses, has specified the O&M expenses for 2014-19 as shown below:

Table 6: O&M expenses as specified for NHPC stations (₹ in Lakh)

Name of Station	FY 2014-15	FY 2015-16	FY 2016-17	FY 2017-18	FY 2018-19
Bairasiul	8696.25	9274.03	9890.19	10547.30	11248.06
Loktak	9673.64	10316.36	11001.78	11732.74	12512.26
Salal	14429.58	15388.29	16410.68	17501.01	18663.78
Tanakpur	7101.62	7573.45	8076.63	8613.24	9185.51
Chamera – I	10664.95	11373.53	12129.19	12935.05	13794.46
Uri	7419.40	7912.34	8438.04	8998.66	9596.54
Rangit	4576.46	4880.52	5204.78	5550.58	5919.36
Chamera – II	7256.54	7738.66	8252.82	8801.14	9385.89
Dhauliganga	7181.89	7659.05	8167.92	8710.59	9289.33
Dulhasti	13746.97	14660.32	15634.36	16673.10	17780.86
Teesta- V	8297.32	8848.59	9436.50	10063.46	10732.07
Sewa-II	6157.56	6566.67	7002.96	7468.24	7964.43

30.23 As regards stations of NEEPCO, the Commission in the Explanatory Memorandum to the draft Regulations while approving draft norms for Khandong station, stated that since the data has not been submitted by NEEPCO, the Commission has decided to consider the same per MWO&M expenses proposed for Doyang HEP. The Commission has still not received O&M expenses data for the station and therefore, the Commission has reviewed its methodology for deriving the norms for the station. The Commission has accordingly derived the O&M expenses for FY 2014-15 after considering an escalation rate of 6.64% on the O&M expenses specified for FY 2013-14. Similarly for Kopili-II station, NEEPCO has not submitted the actual O&M data and therefore, the Commission has derived the O&M expenses for the station after considering an escalation rate of 6.64% on the approved O&M expenses for FY 2013-14.

30.24 The Commission had accordingly approved the following O&M expenses for NEEPCO stations.

Table 7: Approved O&M expenses for NEEPCO Stations (₹ in Lakh)

Stations	FY 2014-15	FY 2015-16	FY 2016-17	FY 2017-18	FY 2018-19
Kopili HEP	6132.72	6540.18	6974.71	7438.11	7932.3
Ranganadi HEP	7033.08	7500.36	7998.68	8530.12	9096.86
Doyang HEP	3900.10	4159.22	4435.56	4730.26	5044.54
Khadong HEP	1233.87	1317.89	1405.45	1498.82	1598.41

Kopili Stage II HEP	321.00	342.33	365.07	389.32	415.19

30.25 The draft Regulations specified the O&M norms for the two hydro generating stations of NHDC, namely Indira Sagar and Omkareshwar. NHDC has suggested that its Man:MW ratio is considerably lower than others and therefore, it should be allowed to recover any under recovery on account of lesser manpower. The Commission, as also discussed earlier, has approved norms on the basis of actual data and therefore, suggestions to allow O&M expenses over and above the actual expenses cannot be accepted.

30.26 Further, as regards the O&M expenses proposed for Indira Sagar station in the draft Regulations, there was an inadvertent error in deriving normalised O&M expenses for FY 2012-13. The Commission had derived normalised O&M expenses for FY 2012-13 as ₹ 13.13 lakh/MW as against the correct value of ₹ 7.61 lakh/MW. The O&M expenses have been revised suitably.

30.27 As regards O&M expenses for Omkareshwar station, the Commission in the draft Regulations had proposed norms based on the actual O&M expenses submitted for the station. However, the PRP expenses, CSR and rebate to customers were not deducted while normalising the expenses. The Commission has now deducted the same and has accordingly computed the O&M expenses for the stations as shown below:

Table 8: Specified O&M expenses for NHDC Stations (₹ in Lakh)

Stations	FY 2014-15	FY 2015-16	FY 2016-17	FY 2017-18	FY 2018-19
Indira Sagar	8607.73	9179.63	9789.52	10439.94	11133.57
Omkareshwar	4515.31	4815.30	5135.23	5476.42	5840.27

30.28 As regards O&M expenses for hydro stations of DVC, the Commission has not received the details of the actual O&M expenses in the prescribed format and therefore, the Commission has escalated the approved O&M expenses for FY 2013-14 by 6.64% to derive the O&M expenses to be allowed for 2014-19. The Commission has accordingly specified the following O&M expenses for the hydro stations of DVC:

Table 9: Approved O&M expenses for hydro stations of DVC (₹in Lakh)

Name of Station	FY 2014-15	FY 2015-16	FY 2016-17	FY 2017-18	FY 2018-19
Panchet	1546.42	1649.17	1758.74	1875.59	2000.20
Tilaiya	698.99	745.43	794.95	847.77	904.10
Maithon	1914.46	2041.66	2177.31	2321.97	2476.24

Norms for O&M expenditure for Transmission {Draft Regulation 29(3)(a) and 29(3)(b)}

31.1 In line with the CERC Tariff Regulations, 2009, in the draft Regulations, the gradation of O&M expenses was done on the basis of the voltage for sub-stations and on per km basis with additional gradation based on circuit configuration for AC and HVDC lines. Further, for transmission lines, gradation was done on the basis of sub-conductor. Further, in line with the CERC Tariff Regulations, 2009, norms for O&M expenses per 500 MW capacity of HVDC Back to Back stations was proposed. Further, separate stand-alone norms for HVDC bipole projects namely Rihand-Dadri, Talcher-Kolar scheme, and Balia-Bhiwadi were proposed.

A) Norms for O&M expenditure for Transmission System (AC)

Stakeholders' Comments/Suggestions

31.2 POWERGRID submitted that if the CAGR of actual O&M expenses is calculated till FY 2011-12, the overall increase in O&M expenses is around 8.25% p.a., which is almost in line with the WPI/CPI indices of 8.35% p.a. The reduction in O&M expenses specifically in FY 2012-13 is a transition phase with assets getting added and a non-commensurate increase in manpower expenses. It submitted that the escalation factor should be based on the market indices, i.e., WPI/CPI indices, as adopted earlier by the Commission.

31.3 Adani Power Ltd. submitted that the Commission considered CPI and WPI for 2004-09 and 2009-14 Tariff Regulations. It further submitted that drastic reduction in O&M expenditure will impact grid security. It submitted that escalation rates notified by the Commission and that in the Model PPA also considers WPI and CPI. It suggested that annual escalation rate of O&M expenses should be continued to be computed based on CPI and WPI data.

31.4 TATA Power Company Limited, Association of Power Producers, Confederation of Indian Industry submitted that the basis for arriving at 4.14% escalation rate has not been explained in the Explanatory Memorandum.

31.5 Jaiprakash Power Ventures Limited submitted that considering the ratio of WPI:CPI as 70:30, the CAGR (inflation) in last five years is more than 8.25%. Therefore, the Commission may consider the same as % of escalation for O&M expenses (Thermal, Hydro, Transmission, etc.)

31.6 Haryana Power Purchase Centre submitted that escalation rate should be as per CERC escalation index.

31.7 POWERGRID submitted that the escalation factor derived for AC portion of transmission system cannot be applied for HVDC system and the same needs to be on a normative basis linked to CPI and WPI indices.

31.8 Association of Power Producers, M/s. TATA Power Company Limited, Confederation of Indian Industry, Powerlinks and others submitted that the proposed O&M norms are inadequate for a single project transmission company and the normative O&M costs allowed are less than the actual expenditure incurred by the Company. They further submitted that there is need to give separate consideration to the licensees as such companies do not enjoy economies of scale.

31.9 Torrent Power Grid Limited (TPGL) requested the Commission to consider the actual expense incurred for FY 2011-12 and FY 2012-13 as the basis and to allow increase for new Tariff Period considering the recent trend of WPI and CPI.

31.10 TPGL further submitted that as per the MoU with POWERGRID, TPGL is required to pay O&M charges at the rate determined by the Commission towards the maintenance of bays installed at POWERGRID substation. However, TPGL is required to pay Service Tax (current applicable service tax rate is 12.36%) on payment of such O&M expenses to POWERGRID. It submitted that material for maintenance of bays is also being provided by TPGL and hence, consumption of such material should be considered at actual over and above the charges payable to

POWERGRID for maintenance of bays. Hence, the Commission should give due consideration to such additional expenses.

31.11 Association of Power Producers, M/s. TATA Power Company Limited, and Confederation of Indian Industry, submitted that the decrease in the normative O&M expenses for the first year of the Tariff Period 2014-19 is on account of the method of normalization of the actual O&M Expenses with the actual CAGR in the ratio of 70:30 for sub-station to Transmission Lines. It requested to consider the normative O&M expenses of FY 2013-14 for applying the effective CAGR for deriving the normative O&M Expenses for the FY 2014-15.

31.12 Powerlinks submitted that the Commission should reconsider the norms for O&M expenses by fixing higher level of entitlement for FY 2014-15 and allow escalation between 8% to 10% for single transmission project companies like Powerlinks, where the cost per ckt-km does not go down due to economy of scale.

31.13 One stakeholder submitted that normative O&M expenses proposed for all transmission systems appear to be very high and suggested to consider a reduction of at least 10%. It further submitted that these expenses are quite high as compared with the expenses allowed by the State Electricity Regulatory Commissions.

31.14 One stakeholder submitted that the O&M expenses for inter-State transmission tariff has been increased very steeply without addition to the electricity generation, and the Commission may approve certain benchmarks taking into consideration the O&M cost of other State Utilities in the country

31.15 Some of the stakeholders submitted that the Commission has not provided any reason for such huge expenses per bay of substation and per km length of the transmission line. Since, substations and lines are stationary equipments, not much O&M expenses are necessary, therefore, it must be restricted to reasonable amount of ₹ 2 Lakh/bay/year and ₹ 0.20 Lakh/km/year subject to prudence check and trued up. Similarly, expenses for AC and HVDC line should be subjected to a ceiling of ₹ 0.20 Lakh per km per year subject to prudence check.

31.16 Jaiprakash Power Ventures Limited submitted that with reference to D/C (Bundled conductor with four or more sub-conductors), O&M expenses per bay as well as per km have been reduced for FY 2014-15 vis-à-vis FY 2013-14 levels. It submitted that the escalation has also been reduced to 4.13% in comparison to the previous Tariff Period 2009-14 where it was 5.7% and the Commission should consider the inflation as 8.25% in line with the inflation of last five years. It submitted that the Commission should also consider the size of the company while allowing the O&M expenses, and it would be unjust to prescribe O&M expenses for all stakeholders on the basis of POWERGRID.

31.17 Adani Power Ltd. submitted that O&M expenses norms for single-project licensees should be fixed on case to case basis. It suggested that the O&M norms for AC lines and substation be specified considering FY 2013-14 as base and escalation of 5.72% as considered during FY 2009-10 to FY 2013-14.

31.18 TANGEDCO submitted that POWERGRID includes the number of bays utilised by them in their various substations and claims O&M charges as per applicable Regulations, however, they are not agreeable to pay the O&M charges for their line's termination in the substation owned by the State Transmission Utility. Further, while POWERGRID charges the beneficiaries at the rates indicated by the Commission in the Regulations, they are not agreeable to pay the same O&M charges to the bays terminated and maintained by STUs in their substations. TANGEDCO submitted that O&M charges to be paid by POWERGRID for their bays terminated in STU's premises should also be at the same rate as indicated in the Regulations. It further submitted that the draft Regulations are silent on this issue and it should be included as an additional item under the tabulation of O&M expenses for substations and bays or as a foot note indicating the same charges for the line bays and substations irrespective of ownership.

31.19 POWERGRID requested to derive O&M expenses norms based on following submissions:

- **Performance Related Pay (PRP):** Normalized O&M expenditure for FY 2008-09 to FY 2012-13 may be determined considering PRP since, the PRP is part of employee cost and should not be excluded at the time of normalization of expenses.

- **Employee Efficiency factor:** It submitted that the growth and efficiency is already captured in actual O&M expenditure for FY 2008-09 to FY 2012-13 and re-applying of employee efficiency factor of FY 2012-13 level to reduce the O&M expenditure for FY 2008-09 to FY 2011-12 is duplication and may be avoided. It also submitted that it is being penalized for its own efficiency and optimization and it may not be able to cover the expected O&M expenses in the future when the manpower engaged in construction would be absorbed in the O&M.

31.20 Further during the public hearing, CMD, POWERGRID submitted that keeping in view the present and future grid conditions, and technical and economic scenario in the country to provide scope for enhanced performance through new technologies for ensuring reliable and secure services to the consumers, the Commission may consider reasonable O&M charges for transmission sector as has been done earlier.

31.21 Haryana Power Purchase Centre with reference to the O&M expense norms for transmission submitted that norms should be tightened as technology is improving.

31.22 Adani Power Ltd submitted that reduction in O&M expenses to such an exorbitantly low level would be detrimental for new transmission licensees. It further submitted as under:

- Norms are predominantly based on POWERGRID data, who is a multi-project licensee, has an advantage of economy of scale, etc**.** Basis considered for deriving per bay and per ckt-km cost may not be equally prudent for other licensees;

- It suggested to allow additional O&M expenses for coastal substations and transmission lines, as they face typical issue of corrosion due to high salinity.

Commission's Views

31.23 Some stakeholders have suggested that the basis for arriving at 4.14% escalation rate is not explained in the Explanatory Memorandum to draft Regulations. It is clarified that the explanation for arriving at effective CAGR of 4.14%for O&M expenses for the period from FY 2008-09 to FY 2012-13 is provided at the Table on Page 155 and Para 13.5.14 (Page 156) of the Explanatory Memorandum.

31.24 Considering the suggestions of various stakeholders, the Commission has reviewed the proposed methodology of deriving norms for O&M expenses. The methodology adopted by the Commission for deriving O&M expenses for FY 2014-15 to FY 2018-19 is discussed in subsequent paragraphs.

31.25 As regards details of network parameters, since information for the period from 1st April, 2009 to 1st April, 2013 was available while arriving at the O&M norms in the draft Regulations, average values for the year had been calculated by taking average of respective values as on 1st April of two consecutive years except for FY 2008-09, for which the values as on 1stApril, 2009 had been used. Subsequently, details for network parameters as on 1st April, 2008 were sought from POWERGRID. Based on these values, the Tables below captures details of number of bays and ckt-kms based on the gradation and equivalent 400 kV bays and equivalent Single Circuit (S/C) twin conductor ckt-kms, respectively.

Table 10: Number of AC sub-station bays

	Actual average no. of bays in commercial operation					W.F.	Eq. No. of bays (400 KV) in commercial operation				
	FY 09	FY 10	FY 11	FY 12	FY 13		FY 09	FY 10	FY 11	FY 12	FY 13
765 kV	5.5	6	6	24.5	83.5	1.4	7.7	8.4	8.4	34.3	116.9
400 kV	833	901	987.5	1155.5	1368.5	1	833	901	987.5	1155.5	1368.5
220 kV	433	481	534	626.5	722.5	0.7	303.1	336.7	373.8	438.55	505.75
Upto 132 kV	104.5	109	119	128	144.5	0.5	52.25	54.5	59.5	64	72.25
Total	**1376**	**1497**	**1647**	**1935**	**2319**		**1196**	**1301**	**1429**	**1692**	**2063**

W.F. = Weightage Factor

Table 11: Ckt-kms of AC and HVDC lines

	Actual average ckt km in operation					Weightage	Equivalent ckt-km (twin conductor) in operation				
	FY 09	FY 10	FY 11	FY 12	FY 13	Factor	FY 09	FY 10	FY 11	FY 12	FY 13
S/C Quad	2086.33	2723.42	3047.32	4119.78	5498.17	1.500	3129.50	4085.12	4570.98	6179.68	8247.26
S/C Triple	0.00	0.00	2.81	3.98	2.35	1.000	0.00	0.00	2.81	3.98	2.35
S/C Twin	17539.91	17506.38	17609.95	17795.98	17858.51	1.000	17539.91	17506.38	17609.95	17795.98	17858.51
S/C Single	1184.07	1238.93	1254.56	1199.69	1184.07	0.500	592.03	619.47	627.28	599.85	592.03
D/C Quad	7207.35	7452.07	8737.17	10859.05	12898.93	1.313	9463.25	9784.57	11471.91	14257.94	16936.30
D/C Triple	1566.26	1566.26	1765.16	2757.43	3887.55	0.875	1370.48	1370.48	1544.52	2412.75	3401.60
D/C Twin	32785.77	35878.99	39331.30	43290.01	46919.81	0.875	28687.55	31394.12	34414.88	37878.76	41054.84
D/C Single	7137.87	7215.15	7323.89	7665.89	8058.31	0.375	2676.70	2705.68	2746.46	2874.71	3021.87
M/C Quad	0.00	6.75	17.24	20.99	20.99	1.152	0.00	7.77	19.86	24.18	24.18
M/C Twin	0.00	0.00	81.34	242.07	333.36	0.767	0.00	0.00	62.39	185.67	255.69
Total	**69507.56**	**73587.95**	**79170.73**	**87954.88**	**96662.05**		**63459.42**	**67473.60**	**73071.03**	**82213.49**	**91394.62**

31.26 The growth in the number of substation bays and transmission lines during the period from FY 2008-09 to FY 2012-13 is evident from above Table. The equivalent number of bays has increased from 1196 in FY 2008-09 to 2063 in FY 2012-13 and the CAGR of bays works out to 14.61%. The length of transmission line has increased from 63,459.42 equivalent ckt-km in FY 2008-09 to 91,394.62 equivalent ckt-km in FY 2012-13 and the CAGR of length of transmission lines works out to approximately 9.55%. Thus, the rate of increase in number of bays is higher as compared to rate of increase in length of transmission lines.

31.27 The normalized O&M expenses for HVDC stations of the concerned region have been deducted from the overall region-wise normalized expenses. The resulting values represent normalized O&M expenses for AC sub-stations and transmission lines (AC as well as DC) for FY 2008-09 to FY 2012-13. Considering normalisation in O&M expenses and the apportioning of such normalised O&M expenses between sub-stations and transmission lines (AC and HVDC lines) in 70:30 ratio, CAGR of O&M expenses per equivalent (400 kV) AC bay for the period FY 2008-09 to FY 2012-13 works out to around 1.61% and CAGR of O&M expenses per equivalent (S/C twin conductor) ckt-km for the period FY 2008-09 to FY 2012-13 works out to 6.31%. By applying the same ratio of 70:30 between sub-stations and transmission lines, the effective CAGR of O&M expenses for the period FY 2008-09 to FY 2012-13 works out to 3.02%.

Table 12: CAGR of O&M expenses for the period FY 2008-09 to FY 2012-13

		FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13
A	Total Normalized O&M Expenses (₹ Lakh)	75833.17	96394.91	108191.92	126950.86	139477.06
B	Normalized O&M expenses allocated to S/S (70% of A) (₹ Lakh)	53083	67476	75734	88866	97634
C	Equivalent No. of sub-station bays	1196	1301	1429	1692	2063
D	O&M expenditure per equivalent (400 kV) AC bay (₹ Lakh/bay)	44.38	51.88	52.99	52.51	47.32
	CAGR (FY 2008-09 to FY 2012-13)					**1.61%**
E	Normalized O&M expenses allocated to AC and HVDC lines (30% of A) (₹ Lakh)	22749.95	28918.47	32457.58	38085.26	41843.12
F	Equivalent ckt-km in commercial operation	63459.42	67473.60	73071.03	82213.49	91394.62
G	O&M expenditure per equivalent (S/C. twin conductor) ckt-km (₹ Lakh/ckt-km)	0.358	0.429	0.444	0.463	0.458
	CAGR (FY 2008-09 to FY 2012-13) (%)					**6.31%**

31.28 The effective CAGR of O&M expenses for AC transmission system during the period FY 2008-09 to FY 2012-13 shows that the increase in O&M expenses per bay and per ckt-km O&M is substantially lower than the rate based on CPI: WPI indices during the same period. The effective CAGR of O&M expenses represents inflation for the period, growth in the assets and the efficiency factor in terms of reduction in number of employees per equivalent bay or per equivalent ckt-km of transmission line. The Commission is of the view that the rate derived in terms of the actual cost drivers (transmission system parameters, i.e., bay and ckt-km) is a more reflective indicator of average increase in O&M expenses than the prevailing rate based on the WPI and CPI. It is pertinent to mention that the average increase in O&M expenses for transmission system as well as in case of generating stations is lower than the prevailing rate of inflation, i.e., 8.35% which effectively reflects RPI – X. Further, the O&M expenses norms derived by applying effective CAGR of O&M expenses provides recovery of prudent O&M expenses of the transmission system as a whole under various scenarios such as business as usual, with asset growth, etc.

31.29 POWERGRID suggested that the reduction in O&M expenses specifically in FY 2012-13 is a transition phase with assets getting added and a non-commensurate increase in manpower, and hence, FY 2011-12 expenses should be considered for calculation of CAGR, resulting in effective CAGR of around 8.25% in line with the CPI: WPI indices of 8.35%.In this context, the Commission observes that on one hand it has been contended that the effective CAGR of O&M expenses during FY 2008-09 to FY 2012-13 (4.14% as indicated in Explanatory Memorandum to draft Regulations) is not based on WPI/CPI, whereas on the other hand it is suggested to adopt the rate of 8.25%, which is in line with the CPI:WPI, merely on account of it being on the higher side. If the suggestion of excluding the figures for FY 2012-13 (the latest year for which various details are available) is to be accepted, then by applying the same approach, consideration of FY 2008-09 (the year from earlier Control Period) for calculation of effective CAGR of O&M expenses also requires to be reconsidered. The Commission has adopted the mechanism of deriving the norms of O&M expenses based on actual performance of past five years data and hence, does not find any merit in the suggestion.

31.30 As regards the suggestion that the escalation factor should be based on the market indices, i.e., WPI/CPI, as adopted earlier by the Commission, or escalation rate as per CERC escalation index or rates based on Model PPA, the Commission reiterates that effective CAGR of O&M expenses based on the normalised O&M expenses are the best indicator for working out O&M norms as it truly captures the actual O&M expenses and the beneficiaries also pay on the basis of an appropriate consideration.

31.31 However, in view of various suggestions, the Commission is of the view that a 10% margin over and above the effective CAGR of O&M expenses of 3.02%, i.e., 3.32%needs to be provided not only for the comfort of project developers in carrying out O&M of the assets but also in the interest of stakeholders from availability considerations. In order to arrive at norms for Tariff Period FY 2014-15 to FY 2018-19, effective CAGR of O&M expenses of 3.32% has been applied to the norms for FY 2013-14.

31.32 As regards the suggestion that the escalation factor derived for AC portion of transmission system cannot be applied for HVDC system, the Commission observed that the CAGR of normalised O&M expenses for the period FY 2008-09 to FY 2012-13 for HVDC bipole scheme as well as in case of HVDC BTB stations is more than 8.35% (except Gazuwaka BTB station).In case of Balia-Bhiwadi, O&M expenses for FY 2011-12 and FY 2012-13were considered in the Explanatory Memorandum. However, it was not possible to derive any rate as expenses for FY 2011-12 are for Pole-I only whereas the expenses for FY 2012-13 are for Pole-II. The Commission observed that when Regulations were allowing 5.72% increase in O&M expenses, year on year increase in O&M charges for HVDC in case of POWERGRID were very high and sometime much higher than inflation rate of 8.35% derived on the basis of WPI and CPI. Therefore, CAGR of O&M expense in HVDC is restricted to 8.35%.Therefore, in order to arrive at norms in respect of O&M expenses for HVDC stations for Tariff Period from FY 2014-15 to FY 2018-19, the CAGR of normalised O&M expenses of 8.35% has been considered, thereby limiting it to the rate of inflation of 8.35%.

31.33 Some stakeholders suggested to consider the normative O&M expenses of FY 2013-14 for applying the effective CAGR for deriving the normative O&M Expenses for FY 2014-15. Since, the Commission has considered the actual expenses over the Tariff Period, which are a better indicator of the expenses as compared to a single year's expense level, the Commission does not find any merit in the suggestion.

31.34 As regards the suggestion that the basis considered for deriving per bay and per ckt-km cost is not prudent and separate treatment be given for the single project transmission companies for the Tariff Regulations 2014-19, the Commission has continued with the approach followed in the CERC Tariff Regulations, 2009. The Commission has analysed the asset configuration of the single project companies and observed that though the single project transmission licensees are not comparable with the other licensees in terms of asset configuration, there should not be significant difference in O&M expenses in terms of cost drivers. The norms for O&M expenses have been derived giving due consideration to the suggestions of stakeholders. Further, single project companies need to undertake more efficient measures to contain the O&M expenses within industry benchmarks.

31.35 As regards the suggestion of POWERGRID that the normalized O&M expenditure for FY 2008-09 to FY 2012-13 may be arrived at by including Performance Related Pay (PRP) as part of employee cost, the Commission is of the view that expenses like PRP are linked to efficient operation of the transmission system and are payable only in case the transmission system achieves normative operational levels or overachieves them. Since, PRP is payable only if the company benefits from efficient O&M, therefore, the same should be paid by the transmission licensee from the increase in revenue due to incentive earned through reduced downtime and efficient operation of the transmission system. By achieving higher availability consistently, which is a performance indicator, POWERGRID is earning incentive, which effectively reimburses the PRP.

31.36 In the Explanatory Memorandum to the draft Regulations, it was suggested that the O&M expenditure considered for formulating norms shall be arrived at from the normalised O&M expenditure by adjusting the employee cost for the period FY 2008-09 to FY 2011-12 by keeping manpower per ckt-km and per bay at the same level as in FY 2012-13.With reference to employee efficiency factor, POWERGRID suggested that the growth and efficiency are already captured in actual O&M expenditure for FY 2008-09 to FY 2012-13 and re-applying the employee efficiency factor of FY 2012-13 level to reduce the O&M expenditure for FY 2008-09 to FY 2011-12 is duplication, and may therefore, be avoided. In this context, it is noted that the effective CAGR of O&M expenses represents inflation for the period, growth in the assets and relevant increase in the expenses, and employee efficiency has already been captured. Accordingly, the Commission finds it appropriate not to re-apply the employee efficiency factor. Further, as clarified above the O&M expense norms provides for recovery of prudent O&M expenses of the transmission system as a whole under various scenarios such as business as usual, with asset growth, etc.

31.37 The following Table shows the process of arriving at the average O&M expenditure per equivalent 400 kV bay and average O&M expenses per equivalent ckt-km of S/C twin conductor at 2012-13 price level. As explained in the Explanatory Memorandum, in order to capture trend of increase in substation bays and lines in the composition of O&M expenses, for the purpose of arriving at norms, it has been decided that total O&M expense shall be apportioned between sub-stations and transmission lines (AC and HVDC lines) in the ratio of 75:25 instead of 70:30.The allocated normalised O&M expenses for FY 2008-09 to FY 2011-12 have been escalated to FY 2012-13 level at the escalation rate of 3.02% per annum and O&M expenses per equivalent (400 kV) AC bay & O&M expenses per equivalent (S/C twin conductor) ckt-km has been derived. Average of such values serves as the base at FY 2012-13 price level.

Table 13: O&M expenses per equivalent (400 kV) bay and per equivalent (single ckt-twin conductor) ckt-km

	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13	Average
Total actual Normalized O&M Expenses (₹ Lakh) (A)	75833.17	96394.91	108191.92	126950.86	139477.06	
Actual Normalized O&M expenses allocated to S/S (75% of A) (₹ Lakh) (B)	56875	72296	81144	95213	104608	
O&M expenses escalated to FY 2012-13 level @ 3.02% (₹ Lakh) (C)	64063	79046	86119	98089	104608	
Equivalent No. of sub-station bays (D)	1196	1301	1429	1692	2063	
O&M expenditure per equivalent (400 kV) AC bay (₹ Lakh/bay)	53.56	60.78	60.26	57.96	50.70	56.65
	FY 2008-09	**FY 2009-10**	**FY 2010-11**	**FY 2011-12**	**FY 2012-13**	**Average**
Actual Normalized O&M expenses allocated to AC and HVDC lines (25% of A) (₹ Lakh) (B)	18958.29	24098.73	27047.98	31737.71	34869.26	
O&M expenses escalated to FY 2012-13 level @ 3.02% (₹ Lakh) (C)	21354	26349	28706	32696	34869	
Equivalent ckt-km in commercial operation (D)	63459.42	67473.60	73071.03	82213.49	91394.62	
O&M expenditure per equivalent (S/C. twin conductor) ckt-km (₹ Lakh/ckt-km)	0.337	0.391	0.393	0.398	0.382	0.380

31.38 The average O&M expenses for FY 2012-13 have been further escalated @ 3.02% to reach to FY 2013-14 level. The average O&M expenses for FY 2013-14 so derived, have been further escalated @ 3.32% per annum to reach FY 2014-15 level. The O&M expenses thus, determined for FY 2014-15 are given in Table below:

Table 14: O&M expenses per equivalent (400 kV) bay and per equivalent (single ckt-twin conductor) ckt-km for FY 2014-15

	Average FY 2012-13 (Pl. refer Table 7)	Escalated @ 3.02% to FY 2013-14 level	Escalated @ 3.32% to FY 2014-15 level
O&M expenditure per equivalent (400 kV) AC bay (₹. Lakh/bay)	56.65	58.36	60.30
O&M expenditure per equivalent (S/C. twin conductor) ckt-km (₹. Lakh/ckt-km)	0.380	0.391	0.404

31.39 The norms for AC sub-station and transmission lines (AC and HVDC) for equivalent 400 kV bay and for equivalent S/C twin conductor ckt-km so determined have then been converted to various voltage levels (for sub-stations) and various circuit and conductor configuration (for transmission lines) by applying weightage factors as contained in Para 30.26. The effective CAGR of O&M expenses of 3.32%

per annum has been applied to the norms for FY 2014-15 to arrive at norms for each of the subsequent years of the Tariff Period 2015-19. Finally, the values obtained for D/C lines have been converted from ckt-km to km basis by doubling them. As already observed, the Commission is of the view that a 10% margin over and above the effective CAGR of O&M expenses of 3.02%, i.e., 3.32% needs to be provided not only for the comfort of project developers in carrying out O&M of the assets but also in the interest of stakeholders from availability considerations.

31.40 As regards the submission that the normative O&M expenses allowed for the transmission licensees are high as compared with the expenses allowed by the State Electricity Regulatory Commissions, the Commission is of the view that the two transmission systems are not directly comparable. Intra-State transmission systems predominantly contain network of 220 kV/132 kV and even lower voltages with mostly single conductor configuration. Moreover, it is pertinent to mention that the norms for O&M expenses have been computed based on the actual O&M expenses, which include employee expenses, repair and maintenance expenses and the differential between the norms for the Inter-State Transmission System and Intra State Transmission System is mostly due to difference in employee expenses of CPSU, which are based on DPE norms.

31.41 As regards the suggestion that O&M expenses norms should be tightened as technology is improving, it is worthwhile to mention that the norms formulated now are based on actual performance data during the last five years. As regards stakeholders' suggestion of consideration of reasonable O&M charges to provide scope for enhanced performance through new technologies for ensuring reliable and secure service to the consumers, it is reiterated that the proposed level of O&M expenses norms provides for recovery of prudent O&M expenses of the transmission system, and also provides enough scope for enhanced/sustained performance through new technologies.

31.42 As regards norms for O&M expenses for coastal substations and transmission lines, the Commission is of the view that classification of assets of transmission lines forming part of transmission system under coastal areas is cumbersome. Further, in the absence of supporting details, specifying separate O&M expense norms may not be feasible.

31.43 As regards the suggestion that the Commission has not provided any reason for huge expenses per bay of substation and per km length of the transmission line, the Commission has continued with the approach followed in the CERC Tariff Regulations, 2009. Stakeholders further suggested that since, substations and lines are stationary equipments, not much O&M expenses are necessary, therefore, it must be restricted to reasonable amount of ₹ 2 Lakh/bay/year and ₹ 0.20 Lakh/km/year subject to prudence check and trued up and expenses for AC and HVDC line should be subjected to a ceiling of ₹ 0.20 Lakh per km per year subject to prudence check. In the absence of supporting details and necessary justification the Commission does not find any merit in the suggestion.

31.44 As regards payment of service tax as per the MoU between POWERGRID and TPGL, the Commission is of the view that this is a matter to be decided mutually between POWERGRID and TPGL. As regards the suggestion of TANGEDCO, the Commission has already dealt with the issue in the Order dated 19.9.2012 in Petition No. 11/2010 and 26.09.2012in Review Petition No. 4/2011 in Petition No. 123/2010, wherein the Commission ruled that the POWERGRID should adopt a uniform approach towards all utilities. The Commission does not see any need to add clarification in the tabulation of O&M charges, as this is a matter to be mutually decided between POWERGRID and TANGEDCO and shall be governed as per the scope and terms and conditions of the arrangement mutually agreed.

B) **Norms for O&M expenditure for Transmission System (HVDC)**

Stakeholders' Comments/Suggestions

31.45 POWERGRID submitted that while the abnormal O&M expenses have been factored in as 20% in the year in which the same have been incurred, however, there should be provision of reimbursing the abnormal O&M expenses as one-time payment subject to prudence check. It further submitted that the cost of future HVDC systems may be linked to the latest HVDC system and as on date HVDC Balia–Bhiwadi is the latest HVDC system. It has been submitted that consideration of cost of Talcher–Kolar system for all future systems, may not be able to capture the cost on account of technological differences of the new systems.

31.46 M/s Adani Power Limited submitted the O&M activities requiring very high maintenance due to specific characteristic of HVDC. It submitted that O&M expenses norms for APL's HVDC system should be based on actual expenses. It also submitted that O&M expenses for HVDC system should be approved on case to case basis.

31.47 Some stakeholders suggested that separate norms on lower side need to be adopted for HVDC lines based on conductor configuration and for an electrode line of HVDC station. They submitted that D/C AC line with 4 conductors per phase will have a total of 24 conductors and 6 insulator strings on each tower. A bi-pole HVDC line with 4 conductors per pole will have a total of 8 conductors and 2 insulators strings on each tower. They further submitted that as per above comparison, the O&M charges of HVDC bi-pole lines should be about 1/3rd of D/C AC line. Further, HVDC norms should be project specific since 800 kV HVDC technology would be introduced in the country for the first time.

Commission's Views:

31.48 As regards the suggestion for determination of separate norms for HVDC lines based on conductor configuration, due to complexity in segregation of exact O&M expenses for HVDC bi-pole project, the Commission considered it appropriate to treat HVDC bi-pole line as S/C Quad line, because HVDC bi-pole quad line (which has eight conductors) cannot be equated with Double Circuit quad AC line (which has 24 conductors) along with differential in number of insulator strings. Accordingly, the following provision has been incorporated in the Regulations:

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

31.49 It is further clarified that as per the above proviso, norms for the O&M expenses of HVDC bi-pole line shall be considered equivalent to that for Single Circuit (Bundled Conductor with four sub-conductors) line. It is further clarified that O&M expenses for earth wire as well as earth electrode shall be based on its conductor configuration and shall be considered equivalent to respective specified norms.

31.50 As regards the suggestions that consideration of cost of Talcher–Kolar system for all future systems may not be able to capture the cost on account of technological differences of the new systems and determination of project specific HVDC norms, the Commission is of the view that capturing the impact of O&M expense for various technological differences in case of future projects may be difficult in the absence of data and may not be in the interest of stakeholders.

31.51 As regards the suggestion for linking of cost of future HVDC systems to the latest HVDC system in reference to Para 13.5.23 of the Explanatory Memorandum, it is observed that Talcher-Kolar HVDC system of 2000 MW was put under commercial operation in 2002-03 and Rihand-Dadri HVDC system of 1500 MW was put under commercial operation in 1991-92.Though, Balia-Bhiwadi is the latest HVDC scheme, the O&M expenses are available for FY 2010-11 to FY 2012-13 only. The O&M expenses submitted for FY 2010-11 are for part of the year, and Pole-II of the scheme became operational only during FY 2012-13. Considering the operational experience of Talcher-Kolar HVDC system of 2000 MW, the O&M expenses for new HVDC bipole scheme shall be calculated pro-rata on the normative O&M expenses for 2000 MW Talcher - Kolar HVDC bi-pole scheme for the respective year. Hence, there is no need of modification of the draft proviso.

31.52 In continuation of the approach followed and detailed analysis elaborated in the Explanatory Memorandum to arrive at norms for HVDC stations, normalised expenses during FY 2008-09 to FY 2011-12 have been escalated @8.35%per annum to reach FY 2012-13 level. The average O&M expenses for FY 2012-13 level have been escalated @8.35% per annum to derive the norms for FY 2014-15 and subsequent years.

31.53 For the purpose of arriving at norms for Balia-Bhiwadi HVDC bipole scheme, normalised expenses during FY 2010-11 to FY 2011-12 have been escalated @8.35% per annum to reach FY 2012-13 level. The average O&M expenses of FY 2012-13 have been escalated @8.35% per annum to derive the norms for FY 2014-15 and subsequent years.

Table 15: Computation of base norms at FY 2012-13 price level for HVDC bipole schemes (₹ in Lakh)

HVDC Station	Normalised O&M expenditure					Escalated to FY 2012-13 level @ 8.35%					Average at 2012-13 level	
	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13	Station wise	For Scheme
Rihand- Dadri Scheme												
Rihand	294.07	352.88	363.32	444.16	541.52	405.29	448.87	426.53	481.25	541.52	460.69	
Dadri	604.82	676.80	486.03	924.89	863.58	833.57	860.89	570.58	1002.12	863.58	826.15	1287
Talcher-Kolar Scheme												
Talchar	308.80	268.00	481.23	496.55	499.80	425.59	340.90	564.95	538.01	499.80	473.85	
Kolar	380.92	275.09	580.28	532.80	494.86	524.99	349.91	681.23	577.29	494.86	525.66	1000
Bhiwadi*												
Balia*	0.00	0.89	699.37	1219.19	1297.83	0.00	1.14	821.04	1320.99	1297.83	1309.41	1309

31.54 Based on the above analysis, norms for HVDC back-to-back stations have been determined as under:

Table 16: Norms for HVDC bipole scheme (₹ in Lakh)

Norms for sub-station (₹ Lakh per bay)	2014-15	2015-16	2016-17	2017-18	2018-19
Rihand-Dadri HVDC bipole scheme (₹ Lakh)	1511	1637	1774	1922	2082
Talcher- Kolar HVDC bipole scheme (₹ Lakh)	1173	1271	1378	1493	1617
Balia-Bhiwadi HVDC bipole scheme (₹ Lakh)	1537	1666	1805	1955	2119

31.55 In continuation of the approach followed and detailed analysis elaborated in the Explanatory Memorandum to arrive at norms for HVDC back -to-back stations, normalised expenses during FY 2008-09 to FY 2011-12 have been escalated @8.35%per annum to reach FY 2012-13 level. The normalized O&M expenses at FY 2012-13 level have been divided by the Station capacity (for every 500 MW) to arrive at values in ₹ Lakh/500 MW. As explained in the Explanatory Memorandum, O&M Expenses for Gazuwaka BTB for the period from FY 2008-09 to FY 2012-13 are not comparable with other BTB stations. Therefore, O&M expenses per 500 MW have been derived by taking average of HVDC BTB stations (excluding Gazuwaka BTB) at FY 2012-13 level. The average O&M expenses for FY 2012-13 level have been escalated @8.35% per annum to derive the norms for FY 2014-15 and subsequent years.

Table 17: Computation of base norms at FY 2012-13 price level for HVDC back to back schemes (₹ in Lakh)

	Normalised O&M expenditure					Escalated to FY 2012-13 level @ 8.35%					Average at 2012-13 level	
HVDC Station	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13	Station wise	per 500 MW
Vindhyachal BTB	222.87	341.58	403.67	503.18	503.93	307.16	434.48	473.90	545.19	503.93	452.93	452.93
Chandarpur BTB	691.78	627.82	753.38	904.05	1198.17	953.41	798.58	884.45	979.54	1198.17	962.83	481.42
Sasaram BTB	378.31	450.51	408.13	489.75	615.36	521.39	573.05	479.13	530.65	615.36	543.92	543.92
Gazuwaka BTB	1399.15	1624.30	2068.95	2112.47	1758.68	1928.33	2066.11	2428.89	2288.86	1758.68	2094.17	1047.09
											Average	492.75

31.56 Based on the above analysis, norms for HVDC back-to-back stations have been determined as under:

Table 18: Norms for HVDC back-to-back stations (₹in Lakh)

Norms for sub-station (₹Lakh per bay)	2014-15	2015-16	2016-17	2017-18	2018-19
HVDC Back–to-back stations (₹ Lakh per 500 MW)	578	627	679	736	797

31.57 As regards the suggestion that there should be provision for reimbursing the abnormal O&M expenses as one-time payment subject to prudence check, POWERGRID has not clarified the type of abnormal expenses, which are anticipated by them. In view of spare convertor transformer provided and capitalized in most of the HVDC projects and no provision of true up of O&M charges, this request cannot be agreed to.

31.58 It is observed that while booking corporate and Regional Head Quarter charges by POWERGRID, around 90 to 95% of these expenses were booked to O&M expenses of transmission business, as transmission assets are reported to constitute approximately 95% of total POWERGRID business. It is also observed that at present POWERGRID is engaged in Competitive Bidding projects in transmission, hence, there is a need to clearly segregate business segments. For proper accounting, POWERGRID should maintain separate accounts for transmission, CTU and other business streams and should also submit number of employees engaged in different business streams so that there is no overlapping of employees' expenditure. In this context, CEA has suggested that CTU should be identified as a separate function. POWERGRID should maintain clear demarcation in respect of assets, accounts and employees working in different business streams.

31.59 The following normative operation and maintenance expenses shall be admissible for the transmission system:

Table 19: Norms for O&M expenditure for Transmission System *(₹ in Lakh)*

Norms for sub-station (₹ in Lakh per bay)	**2014-15**	**2015-16**	**2016-17**	**2017-18**	**2018-19**
765 kV	84.42	87.22	90.12	93.11	96.20
400 kV	60.30	62.30	64.37	66.51	68.71
220 kV	42.21	43.61	45.06	46.55	48.10
132 kV and below	30.15	31.15	32.18	33.25	34.36
400 kV Gas Insulated Substation	51.54	53.25	55.02	56.84	58.73
Norms for AC and HVDC lines (₹ in Lakh per km)					
Single Circuit (Bundled Conductor with six or more sub-conductors)	0.707	0.731	0.755	0.780	0.806
Single Circuit (Bundled Conductor with four sub-conductors)	0.606	0.627	0.647	0.669	0.691
Single Circuit (Twin & Triple Conductor)	0.404	0.418	0.432	0.446	0.461
Single Circuit (Single Conductor)	0.202	0.209	0.216	0.223	0.230
Double Circuit (Bundled conductor with four or more sub-conductors)	1.062	1.097	1.133	1.171	1.210
Double Circuit (Twin & Triple Conductor)	0.707	0.731	0.755	0.780	0.806
Double Circuit (Single Conductor)	0.303	0.313	0.324	0.334	0.346
Multi Circuit (Bundled conductor with four or more sub-conductors)	1.863	1.925	1.989	2.055	2.123
Multi Circuit (Twin & Triple Conductor)	1.240	1.282	1.324	1.368	1.413
Norms for HVDC Stations					
HVDC Back–to-back stations (₹ in Lakh per 500 MW)	578	627	679	736	797
Rihand-Dadri HVDC bi-pole scheme (₹ in Lakh)	1511	1637	1774	1922	2082
Talcher- Kolar HVDC bi-pole scheme (₹ in Lakh)	1173	1271	1378	1493	1617
Balia-Bhiwadi HVDC bi-pole scheme (₹ in Lakh)	1537	1666	1805	1955	2119

Provided that the O&M expenses for the new HVDC bi-pole scheme shall be calculated on the basis of pro-rata rate of O&M expenses norms for 2000 MW Talcher- Kolar HVDC system for the respective year:

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

<u>O&M expenditure for Communication System {Draft Regulation 29(3)(c)}</u>

32.1 The draft Regulations proposed that the operation and maintenance expenses of communication system forming part of inter-state transmission system shall be derived on the basis of the actual O&M expenses for the period of 2008-09 to 2012-13 based on audited accounts excluding abnormal variations if any after prudence check by the Commission.

<u>Stakeholders' Comments/Suggestions</u>

32.2 POWERGRID proposed O&M charges of 7.5% of the Capital Cost and submitted that the same should be allowed on actuals subject to prudence check as per practice being followed in existing ULDC tariff.

<u>Commission's Views</u>

32.3 The rationale for the proposed provisions has been elaborated in the Explanatory Memorandum to the draft Regulations. In the absence of adequate justification, the Commission is not convinced to change the proposed approach. The Commission has also incorporated the following clause as under:

> *"(c) The operation and maintenance expenses of communication system forming part of inter-state transmission system shall be derived on the basis of the actual O&M expenses for the period of 2008-09 to 2012-13 based on audited accounts excluding abnormal variations if any after prudence check by the Commission. The normalised O&M expenses after prudence check, for the years 2008-09 to FY 2012-13 shall be escalated at the rate of 3.02% for computing base year expenses for FY 2012-13 and 2013-14 and at the rate of 3.32% for escalation from FY 2014- 15 onwards."*

33. Impact of Wage revision {Draft Regulation 29(4)}

<u>Stakeholders' Comments/Suggestions</u>

33.1 POWERGRID submitted that the share of employee cost in the overall O&M expenses should be considered as 43%. It submitted that as the next pay revision is due w.e.f. 01.01.2017 and the impact of pay revision will only be known after implementation of pay revision guidelines issued by the Government of India, the impact of pay revision may be allowed based on actuals as per Auditor's certificate.

<u>Commission's Views</u>

33.2 The draft Regulations provided for a normative percentage of employee cost to total O&M expenses for generating stations and transmission system with an intention to provide a ceiling limit so that the same should not lead to any exorbitant increase in the O&M expenses resulting in spike in tariff. The Commission shall examine the increase in employee expenses on case to case basis and shall consider the same if found appropriate, to ensure that overall impact at the macro level is sustainable and thoroughly justified. Accordingly, clause 29(4) proposed in the draft Regulations has been deleted. The impact of wage revision shall only be given after seeing impact of one full year and if it is found that O&M norms provided under Regulations are inadequate/insufficient to cover all justifiable O&M expenses for the particular year including employee expenses, then balance amount may be considered for reimbursement.

34. Computation and Payment of Capacity Charge and Energy Charge for Thermal Generating Stations {Regulation 30}

34.1 Clause 30(1) of the draft Regulations specified that the fixed cost of a thermal generating station shall be computed on annual basis, based on specified norms and recovered on monthly basis under capacity charge. The total capacity charge payable for a generating station shall be shared by its beneficiaries as per their respective percentage share/allocation in the capacity of the generating station. Clause 30(2) of the draft Regulations provided formulae for computation of the capacity charge payable to a thermal generating station. Clause 30(3) of the draft Regulations specified that the PAFM upto the end of a particular month and PAFY shall be computed in accordance with the specified formula.

<u>Capacity Charge</u>

<u>Stakeholders' Comments/Suggestions</u>

34.2 MPERC submitted that the full form of PAFM may be added as *"Plant Availability Factor achieved during the month in percentage"*. CSPGCL submitted that it is not clear whether PAF1, PAF2, etc., stand for monthly PAF for that month or cumulative PAF. However, from the mechanism specified it is understood to be monthly PAF for that particular month. MPPMCL submitted that PAF 1 and PAF 11 should be defined properly to avoid future ambiguity. Jaiprakash Power suggested to replace the clause "*The PAFM upto the end of a particular month and PAFY shall be computed*" in clause 30(3) of the draft Regulations, with "*The PAFM upto the end of a particular month and PAFY upto the year shall be computed* ".

34.3 NLC and some other stakeholders submitted that the formula restricts the monthly recovery of fixed charges to $1/12^{th}$ of the annual value or the actual availability during the month, whichever is lower. NLC submitted that it would be judicial to allow the generators to recover the fixed charges based on cumulative availability at the end of any month. Further, the logical reasoning behind the request for removing the cap of $1/12^{th}$of the yearly value during any month may be taken note of and the formula may be altered accordingly.

34.4 WBSEDCL submitted that the generating company or transmission licensee should be allowed to recover only part of the AFC during Renovation & Modernisation, and AFC may include interest of loan only as the employee cost is a part of O&M cost. GUVNL submitted that in order to avoid undue delay in renovation & modernisation activity, it will be appropriate if the Commission stipulates the time frame/schedule for renovation & modernisation, beyond which beneficiaries are not made liable to pay fixed charges, i.e., O&M, interest on loan, etc. On the other hand, some stakeholders have suggested to include the depreciation also as part of Renovation & Modernisation to facilitate the repayment. NTPC submitted that on the issue of under recovery of depreciation during renovation & modernisation, it has been decided as per Hon'ble APTEL Judgment that any unrecovered depreciation will be charged in future till recovery of 90% depreciation, and the same may be suitably covered in the Regulations as well.

34.5 Some stakeholders submitted that unlike hydro projects, the fixed cost of the power sold by thermal generating stations to home State is not allowed to be recovered from the beneficiaries in proportion to the respective allocation in the saleable capacity (i.e., capacity excluding the variable charge power to the home

State). Hence, about 5 (five) percent to 10 (ten) percent of the total fixed charges of the thermal generating station providing variable charge power to home State goes un-recovered. Therefore, clause 'capacity' should be replaced by 'saleable capacity' in clause 30(1) of the draft Regulations.

Commission's Views

34.6 Considering the views of the stakeholders, the Commission has appropriately modified the formula for computing monthly capacity charge. The PAFN has been defined as percent availability factor achieved upto the end of the nth month and not during the month. This will ensure recovery of Annual Fixed Charges on monthly basis on pro-rata basis, subject to cumulative availability achieved upto the respective month.

34.7 As regards payment of capacity charges during renovation & modernisation period, beneficiaries have suggested to limit the capacity charges to Interest on Loan and part of O&M expenses, while some of the stakeholders have suggested to include the depreciation as part of capacity charges during renovation & modernisation period, to facilitate the repayment. In this regard, it may be noted that renovation & modernisation will be generally carried out at the fag end of the useful life or after completion of useful life and hence, the generating company or transmission licensee would have recovered substantial part of depreciation on original fixed cost and at that stage, there is unlikely to be any repayment obligation remaining corresponding to the loan for original project cost. Therefore, the Commission is of the view that the provision in draft Regulations in this regard is appropriate and does not warrant any change. However, in case actual loans are outstanding and repayment is to be made, the Commission shall consider the matter on a case to case basis on receipt of an application.

34.8 As regards stipulation of time frame/schedule for renovation & modernisation beyond which beneficiaries are not made liable to pay fixed charges, the Commission is of the view that it may not be appropriate to stipulate any uniform schedule for all renovation & modernisation projects, as the project schedule will vary depending upon the scope covered in renovation & modernisation. Clause 15 provides for details to be submitted for obtaining approval, which also include the schedule of completion. Hence, the Commission will approve the schedule for renovation & modernisation projects on case to case basis.

34.9 On the issue of recovery of fixed cost of the power sold by thermal generating stations to home State at variable charge, the Commission would like to clarify that till now no such case for tariff determination has been represented before the Commission.

Incentive {Regulation 30(4)}

34.10 Clause 30(4) of the draft Regulations specified that incentive to a generating station shall be payable at a flat rate of 50 paise/kWh for ex-bus scheduled energy corresponding to scheduled generation in excess of ex-bus energy corresponding to Normative Annual Plant Load Factor.

Stakeholders' Comments/Suggestions

34.11 Several stakeholders submitted that the existing provision regarding incentive in Tariff Regulations, 2009 may be continued. Further, it was suggested that the incentive for lignite fired generating stations using CFBC technology may be allowed as 50% of Fixed Charge. Various Stakeholders have submitted that incentive should be linked to availability and not PLF. One stakeholder submitted that de-linking incentive to generation companies from PAF and linking them to generation (when fuel scarcity is only set to increase) will restrict the operational flexibility of the utility. NLC submitted that incentive should be linked with NAPAF and not NAPLF, else, the NAPLF for NLC TPS I, TPS II and BTPP may be made at par with NAPAF. NLC also submitted that providing incentive as a percentage of AFC may be continued. Alternately, incentive rate at the rate of Capacity Charge/ kWh or ₹ 1.0/kWh, whichever is lesser, may be provided. Jindal Power submitted that the existing dispensation of recovery of capacity charge based on normative annual plant availability factor as in Tariff Regulations, 2009 may be continued with proposed modification:

"The incentive for overachievement during peak hours vis-à-vis normative annual plant availability factor may be allowed @ 75% of AFC instead of capping the capacity charge recovery to 50% of AFC during peak hours."

34.12 MSEDCL and KSEB submitted that this proposal whereby incentive is linked to PLF and not PAF is welcome. Some of the beneficiaries submitted that the incentive is significantly high and incentive around 15% of capacity charge may be fixed. Some of the beneficiaries and other stakeholders requested to reduce the proposed rate of incentive in the range of 10-25 paise/kWh. The suggestion was also received to stagger the incentive rate of 50 paise per unit above 85% (Normative PLF) and up to 90% PLF and 25 paise per unit above 90% PLF.

34.13 Some of the stakeholders have submitted that incentive would be earned mostly by pit head thermal stations, which are required to run on base load with 100% capacity and whose backing down is minimum. For load centre stations, the backing down would be more. Thus, for pit head stations with variable cost of 90 paise per unit, the proposed incentive of 50 paise per unit would be too high and it would distort the merit order. The incentive based on kWh generation may be allowed at 25 paise per unit for PLF in excess of 88% on annual basis. Some of the stakeholders submitted that the linking of the incentive at or in proportion to fixed charge is not correct and incentive must be linked to the ROE with a cap of 10%.

34.14 Some of the stakeholders submitted that the proposed 50 paise/kWh incentive rate can be split into two incentive streams with 25 paise/kWh payable for availability above NAPAF and 25 paise/kWh payable for ex-bus scheduled energy above NAPLF. Further, the NAPLF for incentive can be lowered to 80% in view of the shortage in fuel supplies from CIL. Further, stakeholders submitted an alternate methodology, wherein the Incentive linked to PLF should differentiate between generating stations of different sizes. Any Unit of size more than 300/500 MW shall be at financial loss compared to the smaller Units for which 50 paise/kWh may be sufficient.

34.15 DVC requested to retain the fixed charge recovery formula for thermal generating stations as notified in Tariff Regulations 2009-14. Several stakeholders submitted that the existing provisions for recovery of fixed charges for generating stations in operation for less than 10 years may continue. Further, they suggested that plants with less than 10 years of operations be provided higher incentive at lower PLFs (say from 70% PLF) and for plant with greater than 10 years of operation, the incentive be provided from say 80% PLF.

Commission's Views

34.16 Most of the generating companies have requested to provide the incentive linked to availability as per 2009-14 Tariff Regulations, while on the other hand, most of the beneficiaries and other stakeholders have requested to reduce the incentive of 50 paise/unit linked to PLF as proposed in the draft Regulations. The Commission, in the Explanatory Memorandum to the draft Regulations mentioned that after taking into account the difficulties faced by various distribution utilities and issues arising out on account of payment of incentives without receiving power leading to increased average cost of power purchase, it proposed to re-introduce separate norms for recovery of full fixed charges linked to the target availability and norms for target PLF above which the incentive shall be applicable.

34.17 Considering the prevalent demand supply scenario in the country and other factors affecting the actual generation, it will be more appropriate to have incentive linked to PLF instead of Availability. As regards the suggestion for providing part of incentive linked to Availability and part of incentive linked to PLF, it will complicate the entire tariff computation and billing mechanism in addition to deviation from principle of allowing incentive linked to PLF instead of NAPAF.

34.18 The Availability Based Tariff (ABT) was introduced by the Commission in the year 2000 vide its order dated 4.1.2000 and implemented through Tariff Regulations, 2001. However, incentive was based on Plant Load Factor. This was continued in Tariff Regulation 2004 for the tariff period 2004-09. It is found that mere availability of the station does not lead to commensurate benefit to the beneficiaries. The Commission, in the Explanatory Memorandum to the draft Regulations, has proposed to re-introduce separate norms for recovery of full fixed charges linked to the target availability and norms for target PLF above which the incentive shall be applicable considering the difficulties faced by various distribution licensee. The distribution companies were to pay incentives beyond the target availability without receiving power. This lead to increased average cost of power purchase of distribution licensee.,.

The Commission observed that the all India PLF for coal based generating station during FY 2008-09 was 77.22%, which has decreased to 70% in FY 2012-13. Further, in case of NTPC stations, the average PLF for thermal generating stations during FY 2008-09 was around 91.14% against which the PAF was 92.47% and the gap between the PLF and PAF was not much. However in FY 2012-13, the actual average PLF for NTPC's thermal generating stations dropped to 83% and average PAF was 90.20% and thus, the gap between the PLF and PAF has increased considerably to about 7% in FY 2012-13. tThis gap is higher in case of some of the stations. Several stakeholders have also pointed out the variation in PLF with respect to PAF. One of the reasons for such a difference between PAF and PLF of generating stations could be that some of the generating stations have slipped in merit order and under such circumstances, the incentive linked to PAF will not provide commensurate benefit to beneficiaries in the changed scenario of fuel shortage. Further, in case incentive is linked to PAF, it will not incentivise the generator to optimise the procurement of fuel from alternate sources in case of shortage. In addition, the argument submitted by POSOCO that the incentive should be earned and not granted is also relevant in the present context. The Commission is therefore, of the view that as the PLF has reduced considerably and incentive linked to PAF will lead to payment of incentives to generators even when PLF is much below the NAPAF, it will result in loading of such cost to energy purchase thereby increasing the per unit cost of power. Further, the Commission observed that when the incentives were linked with the plant availability, even if the generating station was not scheduled to provide electricity, the beneficiaries were bound to make payment of incentives in addition to payment of entire fixed cost without receiving any power from the generating station leading to loss to the beneficiaries'. The Commission has therefore, decided to change the methodology for incentives considering the present circumstances, market trends and power scenario in the country.

34.19 As regards the issue of providing incentive at the rate of 50 Paise/kWh, beneficiaries have submitted that the rate should be reduced to 25 Paise/kWh, whereas the generating companies have proposed to increase the same. It is pertinent to mention here that the rate of incentive of 25 paise/kWh was applicable during FY 2004-05 to FY 2008-09, Further, the tax paid on the same was being allowed to be recovered from the beneficiaries. By applying an escalation rate of 6.35% per annum, 25 paise/kWh in FY 2008-09 works out to around 37 paise/kWh for FY 2014-15. Further, as per the regulation, the tax on the incentive shall now be paid by the generator, which works out to around 12-13 paise/kWh. The Commission is of the view that the quantum of incentive has to be good enough to motivate the generators to make adequate efforts to improve the PLF. In view of the above, the Commission has decided to continue with the rate of incentive for thermal generating stations as proposed in draft Regulations without any change.

Energy Charge Rate {Regulations 30(5) and 30(6)}

34.20 Regulation 30(5) of the draft Regulations specified that the energy charge shall cover the primary and secondary fuel cost and limestone consumption cost (where applicable), and shall be payable by every beneficiary for the total energy scheduled to be supplied to such beneficiary during the calendar month on ex-power plant basis, at the energy charge rate of the month (with fuel and limestone price adjustment).Clause 30(6) of the draft Regulations provided the formulae for computation of Energy Charge Rate. There is an inadvertent mistake in the numbering of the Regulation 30(6/7) of the draft Regulations.

Stakeholders' Comments/Suggestions

34.21 MSEDCL requested to include secondary fuel oil consumption in the capacity charge as energy charge going ahead would be a pass through while capacity charge would be applicable to the extent plant is available, which will ensure that inefficiency in secondary fuel oil consumption is not passed on to the beneficiary. KSEB submitted that the expenditure on secondary fuel oil is not incurred when the plant is not in operation and hence, the cost of the secondary fuel thus incurred has to be met through energy charges only and not in Annual Fixed cost.

34.22 JVVNL submitted that a procedure may be prescribed to ensure the correctness of GCV and price of fuel as intimated by generator. JVVNL further submitted that representative from the beneficiary (ies) may also be made part of the procedure. GUVNL submitted that it would be appropriate to cap the differential GCV between GCV as fired and GCV as received at 150 kcal/kg in line with PSERC Tariff Regulations. GUVNL requested to incorporate that generating stations may declare separate availability on domestic as well as imported fuel in line with gas based generating stations. MSEDCL also requested to bring clarity on the energy charge in case of coal being blended whereby a certain ceiling in the price needs to be determined. MPPMCL submitted that a proviso may be inserted after the last proviso of clause 30(6) as under:-

> "*Provided that the generating company shall declare availability for each of domestic coal, imported coal, e-Auction coal and blended coal separately along with tentative energy charges to facilitate the beneficiaries to take decision regarding scheduling of power on the basis of Merit Order Despatch (MOD)*".

34.23 One stakeholder has submitted that the generating station should also obtain approval from the beneficiaries for the blending ratio of imported coal with domestic coal for the reasonability of per unit price of energy. Some of the stakeholders have submitted that as there is a clear difference in GCV of fuel even after moisture correction between "As Fired Basis" and "As Received Basis", norm for pit head stations and non-pit head stations for the same may be incorporated, which could be equivalent to 0.25% of GCV value. Some of the stakeholders further submitted that in case of blending of coal, weighted average GCV as fired may not exactly match with the proportion of blending ratio and so the statement may be deleted. PSERC submitted that the term 'CVPF' in case of lignite, gas and liquid may continue to be defined as existing in the draft CERC Regulations. PSERC further submitted that the term 'CVPF' be defined as follows for working out the energy charge rate in case of coal as primary fuel for thermal generating plants:

> *"Weighted Average Gross Calorific Value of primary fuel (coal) as received, in kCal per kg, minus 150 kCal per kg or actual, whichever is less. (In case of blending of fuel from different sources, the weighted average of Gross Calorific Value of primary fuel (coal) shall be arrived in proportion to blending ratio)."*

Commission's Views

34.24 The Commission, in the draft Regulations, proposed to include the secondary fuel oil cost as part of the energy charge. As the cost incurred towards secondary fuel consumption is a fuel cost, which varies with generation level, the Commission has decided to include the same as a part of Energy Charges.

34.25 On the issue of calorific value of coal to be considered for determining the energy charges, some of the stakeholders including PSERC and GUVNL suggested that for coal based stations, calorific value be defined as weighted average gross calorific value of coal as received in kcal per kg minus 150 kcal/kg or actual, whichever is less.

34.26 PSERC submitted that a study was done by CPRI for three State thermal generating stations in the State of Punjab and CPRI in its study recommended for reduction in drop of GCV of bunkered coal vis-à-vis receipt coal, along with some other recommendations for fuel cost saving and cost reduction. PSERC in its order dated October 8, 2012 directed PSPCL to bring down the drop in GCV between receipt coal and bunkered coal within 150 kcal/kg. PSERC further submitted that after its Order in this regard, the drop in GCV has reduced for all the three State generating stations of Punjab.

34.27 The Central Electricity Authority (CEA) in its recommendations on operation norms for thermal power stations for the Tariff Period 2014-19 on the issue of GCV has opined as follows:

"13. GCV used for computations of Station Heat rate (SHR)

13.1 *It is also important to ensure that the computations of SHR are made in accordance with the spirit of the CERC tariff Regulations and the Regulations appropriately define the principles of computation of SHR.*

13.2 *From the Pro-forma for furnishing "Actual annual performance/operational data" prescribed by CERC it is seen that the following data regarding coal consumption and GCV is required to be submitted by the utilities/stations.*

14.1	*Consumption*
14.1.1	*Domestic Coal (Linked mine/ Other mines/e-auction/spot)*
14.1.2	*Imported Coal**
14.2	*Gross Calorific Value (GCV):*
14.2.1	*Domestic Coal (As Received)*
	(As Fired)
14.2.2	*Imported Coal (As Received)*
14.2.3	*Spot market/e-auction coal (As received)*

14.2.4	*Weighted Average Gross Calorific value (As received)*
14.2.5	*Weighted Average Gross Calorific value (As Fired)*

*Thus the utilities/stations are required to furnish the details of GCV on "**as received basis**" as well as "**as fired basis**" in respect of domestic coal as well as for the weighted average of domestic and imported coal.*

13.3 *However, the stations have furnished only the GCV "**as received**" for imported coal and Weighted average **GCV "as fired" (**for the blend of domestic and imported coal combined) <u>and have not furnished the data for **"as received GCV"** of domestic coal**.**</u> Thus in the absence of details of "**as received GCV"** from the stations, both in respect of domestic coal as well as for the weighted average, it is not possible to determine the basis of computation of Station heat rate (SHR) or verify the correctness of the same; <u>as difference between the **as fired** and **as received** GCV increases the coal consumption correspondingly.</u> For instance taking the "**as fired GCV"** as 100 kcal/kg lower than the **"as received GCV"** understood to be followed by some utilities would project around 3 % increase in the coal consumption for typical 3500 GCV coal.*

13.4 *It may be pertinent to mention that the billing of coal would be on the basis of dispatch GCV by the coal suppliers (which should be approximately same as "as received GCV"). Considering the issues of coal quality being faced by some of the stations with CIL, there could be variations between the dispatch GCV and **as received GCV**; however, difference between the **as received GCV** vis-à-vis **"as fired GCV"** would be very marginal and would be solely on account of marginal loss of heat during the coal storage.*

13.5 *From the data received from stations, it is seen that most stations have very low storage of about 7-10 days coal requirements. The loss of heat value during storage depends on the type of coal and the period of storage. <u>Some International publications indicate a loss of heat value of about 1 % for 1 year storage for high rank coals and 3 % for low rank coals.</u> Thus considering a 3 % heat loss for Indian coals, the average loss of heat value for 10 days storage would be about 0.08% or about 3kcal/kg for a typical coal with 3500 kcal/kg GCV. The intent of this illustration is to just highlight that the storage losses of coal are almost negligible especially for low storage periods as in the Indian stations. Thus the SHR computations could be based on "**as received GCV"** basis; and if considered necessary CERC may provide for appropriate quantum of storage heat loss separately to account for heat loss due to storage. <u>Any arbitrary practice of using **as fired GCV** for SHR computations without proper guidelines for determining the same would only lead to inflated claims of coal consumption.</u>*

13.6 *It is thus felt that all SHR computations may be made on **as received** GCV basis, and the marginal difference between **as received** and **as fired** GCV could be compensated by providing a **coal storage loss** in terms of % of total coal on similar lines as coal transit loss. This will be in line with gate to gate energy* *accounting concept generally practiced Internationally and also envisaged under the PAT (Perform Achieve and Trade) mechanism under the National Mission on Enhanced Energy Efficiency."*

34.28 The CEA in its recommendations has specifically mentioned that international publications indicate a loss of heat value of about 1% for 1 year storage for high rank coal and 3% for low rank coals and thus, considering 3% heat loss, the average loss of heat value for 10 days storage would be about 0.08% or 3 kcal/kg. The CEA has recommended to consider GCV on "as received" basis.

34.29 NTPC, in its observations/comments on the CEA recommendations, has submitted as under:

"2.0 CEA has recommended that Station Heat Rate computation may be done on as received basis and the marginal difference between as received and as fired GCV could be compensated by providing a coal storage loss in terms of % of total coal on similar lines as coal transit loss.

a) As per the FSAs signed with Coal India Limited (CIL) and its subsidiaries by PSUs, state utilities and other private power producers, the clause which provides for payment is based on GCV measured at loading end. This is a uniform clause historically applicable to all generators. Further, the current practice of using GCV as fired is in line with the PPAs signed.

b) It is not prudent to compute SHR based on as received GCV of coal. On migration from UHV to GCV based system w.e.f. 01.01.2012 and in the absence of adequate infrastructure at mine end for sampling and testing there is large variation between GCV measured at mine end and station end. It was expected that with introduction of third party sampling w.e.f. 01.10.2013 the GCV difference issue will be resolved. However, there is no appreciable improvement in variation.

In view of above, existing system of computation of SHR basis on as fired GCV may be continued."

34.30 It is noted that the Commission vide its Order dated 7.6.2013 had directed the generating stations to provide the details regarding the GCV of fuel on "as received" basis as per its formats at Annexure 1, serial number 14.2.3 and 14.2.4. The generating stations have provided the GCV details on "as fired" basis only, and the GCV details on "as received" basis have not been provided by the generating stations, despite clear direction in this regard. The information available on the websites of the generating companies on monthly basis is also not of much assistance because it does not give corresponding "as fired" values and does not help in computing the weighted average GCV for the year.

34.31 Further, blending of imported coal is invariably being done and its GCV is available on as received basis and therefore, it is felt that the GCV of domestic coal should also be on as received basis.

34.32 At this stage, it is pertinent to mention that even the Standard Bidding Documents issued by the Ministry of Power, Government of India also provide for the computation of the monthly energy charges based on the GCV of the fuel on "as received" basis.

34.33 The generators in their suggestions have not contested the CEA's recommendations of considering GCV on as received basis with any factual data. NTPC has only mentioned about the variation in GCV measured at the mine end and GCV as received at the plant but has not deliberated or contested the CEA's recommendation on difference between as received GCV and as fired GCV. As regards the CEA's recommendation of building some margin for stacking loss of coal in the transit and handling losses, the Commission is of the view that existing norms already have margin to accommodate marginal stacking loss of coal and as such, no further margin is required to be provided.

34.34 Fuel audit was carried out by CPRI Bangalore on behalf of PSPCL for thermal generating station in August, 2012. It has recommended to allow a difference of 150 Kcal/kg in GCV between the coal as received and as fired. This was also based on the observation of MERC regarding stacking loss in GCV in its Order for 2012-13 and draft MoP report on operation norms for thermal generating tariff, 1999 as mentioned in the report of CPRI. Accordingly, the difference of 150 Kcal/kg in GCV of coal between as received and as fired was considered by PSPCL and PSERC. However, no scientific justification for the same has been given.

34.35 CPRI Bangalore, in its report submitted to PSPCL, has referred to three technical studies. The findings of these studies are as under:

- Technical study of "Coal-quality deterioration in a coal stack of a power station" was carried out by D. Banerjee, M. Hirani and S.K. Sanyal which was published in Applied Energy journal in June 1999. As per this study, the maximum drop in GCV of coal in the coal yard due to stacking is around 600 Kcal/Kg (2500 KJ/Kg) for 160-170 days from the onset of summer to the end of monsoon and no loss was reported during winter season. On this basis, the weekly loss of GCV works out to 12 kCal/Kg.

- Study on "Drawal of spontaneous consumption of coal through analysis of its mechanism and the affecting factors" was carried out by Dass B and Hucka V.J. As per this study, the drop of GCV in the coal per year is asunder:

Table 20: Drop of GCV in Coal per year as per study carried out by Dass B and Hucka V.J.

Stage	Reaction	Weight	Temperature	Heat Generated (Kcal/Kg)
Absorption	Water absorption	Gain	Any temp	2-25
Chemisorptions	Oxygen absorbed to form peroxides	Gain	70	2-16
Per oxygen decomposition	Disintegration of per oxygen Release of water from coal	Loss	70-150	4-18
Oxycoal formation	Formation of stable oxygen complexes	Gain	150-230	6-27

- Another study on "Effects of outdoor storage on Illinoise Steam Coals" was carried out by Rees O.W., Coolican F.C., Pierron E.D. and Beeler C.W. of Illinoise State Geological Survey, Urbana. As per this study, calorific value for both summer and winter stored coal dropped. The heating value of the summer-stored coal dropped to 2.1 percent in 52 weeks, that for winter-stored coal dropped to 1.4% in 20 weeks and in and in general remained at this level throughout most of the following 59 weeks additional storage period.

34.36 All three studies are relevant to understand the issue of deterioration of coal during storage period prior to its use in bunker after receipt at the generating station coal yard. The findings of all three studies mentioned above are analogous. It provides that loss of calorific value of coal during stacking period is not significant even if it is stored for one year period. Considering the findings of the studies mentioned above, it could be inferred that there will be negligible loss attributed to the generating station on account of stacking of coal for 8-10 days.

Coal being a natural resource, needs to be judiciously utilized. With electricity pricing being inelastic as coal price implications (this has become predominant after the shift from UHV based pricing to internationally accepted GCV based pricing) being a pass through, factors such as quality and quantity becomes paramount while handling the reasonability and efficiency aspects in tariff setting.

The Hon'ble APTEL in its order dated 14.12.2012 in Appeal No. 47 of 2012 in the case of Maharashtra State Power Generation Company Limited versus Maharashtra Electricity Regulatory Commission had expressed concern in regard to the variation of GCV of coal during handling at the generating stations. The relevant extract of the order is quoted as below:

"*Before we consider the next issue we would like to express our concern over loss of CV and vast difference between calorific value of fuel 'as received' and 'as fired'. The coal looses calorific value when stored for very long time in the open due to presence of oxygen in atmosphere. It is understood that presently, due to country wide shortage of coal, power stations have fuel stock for few days only. Any loss of CV in such a short duration needs proper explanation.* "

For variations in quantity and quality as received at generating station , provisions of Fuel Supply Agreement between procurer and supplier should be used to settle the deviations and consumers should not be burdened with the additional cost. However, coal once received at Thermal Power Station, entire control of handling and storage till it is fired , is with the Generator. As already brought out, there are marginal losses for limited period of stacking and handling which are totally in control of Generating Company. Proper process of compacting, piling /

stacking, reclaiming during the short storage period by the generator can effectively control the loss thereby ensuring judicious utilization of costly natural resource and efficiency.

Section 61(c) of the Electricity Act provides that the appropriate Commission shall be guided by the factors which would encourage competition, efficiency, economical use of the resources, good performance and optimum investment. The studies referred above and recommendations of CEA brings out clearly that there is negligible difference between the GCV of coal as received GCV and as fired when the stacking is for 8-10 days. There is no reason for allowing any difference to the benefit of the generator on account of GCV. The gross station heat rate norms fixed by the Commission for various sizes of units have sufficient margin to absorb this negligible difference. In view of the abovediscussions, the GCV measurement of coal has been shifted to 'as received basis' for the purpose of energy charges computation in the Tariff Regulation.

34.37 In view of the above discussions, the Commission has modified the provisions related to Calorific Value for Primary Fuel (CVPF) as follows:

> *"CVPF=(a) Weighted Average Gross calorific value of coal as received, in kCal per kg for coal based stations;*
>
> *(b) Weighted Average Gross calorific value of primary fuel as received, in kCal per kg, per litre or per standard cubic meter, as applicable for lignite, gas and liquid fuel based stations;*
>
> *(c) In case of blending of fuel from different sources, the weighted average Gross calorific value of primary fuel shall be arrived in proportion to blending ratio."*

<u>Landed Cost of Fuel {Regulations 30(6) and 30(7)}</u>

34.38 Regulation 30(6) of the draft Regulations specified that the generating company shall provide details of the parameters of GCV and price of fuel to the beneficiaries of the generating station. Regulation 30(7) of the draft Regulations specified that the landed cost of fuel for the month shall include price of fuel corresponding to the grade and quality of fuel inclusive of royalty, taxes and duties as applicable, transportation cost by rail/road or any other means, for the purpose of computation of energy charge. In case of coal/lignite, the landed cost shall be arrived at after considering normative transit and handling losses as percentage of the quantity of coal or lignite dispatched by the coal or lignite supply company during the month as given below:

Pithead generating stations	:	0.2%
Non-pithead generating stations	:	0.8%

<u>Stakeholders' Comments/Suggestions</u>

34.39 NTPC submitted that the transit and handling losses of 0.2% on imported coal would be applicable only for shipments on 'FOR' basis. Hence, transit and handling losses on actual basis for imported coal if procured through FOB or CIF basis may be specified. Some IPP developers submitted that transit and handling losses of 0.8% should be allowed for imported coal. MPERC submitted that the rationale for considering 0.2% transit loss for imported coal needs to be reviewed.

34.40 DVC submitted that landed cost of coal should be redefined in the new Regulations and should comprise cost of coal and other associated direct cost of acquisition incurred in bringing the coal to their present location, viz., cost of transit security for rail transportation (from loading end to unloading end), cost of railway track security in the private-siding, maintenance of railway tracks in the private siding portion, cost of handling sick wagons, cost of Joint sampling and analysis of loaded coal at loading end, cost of segregation and stacking of stones/boulders in the stack yard, O&M cost of Weigh-Bridge at unloading end.

34.41 GRIDCO submitted that "Pit–head Stations" and "Pit-head Mines" may be defined to avoid any ambiguities in the rate of transit and handling losses of fuel (coal &lignite, etc.). GUVNL submitted that the usage of imported coal in pit head stations may be discouraged and the Regulations may specify that imported coal should only be utilized for nearest coastal project. The provision related to normative transit and handling loss as contained in Clause 30(7) is contradictory to the proviso in Clause 22 of the draft Regulations.

34.42 Some stakeholders suggested that 0.8% transit loss in case of imported coal for non-coastal generating station and 0.2% transit loss in case of coastal generating station may be approved. CSPGCL further submitted that for all plants, which do not have dedicated transport system higher transit loss of 0.8% should be allowed and for pit head stations having dedicated systems, the transit loss should be retained at 0.3% level. One IPP developer submitted that the transit and handling losses for non-pit head stations should be revised and should be linked to the distance between the fuel source and generating station. Reliance Power submitted that the transit loss in case of plants located at a distance exceeding 750 km should be minimum 2% or actual, whichever is lower, irrespective of domestic or imported coal.

<u>Commission's Views</u>

34.43 The Commission, in the Explanatory Memorandum to the draft Regulations, mentioned that *"considering the actual data, the Commission is of the view that the current norms are close to the actual and therefore the Commission proposes to retain the current norm for transit and handling losses for pit head and non pit head stations. With regards to transit and handling losses for imported coal the Commission observes that there is some transit and handling losses the Commission based on the five year actual data proposes to approve a norm of 0.20% as allowable transit and handling loss for imported coal."*The Commission has analysed the actual transit loss data for NTPC stations for last five years and observed that the actual transit loss for imported coal for most of the stations was less than 0.2% with few exceptions. Hence, the Commission has specified the transit loss of 0.2% for imported coal. As the transit loss norms have been specified based on detailed analysis of actual transit loss data for last five years, the same does not require any change.

34.44 On the issue of contradiction between clause 22 and clause 30 (7), the Commission would like to clarify that clause 22 specifies that energy charges shall be derived on the basis of the landed fuel cost only, while clause 30(7) elaborates in detail the landed cost of fuel and specifies that the landed cost of fuel in case of coal or lignite shall be arrived at after considering normative transit and handling losses as percentage of the quantity of coal or lignite dispatched by the coal or lignite supply company and provides the details of the transit and handling losses.

34.45 On the issue of defining pit head and non-pit head generating stations, the Commission would like to clarify that the Environment (Protection) Rules, 1986 defines pit-head generating station as a generating station having captive transportation system for its exclusive use for transportation of coal from the loading point at the mining end up to the unloading point at the generating station without using the normal public transportation system.

Alternative Source of Fuel Supply {Regulation 30 (9)}

34.46 Clause 30(9) of the draft Regulations specified that in case of part or full use of alternative source of fuel supply by coal based thermal generating stations other than as agreed by the generating company and beneficiaries in their power purchase agreement for supply of contracted power on account of shortage of fuel or optimization of economical operation through blending, the use of alternative source of fuel supply shall be permitted to generating station. The third proviso to clause 30(9) of the draft Regulations specified that where the weighted average price of use of alternative source of fuel exceeds 30% of base price of fuel or 20% of fuel price for the previous month, whichever is lower, prior consultation with beneficiary shall be made not later than three days in advance.

Stakeholders' Comments/Suggestions

34.47 Some of the beneficiaries submitted that they should be apprised about the procurement and cost of alternate fuel and the utilization of alternate fuel should be allowed with concurrence of beneficiaries only. MSEDCL further submitted that the clause may not be limited to coal based power plant and the word "Coal" may be replaced with the word "Fuel" which includes any fuel used for thermal power station. MSEDCL further submitted that the weighted average price may be reduced from 30% of base price to 10-20% range. One stakeholder submitted that the generator must obtain consent of beneficiary sufficiently in advance before arranging the import of coal. It also submitted that the alternate option of obtaining additional coal through e-auction needs to be examined and discussed before considering the proposal for import. GRIDCO submitted that blending may be restricted to 10% to 15% considering the capacity of the respective power plants.

34.48 NTPC submitted that the stipulation that prior approval from beneficiary is to be taken 3 days in advance for blending is impractical and cannot be implemented. NTPC further submitted that it has been seen that the imported coal blending can go upto more than 30% in some stations and CEA in its study of range of blending of imported coal with domestic coal has recommended a maximum blending ratio of 30% by weight. Hence, this limit may be considered as the maximum blending ratio. NTPC further submitted that Commission may cap the maximum blending ratio instead of capping the price of coal. NTPC further submitted that in the deficit scenario of domestic coal and monopolistic domestic coal market dynamics and highly volatile import coal price, restricting price variation up to 30% shall adversely affect target availability of station. The station wise fixation of base price and escalation index of coal to be applied will be extremely complicated to decide. NTPC further submitted that the base price for a station would depend on the composition of different types of coal being consumed at the time of fixation of base price. This composition may undergo significant change in due course of time because of the various constraints in sourcing of domestic/ imported/ e-auction coal.

34.49 Some other stakeholders also submitted that there may not be any limit for using the coal from the alternative sources and also, the condition of prior consultation with the beneficiary should be removed. They further submitted that it would be impractical to obtain prior permission from all of the beneficiaries where the likely increase in price is in excess of 30%/20%. Therefore, the Regulation may be amended to provide that in the event one or more beneficiaries have accorded approval for procurement of power at more 30%/20% increased rates, the other beneficiaries shall also take such quantities to ensure running of plant at minimum technical limit. Further, CII submitted that with regard to consultation process with beneficiaries, it is necessary to include a provision in the Regulations so that the matter can be taken up by the Commission for necessary review.APP further submitted that considering that the Commission has already fixed the formula for price of imported fuel, at any given time the price of imported fuel required to reach normative availability should be a pass through and computed based on the CERC formula irrespective of the price increase. Some generating companies also submitted that e-auction coal and imported coal prices are higher by much more than the proposed limits of 30% and therefore, limits should be enhanced appropriately.

34.50 KSEB submitted that the paragraph 15.5.12 of the Explanatory Memorandum states that *"in case blending of coal leads to a price increase of blended coal in ₹/kCal terms by over 30% of the base price of fuel or 20% of price of fuel for the previous month, whichever is lower, the generator must intimate the beneficiaries three days in advance and take beneficiaries consent before going for such blending."*However, as per the clause 30(9) (3rd proviso) of draft Regulations, the generators are allowed for blending with prior consultation only, this ambiguity may be clarified.

34.51 Clause 30(10) of the draft Regulations specified that the Commission through the specific tariff orders to be issued for each generating station shall approve the fuel price for the FY 2014-15. The fuel price so approved shall be the base price of fuel and shall be applicable for the month of notification of such tariff orders. For subsequent months, the base price of fuel shall be escalated by escalation rates as notified by the Commission from time to time for bidding purpose.

34.52 With regards to specific tariff orders to be issued for each generating station by the Commission, GUVNL submitted that clarification may be provided that whether this shall be applicable to fuel shortage scenario or in general or in which type of circumstances. KSEB submitted that as regards clause 30(10) of the draft Regulations, the Regulation should clarify on the relevance on escalating the base price every month based on the escalation rates notified by the Commission. Whereas, as per the clause 30(6&7) of the draft Regulations, the billing shall be based on actual landed cost of coal.

Commission's Views

34.53 Most of the Generating Companies have suggested to remove the provisions related to consent from beneficiaries for utilising alternate fuel, while on the other hand, the beneficiaries have suggested that the usage of alternate fuel be allowed only with consent of beneficiaries.

34.54 As discussed in the Explanatory Memorandum, the Commission is of the view that it may not be practically possible to obtain beneficiaries' consent before blending of coal for all the instances. Considering the coal shortage situation in the country, and to protect the interests of generating companies as well as beneficiaries, the Commission felt it appropriate to fix some limit beyond which the generator should obtain beneficiaries consent before blending of coal.

34.55 The Commission in the third proviso of clause 30(10) has specified as follows:

> *"Provided further that the weighted average price of use of alternative source of fuel shall not exceed 30% of base price of fuel computed as per clause (11) of this regulation"*

The Commission would like to clarify that through the above proviso, the Commission intends that the energy charge rate as computed on the basis of weighted average price of alternative fuel should not exceed 30% of the base energy charge as computed as per clause 30(11) of the Regulations.

34.56 Further, to remove the ambiguity in this regard, the Commission has decided to specify the limit in terms of energy charge rate and accordingly modified the third proviso as follows:

> *"Provided also that where the energy charge rate based on weighted average price of use of fuel including alternative source of fuel exceeds 30% of base energy charge rate as approved by the Commission for that year or energy charge rate based on weighted average price of use of fuel including alternative sources of fuel exceeds 20% of energy charge rate based on weighted average fuel price for the previous month, whichever is lower shall be considered and in that event, prior consultation with beneficiary shall be made not later than three days in advance."*

34.57 Similarly, the Commission has decided to modify the clause 30(11) of the Regulations as under:

> *"(11) The Commission through the specific tariff orders to be issued for each generating station shall approve the energy charge rate at the start of the tariff period. The energy charge so approved shall be the base energy charge rate at the start of the tariff period. The base energy charge rate for subsequent years shall be the energy charge computed after escalating the base energy charge rate approved at the start of the tariff period by escalation rates for payment purposes as notified by the Commission from time to time for under competitive bidding guidelines."*

34.58 The Commission would like to clarify that clause 30(11) of the Regulations shall only be applicable in case of fuel shortage situations under clause 30(10) of the Regulations and for tariff purposes, the energy charge rate shall be computed as per Clause 30(6) of the Regulations.

35. Computation and Payment of Capacity Charge and Energy Charge for Hydro Generating Stations {Regulation 31}

35.1 The proviso to clause 31(1) of the draft Regulations specified that during the period between the date of commercial operation of the first Unit of the generating station and the date of commercial operation of the generating station, the annual fixed cost shall provisionally be worked out based on the latest estimate of the completed cost for the generating station, for the purpose of determining the capacity charge and energy charge payment during such period. Clause 31(2) of the draft Regulations provided a formula for the computation of the capacity charge (inclusive of incentive) payable to a hydro generating station for a calendar month. Clause 31(3) of the draft Regulations provided the formula for the computation of Plant Availability Factor for the calendar month (PAFM).

35.2 Clause 31(6) of the draft Regulations specified the treatment in case actual total energy generated by a hydro generating station during a year is less than the design energy for reasons beyond the control of the generating company.

35.3 Clause 31(7) of the draft Regulations provided that in case the energy charge rate for a hydro generating station exceeds ninety paise per kWh, and the actual saleable energy in a year exceeds { DE x (100 – AUX) x (100 – FEHS) / 10000 } MWh, the energy charge for the energy in excess of the above shall be billed at ninety paise per kWh only. Clause 31(8) of the draft Regulations provided that in case of the hydro generating stations located in the State of Jammu and Kashmir, any expenditure incurred for payment of water usage charges to the State Water Resources Development Authority, Jammu under Jammu & Kashmir Water Resources (Regulations and Management) Act, 2010 shall be payable by the beneficiaries as additional energy charge in proportion of the supply of power from the generating stations on month to month basis.

Stakeholders' Comments/ Suggestions

35.4 One stakeholder submitted that in case the sum of interest on loan and depreciation components of the Annual Fixed Cost (AFC) exceeds 50% of AFC, the developer should be allowed to approach the Commission praying for increasing the proportion of capacity charges as percentage of AFC, currently being 50%.

35.5 Some stakeholders submitted that as per Tariff Regulations, 2009, filing of application was not a pre-requisite for the mechanism related to actual total energy generated by a hydro generating station during a year being less than the design energy for reasons beyond the control of the generating station and as such, the provision should be reinstated. NHPC further submitted that reasons beyond the control of generator may be furnished with truing up petition. Jaiprakash Power submitted that when the Commission has already provided the mechanism then there is no need to file an application. However, in case of a dispute between generator and beneficiary, the generator should approach the Commission.

35.6 One stakeholder submitted that instead of stipulating fixed energy charge rate, secondary energy charge rate may be linked with CERC domestic coal based indexation mechanism, to be revised on a semi-annual basis. THDC submitted that the Energy Charge Rate for the energy generated in excess of the scheduled saleable design energy should be 150 paise/kWh instead of 90 paise/kWh. One stakeholder submitted that Energy Charge Rate (ECR) for a hydro generating station for the energy in excess of design saleable energy should be ₹ 1.25/kWh in place of ₹ 0.90/kWh.

35.7 Referring to clause 31(8) of the draft Regulations wherein a specific clause has been provided on hydro generating stations located in the State of Jammu and Kashmir, WBSEDCL submitted that this clause should be made applicable for the PPAs to be executed from the date of finalization of the Tariff Regulations and at the same time, the same clause may be made applicable for those PPAs having CERC regulated tariff.

Commission's Views

35.8 On the issue of recovery of AFC for hydro stations, the Commission would like to clarify that the two-part tariff for hydro stations was implemented after detailed deliberations and the same provision of recovering 50% of AFC through capacity charge was present in 2009-14 Tariff Regulations also. Hence, the Commission does not find any reason to modify the same.

35.9 On the issue of the mechanism related to actual total energy generated by a hydro generating station during a year being less than the design energy for reasons beyond the control of the generating station, the Commission is of the view that under regulated regime, some checks and balances are required and hence, the Commission has included the provision of making an application. Further, to take care of the situation of actual generation lower than the design energy on continuous basis, the Commission has decided to include the following proviso to clause 31(6)(a) of the draft Regulations:

> *"Provided that in case actual generation form a hydro generating station is less than the design energy for a continuous period of 4 years on account of hydrology factor, the generating station shall approach CEA with relevant hydrology data for revision of design energy of the station."*

35.10 On the issue of energy charge rate of 90 paise/kWh for excess energy above design energy, as discussed in the Explanatory Memorandum, the Commission observed that the rate should be slightly lower than the lowest variable cost of thermal generating station and therefore, the Commission has decided to fix the energy charge rate at 90 paise/kWh, which is slightly lower than the current variable charge for Korba thermal power station.

35.11 On the issue of expenditure incurred for payment of water usage charges to the State Water Resources Development Authority, Jammu, which shall be payable by the beneficiaries as additional energy charge in proportion of the supply of power from the generating stations on month to month basis, the Commission would like to state that the State of Jammu & Kashmir created State Water Resources Development Authority, Jammu under Jammu & Kashmir Water Resources (Regulations and Management) Act, 2010, under which the hydro generating stations are required to obtain licence and pay licence fees for use of water and also pay the water charges. NHPC has challenged the said Act before the Hon'ble High Court of Jammu & Kashmir in OWP No.604/2011. The Hon'ble High Court in its order dated 4.5.2011 has directed NHPC to apply for licence and deposit the water usage charge raised by the State Water Resources Regulatory Authority. The High Court has directed the State Water Resources Regulatory Authority to keep the amount collected from the petitioner on account of water usage charges in a separate account subject to the outcome of the writ petition. Since, this is an additional cost to the hydro generating company, the Commission after hearing the beneficiaries in its order dated 21.10.2011 had decided to reimburse the water usage charges and licence fees subject to the decision of the Hon'ble High Court on the writ petition. The Commission, in its Order dated 21.10.2011 in Petition No. 106/2011 had directed as under:

> *"20. In view of our decision to reimburse the water usage charges and licence fees, we direct the staff of the Commission to move appropriate amendment to the 2009 regulations. The petitioner is pursuing the matter in the Hon'ble High Court of Jammu & Kashmir. The petitioner is directed to keep the Commission and the beneficiaries apprised about the development of the court case.*
>
> *21. Subject to amendment of the 2009 regulations, the petitioner shall be entitled for reimbursement of expenditure on water usage charges and licence fee from the beneficiaries. In the event the petitioner succeeds in the writ petition, the water usage charges and the licence fees shall be refunded to the beneficiaries."*

35.12 It is pertinent to mention here that NHPC, during the pendency of the writ petition, has deposited the water usage charges and licence fees in terms of the interim directions of the High Court. Thus, NHPC is incurring the expenditure on water usage charges in order to ensure that power is generated by its generating stations and supplied to the beneficiaries. Therefore, NHPC is entitled to reimbursement of the water usage charges and hence, these water charges are being allowed as additional energy charges for hydro stations of NHPC. The provisions of this Clause 31(8) of the Regulations are subject to the decision of the Hon'ble High Court of Jammu & Kashmir in OWP No. 604/2011. Hence, it will not be appropriate to limit the applicability of this clause for the PPAs to be executed from the date of finalization of Tariff Regulations.

36. Pumped Storage Hydro Generating Stations {Regulation 32}

36.1 Clause 32(1) of the draft Tariff Regulations specified that the fixed cost of a pumped storage hydro generating station shall be computed on annual basis and recovered on monthly basis as capacity charge. The capacity charge shall be payable by the beneficiaries in proportion to their respective allocation in the saleable capacity of the generating station, i.e., in the capacity excluding the free power to the home State. Clause 32(2) of the draft Regulations provided the mechanism for the computation of the capacity charge payable to a pumped storage hydro generating station for a calendar month.

36.2 Clause 32(3) of the draft Regulations specified that the energy charge shall be payable by every beneficiary for the total energy scheduled to be supplied to the beneficiary in excess of the design energy plus 75% of the energy utilized in pumping the water from the lower elevation reservoir to the higher elevation reservoir, at a flat rate equal to the average energy charge rate of 20 paise per kWh, excluding free energy, if any, during the calendar month, on ex-power plant basis. Clause 32(4) of the draft Regulations provided the mechanism for energy charge payable to the generating company for a month.

<u>Stakeholders' Comments/ Suggestions</u>

36.3 THDC submitted that the methodology proposed for recovery of AFC shall pose practical problems for recovery of AFC when Tehri PSP will become operational. Hence, the clause 32(1)of the draft Regulations may be modified as under:

> *"(1) ....and recovered on monthly basis as capacity charge <u>and energy charge</u>. The capacity charge <u>(inclusive of incentive)</u> and <u>energy charge</u> shall be payable by the beneficiaries in proportion..............."*

36.4 THDC submitted that clause 32(2) of the draft Regulations may be modified as follows:

"(2) The capacity charge (inclusive of incentive) payable to a pumped storage hydro generating station for a calendar month shall be computed on daily basis beneficiary-wise as under:

(a) For the days when pumping & generation take place:

Capacity Charge (Rs.) (inclusive of incentive) = (AFC x % allocation of the beneficiary in the capacity of the station x Scheduled Energy *supplied to the beneficiary during the day during peak hours) / (NDY x 100 x 75% of the scheduled energy supplied by beneficiary during the day)*

(b) For the days when pumping & generation do not take place (due to hydrological reasons beyond the control of the generating station / design of the generating station as such / beneficiary does not provide the pumping energy / any reason beyond the control of the generating station)

Capacity Charge (Rs.) = (AFC x percentage allocation of the beneficiary in the capacity of the station) / (NDY x 100)

The total capacity charge for the month shall be the sum of daily capacity charges calculated as per (a) & (b) above. The total Capacity Charge for the year shall be the sum total of the monthly Capacity Charges calculated as above for the individual months. The utilisation of the plant in terms of quantum of pumping energy and corresponding peak generation shall be subject to limitation as per DPR of the project / approval of the Authority."

36.5 THDC submitted that clause 32(3) and 32(4)of the draft Regulations may be modified as follows:

"(3) The energy charge shall be payable by every beneficiary at a flat rate equal to the average energy charge rate of 20 paise per kWh, excluding free energy, if any, during the calendar month, on ex power plant basis."

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

= 0.20 x (Design Energy for the month x percentage allocation of the beneficiary) x (100 - FEHS) / 100.

Where,

DEm = Energy (kWh) for the month specified for pumped storage hydro generating station to be produced using natural flow of water only (i.e., without using recycled water) duly approved by Authority.

FEHS = Free energy for home state, in percent, as defined in Regulation 42, if any, out of the energy generated due to natural flow of water only (i.e., without using recycled water)."

36.6 THDC submitted that as Tehri pumped storage plant will be the first of its kind in the Central sector and is expected to go on stream by the end of 2016,it may take some time for it to stabilize. Therefore, the outages @20% may be considered. Hence, annual availability of 80% may be specified.

<u>Commission's Views</u>

36.7 The Commission has added a proviso in the Final Regulations for annual reconciliation of Annual Fixed charges, as under:

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

37. Norms of Operation {Regulation 36}

37.1 The Commission initiated the process of framing the terms and conditions for tariff determination for the next Control Period starting April 01, 2014, and in order to reasonably frame the norms of operation directed various Central and State generating utilities to furnish the operational and performance data for the period FY 2008-09 to FY 2012-13 vide its Order dated June 07, 2013.

37.2 The Commission vide letter dated May 07, 2013 requested CEA to recommend suitable operational norms for the thermal generating stations. The Commission published the draft Regulations on December 06, 2013 specifying terms and condition of tariff for the five year Tariff Period 2015-19 including norms for operation on its own in the absence of CEA recommendations. The Commission, however, stated in the Explanatory Memorandum that the CEA recommendations shall be considered once it is received. CEA made their recommendations on 16.1.2014 only after issue of the draft notification. Commission published the recommendations of CEA on the CERC website inviting comments of the stakeholders on the recommendations of CEA by 22.1.2014 which was extended to 29.1.2014.

37.3 NTPC submitted its comments on the recommendations of CEA along with their comments on the draft Regulatins on 29.1.2014. NTPC in the meantime, in response to the CEA recommendations, communicated to CEA through its letter dated January 24, 2014 for reconsideration of its recommendations on operational norms for thermal power stations for 2014-19. CEA in response to the above communication through its letter dated February 11, 2014 stated that CEA's recommendations on operational norms are based on actual operating data from the stations and duly considering operational factors like unit loading, PLF, start-ups, etc., CEA has further stated that review of its recommendations on operation norms for thermal stations is not considered necessary. Operational norms have been reviewed in due consideration of CEA recommendations, and their reply to NTPC with Copy to CERC in response to NTPC letter dated 24.1.2014 and comments/suggestions of stakeholders and are discussed in subsequent paragraphs.

37.4 The Regulation 36 covers the following four aspects:

Normative Annual Plant Availability Factor (NAPAF) and Normative Annual Plant Load Factor (NAPLF)

Stakeholders' Comments/Suggestions

37.5 NTPC submitted that the target Availability for recovery of fixed charges should be specified at 70% for stations commissioned after 01.04.2009 and 80% for stations commissioned before 31.03.2009.NTPC further submitted that for Farakka (1600 MW), Kahalgaon (1840 MW), and Ramagundam–III (500 MW), target Availability should be specified at 70%, 65% and 55%, respectively. NTPC further submitted that the target Availability of gas stations may be reduced to 70% till the domestic gas availability scenario in the country improves. DVC submitted that 75% NAPAF proposed for CTPS Unit 1, 2 & 3 is 5% higher than the average NAPAF ever achieved and is practically not achievable with these vintage Units. Therefore, the relaxed norms in respect of PAF, AEC, SOC and Heat Rate specified in the Tariff Regulations, 2009 may be continued.NLC submitted that the NAPAF for 600 MW TPS I may be reduced to 70% from 72%.

37.6 Some of the beneficiaries requested to provide justification as to why the norms of NAPAF have not been elevated for NLC stations, Bokaro TPS, Durgapur TPS, Assam GPS. Some stakeholders submitted that the target availability norms should be increased from 85% to 90% for recovery of full fixed charges and in case there are specific stations such as Farakka and Kahalgaon with lower availability, it does not mean or justify that the target availability of all the stations should be lowered. At the most Farakka and Kahalgaon may be given relaxed availability norms while for other stations, 90% target may be fixed.

37.7 Some of the beneficiaries submitted that the NAPAF may be increased to 90% for recovery of fixed cost. Some stakeholders submitted that PAF and PLF should not be less than 95% for coal and gas based thermal generating stations. One stakeholder submitted that higher NAPAF may be fixed for the generating stations having better performance. TERI submitted that Bokaro, Chandrapura and Durgapur thermal generating stations of DVC have not shown any improvement and NAPAF of these plants is very low and should be raised to 85% or else, these power plants should be given progressively higher targets in each year of the Tariff Period 2014-19 so that they are able to achieve the availability of 85% by the end of the Tariff Period.

37.8 One stakeholder submitted that NAPAF may be reduced to 80% or linked with FSAs. Some stakeholders submitted that the vintage of asset should be considered for specifying various operational norms. One stakeholder submitted that though capacity is available for generation, it is not used fully due to non-availability of domestic coal. Therefore, the target availability of 85% may be revisited until the domestic coal is easily available. One stakeholder submitted that the benchmark performance parameters need to be set considering the evolving structure of the industry rather than actual performance in the preceding Tariff Period and as fuel availability has an impact on other operational parameters, a forward looking approach must be taken while fixing such benchmark parameters. One stakeholder submitted that in case of supply shortfall from CIL and reluctance of DISCOMs to allow alternative coal procurement, and the station being dispatched at a lower level, NAPAF should be aligned to an appropriately lower level for recovery of full fixed charges. One stakeholder suggested that deemed Availability should be considered to the extent of normative availability, in the event of shortage in linkage coal and denial of alternate coal procurement by beneficiaries.

37.9 Some stakeholders submitted that due to inherent disadvantages of Circulating Fluidised Bed Combustion (CFBC) technology and lignite usage, it is very difficult to achieve Availability of 80% for lignite fired thermal generating stations with CFBC technology. Therefore, PAF for these stations may be specified as

75% for the life of the plant instead of presently 75% for initial 3 years and 80% after 3 years of COD. One stakeholder submitted that the Availability factor for lignite fired thermal generating stations with CFBC technology may also be prescribed using coal due to non-availability of Lignite. POSOCO submitted that seasonal target availability needs to be factored, which should be different for different plants.

37.10 Some stakeholders submitted that for coal based thermal generating stations, NAPLF may be increased to 90%.One stakeholder submitted that NAPLF may be reduced to 80%.Some stakeholders submitted that NAPLF for incentive for lignite fired generating stations using CFBC technology may also be specified as is being specified for NLC lignite fired power plant.

37.11 One stakeholder submitted that recovery of annual fixed cost on the basis of NAPAF may be replaced with recovery of annual fixed cost on the basis of NAPLF.

37.12 TANGEDCO submitted that the target availability in respect of lignite based stations is lower or equal to the plant load factor indicated in the draft Regulations. The PLF cannot be more than the PAF. The error may be rectified while issuing the final notification. TANGEDCO further submitted that the availability and PLF of TPS-II and TPS-I Expansion for payment of incentive should be on par as that of the 210 MW/200 MW coal fired stations owned by NTPC.

Commission's Views

37.13 Most of the generators have suggested to reduce NAPAF norms for thermal generating stations citing fuel availability issues. Further, some of the stakeholders suggested that the NAPAF should be increased to 90% from the proposed norm of 85%. The Commission, in the Explanatory Memorandum has stated based on actual data, that almost all the generating stations have achieved the NAPAF norms of 85% during FY 2008-09 to FY 2012-13 with most of the stations even achieving 90% during the said period. The Commission in view of the actual performance of these plants proposed to approve the NAPAF norms of 85% in the draft Regulations. The Commission, in the Explanatory Memorandum also stated that the arrangement of fuel is the generator's responsibility and it can declare its capacity on the basis of fuel other than the linked/domestic fuel sources. CEA, in its recommendations, has also suggested NAPAF of 85% for generating stations. The Commission accordingly specifies NAPAF of 85% however, with an intent to mitigate the risk of recovery of fixed charges by the generators, the Commission has decided that in case there is shortage of coal and uncertainty of assured coal supply on sustained basis the fixed charges will be recovered at availability of 83% till the time the same is reviewed by the Commission. To this extent, the norm proposed in the draft Regulations has been modified.

37.14 The Commission has not extended the relaxation in NAPAF norms for the gas based stations as the past years PAF declaration by gas stations suggests that though there was scarcity of domestic gas during FY 2008-09 to FY 2012-13, the PAF data indicates the availability declaration of these stations was well above target availability of 85% and is around 90%, mainly on account of capacity declaration on APM gas, spot gas, and RLNG. The availability declaration on alternative source of gas has enabled the generating companies to recover full fixed charges without any financial implications. The Commission has accordingly not provided relaxation in NAPAF for gas based stations.

37.15 NLC and DVC suggested to reduce the NAPAF norms of their stations on account of vintage of the plant, while some of the stakeholders have suggested to increase the NAPAF norms for DVC, NEEPCO and NLC stations. The Commission is of the view that the norms for TPS-I of NLC and Chandrapura TPS are already relaxed. The TPS-I of NLC is expected to be phased out. The Chandrapur station is expected to go for renovation & modernisation. However, consumers cannot be indefinitely burdened on account of poor plant performance citing vintage issues. The Commission has therefore, retained the NAPAF of these stations to prompt NLC to phase out TPS-I as soon as possible and DVC undertake R&M of the Chandrapur station.

37.16 As regards the suggestion to have seasonal target availability, the Commission is of the view that the target availability norms specified are for the complete year and the fixed charges recovery of generating station gets reconciled by the end of the year and any seasonal variation gets adjusted and hence, it is not required to prescribe seasonal target availability.

37.17 Some of the stakeholders have suggested increasing the NAPLF to 90%, however, generating companies have suggested reducing the PLF to 80%. Keeping the target PLF too high shall vitiate the whole purpose of providing incentive. Further, providing low target PLF shall result in undue incentives to the generator. The Commission is therefore, of the view that the proposed norms of target PLF are appropriate.

37.18 As regards the suggestion received for linking the recovery of AFC to target PLF, the Commission is of the view that recovery of fixed charges for a generating station should continue to be linked to the availability of the station and should not be linked to the actual generation, as the actual generation depends upon various other factors like beneficiary schedule. Therefore, recovery of fixed charges should not be linked to PLF as this may lead to shortfall in recovery of fixed charges for no fault of the generator.

37.19 As regards TANGEDCO's suggestion that target PLF cannot be higher than the target availability. The intention behind keeping the target PLF higher than the target PAF is that the station will have to earn incentive and for that they will have to perform beyond target plant availability factor and not at sub-optimal performance levels. Further, as regards the suggestion that the target PLF of NLC TPS-II and TPS-I Exp. be kept same as that of NTPC stations, the Commission is of the view that the target PAF of lignite fired station should be 5% lower than the target PAF of 85% specified for coal based generation and therefore, the target PLF of these stations have been kept in line with PAF except in case of TPS-I wherein a lower target PLF has been specified, as the target PAF norm is relaxed.

<u>Gross Station Heat Rate</u>

<u>Stakeholders' Comments/Suggestions</u>

37.20 NTPC submitted that existing norms of station heat rate should be continued in case of 200 MW and in case of 500 MW the norms need to be specified as 2450 kcal/kWh. NTPC further submitted that in case of new Units, margin above design heat rate should be 8.0%. NTPC also submitted that for the gas stations of Anta, Faridabad, Kawas, Gandhar and Kayamkulam Station, norms should be increased by 25 kcal/kWh from the existing norm and for Auraiya it should be increased by 50 kcal/ kWh.

37.21 NLC submitted that for the projects under construction/commissioning (NNTPS, TPS II Expansion, and NTPL), the gross station heat rate should be multiplied with the multiplication factor and minimum boiler efficiency specified in 2009-14 Tariff Regulations may be continued and these relaxations may be extended to lignite based power stations taking into consideration the lacuna, specific to lignite based thermal generating stations.NLC further submitted that existing gross station heat rate for NLC Barsingsar TPP may be allowed and specified separately as 2621 kcal/kWh.

37.22 DVC submitted that in view of the fact that the station heat rate is one of the controllable parameters to be considered during truing up and net gain out of better achievement on this ground is to be shared with the beneficiaries, the normative heat rate values as per Tariff Regulations, 2009 may be continued.DVC further submitted that the Commission has proposed to continue the methodology for heat rate determination based on design parameters subjected to a ceiling value with the intention to bring down the margin to 4.50% from the current 6.50%, as expressed in the Explanatory Memorandum. However, while charting maximum design heat rate using sub-bituminous coal, the same is not quoted at par with the values charted in Tariff Regulations 2009-14.This may be reviewed.

37.23 One stakeholder submitted that from the statistics of export import data bank of Department of Commerce, out of 106 MT of coal imports to India during FY 2012-13, around 81 MT (77%) was imported from Indonesia, which has very high moisture content (25-35%) and GCV in the range of 4200-5000 kcal/kg. Therefore, separate category for sub-bituminous imported coal with minimum boiler efficiency as 84% may be allowed. GRIDCO submitted that in case of TTPS, there should not be any relaxed separate norms and Gross Station Heat Rate of TTPS should not be more than the rate proposed for Tanda TPS in the draft Regulations.

37.24 Some of the stakeholders submitted that the amendment in GSHR is most welcome as the tightening of SHR would translate into more efficient operation of the generating company. GUVNL submitted that as Station Heat Rate norms are based on past performances of generating stations, there are margins available to generating stations, which need to be narrowed down. One of the stakeholders submitted that Hon'ble APTEL vide Order dated December 15, 2011 in appeal no. 182/2010 (M/s Raj West Vs RERC) has decided (vide Para 9.9) that moisture correction factor on Station Heat Rate will also apply to imported coal with high moisture content and therefore, norms for lignite fired thermal generating stations and new thermal generating stations achieving COD on or after 01.04.2014 may be modified. Some stakeholders submitted that the proposed SHR norms of 2425 kcal/kWh for 200/210/250 MW units and 2375 kcal/kWh for 500 MW units is in order and is justified on the basis of actual performance data but the SHR norms for combined cycle gas stations need to be marginally amended as under:

Station	**Proposed SHR (kcal/Kg)**	**Suggested SHR (kcal/Kg)**
Anta	2075	2070
Auraiya	2100	2100
Dadri gas	2000	1990
Faridabad	1975	1955
Kawas	2050	2040

37.25 CSPGCL submitted that the drastic reduction of 3% in SHR norms is not only impracticable but is contrary to the Tariff policy too, which stresses that norm should not be ideal but should be achievable. CSPGCL further submitted that in view of the Hon'ble APTEL judgment in Appeal No. 86 & 87 of 2007, the norms should be restored to the earlier level. CSPGCL further submitted that following reasons should be considered while specifying the norms:

a. All technical standards vouch that achievable SHR has a direct relationship with age of the plant.
b. Though the rated pressure and temperature have an extremely significant impact on thermal efficiency of the plant, yet no differentiation on the basis of pressure and temperature has been considered.
c. Another important aspect, which needs to be accounted for is coal quality and general change in climatic conditions. With rise in atmospheric temperature, the heat balance has been affected adversely and this fact has not been accounted for in revisiting the SHR norms.

d. Further, the impact of RGMO/FGMO on the SHR also needs to be deliberated.
e. Any law or statute cannot convert impossibility into possibility and no one should be forced to be liable to pay for not achieving that impossibility.

37.26 One stakeholder submitted that since, the proposed provision of 1.045 X Design Heat Rate is applicable for new Thermal Generating Station achieving COD on or after 1.4.2014, what would be the applicable normative heat rate for power plants commissioned between 1.4.2009 to 31.3.2014 for which the Commission had specified normative heat rate of 1.065X Design Heat Rate. One stakeholder further submitted that 4.5% margin above design heat rate is too stringent and that 6.5% as provided in the earlier Regulations may be retained. Some other stakeholders submitted that for the maximum turbine heat rate specified for power plant with steam parameters of 247 kg/cm^2, 565/593 and sub bituminous coal boiler efficiency, the original values of 1850 kcal/kWh and 0.85 may be retained. Some stakeholders submitted that multiplying factor as specified in the draft Regulations should be considered as 1.065 times Design Heat Rate as was the case earlier.

37.27 One stakeholder submitted that SHR for existing generators having 300/330/350 MW Unit size is not specified and may be added in clause 36(C) (a). One stakeholder suggested that the multiplying factor for units of 125MW with CFBC technology may also be specified. One stakeholder submitted that the Tariff Regulations may specify the normative unit heat rate in the calculation of variable cost of generation instead of station heat rate. It further submitted that plants operating away from the proposed normative parameters may be provided timeframe (typically 2 to 3 years) to modernize and enhance efficiency. It further recommended incentivising utilities that are committing/achieving efficiencies better than normative operational Unit Heat Rate.

37.28 UPPCL and UPCL submitted that justification may be provided for not improving the normative value of GHSR for Bokaro, Chandrapura, Durgapur TPS of DVC, NLC TPS I and for gas turbines operating on open cycle in case of the Gandhar GPS, Anta GPS and Auraiya GPS and for the combined cycle generating stations of Gandhar GPS, Kawas GPS, Anta GPS, Dadri GPS, Auraiya GPS, Faridabad GPS, Kayamkulam GPS and Assam GPS.

37.29 TERI submitted that Bokaro, Chandrapura and Durgapur TPS have not shown any improvement and the SHR has been consistently low. One stakeholder submitted that the gross station heat rate is required to be reduced by 200 kcal/kWh in the case of existing thermal generating stations as the same is also on the higher side. Some stakeholders submitted that the heat rate prescribed for combined cycle gas turbine in 1992 was 2000 kcal/kWh, however, present heat rate prescribed in the draft Regulations is much higher, and similar is the case with thermal power generating unit.

37.30 Prayas Energy Group submitted that median Net Heat Rate (MNHR) may be devised for all plants covered under the scheme, segregated by size as done currently by the Commission and the data set for estimating the MNHR may include all coal plants of that size in the country including plants owned by State and private companies, and may not be restricted to plants regulated by the Commission. Prayas Energy Group further submitted that for the interim period, norms based on the design Net Heat Rate (DNHR) may be developed. Prayas Energy Group further submitted that just as the draft Regulations propose a norm 4.5 percent above design heat rate for new plants, the same process may be applied to existing plants also. Prayas Energy Group further submitted that heat rate norms are also being set up under PAT and so it is important that there be coordination between the Commission and BEE on this issue.

37.31 One stakeholder submitted that the Turbine Generator heat rate increases with decrease in load while the boiler efficiency is not adversely affected by decrease in load. Hence, a formula needs to be evolved for varying GSHR. Some stakeholders submitted that an annual Heat Rate Degradation factor may be introduced on case to case basis after considering Energy Audit Reports done by competent third party, viz., CPRI, Bangalore. Further, the different heat rates may be specified for different loading profiles/PLFs as Heat Rate varies inversely with the loading. The stakeholders further submitted that this concept of heat rate profile has been recognized by MOP and has been incorporated in the latest Case-l/Case-2 Model Power Supply Agreement. They submitted that a mechanism needs to be determined for Heat Rate compensation due to reasons beyond the control of the generator and there may be suitable correction in Heat Rate in case of plants operating on blended coal. They submitted that additional SHR may be allowed if required for installation of new technologies like air cooled condensers, etc. NEEPCO submitted that based on the average actual GSHR for the thermal Power plants of NEEPCO, the revised GSHR proposed for the Tariff Period 2014-19 are as follows:

Power Plant	**Open Cycle (kcal/kg)**	**Combined Cycle (kcal/kg)**
AGBPP	3440	2689
AGTPP	3770	

37.32 One stakeholder submitted that 660 MW and above Units are still new to India and their reliability and operational ease would take some time and therefore, conditions specific for 660MW Units need to be considered. It further submitted that for new 660 MW Units, the norm of 6.5% operational variation needs to be retained and the proposed parameters with regard to maximum THR as 1830 kcal/kWh and minimum boiler efficiency as 87% on Indian Coal should not be applied for the plants ordered between 2009 and 2014. It further submitted that no plant of 660 MW size has been able to achieve efficiency of more than 0.85 and the factor of 1.065 is necessary to take care of loss of efficiency in the later years of operation. Therefore, the norms as per existing Regulations may be retained.

37.33 One stakeholder submitted that the boiler efficiency of 89% for imported coal is rather stringent and not practical. It further submitted that the norm requires use of only bituminous coal in case of import, which is also restrictive in nature. It further submitted that instead of stipulating a single type of bituminous coal, which should give minimum of 89% boiler efficiency, multiplying factors may be specified for imported coal also to be fair to use any type of imported coal with minimum GCV of 5000 kcal/kg from environmental point of view and accordingly the multiplying factors may be specified for moisture content up to say 6% as in case of lignite, without specifying any specific type of coal.

37.34 One stakeholder submitted that for new Unit, norms of 4.5% above the design station heat rate is justified particularly as it would apply to the new Units commissioned during this Tariff Period.

37.35 One stakeholder submitted that the date of reckoning for the new plants should be date of placement of BTG order instead of COD. It further submitted that the margin of 4.50% on Design Heat Rate is not appropriate. It further submitted that suitable Heat Rate correction is required for imported coal as it undergoes GCV loss while stacking. It further submitted that since DISCOMs can despatch Units at as low as 40% rated load, sliding scale of Heat Rate with respect to unit load should be allowed.

37.36 Some stakeholders submitted that heat rate of the new generating stations should be based on the Performance Guarantee ("PG") Test results and not on the design heat rate as provided in the OEM Contract. They further submitted that separate provisions of heat rate during the stabilization period may be included. One stakeholder further submitted that most power plants under construction and about to be commissioned have been ordered based on the norms specified in 2009-14 Tariff Regulations and with 85% boiler efficiency and hence, boiler efficiency of 85% may be continued and any increase in efficiency should be made applicable for those Units which are yet to place BTG order with manufacturers, and it should be linked to certain minimum coal quality.

37.37 Some stakeholders submitted that the 6.5% margin allowed over the design heat rate as per existing Regulations should be continued. TANGEDCO submitted that the SHR norms of coal based stations namely 2425 kcal/kWh may also be indicated for NLC TPS-I Expansion and the SHR for TPS-II may kindly be limited to 2500 kcal/kWh.

37.38 CSPGCL submitted that in view of the following reasons, norms should be restored to the earlier level:

a. 4.5% margin over the design value is not sustainable.
b. With reducing frequency range and increasing backing down in off peak hours, 100% MCR is not achievable.

c. With such variations, even maintaining the existing norm of 6.5% is becoming a challenge.
d. Though there has been no noticeable breakthrough in boiler technology, the boiler efficiency norms have been upgraded significantly.
e. Vide fifth proviso such change has also been adopted for the Units commissioned before 01.04.2014. Thus, for a 500 MW set commissioned before 01.04.2014 there are two norms – one under sub clause 31 (C) (a) (i) and the other under fifth proviso of clause 31(C) (b). Thus, if two Units, having similar technical specifications, have been commissioned on the same date, then a Unit commissioned in a power station where erection of another extension Unit is in progress will have a different SHR than the Unit, which was commissioned at a plant where no further extension is in progress. SHR is a technical parameter and cannot change merely on the basis of location.

37.39 Some stakeholders submitted that the minimum boiler efficiency for Indian sub-bituminous coal may be retained at the existing 0.85 level.

37.40 One of the stakeholders submitted that different gross station heat rate may be determined for use of sub-bituminous Indian coal, bituminous imported coal and blended coal so as to have a reasonable and justifiable GSHR for every new generating station while determining the tariff.

37.41 One of the generating stations submitted that the thermal generating stations, which are under advanced stage of construction, have followed existing Tariff Regulations and may achieve COD after 1.4.2014. The Commission may allow the existing guidelines for projects, for which EPC contracts have already been placed and project is under construction. PCKL submitted that since the Gross Station Heat Rate for generating stations commissioned after 01.04.2009 were based on pressure rating (kg/cm2) and minimum boiler efficiency irrespective of Unit size configuration similar to projects due for commissioning on or after 01.04.02014, the caption to clause 36(C)(b) of the draft Regulations needs to be changed from "(b) New Thermal Generating station achieving COD on or after 1.4.2014" to "Thermal Generating station achieving COD on or after 1.4.2009"

37.42 One of the stakeholders submitted that the table in clause 36(C) (a) of the draft Regulations may also be applicable for the power stations as existing on 31.3.2009.

Commission's Views

37.43 Most of the generating stations have suggested increasing the proposed heat rate whereas the beneficiaries have suggested to retain the proposed norms for 200/210/250 MW and 500 MW Units. The Commission had proposed heat rate norm of 2425 kcal/kWh for existing 200/210/250 MW Units and 2375 kcal/kWh for existing 500 MW Units in the draft Regulations based on detailed analysis of actual heat rate as discussed in explanatory memorandum to draft Regulations. The norms were proposed for Units with steam operated boiler feed pumps. As per the actual performance data submitted by generators for FY 2008-09 to FY 2012-13 as elaborated in explanatory memorandum to the draft Tariff Regulations, the average five year heat rate for 200/210/250 MW Units was around 2400kCal/kWh and for 500 MW Units the average five year heat rate was between 2350 to 2362 kCal/kWh. CEA in its report recommended heat rate norm of 2450 kcal/kWh for 200/210/250 MW Units and 2375 kcal/kWh for 500 MW units.

37.44 The Tariff Policy of Government of India in respect of operational norms provide as follows:

> "*Suitable performance norms of operations together with incentives and dis-incentives would need to be evolved along with appropriate arrangement* ***for sharing the gains of efficient operations with the consumers.*** *Except for the cases referred to in para 5.3 (h)(2), the operating parameters in tariffs should be at "normative levels" only and not at "lower of normative and actuals". This is essential to encourage better operating performance.* ***The norms should be efficient, relatable to past performance, capable of achievement and progressively reflecting increased efficiencies*** *and may also take into consideration the latest technological advancements, fuel, vintage of equipments, nature of operations, level of service to be provided to consumers etc.* ***Continued and proven inefficiency must be controlled and penalized.***
>
> *The Central Commission would, in consultation with the Central Electricity Authority, notify operating norms from time to time for generation and transmission.*

> *The SERCs would adopt these norms. In cases where operations have been much below the norms for many previous years, the SERCs may fix relaxed norms suitably and draw a transition path over the time for achieving the norms notified by the Central Commission.*

The Tariff Policy provides for sharing of gains of efficient operations with the consumers. The Commission approach so far has been to allow generator to retain the gains of efficient operation during the tariff period and pass on the same to the consumer in the next tariff period. In line with this approach Commission has allowed the gains of efficient operation to be passed on to the consumers by revising the norms.

37.45 NTPC has submitted that there is no operation margin in the heat rate norm. It is not the case that the operation norms will lead to losses to NTPC at the existing average performance level during last 5 years. Its argument is that there was significant reduction in the demand for electricity and stations were operating at a low plant load for the last 2 years namely 2012-13 and 2013-14, implying that heat rate norms should have been specified based on last two years data. However, it is not desirable to specify norms based on single or two year performance. The approach of the Commission has been to specify norms based on past 5 years average which is consistently being followed during last 2 tariff periods. This methodology ensures that if generator incurs loss in one year, it should be possible to recover in other years. Further, it is not necessary for the Commission to provide margins in all conditions and it is felt that it is not necessary to provide a higher margin in the norms in the changed circumstances. We are not in agreement with NTPC that the reduction in generation level (reduction of PLF) of generating stations is also likely to continue during the tariff period 2014-19. The NTPC has submitted that there is considerable reduction in demand for electricity. The reduction in demand could be due to many reasons such as declining industrial growth, reduction in purchase of electricity by the distribution licensees, substantial addition of capacity, significant increase in non-conventional energy projects, shortage of domestic supply of coal/gas and blending of imported coal etc. However, it is unlikely that Indian economy would not recover and there will be no improvement in the industrial growth during the tariff period 2014-19. Prices of imported coal have also seen upward as well as down word movement. Power utilities are blending imported coal of low GCV leading to increase in prices and non materialization of dispatch by distribution licensees. Further, NTPC has also been allocated captive coal mining blocks and some of them are basket mines (not linked to any particular power station but for supply to any station). The supplies from own mines of NTPC are expected to start from 2014-15 and to pickup supplies in subsequent years of tariff period. Supply of coal from such mines will help in bridging the shortfall of domestic coal and reducing import content, thereby improving unit loading and PLF during tariff period 2014-19. This is likely to induce discoms to give more schedules for the power. In the light of this, we are of the view that the chances of further deterioration of heat rate are low and improvement in future cannot be ruled out.

37.46 Prior to 2009, performance level and unit loading of NTPC stations was of the order of 100% and therefore, while specifying norms Commission provided certain margin thinking that such high performance may not be sustained. But now it is seen that despite reducing trend in PLF, there is improvement in heat rates. The units loading still remain high over and above 91.4%.

37.47 NTPC has also submitted that there is deterioration of plant load factor in the last few years and is likely to further deteriorate in future. However, it needs to be appreciated that the station heat rate is not directly related to the station PLF but depends on the unit loading. The average unit loading for NTPC stations for the period 2008-09 to 2012-13 is worked out as 91.40% and even in some cases it is more than 100% (refer CEA's recommendation vide Para 7.15 on page 17 & 18). CEA has clearly concluded that no part load compensation would be applicable for the units under consideration for norms with the present loading pattern.Moreover, further deterioration in the unit loading is perceived.

37.48 NTPC suggested for higher operational norm for older units. The operational data for the NTPC stations do not support the suggestion of NTPCthat the higher operational performance is not sustainable for older units. Para 7.7.1 and 7.7.2 of CEA's recommendations reads as follows:

> "*Para 7.1.1 Most of the units in these stations are old units – out of total capacity of 31,000 MW – 10,000 MW is over 20 years old and – 13,000 MW capacity is 15 years old; only – 8000 MW capacity has been installed after 1st April 2009. Thus even*

with combination of considerable share of old capacity, the overall operating deviation of heat rate has been around 4.5%

Para 7.1.2 it is also seen that some of the stations where all the units are quiet old like Singrauli and Korba TPS have shown quiet low deviation in operating heat rate. This highlights that O&M practices are the single most important factor determining efficiency; and with due care and efforts, consistently high level of operating efficiency can be achieved even in the old units."

In view of above, the Commission is not in agreement with the suggestion of NTPC in regard to the norms for heat rate.

37.49 It is true that NTPC generating units are amongst the good performing units in the country but in this context the argument of the NTPC cannot be sustained that operational norms should not be based on the best performing units in the country. It would be a great fallacy if the good performing units are set with low norms looking at performance of units which are not performing to their potential or not performing optimally.

37.50 NTPC has suggested that the station heat rate of Rihand STPS has to consider corrections on account of motor driven BFPs. It is clarified that the Commission has while deciding the norms of station heat rate for 500 MW units, has taken into consideration the above fact

37.51 NTPC has suggested that the performance guarantee test could be a good reference point for specifying norms rather than the design heat rate. In our view, specifying norms with reference to the design heat rate guaranteed by the OEM corresponding to the design conditions and designed fuel is more appropriate. The performance test result would include operational margin which will correspond to actual site conditions, actual fuel used and loading of unit during performance testing. Therefore, margin above the performance results shall lead to additional margin and the Commission cannot subscribe to the suggestion made by NTPC.

37.52 The Commission has, in the light of above and in line with the recommendations received from CEA, reviewed the heat rate norm for 200/210/250

MW units and revised it to 2450 kcal/kWh from the proposed norm of 2425 kcal/kWh. However, for 500 MW units, the Commission has retained the norm of 2375 kcal/kWh, which has also been recommended by CEA. In line with the Tariff Policy, the norms specified by the Commission are for efficient plant operation, relatable to the past performance based on operation data of five years 2008-09 to 2012-13, capable of achievement and progressively reflecting increased efficiencies over previous tariff periods.

37.53 As regards the heat rate norms specified for gas based stations, NTPC has suggested to increase the norm. However, some of the stakeholders have suggested to reduce the norms. The Commission is of the view that since, the proposed norms for the gas based generating stations are based on the actual performance data for FY 2008-09 to FY 2012-13, therefore, the proposed norms have been retained.

37.54 As regards the heat rate norms for Tanda, Badarpur and Talcher TPS, the Commission had reviewed the norms in the draft Regulations as compared to the actual performance during FY 2008-09 and FY 2012-13. The Commission has retained the norms for these stations as proposed in draft Regulations.

37.55 Most of the generating stations have suggested to increase the margin to 6.50% to 8.00% over and above design heat rate as compared to 4.50% proposed for new coal based generating stations in the draft Regulations and have also suggested to relax the boiler efficiency. CEA, in its recommendation, has specified a margin of 3% for the station heat rate of new generating stations. As regards lowering the boiler efficiency, CEA in its report has stated that

> *"…in most of the stations the boiler efficiency for subsequent units installed later has been much lower than the boiler efficiency for the previous units. In some of the cases, the boiler efficiency has been alarmingly lower.*
>
> *There appears to be no justification for such reduction in boiler efficiency when the earlier units have higher boiler efficiency with same/comparable coal quality. Technology must progressively lead to efficiency improvements and not the other way and thus improvements in technology over the years are expected to lead to higher boiler efficiency for subsequent units installed later.*

In some of the cases it is seen that utilities in their recent specifications have specified that a minimum carbon loss of 1 to 1.5% would be considered for quoting boiler efficiency - thus, leading to corresponding reduction in boiler efficiency (and consequent increase in design heat rate).

Such practices defeat the purpose of specifying the normative heat rate in terms of the design heat rate. It needs to be understood that the operating margin (over the design heat rate) provided in the norms is intended to cover the variations over a certain base line, and the quantum of variation allowed has been fixed considering this base line as the design heat rate at design CW temperature/back pressure, zero percent makeup etc. as specified in the norms.

Contrary to the above, the provisions of minimum carbon loss etc. lead to artificially inflating or jacking up the base line (design heat rate) itself. Thus such a practice by the utilities is seen as an attempt to build up certain margin upfront in the design heat rate thus leading to a higher design heat rate and consequently leading to a higher normative heat rate value ultimately.

7.20.3 It is, therefore, recommended that such practices by the utilities should be discontinued forthwith. A review of all Specifications should be undertaken by CERC and where such provisions leading to build up of margin upfront in the design heat rate are found, the operating margin provided in norms should be correspondingly lowered to the extent that such build up in terms of additional losses etc. have been provided in the specifications. Only then would the true spirit of allowing intended operating margin over DHR for normative purposes would be realized."

37.56 The Commission, in the draft Regulations, had proposed to limit the boiler efficiency to 87%. The Commission is of the view that the CEA's computation of 3% margin on design heat rate is based on the lower boiler efficiency, which for recently installed units is in the range of 84%-85%.However, the Commission had proposed a margin of 4.50% at higher boiler efficiency of 87%. The Commission considering the recommendations of CEA and other suggestions received from the stakeholders, has revised the boiler efficiency to 86% from 87%proposed in the draft Regulations for new generating stations achieving COD on or after 01.04.2014 while retaining the margin of 4.50% for heat rate.

37.57 Further, for generating stations that have achieved COD between 1.4.2009 to 31.03.2014, the margin has been revised to 4.50%. The Commission would like to point out the observation made by CEA on the alarming trend of decreasing boiler efficiency, which has dropped down to level below 85% for recently commissioned Units of the same station operating on similar coal. The Commission is of the view that practices, which lead to unnecessary burdening of consumers should be discouraged. The Commission has, therefore, reduced their margin over and above design heat rate to 4.50%.Further, in order to limit the heat rate so derived, the Commission is of the view that the same should not exceed the heat rate norms approved during FY 2009-10 to FY 2013-14.

37.58 Other generating stations have suggested that the heat rate norms for their stations should be relaxed. The Commission would like to state that the norms for these generating stations have been specified considering the actual performance during the period FY 2008-09 to FY 2012-13 as explained in the Explanatory Memorandum to the draft Regulations. The Commission is of the view that the heat rate norms specified for these generating stations are appropriate and need no review.

37.59 As regards the suggestion received from generating stations to review the turbine cycle heat rate norm of 1830 kcal/kWh specified for new generating stations with steam parameter of 247 kg/cm2, 565/5930C, CEA in its report has also recommended turbine cycle heat rate of 1850 kcal/kWh. The Commission has therefore, revised the same from the proposed turbine cycle heat rate of 1830 kcal/kWh to 1850 kcal/kWh.

37.60 Further, CEA has in its report recommended that for stations that employ dry cooling system, suitable adjustment should be provided in the turbine cycle heat rate. The guaranteed design heat rate of the station should take into account the use of dry cooling system by the OEM however, while applying the ceiling limit of efficiency suitable adjustment in turbine cycle heat rate will have to be provided. The Commission has therefore accepted the same and specified in the Regulations that maximum turbine cycle heat rate shall be adjusted for dry cooling system suitably at the time of tariff determination.

Secondary Fuel Oil Consumption (SFC)

Stakeholders' Comments/Suggestions

37.61 Some stakeholders submitted that normative fuel oil consumption of lignite fired CFBC power plants may be retained as 1.25 ml/kWh. They further submitted that existing norms should be continued. NLC submitted that for 600 MW TPS I, Secondary Fuel Oil consumption may be retained at 3.5 ml/kWh. NTPC submitted that in case of Badarpur and Farakka, there should be same relaxation in secondary fuel oil consumption over the existing norms for 2009-14.

37.62 MPERC submitted that Para 18.5.1 of the Explanatory Memorandum interprets that the norms for Secondary Fuel Oil consumption are provided separately for pit head and non-pit head coal based generating stations on the basis of some past data. This should be reviewed as the Secondary Fuel Oil Consumption may not be linked to coal based generating stations being pit-head or non pit-head.

37.63 Some beneficiaries submitted that Secondary Fuel Oil consumption (SFC) of coal-based generating stations specified in draft Regulations is different in case of pit head stations and non pit head stations, whereas SFC is independent of the location of the generating stations. They further submitted that clarification may be provided as to why improved norms for SFC consumption have not been specified for Durgapur TPS.

37.64 One stakeholder submitted that the secondary fuel oil consumption for non pit head station has been prescribed as 1.00 ml/kWh, which is high and should be 0.6 ml/kWh at the most. Further, the specific oil consumption for lignite fired generating station except those using CFBC technology, also appears to be high and should be reduced to 1.5 ml/kWh.

37.65 Some stakeholders submitted that a norm of 0.3 ml/kWh and 0.75 ml/kWh for pit head and non-pit head based stations is justified since the proposed norms of 0.5 ml/kWh and 1.0 ml/kWh would be too liberal.

37.66 Some stakeholders submitted that relaxed secondary fuel oil consumption norms may be provided for the stabilization period as provided for in Tariff Regulations 2004-09 (2ml/kWh). They further submitted that there could be cases where higher consumption of secondary fuel oil needs to be allowed, which becomes necessary due to reasons beyond the control of the generator, such as backing down orders due to grid conditions, additional start ups after shut down taken due to the requirement of the operation as per grid conditions, etc., which should be compensated additionally at actual. Various stakeholders requested to do away with the separate norms for pit-head and non-pithead stations and approve a single norm for all stations. CSPGCL further submitted that if differentiation needs to be created then it should be made on the basis of coal quality such as imported vs. domestic, etc. Some beneficiaries suggested that normative specific oil consumption may be uniformly maintained at 0.5 ml/kWh for all coal fired stations irrespective of their location.

37.67 TANGEDCO submitted that the specific oil consumption in respect of TPS-II and TPS-I may be reduced to 1.0 ml/kWh. Some stakeholders submitted that the Regulations may specify separate norms for secondary fuel oil consumption, as done in case of Tariff Regulations. 2004, for pre-stabilization and post-stabilization period of six months from the date of COD of the Units. MPPMCL submitted that the secondary fuel oil consumption should not be more than 0.5 ml/kWh for the generating stations of DVC also. One stakeholder submitted that the norm for secondary oil consumption for non pit head station may be reduced from 1ml/kWh to 0.5 ml/kWh as the actual consumption is about 0.2ml/kWh to 0.5ml/kWh for most of the plants except some plants like Farakka, Kahalgaon, Dadri TPS and Badarpur, which may be asked to submit the road map to achieve improvement like other plants.

37.68 One stakeholder submitted that as resynchronization after Reserve Shut Down (RSD) involves substantial SFO consumption and the same is not on account of the generator, reimbursement may be allowed for actual SFO expenses or suitable norm for different sizes of machines may be fixed. One stakeholder submitted that given that GCV and the quality of rejects would be very low, the specific oil norms specified for coal reject based plants are not sufficient and need to be revised. One stakeholder submitted that the existing guidelines may be allowed for projects whose EPC contracts have already been placed and are under construction. One stakeholder submitted that actual fuel cost for start up (including cold start-up) and ramp up/ramp down and shutdown should also be allowed.

Commission's Views

The Commission, in the draft Regulations, had proposed separate norms for pit-head and non-pit head generating station on the basis of actual data submitted for FY 2008-09 to FY 2012-13. CEA, in its Report, has stated that the proposed norm of 1 ml/kWh for some stations is too liberal and recommended that the norms should be fixed at 0.25 ml/kWh, which shall include seven start-ups per Unit per year. CEA further recommended that additional secondary fuel oil consumption should be approved for subsequent start ups. It was found that most of the pit head generating station and many of the non-pit head generating stations have secondary fuel oil consumption less than 0.5 ml/kWh except a few non-pit head generating stations like Farakka, Talcher, Kahalgaon and Badarpur. The secondary fuel oil consumptions is high due to very high number of start-up and trippings. In this regard, the Commission is of the view that these stations may reduce their oil consumption through sustained efforts. Commission, has therefore, specified SFC norm of 0.50 ml/kWh for both pit-head and non-pit head stations.

37.69 Some generating companies have suggested to relax the norms for their generating stations, however, the Commission is of the view that the norms specified for these generating stations are on the basis of actual performance of generating stations during FY 2008-09 to FY 2012-13 wherein most of the generating stations have been able to achieve approved norms. For stations of DVC and NLC with relaxed SFC norms, the actual SFC consumption during FY 2008-09 to FY 2012-13 is much lower than the current norms. The Commission cannot allow relaxed norms for such stations and these stations need to improve their operational performance. Therefore, in view of the actual performance of these generating stations, the Commission has decided revised norms for these stations.

37.70 Further most of the generating stations have suggested that additional SFC should be allowed in case the generating stations are required to back down for reasons beyond their control. Given that CEA in its report has recommended SFC of 0.25 ml/kWh, the Commission has approved 0.50 ml/kWh norm which should take care of these backing downs. However, in case the generating station is getting affected on account of frequent backing down for reasons beyond its control, the generating station can approach the Commission for consideration provided that the generating station can substantiate its claims with number of start-ups, loading of the Units and records of backing down instructions received.

37.71 Some of the stakeholders have suggested that more relaxed norms of SFC consumption should be specified during first six months after COD. The Commission is of the view that once a generating station achieves COD, the same is expected to operate at optimum level and there is no case for assuming that the plant will consume more secondary fuel oil as the plant is not stabilised. A generating station is expected to issue a certificate that the generating station had adhered to all the relevant provisions of technical standards of CEA as per **Appendix VI** of the Tariff Regulations. The Commission is of the view that there is no basis for treating the first six months after COD as stabilisation period and allowing relaxed norms as the plant meets all the technical standards as on COD and should therefore operate at optimum levels. The Commission has therefore specified uniform norms from COD of the generating station.

Auxiliary Energy Consumption (AEC)

Stakeholders' Comments/Suggestions

37.72 NTPC submitted as under:

a. Performance of Units cannot be sustained in the coming years as Unit loading is expected to be low in view of the inadequate fuel availability, lower demand/schedule by customers, ageing of units, renovation & modernisation, etc.
b. Hence, the existing AEC norms should be continued with provision of additional AEC on account of new technologies like FGD, desalination plant, pipe conveyors, ash disposal system, etc.
c. As gas stations are facing heavy partial loading due to low schedule, the existing AEC norms of gas stations need to be revisited with additional consideration for partial loading below 80% for all gas stations.
d. Beneficiaries should share the energy bill paid by NTPC stations for drawing energy from grid during plant shutdown due to lower schedule in the proportion of their allocation.

37.73 NLC submitted that for 600 MW TPS I, the norm for auxiliary energy consumption (AEC) may be raised to 13%. NLC further submitted that for TPS I (Expansion), AEC may be retained at 9.5% and for NTPL, AEC norm may be increased from 6% to 6.5%. DVC requested to allow a normative auxiliary consumption of 10.6% for MTPS Unit # I to IV. DVC further submitted that CEA has recommended in favour of continuation of DVC's existing norms for old stations of DVC namely Bokaro-TPS, Chandrapura TPS, Durgapur TPS & Mejia TPS Unit I to IV.

37.74 One stakeholder submitted that the draft Regulations provides Auxiliary Energy Consumption based on past performances of generating stations and there are margins available to generating stations, which need to be narrowed down. Some stakeholders submitted that AEC norms for CCGT stations of NTPC should be kept at 2.4% with relaxed norms of 2.5% for Auraiya as the station is a depreciated station. Some stakeholders submitted that as the colony consumption will not be a part of auxiliary energy consumption, the normative AEC level should be reduced at least by 1-2% in case of thermal generating plants. MPPMCL submitted that the draft Regulations very correctly proposes to abolish the addition of colony consumption and construction power and the same should not form part of auxiliary energy consumption. UPPCL and UPCL submitted that clarification may be provided as to why the norms for AEC in case of the coal based generating stations of 200/300/330/350/500 MW size, Talcher TPS, Tanda TPS, Bokaro TPS, Durgapur TPS, NLC TPS I and TPS II, have not been improved. UPPCL and UPCL further submitted that clarification may be provided as to why the AEC in case of generating station based on coal rejects been fixed as high as 10%, which is more than the AEC of 8.5% in case of Badarpur TPS, which is not a very efficient power station.

37.75 TERI submitted that the AEC of Bokaro and Durgapur TPS may be fixed at not more than 10%. GRIDCO submitted that in case of TTPS there should not be any relaxed separate norms considering the huge renovation & modernisation expenses incurred on this plant and hence, the auxiliary energy consumption in case of TTPS should accordingly be fixed at a lower % than the proposed level of 10.50%. Some stakeholders submitted that all auxiliary energy consumption must be metered for all generating Units and transmission substation and must be subject to ceiling of not more than 5% and 0.25%, respectively, and for gas based thermal stations, auxiliary energy consumption should not be more than 2%. One stakeholder submitted that AEC of 8.5% needs to be reduced to 7.5% for 200 MW Units, because the average of 5 years in many plants is below 7.25% and the electricity consumption of colony and construction power is not included in Auxiliary Energy Consumption.

37.76 CSPGCL submitted that based on the rated parameters and measured values, additional AEC of 0.35% should be allowed for Units with static excitation system. PCKL submitted that separate percentage of auxiliary energy consumption needs to be specified as under, on par with induced and natural cooling towers as specified in the Tariff Regulations. Some stakeholders submitted that a suitable proviso may be added for normative auxiliary energy consumption based on various PLFs, to take care of higher auxiliary energy consumption due to lower scheduled generation. They further submitted that additional AEC should be allowed for installation of new technology/additional equipment as given below:

a. For FGD, additional 2% may be considered.
b. Additional AEC of 0.5% may be allowed for plants with sea water cooling.

37.77 Some stakeholders submitted that AEC norms for lignite-fired 125MW/135 MW Units using CFBC technology have not been specified, which may be specifically incorporated in line with that of NLC Barsingsar. Some stakeholders submitted that for stations getting water through long distance pipelines, additional auxiliary energy consumption of 0.3% for every 50 km may be allowed. They further submitted that norms for extra auxiliary energy consumption for reactors installed in power stations to maintain bus voltages may be specified. They further submitted that the norms of Auxiliary Energy Consumption may be allowed up to 6.6% for generating Units using hybrid system (ESP and fabric filter). They also submitted that in case of part load operations due to non-acceptance of alternate coal procurement by beneficiaries, increase in Auxiliary Energy Consumption should be compensated by beneficiaries.

37.78 PPCL submitted that AEC for combined cycle power plants is very low and may be changed to 3%. PPCL further submitted that when scheduling is below 85%, AEC may be allowed as per actual. PPCL added that a normalization factor may be devised to take care of effect of SHR and AEC variation. PPCL further submitted that the amount of power consumed during total backing down, shutdown for overhauling and breakdowns may be allowed to be recovered as additional O&M expenditure at normative rate of energy sent out from the generating station. One stakeholder submitted that the normative auxiliary consumption for gas based plants needs to be retained at the existing level of 3%. It further submitted that if dedicated transmission line of a generation project is more than 50 km long, the AEC for such generating stations should be allowed as normative AEC plus at least 2% towards dedicated transmission line losses.

37.79 NEEPCO submitted that norms for AEC should continue as per the provisions of Tariff Regulations, 2009 for gas turbine/combined cycle generating stations. OTPC submitted that in Judgment dated 21.11.2012, the Hon'ble ATE has approved the Auxiliary Energy Consumption of 5.5% of gross power generation for FY 2011-12 considering the CEA recommendation in 'CEA Technical Standards on Operation Norms for CCGT Stations'. OTPC further submitted that AEC for gas turbine/combined cycle generating stations using electric driven gas booster compressor should be 4%. One stakeholder submitted that for projects based on dedicated gas wells and projects located in remote areas where there is no national gas grid, an additional 0.5% auxiliary energy consumption over 2.5% may be allowed and auxiliary energy consumption up to 2% extra may be allowed for projects where FGD is a requirement of MoEF. One stakeholder submitted that for Barsingsar generating station of NLC using CFBC technology, AEC should be 11% instead of 11.50% and for TPS-I, it should be 11% instead of 12%.

37.80 MPERC submitted that the Regulations may also specify the norms for coal reject based power stations along with their capacities. TANGEDCO submitted that the clause 36 (E) (d)(i) of the draft Regulations specifies that the auxiliary energy consumption norms of all lignite fired thermal generating stations with capacity 200 MW and above shall be 0.5 percentage more than the auxiliary energy consumption norms of coal based generating stations at (v) (a) above. However, it is seen that there is no Para starting with clause (v) (a) as stated. TANGEDCO further submitted that the clause 36 (E)(a) for 200 MW series indicate an auxiliary energy consumption of 8.5% with provision for 0.5 percent extra wherever induced draft cooling towers are in position. Therefore, the table under Clause 36 (E)(d)(iii) indicating auxiliary energy consumption for TPS-II and TPS-I Expansion is redundant and may be deleted. TANGEDCO further submitted that the auxiliary energy consumption for TPS-I may be retained at 12% considering the vintage of the station.

37.81 TANGEDCO submitted that the final notification may indicate the norms for 600 MW subcritical and 660 MW supercritical boilers also along with the permitted auxiliary energy consumption. In absence of this, it is presumed that the norms applicable for 500 MW sets (subcritical) are applicable for 600 MW (subcritical) and 660 MW (supercritical) boilers also.

Commission's Views

37.82 Most of the generating stations have suggested to allow the current norms as per tariff Regulation 2009 along with additional margin for various equipments to be installed. The Commission while specifying the auxiliary energy consumption norms for 200/210/250 MW and 500 MW stations had retained the current norms. However, CEA in its report has recommended to reduce the auxiliary energy consumption for new 500 MW Units by 0.75% stating that though there is a scope of reducing the norm by 1%, however, with a view to allow some operational flexibility to the stations, 0.75% has been recommended by CEA. In view of the same, the Commission has reviewed the auxiliary energy consumption norm for existing as well as new 500 MW Units and has reduced the current norm by 0.75%. As regards the norms for 200/210/250 MW Units, the Commission has retained the norms proposed in the draft Regulations.

37.83 In regard to increase in auxiliary consumption due to partial loading, the auxiliary consumption norms are in due consideration of historical power consumption furnished for various generating stations for the past five year period 2008-09 to 2012-13. This actual power consumption is an average consumption taking into account the partial loading of the generating stations . Thus, the additional consideration of power consumptions due to partial loading is not required. If the loading is decreased considerably, the generators opt to shutdown entire unit thereby on saving the auxiliary consumption. The argument of NTPC is that stations were operating at a low plant load factor for the last 2 years namely 2012-13 and 2013-14 implying that auxiliary consumption norms should have been specified based on last two years data. However, it is not desirable to specify norms based on two year performance. The approach of the Commission has been to specify norms based on past 5 years average consistently followed during previous tariff periods. This methodology ensures that generator if loses in one year then it should be possible for him to recover in other years.

37.84 Most of the generating stations have suggested that additional auxiliary energy consumption should be allowed for FGD, desalination plant, ash handling, etc. The Commission has referred CEA's recommendations in this regard. CEA has recommended to provide additional AEC for dry cooling systems as stated below:

> *"Considering the above, it is suggested that Additional Auxiliary Energy Consumption of 0.5 % may be allowed for plants with Indirect cooling type dry cooling system and 1.0 % for direct cooling type air cooled condensers with mechanical draft fans. "*

37.85 The Commission in accordance with the above has approved additional AEC for dry cooling systems. Further, as regards allowing additional AEC on account of other equipment/auxiliary system, as suggested by many generators, the Commission is of the view that the same shall be looked into on a case to case basis even if it is located outside the power plant premises, but only if such auxiliary system is being used for generation of electricity from the plant.

37.86 Some generating stations have suggested to increase the AEC norms for gas based station. However, some stakeholders have suggested to reduce the norm further. CEA in its report has recommended that the AEC norms for gas based stations should be kept as 2.50%. The Commission, in the Explanatory Memorandum, has observed that the actual auxiliary energy consumption for gas based stations, which are operating at lower PLF is around 2.50% with some of the stations having lower AEC, and therefore, the Commission proposed a norm of 2.50%. The Commission is of the view that the AEC norm is appropriate and therefore, needs no review.

37.87 While some of the generating companies such as DVC and NLC have suggested to relax the AEC norms for their stations, some of the stakeholders have suggested that the proposed norms should be reduced further. The Commission proposed the norms in the draft Regulations based on the actual performance of these stations and therefore, the same is not being reviewed.

37.88 Most of the stakeholders have suggested to exclude colony consumption from the auxiliary energy consumption and to review the proposed norms. However, some of the generating stations have proposed that the norms should include colony consumption. The Commission has clarified in the Explanatory Memorandum that such consumption should not be considered as a part of auxiliary energy consumption. In this regard, it is to clarify that for all practical purpose the housing colony is treated as integral part of generating station but the consumption of electricity is not accounted for in the auxiliary energy consumption of the station but the fuel expenses corresponding to electricity supply to the colony from the station net of revenues received from employees for consumption of electricity are accounted for in the operation and maintenance expenses of the generating station while framing norms for the operation and maintenance expenses. Therefore, if the housing colony consumption is included in the auxiliary energy consumption norm of the generating stations then it would tantamount to the double charging of the same from the beneficiaries. Therefore, consumption of electricity in housing colony, though integral part of the generating station cannot be included in the auxiliary energy consumption norm. In view of above, the suggestion to include colony consumption in auxiliary consumption cannot be accepted.

37.89 The deterioration of coal quality over the years has already been factored in the historical data and no further correction is required to be made on account of this as suggested by NTPC.

37.90 As regards the suggestion received to approve the AEC norms separately for 600 MW (subcritical) and 660 MW (supercritical) units, the Commission is of the view that the norms for 500 MW stations have been reduced by 0.75% to 5.25% and not much improvement in the AEC is envisaged at this point for super critical units and therefore the same auxiliary energy consumption norms have been specified for these Units.

37.91 Some stakeholders suggested that the AEC norms for power plants based on coal rejects should be lower than 10%. However, some of the generating companies have suggested to increase the norm to 12%. The Commission approved the norms for such stations in accordance with 125 MW lignite fired stations, considering that such stations shall be based on smaller Unit sizes. The Commission is of the view that the prescribed norm of 10% is appropriate and has hence, retained the same.

38. Norms of operation for Hydro generating Stations {Regulation 37}

38.1 Clause 37 of the draft Regulations specified the norms of operation for hydro generating stations.

<u>Stakeholders' Comments/Suggestions</u>

38.2 Some of the stakeholders submitted that in order to incentivise hydro station to use 10% extra capacity it is proposed that NAPAF norms of all the station with 10% extra capacity should be increased by at least 5%.

38.3 Some of the stakeholders submitted that separate norms for run-of-river with pondage may be specified. PTC submitted that in the absence of any specific formula, it is presumed that capacity charge for run-of-river type is as good as energy charges. PTC further submitted that for the sake of clarity, it may be better to state that in respect of run-of river type hydro power station, the entire Annual Fixed Charge (AFC) is to be recovered as Design Energy Charge and capacity charge does not apply and therefore, exemption of 3 hour peaking requirement for run-of-river type power station may be brought out.

38.4 THDC submitted that Para 3 of Regulation 37(3) may be modified as follows:

> *"Provided further that the beneficiaries share of capacity in the generating station, in part is reallocated by the Central Government, and the owner of the capacity share shall be responsible for arranging the equivalent energy to the generating station in off-peak hours, and be entitled to corresponding energy during peak hours in the same way as the original beneficiary was entitled.*
>
> *In case, the beneficiary surrenders its share in the PSP, the corresponding capacity charges shall be continued to be borne by the original beneficiary till their share of capacity is reallocated by the Government of India."*

38.5 NHPCsubmitted that NAPAF of Loktak power station should be fixed at 80% after allowing a relaxation of 5% applicable to projects of North East region. NHPC further submitted that NAPAF for Bairasiul, Uri, Rangit and Dhauliganga for current tariff period may be retained. SJVN submitted that the norms of operation for hydro generating stations for pondage type plants where plant availability is significantly affected by silt have been considered as 85%. Therefore, in consideration of above facts, being significantly affected from the silt, NAPAF of NJHPS may be considered as 85%. NHDC submitted that in multipurpose projects, head will be constrained due to water utilization at different sources and therefore with passage of time NAPAF of ISP may be allowed to be reduced to 80% and OSP 85%.

38.6 NEEPCO submitted that the recommended NAPAF of 79% for Kopili Stage 1 is not achievable by the said power station as it is facing a special case of acidification of its reservoir water which started during 2009-10 and is aggravating year by year causing frequent outages of the units. Therefore, the normal procedure of fixing NAPAF on the basis of operational data of last five years will not be justifiable in this case. NEEPCO further submitted that a special treatment for Kopili stage 1 and NAPAF may be considered on the basis of average from FY 2009-10 onwards as follows.

Year	**2009-10**	**2010-11**	**2011-12**	**2012-13**	**2013-14 (Till Nov, 13)**	**Average**
NAPAF (in %)	63	68	78	63	63	67

38.7 APDCL submitted that the actual Plant Availability Factor achieved by RHEP during last four years is on higher side and therefore NAPAF fixed for RHEP may be re-fixed at a higher level. OHPC submitted that for existing hydro power stations, the type of power stations and years of operation of these power stations as on 01.04.2014 may also be indicated.

Commission's Views

38.8 Some of the stakeholders have suggested that the NAPAF norms for hydro generating stations having 10% additional capacity should be increased by 5%. The Commission is of the view that the norms prescribed by the Commission are on the basis of actual PAF during FY 2008-09 to FY 2012-13. Any declaration of capacity over and above 100% of the installed capacity in the past has already been captured in the PAF achieved by the station and therefore the same is getting factored in as the norms are determined on the basis of actual performance data.

38.9 With regard to the suggestion received from SJVNL to retain the norms for the station as 85%, the Commission is of the view that the station has average plant availability factor of 97.97% and therefore the suggestion to retain the current norm of 85% is not justified.

38.10 With regard to suggestion received from NHDC that NAPAF of its stations shall be affected by increase in water utilisation for some other purpose and therefore the NAPAF should be relaxed for its stations. The Commission in this regard is of the view that the data for FY 2008-09 to FY 2012-13 suggests that NHDC stations have been able to achieve the norm and the norms have been specified accordingly and there is no reason that these stations will not be able to achieve NAPAF if operated optimally.

38.11 The Commission with regard to Sewa II had proposed NAPAF norm of 80%. However, the Commission is of the view that the NAPAF for the station being a pondage type plant, and the plant being able to achieve 85% NAPAF during FY 2011-12, should be revised to 85%. The Commission has accordingly revised the norm for the station from 80% to 85%.

Auxiliary Energy Consumption (Regulation 37(6))

<u>Stakeholders' Comments/Suggestions</u>

38.12 NHPC submitted that auxiliary energy consumption should be retained as per existing norms. NHPC further submitted that in case of Nimmo Bazgo and Chutak projects located in Laddakh region, requiring de-icing at barrage intake, huge heating is required in winter season and therefore higher auxiliary energy consumption than normative auxiliary energy consumption as per actual may be permitted. NHDC submitted that as the quantum of auxiliary energy consumption is expected to increase with the age of the machinery, it would be prudent that the auxiliary energy consumption norms for a generating station may be linked with the age of Generating Station. OHPC and THDC submitted that for Surface hydro generating stations with static excitation system, AEC may be specified as 1.0% and for Underground hydro generating stations with static excitation system AEC may be specified as 1.2%. SJVN submitted that auxiliary energy consumption in the draft

Regulation for high silt plant like NJHPS may please be considered same as in the Regulation 2009-14.

38.13 One of the stakeholders submitted that the norms for auxiliary energy consumption should be revised as follows:

"a) Surface hydro generating stations

(i) with rotating exciters mounted on the generator shaft : 0.7%

(ii) with static excitation system : 1.0%

b) Underground hydro generating stations

(i) with rotating exciters mounted on the generator shaft : 0.9%

(ii) with static excitation system : 1.2%"

38.14 Various stakeholders submitted that the Auxiliary energy consumption should not be reduced and must be allowed on actual based on differential figures of Generator Energy Meter and Bus bar Energy Meters. Various stakeholders submitted that the hydro station's auxiliary energy shall cover operations at reservoirs (Head Works) and colony power as they are usually at remote locations. Various stakeholders further submitted that the hydro generating units below 200 MW should be allowed an auxiliary power energy of 2%.Jaiprakash Power submitted that AEC for underground hydro generating stations with static excitation system should be retained as 1.2%.

Commission's Views

38.15 The Commission in its draft regulation proposed auxiliary energy consumption norms on the basis of data furnished by the generating stations. However, NHPC submitted that the auxiliary energy consumption data submitted doesn't include transformational losses and accordingly requested to consider 0.50% as transformational loss. The Commission has computed auxiliary energy consumption of NHPC stations as follows.

Table 21: Auxiliary Energy Consumption for NHPC stations

S. No	Stations	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13
1	Bairasul Power Station	1.18%	1.42%	1.44%	1.72%	1.93%
2	Loktak Power Station	1.76%	1.94%	1.54%	1.81%	2.38%
4	Tanakpur Power Station	0.65%	1.10%	1.22%	1.17%	1.34%
5	Rangit Power Station	0.96%	2.09%	2.36%	2.20%	1.99%
6	Dahuliganga Power Station	1.01%	0.67%	1.20%	1.20%	1.23%
7	Dulhasti Power Station	0.98%	1.01%	0.97%	0.95%	1.04%
8	Teesta- V Power Station	1.01%	0.54%	1.10%	1.13%	1.33%
9	Sewa-II Power Station	NA		1.08%	1.38%	1.45%

38.16 In view of the above, the Commission has reviewed the norms proposed in the draft regulations and has specified the current norms of auxiliary consumption as shown below:

Auxiliary Energy Consumption

(a) Surface hydro generating stations

(i) with rotating exciters mounted on the generator shaft : 0.7%

(ii) with static excitation system : 1.00%

(b) Underground hydro generating stations

(i) with rotating exciters mounted on the generator shaft : 0.9%
(ii) with static excitation system : 1.2%

39. Other Comments on O&M Norms for Generation

39.1 GUVNL submitted that the supply of power is greater than the demand and the generating stations have to put their Units on Reserve Shut Down (RSD). However, Central Sector Generating stations (CSGS) are compulsorily operating the plants at technical minimum as and when it gets power requisition of even small quantum from single beneficiary whereas other beneficiaries have to force avail their share though not requisitioned. This leads to the issues of load management for beneficiaries and they are getting instruction from RLDC/SLDC. Therefore, CSGS may be directed to put their units under RSD in such condition or schedule the entire technical minimum power to the beneficiary who has requisitioned the power.

39.2 POSOCO submitted that to support the part load operation/two shifting by thermal generators, provision for separate Heat rate and secondary oil consumption norms may be made. POSOCO further submitted that technical minimum for different types of units may be specified to avoid operational difficulties. One of the stakeholder submitted that the proposed norms in the Draft Notification have been tightened compared to the norms applicable for the previous five years block of 2009-14. It further submitted that norms need review. TERI submitted that the Commission may define a trajectory (signifying annual improvement) for the Units, where no perceptible improvements in operating parameters have occurred.

39.3 Prayas Energy Group submitted that in light of the present issues as well as importance of fuel cost as a major factor influencing generation tariff, there is a need to facilitate more informed public understanding and one simple and inexpensive way of doing this would be to mandate all generating companies to publish station wise (later, when unit-wise measurement systems are in place, data should be published at unit level) information regarding source wise (i.e. CIL subsidiary, captive mine, e-auction and/or imports) quantity and cost (separating out transportation cost) of coal procured on monthly basis. Prayas Energy Group further submitted that in similar manner, all generating companies regulated by CERC must be directed to share on their website monthly unit-wise performance in terms of net and gross generation, auxiliary fuel consumption, heat rate, load factor and availability along with fixed and variable costs for that period.

Commission's Views

39.4 With regard to problem faced by the generator and beneficiaries on account of operating the plants at technical minimum, the Commission is already aware of the issue and shall appropriately address the issue separately. Further with regard to suggestion received that a trajectory should be specified for generating stations that have showed a little or no improvement in past, the Commission in this regard has already specified improved norms of various generating stations with regard to various operational parameters as well as O&M expenses.

39.5 With regard to the suggestion to upload daily generation and associated fuel cost data, the Commission has, through its order dated December 31, 2012 directed the generating companies to specify key operational parameters and fuel cost details. The Commission agrees that a greater level of transparency is needed and the same can be achieved by sharing of information by the generating company with the beneficiaries on regular basis. The Commission would appropriately address the issue separately, at an appropriate time.

40. Normative Annual Transmission System Availability Factor (NATAF) {Draft Regulation 38} and Computation and Payment of Transmission Charge for Inter-State Transmission System {Draft Regulation 33}

40.1 For recovery of Annual Fixed Charges, the draft regulations proposed NATAF in case of AC System and HVDC bi-pole lines and HVDC back-to-back stations as 98% and 95% respectively. The draft regulations also proposed the separate NATAF of 99% and 98% for incentive consideration of AC System and HVDC bi-pole lines and HVDC back-to-back stations respectively. For Computation and Payment of Transmission Charge for Inter-State Transmission System the draft Regulations proposed with the existing provisions specified in the CERC Tariff Regulations, 2009.

Stakeholders' Comments/Suggestions

40.2 POWERGRID submitted as under:

a. Given the substantial increase in number of transformers and reactors at 765 kV level, there is substantial impact on regional availability due to outage of 765 kV transformers and reactors. The impact on monthly availability will be huge and it will bring down the regional availability below 96% in some regions due to outage of only one 765 kV transformer;
b. Annual maintenance carried out for HVDC station generally requires around 7 days for carrying out the annual maintenance of each pole in

HVDC station. This will bring down the monthly availability of HVDC system to 76.67%, with further tripping due to problem in HVDC station or problem in the line and the monthly availability will come down below 75%. Setting high target of normative target availability will force the utilities to compromise the maintenance of the system resulting in threat to stability and reliability of the grid and the Annual availability for HVDC system for Transmission charges & Incentives may be reconsidered;

c. The Commission may provide explanation for deriving the multiplication factors since POWERGRID believes that it is difficult to correlate the three elements since transmission line carries active load, transformer also carries active load but reactors never carry active load;

d. The calculation made by CERC appears incorrect as transmission line length considered by CERC for the availability calculation is inclusive of line length of HVDC lines, whereas, HVDC availability is calculated separately. If HVDC lines were to be considered, then in such a case MVA of HVDC system should also have been considered for the calculation. Further, CERC has only considered switchable MVAR capacity and not the total MVAR capacity installed in the Grid;

e. It submitted that the present trend of asset addition under three heads of MVAR, MVA and ckt x NSA in different proportion is likely to continue during the tariff period 2014-19. Therefore, the concept as adopted by CERC will not hold good in future. The multiplication factors will vary widely over the years and it will get reduced. Hence, the same cannot be applied. It proposed to restore the availability calculation in line with the calculation adopted in Regulation 2001-04 and 2004-09, which will take care of the above issues;

a. Availability for both AC and HVDC system need to be reduced; and

b. Reliability Index needs to be reviewed in the present condition of the transmission system.

40.3 Power System Operation Corporation Limited (POSOCO) submitted following suggestions:

a. The availability target for full fixed charge recovery may be reduced to encourage proper maintenance;

b. Number of tripping per annum may also be factored i.e., each tripping above a value (as may be decided by CERC) may be considered as reduction of availability, say 12 hours;
c. The Fixed Series Capacitors (FSCs) and Thyristor Controlled Series Capacitors(TCSC) may be considered as a separate asset pool, like SVCs and the treatment of availability of the Line reactor may be done as part of the Transmission line;
d. The control equipment such as HVDC Filters, Line Reactors, etc., are an essential part of transmission system. Their non-availability poses difficulty in the reliable and secure system operation. Therefore, non-availability of control equipment may also be dis-incentivized;
e. The treatment for estimation of Availability when different transmission licensees are associated for bays and lines;
f. Dependability should also be captured for recovery of fixed charges, as availability is necessary, but not sufficient condition. There are factors that affect the reliability of the power system; and
g. Fixed Charges recovery of existing generating stations/transmission system (as applicable) may also be linked to various suggested items.

40.4 Some of stakeholders submitted that in view of higher availability achieved in transmission system, the norms of NATAF for AC system should be increased to 99% and for HVDC it should be increased to 97% for recovery of fixed charges, whereas, for incentive consideration NATAF norms should be fixed at 99.5% (in case of AC) and 98.5% (in case of HVDC).

40.5 Delhi Transco Limited submitted that the normative target availability for full recovery of fixed cost of the transmission system may be fixed at 96% for AC transmission system and the planned maintenance outage should be excluded from the calculation of transmission system availability. It further submitted that the calculation of availability, which was applicable for the Tariff Period from FY 2001-04 and FY 2004-09 may be applied. However, the guidelines specified in CERC Tariff Regulations, 2009 are appropriate and may be retained for the ensuing Tariff period with the exception of the calculation of availability, which needs to be modified.

40.6 SRPC proposed the NATAF for recovery of Annual Fixed Charges & incentive consideration as follows:

(1) AC system:98%
(2) HVDC bi-pole links and HVDC back-to-back stations: 95%

Provided that for recovery of incentive, NATAF in case of HVDC bi-pole links and HVDC back-to-back stations 2.04% (100/0.98) would be proportionately distributed beyond 95% to 100%

It submitted that in this case there would be no incentive for transmission licensee to maintain its asset if it knows that it cannot meet NATAF of 99% and 98%. There would be no incentive area in between 98 and 99% for AC system and 95-98% for HVDC system. However, if construction outages are considered in Transmission Licensee account its incentive could be given beyond 98% and 95%.

40.7 Tata Power Company Limited, Adhunik Power & Natural Resources Ltd., Confederation of Indian Industry, Association of Power Producers and some other stakeholders submitted that the proposed norm for incentive shall drastically affect the performance planning of Transmission Companies and undo the basis/reason on which the investments were made during last Tariff Period (FY 2009-14) to enhance the reliability and availability of the lines. It is proposed that Normative Availability of transmission system may be kept at 98% to incentivize the transmission system operator. They further submitted the observation that for certain standalone transmission system any one major failure/breakdown may affect the transmission availability significantly.

40.8 Powerlinks submitted that maintaining average line availability above 98% for a single project company is challenging compared to central transmission company like POWERGRID. Association of Power Producers, TATA and Powerlinks submitted the observation that for certain standalone transmission system any one major failure/breakdown may affect the transmission availability significantly. Some of the stakeholders submitted that the Commission would agree that such mid-life investments are done keeping in mind the returns during the balance life and any significant upward change in the performance benchmarks shall prove adverse for the Companies and the Stakeholders contrary to Section 66 of the Act. They proposed that the existing normative Transmission Availability of 98% should be retained beyond which the Transmission Licensee should be allowed to recover the Incentive.

40.9 Jaiprakash Power Ventures Limited submitted that existing norm of Plant Availability for incentivizing the transmission licensee is already very stringent and any further increase will be very harsh for the developer. It suggested that it should be reduced to 97% and if not reduced, it should be at least retained at 98%.

40.10 TPGL suggested that the NATAF for incentive consideration should be specified at the level of NATAF for recovery of Annual Fixed Charges of transmission system i.e. at 98% in line with the prevalent Regulation.

40.11 GUVNL, with reference to Regulation 33(4), submitted that the draft Regulation provides that transmission licensee shall issue monthly bills based on estimated TAFM ((Transmission availability factor of month) and subsequently adjustments needs to be made. The present practice of issuing bills based on certification of Regional Power Committees (RPC) may be continued to avoid duplication or adjustments.

40.12 SRPC with reference to regulation 33(2) submitted that the formula can be used only if NATAF is same for recovery of AFC and incentive. However, since NATAF is different for AFC recovery and incentive, formula would be required to be modified.

40.13 SRPC submitted that the NAFM does not consider the voltage levels, and one circuit of 765 kV would be equivalent to one circuit of 400 kV or 220 kV line if ckt-km length is same. It proposed weightages for transmission lines of 765kV/400kV/220kV & below. It submitted that it may be clarified whether 'r', which has been identified as a bus reactor, switchable line reactor or SVC, contains line reactor or not. It further, submitted that the CERC Standard of Performance Regulations specified it as Reactor, however, in this regulation it clearly specifies as Bus Reactor & switchable line reactor.

40.14 SRPC submitted that shutdown of existing elements on account of construction activities of new elements by a transmission licensee could be removed from deemed availability since around 14.4 hrs (at NATAF of 98%) are available in every month for each element. Hence, construction activity period could easily be absorbed by all the elements. This would also ensure that transmission licensee avails minimum possible time for construction activity. It also submitted that outages due to other business should not be considered as deemed available. Further, determination of reasonable time is also very difficult to compute.

40.15 SRPC submitted that Force Majeure definition may need to be defined with more clarity as there have been instances of the transmission licensee claiming relief under this for lightning, storm, bushfire, etc.

40.16 WBSEDCL submitted that there is no remedy for failure of transmission service. If the transmission service provider is unable to cater to the long term beneficiaries, generator and DIC, then care is to be taken through this regulation that neither the generator nor the beneficiaries suffer out of this. As such, any loss due to unavailability of the transmission system is to be shared equally both by the generators and the beneficiaries considering it to be a force majeure condition. It sought clarification on this aspect.

40.17 TANGEDCO submitted that it is seen from the formulae given in para. 33(2), the incentive for the transmission system is included as a percentage of the annual transmission charges. By linking the incentive with the annual fixed charges, the incentive is not uniform for all transmission assets and depends on the Capital cost, which is the backbone for determination of transmission charges.

Commission's Views

40.18 The Commission in the Explanatory Memorandum to draft Regulations analysed the actual availability of transmission system and observed that average transmission system availability for regional AC transmission system in five regions from FY 2008-09 to FY 2012-13 ranges from 99.59% to 99.89%, with an average of five regions around 99.76%. The average availability of AC system for the period FY 2003-04 to FY 2007-08 was 99.50% and that for period from FY 2008-09 to FY 2012-13 was 99.76%.

Table 22: Transmission System Availability of Regional AC Transmission System from FY 2008-09 to FY 2012-13 (Figures in %)

Region	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13	Average
NR	99.67	99.66	99.86	99.92	99.87	**99.80**
WR	99.55	99.73	99.42	99.95	99.91	**99.71**

ER	99.73	99.83	99.95	99.99	99.95	**99.89**
SR	99.53	99.84	99.95	99.94	99.96	**99.84**
NER	99.28	99.24	99.57	99.93	99.925	**99.59**

Table 23: Transmission System Availability of Regional AC Transmission System from FY 2003-04 to FY 2007-08 (Figures in %)

Region	FY 2003-04	FY 2004-05	FY 2005-06	FY 2006-07	FY 2007-08	Average
NR	99.11	99.70	99.59	98.27	99.47	**99.23**
WR	99.78	99.82	99.75	99.81	99.76	**99.78**
ER	99.66	99.91	99.38	99.48	99.66	**99.62**
SR	98.33	99.64	99.64	99.74	99.59	**99.39**
NER	99.41	99.57	99.59	99.44	99.47	**99.50**

40.19 Similarly, in case of HVDC Bipole scheme Rihand-Dadri and Talcher-Kolar average transmission system availability from FY 2008-09 to FY 2012-13 is 99.05% and 99.10% respectively. In case of HDVC back-to-back stations average transmission system availability from FY 2008-09 to FY 2012-13 ranges from 99.33% to 99.75%.

Table 24: Transmission System Availability of HVDC transmission System from FY 2008-09 to FY 2012-13 (Figures in %)

Region	FY 2008-09	FY 2009-10	FY 2010-11	FY 2011-12	FY 2012-13	Average
Rihand-Dadri	98.27	99.32	98.70	NA	99.93	**99.05**
Balia-Bhiwadi#	-	-	-	-	-	
Talcher-Kolar	99.23	98.03	99.75	99.16	99.32	**99.10**
Vindhyachal BTB	98.81	98.78	99.35	99.92	99.78	**99.33**
Chandrapur BTB	99.13	98.46	97.85	99.46	99.79	**98.94**
Sasaram BTB	98.94	99.99	100.00	100.00	99.83	**99.75**
Gazuwaka BTB	99.63	99.41	99.07	99.71	99.73	**99.51**

40.20 Further, spare converter transformers are also available in the HVDC stations and it would be appropriate to pass on the benefit to consumers in terms of availability.

40.21 Some stakeholders submitted that the proposed norm for incentive shall drastically affect the performance planning of Transmission Companies and undo the basis/reason on which the investments were made. It is worthwhile to mention that the target availability for the generating station has been increased during the tariff periods, whereas the availability in case transmission system remained unchanged at 98%(AC). For HVDC stations (bi-pole links) it was changed from 95% to 92%, and for HVDC back-to back stations it remained unchanged at 95%. As regards submission that any significant upward change in the performance benchmarks shall prove adverse for the Companies and the Stakeholders contrary to Section 66 of the Act, the Commission is of the view that such target setting is done as per the Section 178 of the Act read with Section 61. Section 61 requires that while specifying the terms and conditions for determination of tariff, the Commission shall be guided by factors which encourage good performance and the principles rewarding efficiency in performance. Though, the objectors have mixed the issue of specifying the norms of operation with Section 66, the Commission is of the view that such target setting is not contrary to the Section 66 of the Act. In fact the Section 66 of the Act mandates CERC to promote development of markets in electricity (including trading) through regulations. In view of past performance, technological advancement and prudent practices followed by the transmission licensees, the target of incentive applicability has been set. The Commission is of the view that specified NATAF level shall result in increased availability of transmission system, which shall be in the interest of consumers.

40.22 Views of the stakeholder that the availability target for full fixed charges recovery may be reduced to encourage proper maintenance was examined with respect to the availability achieved in the past years. It was found that most of the planned maintenance was done by availing the time available when lines were opened under high voltage conditions which sometimes continued for days together. In addition various opportunities are available wherein it is possible that through co-ordination with upstream and downstream network owners, planned maintenance can be done without affecting availability factor. The availability targets therefore need not be reduced.

40.23 Accordingly, the Commission has decided to specify the following targets:

Normative Annual Transmission Availability Factor (NATAF) for recovery of Annual Fixed Charges shall be as under

(1) AC system : 98%

(2) HVDC bi-pole links and HVDC back-to-back Stations : 95%

Normative Annual Transmission Availability Factor (NATAF) for Incentive applicability shall be as under

(3) AC system : 98.50%

(4) HVDC bi-pole links and HVDC back-to-back Stations : 96%

Provided that for new HVDC stations, NATAF shall be considered as 95% for first three years of operations for the purpose of incentives.

40.24 It is clarified that three years of operation in case of HVDC stations shall be considered from the date of COD

40.25 In case of new HVDC stations, taking into consideration the teething troubles during the initial period due to new technology, configuration issues, etc., it has been decided based on the experience in case of national and international projects that the norms for incentive be reduced by 1%, and be kept as 95%.

40.26 Views of the stakeholders that setting high target of normative target availability will force the utilities to compromise the maintenance of the system resulting in threat to stability and reliability of the grid, was analysed in detail. Further, stakeholders requested to reconsider the Annual availability for HVDC system for Transmission charges & Incentives. The Commission observed that outage required for carrying out annual maintenance for different transmission elements is in the range of 8 to 12 hours. As regards annual maintenance carried out for HVDC station, generally around 7 days are required for carrying out the annual maintenance of each pole in HVDC station. In the Ofgem report on 'Calculating Target Availability Figures for HVDC Interconnectors', the estimated scheduled maintenance unavailability has been worked out in the range of 0.27% to 0.82%. Further, as stated in the para above, the transmission licensee carries out the maintenance of its transmission system during available opportunity/through hot line maintenance techniques. Moreover, for outages such as opening of lines under high voltage conditions as per instruction of system operator, for which no reduction in availability is done, are being utilized for maintenance purpose. The Commission agrees with the suggestion that certain minimum time is required for maintenance of the system, at the same time, it also needs to ensure that the licensee does not extend the outage hours. Therefore, availability for incentive calculations is capped at 99.75%, to have flexibility for carrying out normal/routine maintenance work throughout the year. Further, the capping is also required for maintaining the system for the purpose of high incentive, which may otherwise come in way of maintaining the system security on account of poor maintenance. Accordingly, no incentive shall be payable for the availability beyond 99.75%.

40.27 As detailed breakup of POWERGRID system were not available, availability figure gave the overall picture in case of HVDC. Further, the norms also formulated based on the international studies. Central Transmission Utility which now has long experience of different type of HVDC configurations both from international vendor and national manufacturer must undertake a component wise study for the HVDC system which should segregate Mean Time Between Failure (MTBF) for all the components of the HVDC system such as mechanical CB, power electronic component, DC CB, etc. for five years of the tariff period and make report available to the Commission. In addition to this, a report on outage each year of all HVDC system shall be submitted to the Commission indicating planned outage hours and unplanned outage hours. The reasons of unplanned outage and time taken to rectify the problem shall be given to the Commission and the System Operator, i.e. NLDC.

40.28 POSOCO suggested that availability does not ensure the reliability and submitted factors viz. certain number of trippings per year, multiple tripping of lines and/or generating units leading to loss of generation/load, faults causing more than one element tripping due to undesirable operation of the power system, which affects reliability of the power system. It suggested that for factoring of tripping per annum and each tripping above a value may be considered as reduction of availability. The Commission agrees with the suggestion of POSOCO that tripping are to be seen element wise and is of the view that to begin with for each AC system element i.e. for individual line, ICT, Reactor, SVC, etc., two trippings per year shall be allowed, and after two trippings in a year, 12 hours of outage to that particular element for each such tripping shall be considered in addition to the actual outage. Further in case of outage of a transmission element affecting evacuation of power from a generating station outage hours shall be multiplied by a factor of 2.

40.29 The Statement of Objects and Reasons for CERC (Terms and Conditions of Tariff) Regulations, 2009 stated as under:

> *"…. Factors have been applied such that a 315 MVA transformer would have the same weightage as a 200 km long D/C line with twin conductors, and a 50 MVAR switched reactor would have one-fourth the weightage of a 315 MVA transformer. The transmission lines shall have a weightage proportional to their circuit – km and number of sub-conductors (to which the current carrying capacity is directly proportional). Voltage has been omitted by design for the present, to deliberately enhance the weightage for 220 kV and 132 kV lines (as they are critical for supply to beneficiaries), and to suppress the weightage for 765 kV lines (since they presently carry power much below their capability). The Commission may review and modify the formula when the situation changes in future."*

40.30 It is noted that the number of 400 kV/765 kV lines have been increasing exponentially and their weightage (outage) needs to be suitably factored in the availability computation. It is observed that resultant formula after incorporating formulations for voltage wise weightages for line and different capacity of transformers and reactors and other suggestions loses significance. POWERGRID submitted that the asset addition to grid is much different on a year to year basis for Ckm, MVAR, MVA. Further, present trend of asset addition under all three heads are in different proportion is likely to continue over the ensuing years in the Control Period 2014-19. POWERGRID also submitted that the multiplication factor as derived by CERC will get substantially distorted over the years and it may so happen that the multiplication factor for transformer may come down below 1.0 with the addition of 1200 kV system.

40.31 The Commission has considered suggestions of POSOCO and is of the view that ICTs and reactors are important elements for reliable supply to the beneficiaries and their weightages need to be higher in the calculation.

40.32 Considering the suggestions received, the Commission has decided to re-adopt the formula for calculation of availability of AC and HVDC portion of transmission system specified under Appendix-III 'Procedure for calculation of Transmission System Availability' under the CERC (Terms and Conditions of Tariff)

Regulations, 2004, with necessary modifications. This formula gives due weightage to 765 kV and 400 kV transmission lines, which are now major part of the inter-State transmission system. However, the Commission has retained other provisions of the 'Procedure for calculation of Transmission System' specified in CERC Tariff Regulations, 2009 with necessary modifications.

40.33 In this regard the question may be raised about the grounds given in the Statement of Reasons to the CERC (Terms and Conditions of Tariff) Regulations, 2009 that Surge Impedance Loading (SIL) has no direct relationship with the power carrying capability of transmission line and SIL loses its significance totally in case a line has a shunt reactor or series compensation. SIL was also not considered appropriate due to change in SIL values due to addition of reactors. This has been taken care of by providing that in case of series and shunt compensated line, the value of SIL shall be modified in accordance with reactor configuration and percentage of compensation.

40.34 As regards suggestion that NAFM formula does not consider the voltage levels, the Commission has, for the tariff period 2014-19,adopted the earlier formula for calculation of availability specified during the tariff period 2004-09 with suitable modification.

40.35 As regards suggestion on providing clarity on definition of 'Force Majeure', the relevant definition has been incorporated under the main Regulations.

40.36 As regards suggestion on provision of issuance of monthly bills by the transmission licensee based on estimated TAFM (Transmission availability factor of month) and subsequent adjustments, the Commission has removed the said provision in the Regulations.

40.37 As regards determination of reasonable restoration time, 'a procedure for calculation of transmission system availability factor for a month' has been updated with a provision which reads as under:

> *'…A reasonable restoration time for the element shall be considered in accordance with Central Electricity Regulatory Commission (Standard of*

> *Performance of inter-State transmission licensees) Regulations, 2012 as amended from time to time and…'*

Further, the provision reading *'Member Secretary, RPC may consult the transmission licensee or any expert for estimation of reasonable restoration time'* has been dropped.

40.38 As regards suggestion of WBSEDCL regarding remedy for failure of transmission system, the procedure of calculation for transmission system availability factor for a month envisages different scenarios. Further, the Commission has also introduced a proviso which states as under:

> *'Provided also that in case of outage of a transmission element affecting evacuation of power from a generating station outage hour shall be multiplied by a factor of 2.'*

40.39 As regards suggestion on modification on AFC recovery and incentive formula on account of different NATAF, the Commission has incorporated following formula in the regulations.

(2) The Transmission charge (inclusive of incentive) payable for a calendar month for transmission system or part shall be

For AC system:

a) For TAFM ≤ 98%

AFC x (NDM/NDY) x (TAFM/98%)

b) For TAFM: 98%< TAFM <98.5%

AFC x (NDM/NDY) x (1)

c) For TAFM: 98.5%<TAFM ≤99.75%

AFC x (NDM/NDY) x (TAFM/98.5%)

d) For TAFM ≥99.75%

AFC x (NDM/NDY) x (99.75%/98.5%)

For HVDC bi-pole links and HVDC back-to-back Stations:

a) For TAFM ≤ 95%

AFC x (NDM/NDY) x (TAFM/95%)

b) For TAFM: 95%< TAFM <96%

AFC x (NDM/NDY) x (1)

c) For TAFM: 96%≤ TAFM ≤99.75%

AFC x (NDM/NDY) x (TAFM/96%)

d) For TAFM $\geq$99.75%

AFC x (NDM/NDY) x (99.75%/96%)

Where,

AFC = Annual Fixed Cost specified for the year in Rupees

NATAF = Normative annual Transmission availability factor, in per cent

NDM = Number of days in the month

NDY = Number of days in the year

TAFM = Transmission System Availability Factor for the month, in percent computed in accordance with Appendix III.

40.40 Further, non availability of related substation line bay/bay equipment shall be considered as non-availability of transmission line.

41. Auxiliary Energy Consumption in the sub-station {Draft Regulation 39}

41.1 For Auxiliary Energy Consumption in the AC sub-station and HVDC sub-station the draft regulations proposed to continue with the existing provisions specified in the CERC Tariff Regulations, 2009.

Stakeholders' Comments/Suggestions

41.2 POWERGRID referred to the CEA Regulations, 2010 and submitted that it is facing some difficulties for implementation of CEA regulation as two independent sources of supply for a substation are not available for a number of its substations. It submitted that this auxiliary power supply is also not reliable for a number of cases because of frequent outages in utility system and in order to run the system smoothly with reliable auxiliary power supply, it proposed for inclusion in the regulation that tertiary of ICTs installed in a substation be utilized for auxiliary power supply through an auxiliary transformer for O&M of the substation. It submitted that this will not only comply with CEA Regulations of two independent sources but also will ensure higher reliability. POWERGRID further submitted the proposed formulation of Regulations.

"a) AC System

Tertiary of ICTs installed in a substation be utilized through an auxiliary transformer for reliable auxiliary power supply for O&M of HVAC substation.

For auxiliary energy consumption in HVAC sub stations, the Central Government may allocate an appropriate share from one or more ISGS. The variable charges for such power shall be borne by the transmission licensee and are included in the normative operation and maintenance expenses.

b) HVDC sub-station

For auxiliary energy consumption in HVDC sub-stations, the Central Government may allocate an appropriate share from one or more ISGS. The charges for such power shall be borne by the transmission licensee and are included in the normative operation and maintenance expenses."

Commission's Views

41.3 The CEA in exercise of powers under Section 73 of the Act has specified the CEA (Technical Standards for Connectivity to the Grid) Regulations, 2007. POWERGRID has submitted its difficulty in implementing the Regulations. The Commission is of the view that removing difficulty in CEA Regulations through the regulations and that too under Tariff Regulations is not a correct approach. As regards allocation of appropriate share from the ISGS for auxiliary energy consumption of HVDC stations in the absence of any indication/sufficient justification, the Commission is not inclined to add such provision. Therefore, no change is required in the existing provision on this account.

42. Billing and Payment of Charges (Regulation 42)

42.1 The Commission in its Regulation 40 of Draft Tariff Regulations proposed that the generating company/transmission licensee shall raise the bills on monthly basis and accordingly the beneficiaries or long term customers/DICs shall pay directly to the generating company/transmission licensee. The payment of the capacity charge for a thermal generating station shall be shared by the beneficiaries of the generating station as per their percentage shares for the month (inclusive of any allocation out of the unallocated capacity) in the installed capacity of the generating station. Payment of capacity charge and energy charge for a hydro generating station shall be shared by the beneficiaries of the generating station in proportion to their shares (inclusive of any allocation out of the unallocated capacity) in the saleable capacity to be determined after deducting the capacity corresponding to free energy to home State. Further, the Commission proposed that the beneficiary State may surrender their part of allocated firm share to other states/outside the region and accordingly the reallocation may be done by the appropriate authority.

42.2 With regard to the hydro power project, the Commission proposed free energy equal to 12%, in addition to energy corresponding to 100 units of electricity to be provided free of cost every month to every project affected family for a period of 10 years from the date of commercial operation of the generating stations. In this regard, the Commission further proposed that such free energy shall be equal to 13% in case where the State Govt. awarded the site of hydro project to a developer by following a two stage transparent process of bidding.

Stakeholders' Comments/Suggestions

42.3 West Bengal State Electricity Distribution Company Ltd. (WBSEDCL) has proposed that the free energy for hydro power projects may be kept at 12% instead of 13%. In this regard, NHPC has further proposed that free energy for home State for hydro power projects may be kept as 12% or 13% as per allocation of power issued by Ministry of Power, Govt. of India. Further, THDC India Ltd. has proposed that no free power to home state shall be admissible out of the energy generated from the recycled water in case of a Pumped Storage Hydro Generating Station as the water is not being used in the natural way using its potential energy for generation of conventional power.

42.4 With regard to the un-requisitioned quantum of power, Southern Regional Power Committee (SRPC) suggested that all the generating stations, be allowed to change schedule for the un-requisitioned quantum of power from one beneficiary(s) of the same power station on the requisition by these beneficiaries through the provision provided in the IEGC. In case original beneficiary requests back for its share of power, then its schedule and schedules of beneficiary who had availed URS power would be revised in the six time block again, or as specified in the IEGC as amended from time to time. These schedule revisions would be treated as allocation of power on temporary basis.

42.5 West Bengal State Electricity Distribution Company Ltd. (WBSEDCL) has proposed that there must be maximum period (say six month from the surrender of allocation by the beneficiaries) during which re-allocation must be made by Central

Govt. so that beneficiaries may be relieved from the burden of Capacity Charge for the surrendered capacity. Further, during the said six month period the fixed charge should be shared by Generating Company as well as beneficiaries in the ratio of 1:1.

Commission's Views

42.6 On the issue of free energy for hydro projects to be considered as 12% or 13%, the Commission has decided to modify this provision as follows:

> *"Note 3*
> *FEHS =Free energy for home State, in percent and shall be taken as 13% or actual whichever is less.*
> *..."*

42.7 The Commission would like to clarify that the issues related to revision of schedule shall be governed by the provisions of the Grid Code.

42.8 On the issue raised by WBSEDCL with respect to re-allocation of capacity to be made within six months, the Commission would like to clarify that the re-allocation of capacity from generating stations is not under the purview of the Commission. Further, the Commission is of the view that the sharing of fixed charge in the ratio of 1:1 pending re-allocation will not be appropriate as the same will lead to under-recovery of fixed charges for the generating company and till the re-allocation of capacity is done, the beneficiary who have been allocated capacity shall bear the Annual Fixed Charges in proportion to its share.

43. Sharing of Transmission Charges {Draft Regulation 43}

43.1 The draft Regulations proposed that the sharing of transmission charges shall be governed by the Central Electricity Regulatory Commission (Sharing of inter-state transmission charges and losses) Regulations, 2010 from the date of coming into effect. For the charges determined in relation to communication system forming part of transmission system, the draft Regulations proposed sharing of charges by the beneficiaries or long-term transmission customers in proportion to their allocated capacity from the inter-state generating stations or as decided by the Commission. However, in case of the communication system under ULD&C other than central transmission system, the Commission proposed sharing of charges by beneficiaries in proportion of their capital cost.

Stakeholders' Comments/Suggestions

43.2 POWERGRID submitted that the communication charges for central sector portion may be recovered under POC mechanism and provisions in the regulations may be modified accordingly. It submitted that as the State sector is responsible for SCADA and WAMS also, the term "under ULD&C" under proviso may be deleted.

Commission's Views

43.3 The sharing of transmission charges is governed by the CERC (Sharing of Transmission Charges and Losses in inter-State Transmission System) Regulations, 2010 as amended from time to time. Therefore, the Commission considers it appropriate to extend the applicability of Sharing Regulations in case of sharing of the charges in relation to communication system forming part of transmission system. The Regulations have been modified accordingly. Further, in line with the POWERGRID suggestion, the proviso has been modified suitably thereby deleting the term 'under ULD&C'.

44. Rebate (Regulation 44)

44.1 In the draft Tariff Regulations, the Commission proposed to continue with the existing rebate of 2% on payment of bills through letter of credit on presentation and rebate of 1% for payment of bills other than letter of credit within 30 days of presentation of bills.

Stakeholders' Comments/Suggestions

44.2 Tamil Nadu Generation and Distribution Corporation Limited (TANGEDCO) has proposed to avoid opening of revolving L.C. as it is a recurring expenditure to the beneficiaries. Alternatively, direct payment may be released within 3 days of presentation of bills supported by a backup L.C. covering the monthly bills in order to provide a security to the generating company/transmission licensee. Further, Power Grid has proposed for payment through NEFT/RTGS in place of LC as this will save the LC operating charges and also its reinstatement every month. GRIDCO has proposed for rebate of 2% for payment of bills through LC (or any other mode having standby LC) within 2 days and a rebate of 1% for payment of bills through any other mode on 30th day.

44.3 Chhattisgarh State Power Generation Company Limited (CSPGCL) proposed for linking the rebate (%) to the working capital interest rate as the Rebate compensates the saving on working capital interest. Further, the rebate should also be computed on daily basis in order to incorporate interest on all short term borrowings.

Commission's Views

44.4 The Commission has gone through the suggestions of the stakeholders and is of the view that it would be appropriate to include payment through NEFT/RTGS for payment of bills and claiming rebate. Accordingly, the Commission has decided to modify the draft Regulation on Rebate as under:

> ***"44. Rebate*** *(1) For payment of bills of the generating company and the transmission licensee through letter of credit on presentation or through NEFT/RTGS 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."*

45. Late Payment Surcharge (Regulation 45)

45.1 In the draft Tariff Regulations, the Commission proposed to modify the existing rate of late payment surcharge from 1.25% per month to 1.50% per month.

Stakeholders' Comments/Suggestions

45.2 Some of the beneficiaries including West Bengal State Electricity Distribution Company Ltd. (WBSEDCL) and Tripura State Electricity Corporation Ltd. (TSECL), Assam Power Distribution Company Ltd. (APDCL), MSEDCL and GRIDCO are in favour of retaining the existing rate of Late Payment surcharge of 1.25% per month. Further, M.P. Power Management Company Ltd. (MPPMCL) has proposed for the late payment surcharge of 1% per month. THDC India Ltd. has proposed that the rate of late payment surcharge should be at par with the rebate of 2% on presentation of bill for prompt payment.

45.3 Association of Power Producers (APP) has suggested for linking late payment surcharge to the lending rate as the late payment leads to increase in loan on working capital. It should be equal to Bank Rate (i.e. SBI = 350 bp) plus 250 basis points per annum for each month of delay.

45.4 Chhattisgarh State Power Generation Company Limited (CSPGCL) has proposed for linking the surcharge (%) to the working capital interest rate as the Delay payment surcharge compensates the additional burden on working capital interest. Further, the surcharge should also be computed on daily basis in order to incorporate interest on all short term borrowings.

Commission's Views

45.5 The Commission has gone through the comments and suggestions of the stakeholders and observed that the generators have requested to link the rate of late payment surcharge to lending rate whereas beneficiaries have requested to reduce the same. The Commission is of the view that the rate of late payment surcharge at 1.50% per month for payment beyond a period of 60 days from the date of billing as specified in the Draft Tariff Regulations is appropriate and does not require any change.

46. Sharing of CDM Benefits (Regulation 46)

46.1 The Commission in draft Tariff Regulations proposed to continue with the existing provisions of sharing the proceeds of carbon credit on account of CDM project. The project developer shall retain 100% of the gross proceeds in the first year after the date of commercial operation of the generating station/transmission system. In the second year, the share of the beneficiaries shall be 10% which shall be progressively increased by 10% every year till it reaches 50%, where after the proceeds shall be shared in equal proportion, by the generating company or the transmission licensee, as the case may be, and the beneficiaries.

Stakeholders' Comments/Suggestions

46.2 Association of Power Producers (APP) and other stakeholders have submitted that the generator takes the development risk to implement the project and no return on equity is earned during implementation period. Therefore, CDM revenues should be retained by the project developer and not be subject to sharing with the beneficiary.

Commission's Views

46.3 The Commission is of the view that under cost plus regime, all the legitimate costs are allowed to be recovered through tariffs, including the return on equity. As the benefits earned through CDM projects will be additional benefits, it will be appropriate to have sharing mechanism as proposed in the Draft Regulations for such benefits.

47. Deferred Tax Liability (Regulation 49)

Stakeholders' Comments/Suggestions

47.1 The Commission in draft Regulations proposed to continue with the existing provision of recovery of deferred tax liability/tax credit, directly from the beneficiaries and the long-term customers/DICs. Such provision is applicable only for the deferred tax liability/tax credit up to March 31, 2009.

47.2 In this regard, Power Grid has suggested for extending this provision for the deferred tax liability/tax credit up to March 31, 2014.

Commission's Views

47.3 The Commission is of the view that up to March 31, 2009 the tax on the income streams of the generating company or transmission of electricity from its core business was allowed to be recovered from the beneficiaries with the provision for adjustment of under-recoveries or over-recoveries. However, from April 1, 2009 onwards, the Commission is allowing the pre-tax ROE i.e., RoE with the grossing up of applicable tax rate. Hence, this provision cannot be extended for the deferred tax liability up to March 31, 2014. Further, in order to remove any confusion and ambiguity, the Commission has decided to modify Regulation as under:

> *"49. Deferred Tax liability with respect to previous tariff period: The deferred tax liability before 1.4.2009 shall be recovered from the beneficiaries or the long term transmission customers/DICs as the case may be, as and when the same gets materialised. No claim on account of deferred tax liability arising from 1.4.2009 up to 31.03.2014 shall be made from the beneficiaries or the long term transmission customers/DICs as the case may be."*

48. Foreign Exchange Rate Variation (Regulation 50 and 51)

48.1 In the draft Tariff Regulations, the Commission proposed to continue with the existing regulation of hedging foreign exchange exposure and repayment of foreign loan. Moreover, the Commission proposed that the generating company or transmission licensee, as the case may be, should communicate to the beneficiaries about its hedging decision (on its approved hedging policy) within 30 days of entering into such hedging transaction. Also, the Commission proposed that in case of inability of hedge the foreign exchange exposure, the generating company or transmission licensee, as the case may be, shall furnish certificate along with claim indicating the reasons for its inability or for its decision for not hedging the foreign exchange exposure in respect of payment of interest or repayment of loans. Further, the Commission proposed to continue with the recovery of hedging and foreign exchange rate variation on year-to-year basis.

48.2 In Regulation (51) of the Draft Tariff Regulations, the Commission proposed to continue with the existing provision for recovery of hedging or Foreign Exchange Rate Variation by the Generating/Transmission Company without making any application before the Commission. In case there is any objection by the beneficiaries/long-term transmission customers/DICs, then the Generating/Transmission Company shall make an appropriate application before the Commission for its decision.

<u>Stakeholders' Comments/Suggestions</u>

48.3 THDC India Ltd. has suggested for removing the provision of furnishing certificate by the generating company or transmission licensee, as the case may be, in case of inability to hedge the foreign exchange exposure. Some of the stakeholders suggested the companies should be allowed to take call of hedging without any restriction or reporting requirement as it is difficult to predict.

48.4 One of the stakeholders has proposed for recovery of Foreign Exchange Rate Variation on monthly basis as per the actual payment profile of Debt Service on Foreign Loan. Further, NTPC Ltd. has proposed for billing the FERV or hedging cost to beneficiaries as and when it is paid by the generating company.

48.5 Power Grid has suggested that in case beneficiaries or long-term transmission customers/DICs have any objection for recovery of hedging or Foreign Exchange Rate Variation by the Generating/Transmission Company, then they shall make an appropriate application before the Commission for its decision.

<u>Commission's Views</u>

48.6 The Commission has gone through the comments and suggestions of the stakeholders and is of the view that the provision with respect to furnishing of certificate by the generating company or transmission licensee, as the case may be, in case of inability to hedge the foreign exchange exposure needs to be deleted. Accordingly, the Commission has decided to remove Regulation 50(5) of the Draft Tariff Regulations, which stated as under:

> *"(5) The petitioner shall furnish certificate along with claim on this count indicating the reasons for its inability or for its decision for not hedging the foreign exchange exposure in respect of payment of interest or repayment of loans."*

48.7 As regards the recovery mechanism for recovery of hedging or foreign exchange rate variation, the Commission is of the view that the mechanism proposed in Draft Tariff Regulations is appropriate and does not require any change.

49. Application fee and the publication expenses (Regulation 52)

49.1 With regard to the application filing fee and the expenses incurred on publication of notices in the application for approval of tariff, the Commission in its draft Tariff Regulations proposed for recovery of such expenses by the Generating Company or the Transmission Licensee directly from the beneficiaries/long-term transmission customers/DICs.

<u>Stakeholders' Comments/Suggestions</u>

49.2 Tamil Nadu Generation and Distribution Corporation Limited (TANGEDCO) has proposed for withdrawing the provision of reimbursement of the fee and the publication expenses directly by the beneficiaries/long-term transmission customers/DICs because such fees is for the interest of his business promotion only. Chhattisgarh State Power Generation Company Limited (CSPGCL) submitted that the petition filing and publication of notice is part of routine business. Therefore, such expense is part of O&M expense and should not be separate pass through to the beneficiary.

49.3 Various Stakeholders has proposed that the application filing fee and the expenses incurred on publication of notices in the application for approval of tariff are the legitimate expenses. In this regard discretion of the Commission may not be required.

49.4 Power Grid has proposed that other taxes including service tax, property tax or any other tax liabilities arises from time to time may also be allowed with retrospective dates.

<u>Commission's Views</u>

49.5 The Commission has gone through the suggestions given by the stakeholders and would like to reiterate that under the cost plus regime, the application filing fee and the expenses incurred on publication of notices in the application for approval of tariff may be allowed to be recovered separately. Accordingly, the Commission is of the view that the draft Regulation is appropriate and does not require any changes.

49.6 With regards to suggestion received on other taxes to be allowed, the Commission while approving the norms of O&M expenses has considered the taxes as part of O&M expenses while working out the norms and therefore the same has already been factored in. With regards to allowing these taxes on retrospective basis, the Commission is of the view that such recovery cannot be allowed on retrospective basis as such expenses were already included in the base norms.

50. Special Provisions relating to Damodar Valley Corporation (Regulation 53)

50.1 In the draft Tariff Regulations, the Commission proposed to continue with the existing special provisions related to tariff determination of the projects owned by Damodar Valley Corporation (DVC). The draft Regulation provided for the following special provisions to DVC:

> "(i) **Capital Cost:** The expenditure allocated to the object 'power', in terms of sections 32 and 33 of the Damodar Valley Corporation Act, 1948, to the extent of its apportionment to generation and inter-state transmission, shall form the basis of capital cost for the purpose of determination of tariff:
>
> Provided that the capital expenditure incurred on head office, regional offices, administrative and technical centres of DVC, after due prudence check, shall also form part of the capital cost.
>
> (ii) **Debt Equity Ratio:** The debt equity ratio of all projects of DVC commissioned prior to 01.01.1992 shall be 50:50 and that of the projects commissioned thereafter shall be 70:30.
>
> (iii) **Depreciation:** The depreciation rate stipulated by the Comptroller and Auditor General of India in terms of section 40 of the Damodar Valley Corporation Act, 1948 shall be applied for computation of depreciation of projects of DVC.
>
> (iv) **Funds under section 40 of the Damodar Valley Corporation Act, 1948:** The Fund(s) established in terms of section 40 of the Damodar Valley

Corporation Act, 1948 shall be considered as items of expenditure to be recovered through tariff."

Stakeholders' Comments/Suggestions

50.2 TERI (Tata Energy Research Institute) has suggested for not providing any special provisions to DVC under fourth proviso of Section 14 of EA, 2003. DVC may be directed to have separate accounts for power generation, flood control and for irrigation. For power projects owned by DVC, the equity should maximum be limited to 30% of the Capital Cost and the return on equity may be accordingly decided. Further, as per DVC Act, DVC funds are made of three activities and there is no reason behind burdening the power sector consumers of this expense. Further, Section 33 of DVC Act mentions of trifurcation of DVC's costs to its three functions. Hence, the Fund(s) established in terms of section 40 of the Damodar Valley Corporation Act, 1948 shall not be considered as items of expenditure to be recovered through tariff In this regard, it is suggested to add a regulation stipulating that DVC should ring fence its power sector activities with other activities and prepare separate accounts for power sector activities and other activities. Further, for depreciation, DVC should follow the provisions of EA 2003. In this regard, the provision regarding depreciation as per CERC Regulations may be followed.

50.3 One of the stakeholders has proposed that subject to the Hon'ble Supreme Court Order in case No. 4289 of 2008 Appeal, special treatment being allowed to DVC is no more relevant.

Commission's Views

50.4 Hon'ble Appellate Tribunal for Electricity (ATE) in its judgement dated 23.11.2007 in Appeal No. 273 of 2006 has interpreted the fourth proviso to section 14 of the Act. The said proviso reads as under:

> *"Provided also that the Damodar Valley Corporation, established under sub-section (1) of section 3 of the Damodar Valley Corporation Act, 1948, shall be deemed to be a licensee under this Act but shall not be required to obtain a licence under this Act and the provisions of the Damodar Valley Corporation Act, 1948, in so far as they are not inconsistent with the provisions of this Act, shall continue to apply to that Corporation:"*

50.5 The Tribunal after detailed examination of the provisions of the Electricity Act and the DVC Act has come to the conclusion that the fourth proviso to section 14 clearly implies that only such of the provisions of the DVC Act which are inconsistent with the Electricity Act shall not apply. The Central Commission cannot frame regulations for determination of tariff of DVC which are inconsistent with the provisions of the DVC Act that do not collide with the Electricity Act. In other words, the Commission is required to frame terms and conditions of tariff regulation which will accommodate such of the provisions of the DVC Act which are not inconsistent with the Electricity Act, 2003.

50.6 The Tribunal in Para 89 of the judgement has stated that the Legislature, expected that the Central Commission while framing regulations under the Electricity Act, 2003 will take care of such provisions of the DVC Act not inconsistent with the Act. The provisions of the DVC Act which are not inconsistent with the Act shall continue to apply. In Para 91 of the judgment held that the regulations under the Act are to be read in addition to and not in derogation of any other law (i.e. provisions of Part IV of DVC Act) for the time being in force that means the Regulations, 2004 formulated by the Central Commission need to be read along with the provisions of Part IV of DVC that relate to the power-object of DVC.

50.7 On specific grounds of appeal, the Tribunal has given the following directions:

a) **Debt-Equity Ratio:** The DVC Act is silent about adopting any specific Debt Equity Ratio for financing of projects. In the interest of equity and fairness, all old projects of DVC commissioned prior to 1992 be assigned debt equity ratio of 50:50 and the recent projects be assigned debt-equity ratio of 70:30 as specified in the 2004 regulations. [Para A-8 of the Hon'ble ATE Judgement dated November 23, 2007 in Appeal No. 273 of 2006]

b) The capital infused by the participating Governments is in the nature of equity capital and for the purpose of determination of tariff, the same should be eligible for return on equity. [Para A-14 of the Judgement]

c) The DVC Act envisages the projects to be built only on capital contributed by the participating Governments and any deficit in the capital amount is to be made good by taking loan on behalf of the participating Government. The debt taken will attract interest. The average interest rate of repayment payable during the tariff year is to be applied on 50:50 normative debt capital for tariff purposes. The excess of equity over the normative debt equity ratio shall be considered as interest bearing debt and serviced accordingly. [Para A-16 of the Judgement]

d) The Central Commission has worked out a sum of ₹.1534.49 crore to create Pension and Gratuity Contribution Fund with the stipulation that 60% thereof shall be recovered through the tariff and the remaining 40% to be contributed by the DVC. The decision of the Commission is not backed by any justification and the entire cost is allowed to be recovered through tariff. However, the recovery should be staggered in a manner that it does not create tariff-shock to consumers. [Para D-1 of the Judgement]

e) The expenditure incurred by DVC on objects other than irrigation, power and flood control be allocated to these three heads as per sections 32 and 33 of DVC Act and expenditure so allocated to power object, should be allowed to be recovered through the electricity tariff. [Para E-12 of the Judgement]

f) Sinking funds established with the approval of Comptroller and Auditor General of India vide letter dated December 29, 1992 under the provision of Section 40 of the DVC Act is to be taken as an item of expenditure to be recovered through tariff. [Para E-15 of the Judgement]

g) **Depreciation** – The Electricity Act does not make any provision for factoring rate of depreciation in tariff determination. Accordingly, DVC Act in so far as depreciation is concerned, not inconsistent with the Act and shall continue to apply to the Corporation. The Central Commission is directed to adopt rate of depreciation as prescribed by Comptroller and Auditor General of India for computation of tariff for the assets based on the principles outlined in Para F-3 of the Judgement. [Para F-2 and F-4 of the Judgement]

h) **Operation and Maintenance expenses** – The Tariff Regulations, 2004 notified by the Commission generally provide for a 4% increase in O&M expenses annually. The same shall be adopted in case of DVC also to offset additional burden on the Appellant due to inflationary measures. [Para GH.5 of the Judgement]

i) Expenditure incurred on repair, renovation and modernization aimed at extending the useful life of the assets would be eligible, subject to prudence check, for capitalization and would be eligible for recovery through tariff once the assets are again put to use. [Para J.2 of the Judgement]

50.8 In view of the above discussion, the Commission feels that the provisions in draft Regulation is appropriate and does not require any changes.

50.9 Further, the special provisions relating to DVC shall be subject to the decision of the Hon'ble Supreme Court in Civil Appeal No 4289 of 2008 and other related appeals pending in the Hon'ble Court and shall stand modified to the extent they are inconsistent with the decision.

51. Timeline for completion of Projects (Appendix I)

51.1 In the Draft Tariff Regulations, the Commission proposed to continue with the existing specified timelines for completion of Projects in case of transmission schemes. Further, based on the stakeholders comments/suggestions on the approach paper, the Commission also proposed timelines in case of '765 kV D/C Transmission line', '400 KV M/C Quad or more sub-conductor Transmission line', '400 KV M/C Twin/Triple Transmission line', and '400 KV S/C Six or more sub-conductor Transmission line'.

<u>Stakeholders' Comments/Suggestions</u>

51.2 POWERGRID in relation to the timelines proposed in the draft regulations for completion of transmission schemes submitted that timelines proposed in the draft regulations have considered the timelines proposed by the Task Force constituted by the Ministry of Power, which covers physical construction time. It submitted that the Task Force recommended that adequate margins needs to be provided on case to case basis depending upon the specific issues pertaining to the transmission element being developed by the Utility. It submitted that timelines should have a period of 6/12 months for pre-award activities in addition to the construction period specified in the Regulations. It submitted that actual time required in arranging clearances/ROW/court matters/Multilateral Agencies like World Bank, ADB etc. may be allowed. It further submitted that the additional RoE should be allowed on stage wise completion of transmission elements, which can be put into regular service independently in line with generation projects.

Commission's Views

51.3 It was observed that a transmission project approved by the Board of transmission licensee has many element in case of projects for evacuation of generation and regional system strengthening scheme. With past experience of 2009-14 tariff period it was found that if additional RoE is subjected to completion of all elements of transmission projects, very few projects qualified for additional RoE. The purpose of additional RoE is to incentivise early completion of the projects which benefit both transmission licensee and beneficiary in form of benefit of power flow and saving in IDC.

51.4 The data for completion of various transmission projects completed during 2009-2013 as submitted by POWERGRID to CEA was analysed. Based on analysis of time period with respect to Investment Approval and actual construction period, it was found that additional time period of six months should be given if timeline is computed with respect to Investment Approval date.

51.5 In view of the suggestions, the Commission considers it appropriate to provide additional time period of 6 months against each of transmission works proposed in the draft Regulations. Further, additional ROE of 0.50% may be allowed if any element of the transmission project is completed within the specified timeline and it is certified by the Regional Power Committee/National Power Committee that commissioning of the particular element has given benefit the system operation in the regional/national grid.

51.6 From the analysis of data it was found that transmission line of shorter length was completed within 18-24 months, therefore, the timelines suggested in draft regulations cannot be applied for short lines, and additional RoE need not be given for transmission lines of length less than 50 km. It is also intended here that LILO are not created for evacuation of generation because operational difficulties were reported by the system operators in case of LILOs. In view of the length of transmission line being commissioned, it is considered that additional RoE shall not be admissible for transmission line having length of less than 50 km. Accordingly, suitable provisos have been made under Regulation 24.

51.7 It is also clarified that these timelines are for allowing additional RoE and shall not be applicable for extension of the existing substation by creating additional bays. The timelines are for new substations for which timelines are computed considering all activities like land acquisition and works, etc.

51.8 The Commission would like to place on record its highest appreciation and sincere thanks for those organisations, stakeholders and interested parties who have spared their time and efforts to respond to our proposals and provided invaluable suggestions in shaping up Tariff Regulations, 2014.

(-Sd-)	*(-Sd-)*	*(-Sd-)*
[A.K.SINGHAL]	**[M. DEENA DAYALAN]**	**[GIREESH B. PRADHAN]**
MEMBER	**MEMBER**	**CHAIRPERSON**

New Delhi
Dated the 24th April, 2014

Annex –1

(The list of stakeholders who offered comments/suggestions on the draft Regulations)

Sr. No.	Name of Stakeholder
1	Madhya Pradesh Electricity Regulatory Commission (MPERC)
2	Punjab State Electricity Regulatory Commission (PSERC)
3	Damodar Valley Corporation (DVC)
4	NEEPCO
5	Neyveli Lignite Corporation (NLC)
6	NHDC
7	NHPC
8	NTPC
9	SJVNL
10	Southern Regional Power Committee (SRPC)
11	Power System Operation Corporation Ltd. (POSOCO)
12	Power Grid Corporation of India Limited
13	Jaipur Vidyut Vitran Company Ltd.
14	Chhattisgarh State Power Distribution Company Limited (CSPDCL)
15	Maharashtra State Electricity Distribution Company Limited (MSEDCL)
16	Uttar Pradesh Power Corporation Limited (UPPCL)
17	Uttarakhand Power Corporation Limited (UPCL)
18	West Bengal State Electricity Distribution Company Limited (WBSEDCL)
19	Assam Power Distribution Company Ltd. (APDCL)
20	Chhattisgarh State Power Generation Company Limited (CSPGCL)
21	Gujarat Urja Vikas Nigam Ltd. (GUVNL)
22	HPGCL (Haryana Power Generation Corporation Limited)
23	Maharashtra State Power Generation Company Limited (MSPGCL)
24	Odisha Hydro Power Corporation Ltd. (OHPC)
25	Power Company of Karnataka Ltd. (PCKL)
26	Pragati Power Corporation Ltd.
27	Punjab State Power Corporation Limited (PSPCL)
28	Tamil Nadu Generation and Distribution Corporation Limited (TANGEDCO)
29	Kerala State Electricity Board (KSEB)
30	Tripura State Electricity Corporation Ltd.
31	Delhi Transmission Company Limited (DTL)
32	GRIDCO Ltd.
33	PTC India Ltd.
34	MP Power Management Company Ltd.

Sr. No.	Name of Stakeholder
35	A D Hydro
36	Adani Power Limited
37	Adhunik Power and Natural Resources Limited
38	Alstom India Ltd.
39	Association of Power Producers (APP)
40	Athena Demwe Power Ltd.
41	BSES
42	DIL
43	GMR Kamalanga Energy Ltd. (GKEL)
44	Haldia Energy
45	Jaiprakash Power Ventures Ltd.
46	Jindal Power Ltd.
47	JSW Energy Ltd.
48	Lalitpur Power Generation Company Limited
49	Lanco Power Limited
50	Madhu Gupta & Co.
51	ONGC Tripura Power Company Limited (OTPC)
52	Reliance Power Limited
53	Rudraksh Energy
54	Sesa Sterlite Ltd.
55	Shalivahana Green Energy Ltd.
56	Tata Power Company Limited
57	Tata Power Delhi Distribution Limited
58	THDC India Ltd.
59	Torrent Power Grid Limited (TPGL)
60	Torrent Power Limited
61	Wartsila India Ltd.
62	Power Link
63	Confederation of Indian Industry (CII)
64	Deutsche Bank
65	IIFL
66	IL&FS Energy Development Company Limited (IEDCL)
67	Aam Admi Party
68	Maharana Pratap Bagh Resident's Welfare Association
69	Mr. A. Raja Rao
70	Mr. Arun Kumar Dutta (Individual)
71	Mr. Bharat Tiwari
72	Mr. BNP Singh (Individual)

Sr. No.	Name of Stakeholder
73	Mr. Gurnek Singh Brar
74	Mr. H. M. Sharma (Individual)
75	Mr. M. S. Narasimhan
76	Mr. Padamjit Singh
77	Mr. R. B. Sharma
78	Mr. Shailendra Jain
79	Mr. Shanti Prasad
80	Ms. Mallika Sharma Bezbaruah (Individual)
81	Prayas (Energy Group)
82	The Energy Research Institute (TERI)
83	Urja Gyan Foundation
84	Mumbai Grahak Panchayat
85	Mr. T. K. Srivastava

Annex – 2

(The list of stakeholders who participated in the public hearing held on 15th and 16th January, 2014)

Sr. No.	Name of Stakeholder
1	MP Power Management Company Ltd.
2	Damodar Valley Corporation (DVC)
3	NEEPCO
4	Neyveli Lignite Corporation (NLC)
5	NHDC
6	NHPC
7	NTPC
8	SJVNL
9	Power System Operation Corporation Ltd. (POSOCO)
10	Power Grid Corporation of India Limited
11	Uttar Pradesh Power Corporation Limited (UPPCL)
12	Uttarakhand Power Corporation Limited (UPCL)
13	West Bengal State Electricity Distribution Company Limited (WBSEDCL)
14	Gujarat Urja Vikas Nigam Ltd. (GUVNL)
15	Gujarat State Electricity Corporation
16	Maharashtra State Power Generation Company Limited(MSPGCL)
17	Pragati Power Corporation Ltd.
18	Punjab State Electricity Board (PSEB)
19	Tamil Nadu Generation and Distribution Corporation Limited (TANGEDCO)
20	Kerala State Electricity Board (KSEB)
21	Tripura State Electricity Corporation Ltd. (Representative from Govt. of Tripura)
22	GRIDCO Ltd.
23	Adani Power Limited
24	BSES (BRPL and BYPL)
25	Lanco Power Limited
26	Madhu Gupta & Co.
27	THDC India Ltd.
28	Torrent Power Limited
29	Wartsila India Ltd.
30	Moserbaer
31	Aam Admi Party
32	Mr. Arun Kumar Dutta (Individual)
33	Mr. Gurnek Singh Brar
34	Mr. Padamjit Singh (PSPCL)

Sr. No.	Name of Stakeholder
35	Mr. H. M. Sharma (Individual)
36	Mr. R. B. Sharma
37	Mr. T. K. Srivastava
38	Prayas (Energy Group)
39	The Energy Research Institute (TERI)
40	Mumbai Grahak Panchayat
41	Mr. V. K. Gupta (PSPCL)

ABBREVIATIONS

Abbreviation	Full Form
AAD	Advance Against Depreciation
AEC/APC/AUX	Auxiliary Energy Consumption
AFC	Annual Fixed Cost
APDCL	Assam Power Distribution Company Limited
APL	Adani Power Limited
APP	Association of Power Producers
APTEL/ATE	Appellate Tribunal For Electricity
BEE	Bureau of Energy Efficiency
BSE	Bombay Stock Exchange
BTG	Boiler, Turbine and Generator
CAGR	Compound Annual Growth Rate
CAPM	Capital Asset Pricing Model
CCEA	Cabinet Committee on Economic Affairs
CCGT	Combined Cycle Gas Turbine
CDM	Clean Development Mechanism
CEA	Central Electricity Authority
CERC	Central Electricity Regulatory Commission
CFBC	Circulating Fluidised Bed Combustion
CGS	Central Generating Station
CII	Confederation of Indian Industry
CIL	Coal India Limited
COD	Commercial Operation Date
CPI	Consumer Price Index
CPRI	Central Power Research Institute
CSPDCL	Chhattisgarh State Power Distribution Company Limited
CSPGCL	Chhattisgarh State Power Generation Company Limited
CSR	Corporate Social Responsibility
CTU	Central Transmission Utility
CVPF	Calorific Value of Primary Fuel
DC	Declared Capacity
DDC MIS	Digital Distributed Control Monitoring and Information System
DICs	Designated ISTS (Inter-State Transmission System) Customers
DISCOM	Distribution Company
DNHR	Design Net Heat Rate
DOCO	Date of Commercial Operation
DPE	Department of Public Enterprises

Abbreviation	Full Form
DPR	Detailed Project Report
DVC	Damodar Valley Corporation
ECR	Energy Charge Rate
FEHS	Free Energy for Home State
FERV	Foreign Exchange Rate Variation
FGMO	Free Governor Mode Operation
FSC	Fixed Series Compensation
GCV	Gross Calorific Value
GFA	Gross Fixed Asset
GIS	Gas Insulated sub-station
GOI	Government of India
G-Sec	Government Securities
GUVNL	Gujarat Urja Vikas Nigam Limited
HEP	Hydro-Electric Plant
HPPC	Haryana Power Purchase Centre
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
IC	Installed Capacity
ICB	International Competitive Bidding
IDC	Interest During Construction
IEDC	Incidental Expenditure during Construction
IEDCL	IL&FS Energy Development Company Limited
IEGC	Indian Electricity Grid Code
IOWC	Interest on Working Capital
IPP	Independent Power Producers
JVVNL	Jaipur Vidyut Vitran Nigam Limited
KSEB	Kerala State Electricity Board
LTSA	Long Term Service Agreement
LTMA	Long Term Maintenance Agreement
MAT	Minimum Alternate Tax
MCR	Maximum Continuous Rating
MERC	Maharashtra Electricity Regulatory Commission
MGO	Minimum Guaranteed Off take
MNHR	Median Net Heat Rate
MoEF	Ministry of Environment and Forests
MOP	Ministry of Power
MoU	Memorandum of Understanding
MPERC	Madhya Pradesh Electricity Regulatory Commission
MPPMCL	Madhya Pradesh Power Management Company Limited

Abbreviation	Full Form
MSEDCL	Maharashtra State Electricity Distribution Company Limited
MSPGCL	Maharashtra State Power Generation Company Limited
NAPAF	Normative Annual Plant Availability Factor
NAPLF	Normative Annual Plant Load Factor
NATAF	Normative Annual Transmission Availability Factor
NEEPCO	North Eastern Electric Power Corporation Limited
NFA	Net Fixed Asset
NHDC	Narmada Hydroelectric Development Corporation Limited
NHPC	NHPC Limited
NJHPS	Nathpa Jhakri Hydro Power Station
NLC	Neyveli Lignite Corporation Limited
NLDC	National Load Despatch Centre
NTPC	NTPC Limited.
O&M	Operation and Maintenance
OEM	Original Equipment Manufacturer
OHPC	Odisha Hydro Power Corporation Limited
OTPC	ONGC Tripura Power Company Limited
PAF	Plant Availability Factor
PAFM	Power Availability Factor for a calendar month
PAFY	Power Availability Factor for a calendar year
PAT	Perform, Achieve and Trade scheme
PCKL	Power Company of Karnataka Limited
PGCIL/POWERGRID	Power Grid Corporation of India Limited
PLC	Programmable Logic Controller
PLCC	Power Line Carrier Communication
PLF	Plant Load Factor
PLR	Prime Lending Rate
PMU	Phasor Measurement Unit
POC	Point of Connection
POSOCO	Power System Operation Corporation Limited
PPA	Power Purchase Agreement
PPCL	Pragati Power Corporation Limited
PRP	Performance Related Pay
PSERC	Punjab State Electricity Regulatory Commission
PSPCL	Punjab State Power Corporation Limited
PSU/ CPSU	Public Sector Undertaking/ Central Public Sector Undertaking
R&D	Research and Development
R&M	Renovation and Modernisation

Abbreviation	Full Form
R&R	Rehabilitation and Resettlement
RBI	Reserve Bank of India
RGGVY	Rajiv Gandhi Grameen Vidyutikaran Yojana
RGMO	Restricted Governor Mode of Operation
RLDC	Regional Load Despatch Centre
RLNG	Re-Gasified Liquefied Natural Gas
ROCE	Return on Capital Employed
ROE	Return on Equity
RPC	Regional Power Committee
RSD	Reserve Shut Down
SBI	State Bank of India
SCADA	Supervisory Control And Data Acquisition
SCOD	Scheduled Commercial Operation Date
SERCs	State Electricity Regulatory Commissions
SFOC/SFC	Secondary Fuel Oil Consumption
SHR	Station Heat Rate
SIL	Surge Impedance Loading
SJVNL	Satluj Jal Vidyut Nigam Limited
SLDC	State Load Despatch Centre
SRPC	Southern Region Power Committee
SVC	Static VAR Compensator
TANGEDCO	Tamil Nadu Generation and Distribution Corporation Limited
TAFM	Transmission Availability Factor of Month
TERI	The Energy Research Institute
THDC	Tehri Hydro Development Corporation
TPGL	Torrent Power Grid Limited
TPL	Torrent Power Limited
TPS	Thermal Power Station
UI	Unscheduled Interchange
ULD&C	Unified Load Despatch & Communication Scheme
UMPP	Ultra Mega Power Project
UPCL	Uttarakhand Power Corporation Limited
UPPCL	Uttar Pradesh Power Corporation Limited
VRS	Voluntary Retirement Scheme
WAMS	Wide Area Measurement System
WBSEDCL	West Bengal State Electricity Distribution Company Limited
WPI	Wholesale Price Index