CERC (Terms and Conditions for Tariff determination from Renewable Energy Sources) Regulations, 2009

Statement of Objects and Reasons

1. Introduction

1.1 The Electricity Act, 2003 (hereinafter referred to as "the Act") under Section 79 assigns the following functions to the Central Electricity Regulatory Commission (hereinafter referred to as the "Commission"), 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;

1.2 Further, Clause 6.4 of Tariff Policy entrusts the responsibility on the Central Commission to frame guidelines for pricing of non-firm power especially from non-conventional sources for the cases when procurement is not through the competitive bidding process.

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

1.4 In exercise of the powers vested under sections 61 and 178 (2)(s) of the Act and all other enabling powers and in compliance of the provisions of Clause 6.4 of the Tariff Policy and the requirement under section 178 (3) of the Act, the Central Commission issued vide public notice no. No.L-7/186(201)/2009-CERC dated 15th May, 2009 the draft of Central Electricity Regulatory Commission (Terms and Conditions for Tariff determination from Renewable Energy Sources) Regulations, 2009 (hereinafter referred to as the draft regulations) along with explanatory memorandum for comments/ suggestions/ objections thereon.

1.5 Subsequently, the amendment in draft Regulations was made by the Commission to incorporate the norms for Solar PV and Solar Thermal technology. The draft of Amendments, consolidated draft Renewable Regulations and explanatory memorandum was issued vide public notice no. No.L-7/186(201)/2009-CERC dated 1st July, 2009 for comments/ suggestions/ objections thereon.

1.6 Subsequently, public hearing was held on 22nd July 2009 to hear views of all the stakeholders and consumers, if any. A statement indicating in brief the comments received from various stakeholders is enclosed as **Annexure-I**. The list of participants in the public hearing held on 22 July, 2009 is enclosed as **Annexure-II**.

2. Consideration of the views of the stakeholders and analysis and findings of the Commission on important issues

<u>Comments on Definitions</u>

3. Definition of Interconnection point

3.1 In the draft Regulations, the inter-connection point for projects based on different RE technologies was specified.

3.2 BEST undertaking suggested that definition of inter-connection point should be in accordance with the definition mentioned in the Competitive Bidding Guidelines and Case -1 Standard Bidding Documents issued by Govt of India:

> "*Interconnection Point" shall mean the point where the power from the Power Station switchyard bus of the seller is injected into the interstate/intrastate transmission system (including the dedicated transmission line connecting the Power Station with the interstate/intrastate transmission system).*

3.3 The Commission is of the view that the issues of evacuation and grid connectivity in case of renewable energy projects with their smaller project/unit size and characteristic features need to be addressed, if more and more renewable energy generation is to be harnessed. The Commission also observes that in most of the States, responsibility of licensee and project developer in developing the evacuation infrastructure for RE projects varies considerably. In most of the cases, inter-connection point stretches up to nearest grid sub-station and associated cost for development of such evacuation infrastructure is required to be borne by the project developer. The Commission considers that responsibility of project developer and licensee towards developing the evacuation infrastructure should be clearly demarcated. Therefore, for providing clarity on this critical issue, the inter-connection point has been defined in the Regulations. Further, definition of interconnection point needs to specifically address requirements of Renewable Energy projects. Accordingly, Interconnection Point in respect of each RE technology has been defined separately.

4. Definition of Non-firm Power

4.1 Some of the stakeholders suggested bringing energy generation from biomass power also under the ambit of non firm power.

4.2 The term non-firm power has not been defined under Electricity Act 2003 or Tariff Policy. As a result the interpretation of the term assumes significance. One reasonable interpretation of the term 'non-firm' is the power that cannot be scheduled. Forum of Regulators (FOR) under its Report on policies for renewables has referred to MNRE's (Ministry of New and Renewable Energy) suggestion that renewable energy sources such as wind energy, solar, small hydel etc. may be treated as Non-firm RE sources. However, in case of biomass power (above 10 MW) and non-fossil fuel based co-generation, the electricity generation can be very well scheduled, if fuel management chain is adequately established and the same may be treated as firm RE sources. Further, the Commission clarifies that principles for preferential tariff determination have been specified for all types of RE sources, whether firm RE or non-firm RE, as the case may be, under the said RE Tariff Regulations.

5. Definition of Renewable Energy Sources

5.1 In the draft Regulations, following definition was provided for renewable energy sources:

> ***"Renewable Energy Sources"*** *means renewable sources such as mini hydro, wind, solar including its integration with combined cycle, biomass, bio fuel cogeneration, urban/municipal waste and other such sources as approved by the MNRE;*

5.2 The Transparent Energy Systems Private Limited submitted to include Industrial wastes of all types i.e. solid, liquid and gaseous in the definition of Renewable Energy Sources.

5.3 Tamil Nadu Electricity Regulatory Commission suggested that word 'non-conventional energy sources' should also be defined, and heat energy generated from the chemical reaction of NCES sources may also be included in the scope of Regulations.

5.4 The Commission is of the view that the definition of Renewable Energy Sources provided in the Regulations is very broad as it covers all RE technologies approved by MNRE. Besides, industrial waste based on fossil fuels cannot be covered under realm of RE sources. However, industrial waste based on non-fossil fuels has been covered (e.g. bagasee based cogeneration) subject to fulfilment of 'Eligibility Criteria' as stipulated under the Regulations.

5.5 As regards defining the word 'non-conventional energy sources', the Commission observes that this word has been widely used in the Policy framework pursuant to the Electricity Act 2003. In many places, the word 'non-conventional energy sources' has been viewed synonymous to the 'renewable energy sources' however, the correct interpretation of these terms establishes difference between these two words. The non-conventional energy sources include all such sources which were conventionally not used for generation of electricity whereas renewable energy sources mean the sources which could replenish themselves through the natural cyclic process. The Section 61(h) of EA 2003 mandates Appropriate Commission to be guided by promotion of 'renewable energy sources' while specifying terms and conditions for determination of tariff. Accordingly, the scope of the Regulations is limited only to specify the tariff parameters for renewable energy sources. Therefore, the heat generated from chemical reaction of NCES or co-generation/generation from fossil fuels has not been included in the scope of the Regulations.

6. Definition of Small Hydro Projects

6.1 In the draft Regulations, the hydro projects upto 25 MW was proposed as small hydro projects.

6.2 The Stakeholders suggested that all type of hydro power plants, irrespective of their capacity should be considered as renewable energy sources as they help in reducing the carbon footprint. Further, sub-classification of small hydro projects into mini hydel plant with capacity in the range of 1MW and 250 kW, and micro hydro with capacity less than 250 kW may be made.

6.3 The Commission has taken into account the eligibility criteria specified by MNRE for small hydro projects. MNRE has considered hydro projects up to 25 MW as small hydro projects for providing incentives and subsidy under its various programmes. Therefore, the limit of 25 MW for Small Hydro projects cannot be revised till MNRE make suitable amendments.

6.4 Further, the proposed draft Regulations had same norms for all size of small hydro projects so as to enable development of most optimal project at a particular location. However, based on views expressed by various stakeholders during public hearing and through their submissions on Draft Regulations, the Commission sought views of MNRE as regards to sub-categorisation of small hydro projects. MNRE expressed that distinction may be made amongst small hydro projects (based on capacity) due to significant difference in their financial and operational performance parameters. MNRE suggested classification of small hydel projects into two sub-categories: SHP less than 5 MW, and SHP of size from 5 MW to 25 MW. Higher capital cost and O&M expense norms should be specified for SHP less than 5 MW as compared to SHP above 5 MW. Accordingly, further sub-classification of SHP into less than 5 MW and SHPs with installed capacity from 5 MW to 25 MW has been incorporated under final Regulations, with appropriate norms for capital cost and operating costs.

7. Definition of Useful Life

7.1 In the draft Regulations, the Useful Life of 25 years was proposed for wind turbine generators.

7.2 Some Stakeholders suggested considering the useful life of 20 years as type test certificate provided by the manufacturers/suppliers/vendors are for 20 years. However, one of the WTG manufactures has also supported useful life for wind energy project as 25 years. Some stakeholders suggested that Useful life of biomass plant should be kept at 15 years instead of 20 years due to lot of wear and tear caused by stones, sand, mud etc present in Biomass.

7.3 MNRE has suggested that Useful life for wind projects should be of 20 years as per international standard practices followed for WTG project life. MNRE also provided the copy of IEC reference document in support of their submission.

7.4 The Commission notes that in the IEC reference document it has been mentioned that useful life of wind turbine should be at least 20 years which means that life of WTG should be 20 years or higher. Further, the Commission also observes that as per European industry association, operating life of WTG is typically in excess of 1,20,000 hours. Further, the operational experience of wind projects shows that wind turbines are running successfully well over 20 years. Further, in the international market, the wind turbines having guaranteed useful life of 25 years are available. Considering all these facts, the useful life of 25 years has been retained for wind projects.

7.5 As regards useful life for biomass projects, the Commission is of the view that in the nature of operation, biomass plants are similar to conventional thermal power plants. Further, the boiler design for biomass plants is not as complicated as it is for coal based thermal power plants as most of the boilers used in biomass power plants are travelling grate boiler capable of burning different kinds of fuel. However, Considering the variation in quality of biomass fuel, the useful life of biomass plants has been kept 20 years while the useful life of 25 years has been specified for fossil fuel based thermal power plants.

8. Scope of Regulations

8.1 The Stakeholders expressed following views on scope of draft Regulations:

- Tariff norms for industrial waste to energy based projects may also be specified.
- Regulations shall not prohibit other modes of sale of power i.e. inter-state or intra-state sale through open access.
- Tariff based on CERC regulations is more attractive, new generation based on RE may have a tendency to contract for power with two or more States.
- Clarification should be given whether these Regulations would work as guidelines as contemplated in Tariff Policy for pricing of Non-firm power.

8.2 The Commission is of the view that every Waste to Energy project is unique in terms of waste fuel characteristics, project sizing, configuration, technology and operational requirement. It is preferred to address case specific nuances of each waste energy project, separately. Accordingly, the Regulations provide for project specific tariff determination for new technologies and waste to energy projects so that tariff could be set on the basis of case specific project cost assessment.

8.3 The proposed Regulations do not restrict any sale of power within or outside State, which shall be subject to applicable regulations and shall be governed by prevalent regulatory framework. The project developer can sale the energy generated from RE projects either to a licensee or to any other third party, subject to the Regulations specified by the Appropriate Commission in this regard.

8.4 Tariff Regulations have been proposed taking into consideration provisions of the Act and Tariff Policy to specify terms and conditions for determination of ‘preferential tariff’. Higher return on equity, shorter loan tenure, and appropriate normative rate of interest has been provided as incentive for RE power.

9. Eligibility Criteria

9.1 In this section, the eligibility criteria for different RE technologies covered under the Regulations were discussed.

9.2 The stakeholders expressed their views on eligibility criteria for different RE technologies:

- Hub-height should also be considered while computing CUF norms and also, elaborate relationship between WPD and wind velocity.
- SHP are approved/get clearance at State level and MNRE plays no role in approval of SHP sites.
- For Biomass projects, MNRE/ IREDA permits up to 25% of fossil fuels in the biomass based projects while in the draft Regulations, this limit has been kept as 15%. Further, the word ‘15% of total fuel consumption’ should be replaced with ‘15% of the total fuel consumption expressed in kCal’ for more clarity.
- Eligibility criteria for Non-Fossil Fuel based Cogeneration plants is theoretical and difficult to monitor.
- Eligibility criteria and norms should also be specified for process waste heat driven power plants, process waste heat cogeneration plants, and non-fossil fuel based power plants, biomass gasification & solar roof top system.

9.3 As regards relationship between wind power density and hub-height, it is noted that a particular wind site can be most optimally harnessed by using wind turbine of appropriate rating and hub-height. For operationalisation of the Regulations, it has been clearly specified in the Regulations that classification in wind zones is based on annual mean wind power density measured at 50 meter hub height.

9.4 MNRE has clarified that SHPs are approved at State level and approval of MNRE is not required. Accordingly, the Commission has modified the eligibility criteria for small hydro projects, specifying that small hydro projects approved by State Nodal Agencies and State Government shall be eligible under this Regulations.

9.5 As regards usage of fossil fuel, this provision should not be viewed as a right to use the fossil fuel. Such provision has been provided to take care of contingencies arising due to non-availability of sufficient biomass in certain months of year to address seasonality aspects. MNRE had revised the limit for maximum usage of coal from 25% to 15% for the biomass projects which are availing capital subsidy, and accordingly, it has been factored in the draft Regulations. Further, for sake of operational simplicity and to facilitate monitoring mechanism, the 15% limit has been stipulated in terms of quantity rather than in terms of heat value (kCal) as demanded by some of the stakeholders.

9.6 As regards eligibility criteria for non-fossil fuel based cogeneration, it is to be noted that such mechanism is already in place since last 6-7 years in some States. The objective of the qualifying criteria is to discourage incidental co-generation and to ensure optimum utilisation of fuel (bagasse/biomass) for useful power output and useful thermal output. For the sake of clarity, the expressions 'useful power output', 'useful thermal output' and 'energy consumption' used in the context have been defined.

9.7 As regards inclusion of norms for other technologies, the Commission would like to mention that present Regulations cover the norms for comparatively matured and established technologies for which financial and operational performance information is available, based on which generic norms can be specified. For new technologies, which are still at nascent stage of development, it is preferred that concerns are addressed on case-to-case basis. Therefore, the Regulations provide for project specific tariff determination.

General Principles

10. Control Period

10.1 In the draft Regulations, it was proposed that Control Period under these Regulations would be of 3 years. The Stakeholders expressed different views on the tenure of Control Period, ranging from 2 years to 5 years. Further, some stakeholders expressed that review process should start at least 12 month before the expiry of the Regulations for regulatory certainty for next Control Period.

10.2 In the explanatory note issued along with the draft Regulations, the rationale for considering the Control Period of 3 years has been elaborated. The Commission considered gestation period of different RE technologies for specifying the Control Period so that project conceptualised on the basis of these norms could receive the same tariff. The Commission would like to further mention that these Regulations are being issued for the first time and therefore, the aspects covered under these Regulations may need to be modified, considering experience of operationalisation of the Regulations. Therefore, short Control Period will enable the Commission to revisit the norms within short duration while ensuring certainty for reasonable duration.

11. Tariff Period

11.1 In the draft Regulations, it was provided that Tariff Period for all RE technologies, except Solar PV and Solar Thermal, shall be of 13 years while for Solar PV and Solar Thermal it was specified as 25 years. The stakeholders suggested duration of tariff period ranging from 5 years to equivalent to the project life.

11.2 The Commission is of the view that tariff period of 13 years is balanced approach considering the provisions of EA 03 and Tariff Policy which outlines preferential treatment to renewable energy projects till such time that RE technologies are allowed to compete in the market. The regulatory support during the 13 year tariff period will provide certainty to the project developer to meet its debt service obligations. After this period, the competitive procurement of renewable energy will ensure that power is procured at most reasonable rate, and benefit passed on to the consumer. However, in case of solar power projects which are still at nascent stage of development in India, it is preferred that preferential tariff support is extended for period at least up to 25 years (useful life) to ensure adequate regulatory support is available to Solar Power projects till such time enough confidence is generated amongst all stakeholders about Solar power technologies.

11.3 Further, it is to be noted that power market operations in India have evolved considerably and there exist other options like sale to open access consumers, sale to trading licensee(s) and sale through power exchange in addition to the traditional market models of sale to distribution licensee. It is envisaged that renewable energy certificate mechanism would also be put in place shortly. The developers will also be benefited by opting most economical option at later part of the project life.

11.4 MNRE has suggested that different dispensation may be provided to small hydro projects below 5 MW. Due to smaller size, these projects will not be able to explore other market models after tariff period of 13 years and would depend on local distribution licensee for sale of power. In order to provide long term tariff certainty and to address concerns of SHPs below 5 MW, the tariff period for SHP below 5 MW has been modified to 35 years, corresponding to the useful life of the project. The tariff period for SHP above 5 MW shall remain 13 years.

11.5 It is clarified that preferential tariff support shall be available for initial Tariff period for 13 years (except for solar power and SHP below 5 MW) and these projects will have to compete to ensure off-take beyond initial Tariff period, as envisaged under Tariff Policy.

12. Project Specific Tariff

12.1 In the draft Regulations, the provision for determining project specific tariff for new technologies was provided. IWPA and Acciona Wind Energy Pvt. Ltd suggested that tariff for wind projects in excess of 100 MW to be developed by a single project developer at one location may also be covered under project specific tariff determination process.

12.2 Project Specific tariff has been envisaged in case of new RE technologies, waste to energy or solar power projects. Project Specific tariff has not been contemplated in case of established and mature RE technologies such as wind energy.

12.3 PGCIL mentioned that normative tariff should be specified upfront at the beginning of each year of Control Period.

12.4 The Commission is of the view that Regulation 8 deals with the process of tariff determination. In order to provide clarity on tariff aspect, the enabling provision related to suo-motu tariff determination at the beginning of each year of Control Period for RE technologies covered under the Regulations has been added as Regulation 8(1). It is envisaged that the process of suo-motu tariff determination may begin 6 months prior to beginning of new financial year.

13. Tariff Structure

13.1 The draft Regulations provided for single part tariff structure for RE technologies. The Stakeholders submitted to specify two part tariff structure for small hydro so that fixed cost could be recovered in case generation is affected due to poor monsoon.

13.2 The Commission is of the view that single part tariff structure for RE technologies is the most simple method to operationalise considering number of projects and unit size of each project and the same has been in practice for RE technologies for long time. In case of RE technologies involving variable cost components such as biomass power and non-fossil fuel based co-generation, single part tariff with two components representing fixed cost component and variable cost component has been specified. It is envisaged that RE project developer shall undertake detailed study and investigation of the project site, location and design unit size (or capacity) taking into consideration site specific aspects. Further, any generation beyond threshold PLF shall also receive same tariff since risk and cost associated with project sizing, project location etc is expected to be borne by project developer.

14. Tariff Design

14.1 In the draft Regulations, it was proposed to determine the tariff on levellised basis for all RE technologies for tariff period. The stakeholders suggested that Front loaded tariff should be specified as levellised tariff impacts cash flow and loan repayment.

14.2 The Commission is of the view that Levellised tariff approach strives to strike a balance amongst various tariff determination mechanisms like front loaded tariff, back loaded tariff etc. While front loaded tariff meets the requirement of the RE project developer, it leads to significant cash flow impact for the utilities during initial period. Besides, there is little incentive for the RE developer to continue with the existing energy purchase agreement with the Utility once the debt service obligations are over. On the other hand, back-loaded tariff structure meet with the requirement of utility, significant back-ending would impact project cash flow and may not meet requirement of the project lenders/investors. Levellised tariff with appropriate discount rate representing weighted average cost of capital or time value of money yields necessary balance between front-loaded or back-loaded tariff. In order to address cash flow related concerns, the higher depreciation rate of 7% per annum for first 10 years has been specified. In order to address the concerns of project developers, the analysis of cost of generation and cashflow requirement was carried out. Further, the discounting factor has been considered equal to the weighted average cost of the capital on the basis of normative debt: equity ratio specified in the Regulations. It is ensured that under levellised tariff approach, the concerns of debt service coverage are well addressed.

15. Scheduling of electricity generated from RE sources

15.1 In the draft Regulations, it was provided that all RE technologies, except biomass and non-fossil fuel based cogeneration above 10 MW, will be treated as Must Run station and would be exempted from merit order despatch. It was provided that non-firm sources like wind and small hydro etc needs to provide tentative forecast in 1.5 hrs time block basis while biomass and bagasse cogeneration will be subjected to scheduling and despatch code.

15.2 The stakeholders expressed that RE generating station should not be subjected to scheduling and despatch code and must be given Must Run status. GETCO submitted that in case of contingency or grid constraint, these plants should be guided by the real time instructions issued by SLDC.

15.3 The Commission is of the view that generation from renewable energy sources such as wind, solar, small hydel etc. is critically dependent on vagaries of nature and hence it is termed as non-firm in nature. Further, the same needs to be maximised as and when such resources are available in order to optimally utilise the assets and maximise generation from such assets already installed. Accordingly, generation from such RE projects is proposed to be treated as 'MUST RUN' and not subjected to merit order despatch principles under scheduling and despatch regime. At the same time, the issue of scheduling of renewable energy projects needs to be analysed from system operations point of view. With significant increase in share of renewable energy in total energy portfolio, frequent increase or reduction in energy injection within short duration may not be in the interest of safe, smooth and reliable grid operations. The system operator must have fair idea of possible energy injection from such renewable energy sources. However, the Commission opines that the feasibility of imposing forecasting requirements on such RE sources need to be investigated and deliberated further.

15.4 While biomass power and non-fossil fuel cogeneration projects are amenable to scheduling for day-to-day operations, if fuel management chain is established. Such projects with installed capacity of lower than 10 MW, in view of their smaller size and complexities of ensuring visibility at SLDC are not amenable to scheduling and despatch requirement unlike their counterparts with installed capacity in excess of 10 MW.

15.5 However, the Commission considers that scheduling and despatch aspect for renewable energy sources need to be deliberated further and therefore, it has been decided to cover this aspect in the comprehensive review of Indian Electricity Grid Code. Further, the aspects included in the present Regulations are:

- All renewable energy power plants except for biomass power plants with installed capacity of 10 MW and above, and non-fossil fuel based cogeneration plants shall be treated as 'MUST RUN' power plants and shall not be subjected to 'merit order despatch' principles.
- The biomass power generating station with an installed capacity of 10 MW and above and non-fossil fuel based co-generation projects shall be subjected to scheduling and despatch code as specified under Indian Electricity Grid Code (IEGC) and Central Electricity Regulatory Commission (Unscheduled Interchange and related matters) Regulations, 2009 including amendments thereto.

16. Grid Connectivity

16.1 The stakeholders submitted that the term 'Concerned licensee' needs to be defined in the Regulations. Maximum distance of the inter-connection point from the power house should be clearly mentioned in the Regulations. Proper regulatory support to remove the bottleneck for grid connectivity should be provided. Grid connectivity may be delinked from payment of OA charges as providing grid connectivity is responsibility of respective state or central transmission utility irrespective of nature of sale of power. Renewable energy projects should be exempted from payment of transmission and wheeling charges.

16.2 The Commission is of the view that concerned licensee covers distribution licensee, State Transmission licensee or Central Transmission licensee, as the case may be, that needs to provide grid connectivity to RE projects and will depend on voltage level for grid connectivity, size of the project, nature of generation scheme etc.

16.3 It has been felt that grid constraint should not hinder the development of renewable energy projects by way of clearly specifying definition of inter-connection point, and entrusting responsibility on concerned licensee for development of evacuation infrastructure beyond inter-connection point etc.

16.4 As regards specifying maximum distance of the inter-connection point, the Commission notes that Regulations provide for development of evacuation infrastructure up to inter-connection point by the project developers beyond which the concerned licensee shall develop the evacuation infrastructure. The definition of inter-connection point has already been provided in the Regulations which itself establishes the distance upto which the developer will develop the evacuation infrastructure.

16.5 While the Commission is alive to the issues around grid connectivity for the renewable energy generators, it is felt that these issues are beyond the scope of the tariff regulations for renewable energy sources. These issues are being dealt with by the Commission separately.

Financial Principles

17. Evacuation Infrastructure

17.1 In the draft regulations the Commission has specified the evacuation infrastructure up to the interconnection point to be developed by the generating company and beyond the interconnection point the concerned licensee shall be responsible for the development of such evacuation infrastructure.

17.2 The Tata Power Company Limited submitted that cost for grid connectivity should be borne by the licensee and not by the project developer. Power Trading Company Ltd submitted that the cost of providing inter-connection for wind and SHP should also be factored in project cost. Gujarat Energy Transmission Corporation Ltd. submitted that the project developer should be made responsible for development of evacuation infrastructure up to nearest grid sub-station and the cost should be included in capital cost. IWPA and Acciona Wind Pvt. Ltd. submitted that the Licensee should be made responsible for development of evacuation infrastructure beyond 10 km.

17.3 The Commission observes that as per the provisions of the Act, the evacuation planning for renewable energy projects shall be the responsibility of appropriate transmission utility. However, it has also been observed that due to several reasons there have been difficulties in developing the infrastructure for evacuation of energy generated from RE sources. The non-availability of infrastructure for evacuation of power has been considered as one of the prime reasons for slow pace development of the renewable energy projects.

17.4 Additionally, renewable energy and cogeneration facilities are often not located close to the grid and the cost of connecting would be prohibitive. As the costs are higher for renewable energy generators due to lower plant load factors and the distance from the grid, interconnection charges can be a significant deterrent.

17.5 Keeping the above facts into consideration, in order to give impetus to the development of RE projects and to address the concerns of the RE developers regarding the modalities of evacuation arrangements, the commission feels that the cost of evacuation infrastructure up to the interconnection point should be included in the capital cost norms whereas concerned licensees should be responsible for development of evacuation infrastructure beyond the point of interconnection. The term ‘inter-connection point’ in respect of each RE technology has been clearly defined under the Regulations.

17.6 The aspect (of cost of evacuation infrastructure upto interconnection point to be included in the capital cost of the project) is already covered in the provisions relating to ‘Capital Cost’ and as such the separate provision on “Evacuation Infrastructure” is being omitted.

18. Debt Equity Ratio

18.1 In the draft regulations, debt to equity ratio of 70:30 has been specified. While this will be the norms, especially for generic tariff, it has been specified that for project specific tariff if equity deployed is more than 30% it will be considered as normative loan and if the equity deployed is less than 30% the same shall be considered for determination of tariff.

18.2 Acciona Wind Energy Pvt. Ltd. submitted that Debt equity ratio for non-recourse financed wind projects is 3:2. Considering equity cost at lending rate for equity above 30% will not be true reflective of weighted average cost of capital. NTPC submitted that Debt equity ratio of 50:50 may be adopted due to higher risk perceived by the banks.CLP India submitted that RE project on IPP basis would not be able to achieve a gearing in excess of 60:40 at a minimum DSCR of 1.4. Therefore, D: E ratio should be 60:40 instead of 70:30.

18.3 The Commission notes that the Tariff Policy notified by the Government of India, stipulates consideration of debt equity ratio of 70:30 for financing all future projects. It is also observed that with proliferation of renewable energy technologies, the risk perception of the lenders and stake-holders for RE projects is undergoing change. Besides, with higher normative depreciation rate, the concerns about debt service coverage are well addressed. Accordingly, the Commission has specified the normative debt to equity ratio of 70:30.

19. Loan Tenure and Finance Charges

19.1 In the draft regulations the Commission has proposed loan tenure of 12 years for the purpose of determination of tariff.

19.2 Majority of Stakeholders have suggested considering 10 years as loan tenure for Renewable Energy projects. Himachal Small Hydro Power Association, Polyplex Corporations GFL have submitted that for small hydro projects, the interest rate should be considered as 200 points above SBI LTPLR due to higher hydrology and geological risk. Tamil Nadu Electricity Regulatory Commission has suggested considering Interest rate offered by IREDA as normative interest rate. Various stakeholders have submitted to consider the Interest rate as 200 to 300 basis point above the SBI PLR for the purpose of determination of tariff.

19.3 The Commission has observed that a number of stakeholders have recommended considering a loan tenure of 10 years for the purpose of determination of tariff. This suggestion has been accepted in view of the loan market for renewable projects and a suitable modification has been incorporated in the final regulations.

19.4 Further, the Commission has observed that a number of stakeholders have submitted that due to high risk associated with the renewable energy generation projects, it will be difficult to get finance at the interest rate consideration of SBI PLR plus 100 basis points, as considered in the draft regulations. The aforesaid suggestion has been accepted by the Commission and a suitable modification has been incorporated in the final regulations.

19.5 However, it is hoped that as this market matures, loan tenure will converge to that for conventional technologies and in few years there will not be any requirement of preferential shorter loan tenure or higher interest rate for RE technologies.

20. Depreciation

20.1 In the draft regulations, it was provided that a differential depreciation approach shall be considered over loan tenure and period beyond loan tenure over useful life computed on ‘Straight Line Method’. The depreciation rate for the first 12 years of the Tariff Period shall be 6% per annum and the remaining depreciation shall be spread over the remaining useful life of the project from 13th year onwards.

20.2 Stakeholders including Indian Sugar Mill Association, UP Sugar Mill Cogen Association have submitted to consider depreciation rate as 7% per annum.

20.3 The Commission has given due consideration to the suggestions made by various stakeholders with regards to the consideration of loan tenure for the purpose of determination of tariff. Accordingly, the Commission has considered loan tenure of 10 years. Further, with regards to the concern for cash flow requirement and addressing requirement of debt service coverage, the Commission has accepted the suggestion made by the stakeholders of considering 7% per annum as depreciation rate for initial period of 10 years i.e. equivalent to the loan tenure. The remaining depreciation shall be spread over balance useful life of the project beyond the initial period of 10 years. Accordingly, the necessary modifications have been incorporated in the final regulations.

21. Return on Equity

21.1 In the draft regulations it has been proposed normative Return on Equity as,

a) Pre-tax 17% per annum for the first 10 years.

b) Pre-tax 23% per annum 11^{th} years onwards.

21.2 The stakeholders expressed their views on Return on Equity as under:

- Benefit of MAT under Section 80IA of Income Tax Act is available for the power stations to be commissioned till March 31, 2010.
- Differential return of 2% for Renewable Energy plants should be allowed over and above the RoE considered for conventional generation projects.
- Post tax base RoE of 17% should be considered which may be grossed up by the applicable tax rate.
- For RE projects, the risk and gestation period is less as compared to the thermal power projects and hence RoE should be kept on lower side.
- ROE of 16% on post tax basis should be considered.
- For SHP, pre-tax 23% ROE should be provided during the first 10 years, and 30% ROE should be provided from 11th year onwards.
- Normative ROE for wind projects should be 23% throughout the project life.

21.3 The Commission would like to clarify that as regards to availability of benefit of MAT under section 80IA, the benefits of 80IA have been further extended for projects to be commissioned up to March 31, 2011 as per Union Budget for FY 2009-10 and the same shall be applicable to the renewable energy generation projects as well.

21.4 As regards providing additional return on equity to RE projects in comparison to conventional power projects, the Commission is of the view that as per provisions of Tariff Policy, for determination of 'Preferential Tariff' for RE projects as compared to conventional power projects, preference has been given in terms of mainly allowing higher tariff than tariff for conventional power.

21.5 The Commission would further like to clarify that the returns for renewable energy generation projects have been specified in pre-tax terms alone. While prevalent tax regime including recent revision in terms of MAT rate and Corporate tax rate has been factored in while specifying Pre-Tax Return on Equity. Accordingly, pre-tax return on equity has been stipulated at 19% per annum (pre-tax) for initial 10 years and at 24% per annum (pre-tax) for subsequent period. However, it is clarified that gains or losses on account of any change in tax rate, MAT or Corporate Tax, as the case may be, shall be to the account of the RE project developer since the returns have been regulated in pre-tax terms. Accordingly, necessary modifications have been incorporated in the final regulations.

22. Interest on Working Capital

22.1 In its norms for computing Interest on Working Capital, the Commission has proposed to consider receivables equivalent to one and half month of sale of electricity at the target normative PLF/CUF. Further the interest on working capital has been specified as short term prime lending rate of State Bank of India (SBI-STPLR).

22.2 A number of stakeholders including NTPC, GUVNL etc. have recommended considering receivables equivalent to 2 months of energy charges as applicable in case of conventional power projects. The Commission has given due considerations to the submissions of the stakeholders and accordingly, suitable modifications have been incorporated in the final regulations.

22.3 Further, with regard to the interest rate on working capital consideration, several objectors have sought interest rate for working capital to be 100-200 basis points above short term PLR since RE project developer due to their size and creditworthiness are unlikely to receive working capital at PLR. Keeping in view the suggestions made by various stakeholders, normative interest rate for working capital has been stipulated as 100 basis points above short term prime lending rate of State Bank of India (SBT-STPLR). Accordingly, suitable modifications have been incorporated in the final regulations. At the same time we would like to reiterate our opinion as expressed in para 19.5.

23. Operation and Maintenance Expenses

23.1 The stakeholders expressed their views on Operation and Maintenance Expenses as under:

- For small hydro projects, O&M expenses are on lower side. On realistic basis for mini hydel project, it works to Rs 92.1 Lakh/MW for a 1 MW plant.
- Escalation rate for wind projects should be less than 5% considering the prevalent inflation rate.
- Due to lack of past experience in case of RE projects, O&M expenses should be as per actuals for first 5 years from the commercial operation and subsequently O&M norms may be fixed.

23.2 The Commission observes that the normative O&M Expenses stipulated by various SERCs for SHP projects are in the range of 1.9% to 2.4%. Further, MNRE has conveyed that O&M expenses for SHP below 5 MW are higher than that applicable for SHP above 5 MW due to higher manpower cost in terms of per MW, remote locations for smaller projects. The Commission has given due consideration to the recommendations of MNRE in this regard and accordingly suitable modification has been incorporated in the final regulations.

23.3 Further, the Commission would like to clarify that, with regard to the escalation factor it has specified an escalation of 5.72% per annum which is based on the inflation indices and is also in line with the escalation factors considered for conventional power projects as per CERC (Terms and Conditions for Tariff) Regulation, 2009.

24. Rebate and Late Payment Surcharge

24.1 Stakeholders have submitted for proposing norms for the rebate on prepayment and late payment surcharge.

24.2 The Commission after due consideration has accepted the suggestions made by the stakeholders in this regard and accordingly additional clauses pertaining to rebate and late payment surcharge similar to that applicable for conventional power projects have been incorporated in the final regulations.

25. Sharing of CDM Benefits

25.1 In the draft regulations it has been proposed to share the CDM benefits availed if any, by RE projects between generating company and the off-takers. In the first year 100% will be retained by the project developer and from second year onwards 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 and the beneficiaries.

25.2 A number of stakeholders have submitted that the CDM benefit should not be shared as entire risk is borne by the project developers. Further some stakeholders have suggested that minimum RoE from the power generation should be ensured to the project developers before sharing the CDM benefits.

25.3 As regards sharing of CDM benefits, the Commission has taken due consideration to the stipulations made under the tariff policy, recommendations by Forum of Regulators (FOR) under its Report on Policies for Renewable Energy and the similar provision in the tariff regulations for conventional power. The same has been incorporated under the final Regulations.

26. Subsidy or Incentive by Central/State Government

26.1 In the draft regulations it has been specified that any incentive or subsidy offered by the Central/ State Government to the renewable energy power plants shall be taken into consideration while determining the tariff.

26.2 A number of stakeholders have suggested that subsidy/incentives should not be considered while computing the tariff as these are extended by the Governments to accelerate growth of RE sector. IREDA has submitted that if State/Central Government subsidies/incentives are in addition to the tariffs then the same should not be considered.

26.3 As regards sharing of subsidy and incentives extended by Government, the Commission is of the view that under ‘Preferential Tariff’ approach based on cost plus regime, the tariff is determined upon ascertaining normative costs and performance parameters and in view of the fact that all reasonable costs and returns are being allowed to be recovered through such preferential tariff, it is fair that any subsidy or generation based incentive be factored in while determining tariff. The Commission finds this position to be consistent with the recommendations made by the FOR that GBI is preferred over capital subsidies and the same should be factored in while determining tariff.

26.4 Further while specifying the final regulations the Commission has also taken into consideration any incentive or subsidy offered by the Central/ State Government, including accelerated depreciation benefit if availed by the generating company, for the renewable energy power plants while determining the tariff. Given that GBI is generally a substitute for accelerated depreciation benefits, such a provision is necessary to ensure level playing field between the projects under GBI and the projects under accelerated depreciation benefits.

26.5 Further, to provide clarity and certainty, it has been provided that the following principles shall be adopted while ascertaining income tax benefit on account of accelerated depreciation:

a) Assessment of benefit shall be based on normative capital cost, accelerated depreciation rate as per relevant provisions under Income Tax Act and corporate income tax rate.

b) Capitalisation of RE projects during second half of the fiscal year.

c) Per unit benefit shall be derived on levellised basis at discount factor equivalent to weighted average cost of capital.

26.6 Thus, the Tariff in respect of RE projects availing income tax benefit on account of accelerated depreciation shall be adjusted to the extent of normative per unit benefit determined on levellised basis as against those RE projects not availing such benefit. Suitable modifications have been incorporated under the final Regulations.

27. Taxes and Duties

27.1 The draft regulations provided for 'Water Royalty Charges' as pass through in tariff.

27.2 Comments received from stakeholders in this regard are as follows :

- Water royalty charges should be paid by the Distribution Company, which is purchasing power from SHP, directly to the State Government. (PMC Power).
- State Government is awarding the Small hydro projects through bidding process wherein project developer is required to quote water royalty and the developer who is quoting highest royalty shall be awarded the project site for development. In case water royalty is a pass-on to beneficiary in addition to tariff, it will put additional burden on beneficiary. It is therefore imperative that water charges should be factored into while determining the tariff. Further, no liability should be pass-on to the beneficiary on account of increase in any taxes, duties, cesses and levies etc. (GUVNL)

27.3 The Commission has considered this issue and feels that taxes, duties levies etc. imposed by the appropriate Government are generally not factored into tariff and they are generally allowed as a pass through. It has, therefore, been decided to provide that "taxes, duties, imposed by the appropriate Government shall be allowed as a past through in tariff" instead of specifically mentioning about reimbursement of water royalty charges.

Wind Power Projects

28. Capital Cost for Wind Projects

28.1 In the draft Regulations, it was provided that capital cost for wind projects to be commissioned during FY 2009-10 shall be Rs 515 Lakh/ MW.

28.2 The stakeholders in their submissions mentioned that proposed capital cost does not reflect actual capital cost as it is based on historical data. The developers claimed the capital cost in the range of Rs 5.57 Cr/ MW to Rs 6.67 Cr/ MW.

28.3 The capital cost as proposed under the Regulations was proposed after in-depth analysis of capital cost for different projects either financed by IREDA or registered with UNFCCC for the purpose of CDM benefits. Further, capital cost norms for FY 2009-10 was worked out after considering the capital cost data for past 5 years and escalating it with indexation formula. Further, MNRE has conveyed that the capital cost for IREDA funded projects in recent past has been around Rs 5.60 Cr/MW but considering the other norms and larger project database as considered by CERC, the capital cost of Rs 5.15 Cr/MW is reasonable.

28.4 Considering above aspect, the capital cost of Rs 515 Lakh/MW has been retained for wind power projects to be commissioned during FY 2009-10.

29. Capital Cost for Indexation Mechanism

29.1 In the draft Regulations, the capital cost indexation mechanism was specified on the basis of assigning the weights based on composition of various cost components of wind power project.

29.2 Shri Shanti Prasad suggested that it may be specified in the Regulations that norms for capital cost, capital cost indexation formula, technical and financial parameters will be reset during the next Control Period. IWPA and Acciona Wind Energy Pvt. Ltd suggested that value of Factor F1 and F2 for wind projects should be 0.10 and 0.09, similar to biomass projects.

29.3 The main objective of the indexation mechanism is to establish a mechanism for taking care of variation in capital cost due to the variation in underlying cost components during a control period which could be reflected through the reliable indicators. The weights to different factors were proposed after duly considering the share of plant and machinery and other works in completed project cost. For the sake of clarity, plant and machinery cost for the base year has been defined in the regulations.

29.4 The Commission is of the view that the norms proposed in the Regulations are applicable for the projects to be commissioned during this Control Period. The Commission may revisit all of the norms or part thereof while specifying the normative parameters for next Control Period based on experience gained through operationalisation of norms under current Control Period. Further, value of different factors has been proposed after duly considering the share of plant and machinery and other works for different renewable energy projects. Therefore, the proportion of factors across the technologies is different.

30. Capacity Utilisation Factor

30.1 In the draft Regulations, the norms for capacity utilisation factor were proposed on the basis of annual mean wind power density, in which wind sites were grouped in five zones. The idea behind such approach was that the energy generation from wind is very site specific and varies considerably from one site to another. Therefore, norms should be set on the parameters which actually govern the energy generation. The norms have been specified on single parameter basis i.e. on WPD basis for ease of its implementation.

30.2 Further, as regards the suggestion of considering hub-height as well while specifying CUF norms, the Commission is of the view that WPD will be different at different heights due to variation in prevailing wind velocity at different heights. On the basis of micrositing and wind resource survey, any wind site would be most suitable for a particular type of machine at a specified hub-height. For operationalisation purpose, it has been mentioned that wind power density mentioned in the Regulations shall be annual mean wind power density measured at 50m hub-height.

30.3 Centre for Wind Energy Technology (C-WET), proposed to group the WPD on the basis of wind resource assessment carried out by them in four groups of annual mean wind power density range i.e. 200-250 W/m^2, 250-300 W/m^2, 300-400 W/m^2, and above 400 W/m^2. C-WET further mentioned that it is in process of preparing the detailed State-wise Wind Atlas which will take some more time. C-WET also provided the State-wise Wind Power Density map, indicating the different annual mean wind power density zones.

30.4 Considering the above suggestions, the norms for CUF have been modified as been given in the following table:

S. No.	Annual Mean Wind Power Density (Watt / m^2)	Capacity Utilisation Factor
1.	200-250	20%
2.	250-300	23%
3.	300-400	27%
4.	Above 400	30%

30.5 The Commission further specifies that Wind Atlas as and when prepared by C-WET shall be basis of categorisation of wind sties. As it will take some time to get it completed, the Wind Power density map provided by C-WET, as annexed under **Schedule 1** of Regulations, shall be basis for categorisation of wind sites as an interim arrangement. Further, a provision has been incorporated under the Regulations that enable the Commission, by notification in Official Gazette, to amend such Schedule from time to time based on the inputs provided by C-WET/ MNRE.

30.6 The Stakeholders also suggested considering single CUF norm of 200 W/m^2 for entire country and also, the development of wind sites having WPD of less than 200 W/ m^2. The Commission does not see any merit in these proposals as all these lead to sub-optimal utilisation of resources. Consideration of single CUF norms will be against the principles of encouraging optimal RE generation based on techno-economic considerations and also, against the consumer interest. The tariff is to be specified on 'cost-plus basis' therefore all the norms for cost and performance parameters should be reasonable. Further, C-WET in its Wind Resource Survey has considered only those sites as potential wind sites which have minimum annual mean wind power density of 200 Watt/m^2 at 50 m hub-height. Therefore, CUF norms have been proposed only for the sites which have annual mean wind power density of 200 W/m^2 and above.

31. Operation and Maintenance Expenses

31.1 The O&M expense of Rs 6.5 Lakh/MW was proposed in the draft Regulations for FY 2009-10 and linked to escalation rate of 5.72% for subsequent years of tariff period. The Commission received divergent views on allowable O&M expenses. GFL submitted to revise the O&M norms to 23 Lakh/MW while GETCO mentioned to keep the O&M expense as 1% of capital cost.

31.2 The Commission notes that none of the Stakeholder submitted documentary evidence in support of their proposition. The norms for O&M expense have been proposed in the regulations after considering the O&M expense norms specified by different SERCs in their Tariff Orders.

Small Hydro Power Projects

32. Capital Cost for Small Hydro Projects

32.1 In the draft Regulations, the capital cost of Rs 630 Lakh/ MW was specified for SHP projects located in Uttarakhand, Himachal Pradesh and North-eastern region while Rs 500 Lakh/MW was specified for SHP projects located in other parts of the country. The Commission received divergent views from the Stakeholders on this matter. The capital cost submitted by different stakeholders was in the range of Rs 6.50 Cr/MW to Rs. 16.67 Cr/ MW.

32.2 The norms for small hydro projects was proposed on the basis of analysis of capital cost for the 25 SHP projects funded by IREDA and 33 SHP Projects listed with UNFCCC which altogether amounts to 423 MW, representing around 20% of small hydro installed capacity in the country.

32.3 MNRE has recommended that small size hydro projects below 5 MW have higher capital cost and higher operating cost due to their small size, remote locations, grid connectivity issues etc. Considering this aspect, the norms for SHP below 5 MW should be higher than SHP between 5 MW to 25 MW. MNRE has conveyed that the proposed normative capital cost for SHP projects above 5 MW as specified under Draft Regulations is in order.

32.4 The Commission agrees with the views expressed by MNRE that small hydro projects below 5 MW require special attention as compared to SHP above 5 MW as these projects are deprived of the benefit of economies of scale and also, sites are located in remote areas. On the basis of MNRE's recommendations and analysis of project database, the norms for capital cost has been modified as follows:

S. No.	Particular	Capital Cost
1.	SHP located in Uttarakhand, Himachal Pradesh, North Eastern Region	
a.	- Less than 5 MW	Rs 700 Lakh/ MW
b.	5 MW to 25 MW	Rs 630 Lakh/ MW
2.	SHP located in other parts of the Country	
a.	- Less than 5 MW	Rs 550 Lakh/ MW
b.	5 MW to 25 MW	Rs 500 Lakh/ MW

33. Auxiliary Consumption

33.1 In the draft Regulations, the auxiliary consumption of 0.5% for small hydro projects was specified. The Stakeholders viewed that norms should be proposed taking into consideration the auxiliary load, operational period, transformation losses, power house location (surface or underground) and suggested that auxiliary consumption ranges from 1.5% to 7.40% (including the transformation losses and transmission upto grid substation).

33.2 The Commission observes that a typical SHP project has very few generator auxiliaries and pumping units and therefore, auxiliary consumption for SHP is less as compared to large size hydro projects. Further, inter-connection point for SHP has been specified as line isolator on outgoing feeder on HV side of generator transformer which means minimal transformation losses and no transmission line losses. To account for transformation losses, additional auxiliary consumption of 0.5% has been provided. Therefore, normative auxiliary consumption including transformation losses shall be 1%.

34. Capital Cost for Indexation Mechanism

34.1 In the draft Regulations, the capital cost indexation mechanism was specified for taking care of variation in the capital cost during the subsequent years of Control Period. The Stakeholders submitted to revise value of factors considered for different components.

34.2 The main objective of the indexation mechanism is to establish a mechanism for taking care of variation in capital cost due to the variation in underlying cost components which could be reflected through the reliable indicators. The weights to different factors were proposed after duly considering the share of plant and machinery and other works in completed project cost. For the sake of clarity, plant and machinery cost for the base year has been defined.

35. Capacity Utilisation Factor

35.1 The draft Regulations provided for normative Capacity Utilisation Factor (CUF) of 45% for SHP located in Uttarakhand, Himachal Pradesh and North-eastern region and normative CUF of 30% for other regions.

35.2 Some of the stakeholders expressed that these norms are high and needs to be revised. The Stakeholders further expressed concern over price of electricity generated above normative PLF. Generation above the normative PLF is purchased by the licensees at very low price while there is no provision for mitigating contingencies during low generation period. Therefore, tariff for small hydro projects should be based on cumulative CUF basis i.e. even if the CUF achieved falls short of the normative CUF in one year then the loss can be recovered in subsequent years.

35.3 The norms for capacity utilisation factor were derived on the basis of CUF considered by the SERCs while approving the tariff for small hydro projects in their respective States.

35.4 As regards issue of free power, the Commission is of the view that this matter is primarily under the jurisdiction of State Government. The State Governments have exempted mini and micro hydro hydro plants from free power for their entire useful life and small hydro projects beyond a threshold capacity are subjected to free power after some moratorium period of 10 to 12 years. As tariff period for SHP above 5 MW is 13 years, therefore, the free power, if applicable will have bearing on project revenues beyond such period of 10 to 12 years. The Tariff Period for SHP projects above 5 MW have been specified as 13 years beyond which such SHP projects will have to compete and establish their offtake arrangements. Thus, risk and benefits of free power due to State Government intervention is solely to the account of the SHP project developer. Accordingly, for the purpose of tariff regulations, the Commission has clarified that normative CUF specified under the Regulations is net of free power to home State, if applicable, and any quantum of free power if committed by the developer over and above the normative CUF shall not be factored into the tariff.

35.5 Further, as regards issue of lower price for generation beyond normative CUF, the Commission would like to clarify that RE Tariff Regulations do not distinguish between RE Tariff for generation in excess of normative generation. Thus, the risk and benefit of lower/excess generation as compared to normative generation is to the account of RE developer.

36. Operation and Maintenance Expenses

36.1 In the draft Regulations, the O&M expense of Rs 12 Lakh per MW was proposed for SHP for FY 2009-10.

36.2 The stakeholders submitted that these norms are on lower side and suggested to consider the O&M norms after realistic assessment by analysing individual item of O&M expenses. The developers proposed the O&M expenses in the range of 1.5% to 4% of capital cost. MNRE has conveyed that the SHP projects below 5 MW are often located at remote locations and difficult terrain requiring to frequent de-silting. This leads to frequent repair and maintenance requirement at these sites to address wear and tear in machine parts. Besides, lack of adequate trained manpower is rarely available at the disposal of such SHP projects below 5 MW which has to be outsourced. Thus, MNRE suggested that normative O&M expenses for SHP below 5 MW are higher than that applicable for SHP projects above 5 MW. Accordingly, MNRE suggested to consider following norms for SHP projects:

S. No.	Particular	O&M expenses
1.	- Less than 5 MW	5% of Capital cost
2.	5 MW to 25 MW	3% of capital cost

36.3 The Commission observes that the SHP developers, IREDA etc. have indicated O&M expenses for SHP projects in the range of 1.5% to 3.5% of the capital cost, much lower than that suggested by MNRE. One of the SHP developers has requested to specify normative O&M expense of Rs 20 Lakh per MW as against Rs 12 L per MW specified under Draft Regulations.

36.4 The Commission is of the view that the norms for O&M expenses have been proposed after normalising the O&M expense norms considered by different SERCs for small hydro projects. The normative O&M expense of Rs 12 Lakh/MW translates to 1.9% of capital cost for the projects located in Himachal Pradesh, Uttarakhand and North eastern region and 2.4% of capital cost for the projects located in other States. The Commission observes that the O&M expense norms suggested by MNRE are higher than the normative O&M expense claimed by the stakeholders.

36.5 For new large size hydro projects, the operation and maintenance expense of 2% of capital cost has been specified under CERC (Terms and Conditions for Tariff) Regulation, 2009. As the small hydro projects would not have the advantage of economies of scale therefore, O&M expense for these projects would be higher than than that specified for large hydro projects. Considering all these factors, normative O&M expense for small hydro projects have been modified as follows:

S. No.	Particular	O&M expense
1.	SHP located in Uttarakhand, Himachal Pradesh, North Eastern Region	
a.	- Less than 5 MW	Rs 21 Lakh/ MW
b.	5 MW to 25 MW	Rs 15 Lakh/ MW
2.	SHP located in other parts of the Country	
a.	- Less than 5 MW	Rs 17 Lakh/ MW

b.	5 MW to 25 MW	Rs 12 Lakh/ MW

Biomass Power Projects

37. Technology Aspect

37.1 In the draft regulations, the Commission has provided following norm,

"The norms for tariff determination specified hereunder are for biomass power projects based on Rankine cycle technology application."

37.2 GUVNL has requested to specify norms for biomass power plants based on technology other than Rankine cycle also.

37.3 The Commission is of the view that among all the technology alternatives available for power generation using biomass fuel, direct fired combustion technology which utilises steam to produce electricity in a Rankine cycle is widely accepted among the developers of biomass power plants. Apart from this the technologies such as gasification are most suitable for the stand-alone / off-grid application. Further, the Commission while specifying the norms for determination of tariff for biomass based power plants have observed that the majority of the plants in India are based on Rankine cycle technology only. Accordingly, the Commission has specified generic norms which are applicable only to those projects that utilises biomass using Rankine cycle technology which are most suitable for grid application. The tariff determination for biomass power projects based on gasification or any other technology other than rankine cycle technology can be dealt with on case-to-case basis under project specific tariff determination route rather than specifying generic norms at this stage.

37.4 Further, the Commission would like to clarify that the norms so specified are for biomass power projects based on Rankine cycle technology using water cooled condensers. The suitable modification has been incorporated in the final regulations.

38. Capital Cost

38.1 In the draft Regulations, it was provided that capital cost for biomass power projects to be commissioned during FY 2009-10 shall be Rs 450 Lakh/ MW.

38.2 The stakeholders expressed their views on capital cost for biomass power projects as under,

- Benchmark capital cost should be Rs 5.5Cr/MW since pre-processing equipment itself cost 1Cr/MW.
- Request to consider capital cost norm of Rs 500Lakhs/MW for (FY 2009-10 during first year of Control Period).

- Capital cost quotations received from EPC contractors are in the range of Rs7Cr/MW and the same may be considered for the purpose of tariff computation.
- The benchmark project costs (with Water Cooled Condenser) per MW are in the range of Rs.4.70Cr/MW to Rs.5.03Cr/MW depending on the location, evacuation system etc.

38.3 In order to determine normative capital cost the Commission has analysed and has taken into consideration the details of the biomass power projects developed through funding assistance from IREDA and also projects which are registered with UNFCCC. The specified norm for Capital Cost are inclusive of Capital works including plant and machinery, civil works, erection and commissioning, financing and interest during construction, and evacuation infrastructure upto interconnection point.

38.4 In addition, the Commission has undertaken study of the various approaches viz. Regulatory Approach or Pooled Cost Approach, Actual Project Cost Approach, etc for the purpose of development of norms for capital cost. The aforesaid approaches have been discussed in length in the Explanatory Memorandum published along with the Draft Regulations. Accordingly, the Commission has retained the norm for capital cost as specified under draft Regulations.

38.5 The Commission would also like to clarify that the norms are specified for the projects which are employing Water Cooled condensers. The norms for projects employing Air Cooled Condensers shall be dealt by the Commission on case to case basis under project specific determination of tariff, if such petition is filed by any project developer.

39. Capital Cost Indexation

39.1 In the draft Regulations, the capital cost indexation mechanism was specified on the basis of assigning the weights to different cost components used in the biomass power project.

39.2 RERC has submitted to clarify if three separate tariffs shall be specified for each category based on their commissioning during first, second and third year of the control period.

39.3 The Commission would like to clarify that while specifying the norms for determination of tariff, a control period of 3 years have been specified. Further, as outlined under Regulation 8, the Commission shall undertake tariff determination on suo-motu basis before commencement of each financial year of the Control period. Normative capital cost alongwith appropriate indexation mechanism as stipulated under the Regulations shall form basis for determination of tariff for projects commissioned during each financial year. For the sake of clarity, plant and machinery cost for the base year has been defined in the regulations.

40. Plant Load Factor

40.1 In the draft regulations with regards to the plant load factor following norm has been proposed,

"Threshold Plant Load Factor for determining fixed charge component of Tariff shall be:

1.	*During Stabilisation:*	*60%*
2.	*During the first year after Stabilisation:*	*70%*
3.	*From 2nd Year onwards:*	*80%"*

40.2 Several objectors have sought clarification regarding duration of stabilisation. MNRE has suggested that the biomass power projects achieve the stabilisation within first six months after commissioning of the project. Further, they have suggested that a stabilisation period shall not be more than 6 months from the date of commissioning.

40.3 Accordingly, the Commission has adopted the suggestion made by MNRE and has suitably modified the norms for plant load factor for biomass power projects and the same has been incorporated in the final regulations.

41. Auxiliary Consumption

41.1 In the draft regulations it has been provided that the auxiliary power consumption factor shall be 10% for the determination of tariff.

41.2 Biomass Energy Development Association has submitted to consider auxiliary consumption of 13% factoring the transmission losses. MBEDA has submitted that the biomass power plants after stabilisation runs at maximum load of about 70%-80% PLF, the auxiliary consumption should be assumed as 11.50%. Some stakeholders have submitted to consider auxiliary consumption as12%.

41.3 The Commission is of the view that the auxiliary consumption factor is one of the key performance factors and is dependent of the size of the plant. The Commission also notes that the auxiliary energy consumption is a function of plant efficiency and the energy conservation methods adopted by the developers. Further, the auxiliary consumption factor may vary according to the need of pre-processing requirement of the biomass fuel. Considering the requirement of pre-processing of the biomass fuel, typical size of the plant and drive towards adopting energy conservation methods, an auxiliary consumption of 10% has been specified.

42. Station Heat Rate

42.1 In the draft regulations the station heat rate of 3650 kCal/kWh for biomass power projects has been specified.

42.2 Various stakeholders have submitted that the norm with regards to the SHR as specified may be difficult to achieve. Some of the stakeholders have suggested to consider SHR in excess of 4000 kCal/kWh in view of operational difficulties, degradation in fuel calorific value due to storage etc.

42.3 The Commission is of the view that with biomass power generation projects based on Rankine cycle technology, essentially two types of boilers are being used, viz. travelling grate combustors (stokers) or atmospheric fluidised bed boilers. However, while fluidised boilers offer higher efficiency as compared to travelling grate, there are limitations in use of fluidised bed boilers due to fuel quality and fuel size requirements. On the other hand, travelling grate type boilers offer flexibility as it can handle variety of type/quality of fuel without significant modifications. Further, it has been observed that biomass project developers, as industry practice have deployed predominantly travelling grate type boilers for biomass based power generation. Typically, the biomass power projects use boilers with steam pressure parameters of 45 bar/60 bar/80 bar and the boiler efficiency is low at around 75%-80%.

42.4 Further, the Commission observes that while design efficiency/design Station Heat Rate is of the order of 3400-3600 kCal/kWh, the operational efficiency is significantly lower (consequently operational station heat rate is higher) due to several factors such as deterioration in quality of fuel due to storage, O&M practices etc. Keeping in view the above fact and the submissions made by the various stakeholders the Commission has suitably modified the norm for Station Heat Rate for biomass power projects and the same has been incorporated in the final regulations.

43. Operation and Maintenance

43.1 In the draft regulation normative O&M expenses of Rs20.25 Lakh/MW for the first year of control period (FY 2009-10) has been specified.

43.2 IREDA has submitted that the project equipment damage frequently due to corrosion/erosion due to usage of variety of biomass fuels, O&M expenses in the range of 6%-7% should be considered. BEDA has submitted that an O&M cost of 9%

should be considered to compensate the steep increases in manpower cost, prices of steel and metals.

43.3 The Commission has already recognized that the size of biomass power plant is comparatively small compared to the conventional power projects. Further, the expenses towards plant manager, shift operators and other establishment and administrative expenses translate into higher proportion of per MW operation and maintenance expenses as compared to the conventional power plants.

43.4 Accordingly, for the purpose of determination of tariff the Commission was considered an O&M expense of 4.5% of the capital cost per MW on annual basis which translates to Rs20.25 Lakh/MW has been specified.

43.5 As regards, increase in manpower and other related costs, the Commission has also considered escalation factor for O&M cost at the rate of 5.72% per annum. In view of above, the Commission does not find any need to modify norm as specified under draft Regulations.

44. Fuel Mix

44.1 In the draft regulations it has been specified that the biomass power plant shall be designed in such a way that it uses different types of non-fossil fuels available within the vicinity of biomass power project such as crop residues, agro-industrial residues, forest residues etc. and other biomass fuels as may be approved by MNRE. Further the biomass power Generating Companies shall establish fuel management plan to ensure adequate availability of fuel to meet the respective project requirements.

44.2 Shalivahana Green Energy Limited suggested waiving the condition of establishing the fuel management plan since it is not feasible to ensure fuel management supply chain on a long term basis and short term contracts are not binding as there is no price guarantee in biomass fuel market**.**

44.3 The Commission is of the view that it is essential to ensure long term availability of biomass fuel for the sustainability of energy generation. Further to this, the availability of biomass fuel for power generation depends on the factors such as cropping pattern, change in rainfall pattern, improvement in irrigation technologies, utilisation pattern of biomass etc.

44.4 The Commission further observe that the fuel procurement and transportation is highly unorganised and most of the times the prices are influenced by local factors. Such factors may highly effect the operation of the biomass based power projects. Keeping such factors into consideration the Commission has specified establishment of fuel supply chain which would be in the interest of biomass power project. This will ensure uninterrupted supply of biomass on a sustained and long term basis. The Commission is also of the view that biomass projects need to be encouraged to use multiple fuel and establish alternate dedicated fuel supply chain rather than depending on single biomass fuel sources. Option of usage of alternate biomass fuel for power generation would also ensure uninterrupted operation.

44.5 In view of above, the Commission has stipulated the requirement to establish biomass fuel supply chain.

45. Usage of Fossil Fuel

45.1 In the draft regulations the usage of fossil fuel of 15% has been specified. Some of the stakeholders have sought to increase the limit to 25% instead of 15% and some stakeholders have also suggested to operationalise such limit in terms of heat content (kCal) of fuels rather than in terms of quantum of fuels.

45.2 It is noted that as per administrative approval of Ministry of New and Renewable Energy conveyed vide letter no. 3/19/2006-CPG dated December 26, 2006, it is stipulated that the usage of coal shall be limited to 15% of the fossil fuel of the total energy consumption in kCals or as per DPR whichever is less; for those biomass projects wishing to seek the capital subsidy. However, such condition is applicable for those projects commissioned after the date of issue of order i.e. December 26, 2006.

45.3 The Commission has kept the usage of fossil fuel in line with the stipulation made by the MNRE and the same may be continued. As and when the MNRE review its policy on the usage of fossil fuel by the biomass power projects, the Commission may also change its provision on Usage of Fossil fuel. However, in order to simplify the operationalisation and monitoring of such limit, it is sought to be applicable in terms of quantum of fuel rather than heat value (kCal) of the fuel.

46. Monitoring Mechanism for the use of fossil fuel

46.1 In the draft regulations it has been specified that the Project developer shall furnish a monthly fuel usage statement and monthly fuel procurement statement duly certified by Chartered Accountant to the beneficiary (with a copy to appropriate agency appointed by the Commission for the purpose of monitoring the fossil and non-fossil fuel consumption) for each month, along with the monthly energy bill.

46.2 The Commission has specified the norm for usage of fossil fuel in line to the recommendations made by the MNRE for providing capital subsidy. Further, the

Commission would also like to clarify that the usage of fossil fuel to an extent of 15% on annual basis shall be permitted. The Commission is of the view that the biomass power plant should be designed in such a way that it uses different types of non-fossil fuels available within the vicinity of biomass power project such as crop residues, agro-industrial residues, forest residues etc. and other biomass fuels as may be approved by MNRE. Use of fossil fuels should only be considered to address seasonal variations. The Commission clarifies that non-compliance with the condition of fossil fuel usage by the project developer, during any financial year, shall result in withdrawal of applicability of tariff as per these Regulations for such biomass based power project.

47. Calorific Value

47.1 In the draft regulations the Commission has specified the norms for calorific value based on the mix of biomass available in the respective states.

47.2 Abellon has submitted that separate norms for Gujarat may be specified. Shalivahana Green Energy Limited has submitted that the Calorific Values (CV) of most of the biomass fuel undergo unpredictable change from high moisture/low CV to low moisture/high CV. MBEDA and BEDA has submitted that the CV should be 3300 kCal/kg in accordance with the recommendations of CEA.

47.3 The Commission wishes to clarify that it has specified the biomass fuel prices and calorific value for the States where significant biomass potential exists and/or yet to be harnessed. The Commission has at present specified biomass fuel price and calorific value for eight States, which comprises around 70% of estimated surplus biomass power potential in the country. There are several other States including Gujarat wherein biomass potential is yet to be explored, however the same has been considered under 'Other State' category.

47.4 Further, the Commission would like to clarify that in order to determine the weighted average calorific value of biomass fuel mix the calorific values of individual biomass have been considered as maintained by Indian Institute of Science, Bangalore. The Commission understands that the same institute has been engaged by the MNRE for the development of Biomass Atlas for India.

47.5 As regards, variation of biomass fuel from one state to another, it is clarified that the GCV specified is for the mix of biomass fuel available in particular State and not for any single biomass. The gross calorific value for individual biomass fuel has been considered as maintained by the Indian Institute of Science, Bangalore.

48. Fuel Cost

48.1 The stakeholders expressed their views on fuel cost as under:

- NEDCAP has submitted that the base fuel cost of biomass for Andhra Pradesh should be considered at Rs 2000 per tonnes as notified by APERC in its tariff order dated March, 2009. MBEDA has submitted that the average fuel cost of Rs 2600/MT (including biomass & coal) should be assumed. This cost will include the expenses incurred on account of site handling/processing & storage losses etc. Torrent Power Limited Methodology adopted for computation of the fuel cost should be reviewed as it appears that cost of coal is exclusive of transportation charges.

48.2 The Commission would like to clarify that in order to compute the biomass fuel price for respective States, 'equivalent heat value approach for landed cost of coal for thermal power stations at respective States has been adopted. For this purpose, the Commission has considered the landed cost and calorific values of coal as approved by the respective State Electricity Regulatory Commission while determining the generation tariff of the respective State Utility. As the approved fuel prices pertain to FY 2008-09 in most States, the biomass prices so derived has been escalated based on fuel price indexation mechanism stipulated under the Regulation to derive fuel prices during first year of the Control Period (i.e. for FY 2009-10).

48.3 As suggested by the stakeholders, the Commission has reviewed the price of biomass fuel mix for the respective States and the same has been reflected in the final regulations.

Non-Fossil Fuel Based Cogeneration Projects

49. Capital Cost

49.1 In the draft regulations the normative capital cost for the non-fossil fuel based cogeneration projects has been specified as Rs.445Lakh/MW for the first year of Control Period i.e. FY 2009-10.

49.2 The stakeholders expressed their views on capital cost norms as under:

- UP Sugar Mill Cogen Association & ISMA suggested considering the Transmission cost of evacuation of power as a part of Capital Cost.
- Indo Greenfuel Private Limited suggested considering the capital cost for cogeneration plants at Rs545Lakhs/MW.
- IREDA submitted that the capital cost are in the range of Rs4.33Cr/MW to Rs 5cr/MW

49.3 As regards considering the transmission cost of evacuation of power, the Commission, in Regulation 13 of the Financial Principles, has specified that the Capital Cost for each RE technology shall be inclusive of all the Capital Works including plant and machinery, civil work, erection and commissioning, financing and interest during construction, and evacuation infrastructure up to interconnection point. Further in case of non fossil fuel based cogeneration plants the interconnection point has been defined as line isolator on outgoing feeder on HV side of the generator transformer.

49.4 Further, the rationale for adopting the normative capital cost norms is based on the detailed study undertaken by the Commission for the various approaches viz. Regulatory Approach or Pooled Cost Approach, Actual Project Cost Approach, etc. The aforesaid approaches have been discussed in length in the Explanatory Memorandum published along with the Draft Regulations.

49.5 In order to determine normative capital cost the Commission has analysed and has taken into consideration the details of the co-generation projects developed through funding assistance from IREDA and also projects which are registered with UNFCCC. Accordingly, the Capital Cost norm for co-generation projects has been specified.

50. Plant Load Factor

50.1 In the draft regulations it has been specified that for the purpose of determining fixed charge, non-fossil fuel based cogeneration projects shall be considered to be operational for the period of 240 days (180 days during crushing season – cogeneration mode and 60 days of off-season/non-crushing season). Accordingly, the normative plant load factor for cogeneration project shall be considered as 60% (i.e. Availability factor 66% x load factor 90%).

50.2 However, ISMA and UP Sugar Mill Cogen Association has submitted that state-wise PLF may be stipulated taking into consideration the fact that the crushing season varies from State to State. For example, in UP average crushing season is only around 120 days.

50.3 The Commission received inputs from MNRE and IREDA in the matter. The Commission has also looked at the average crushing season data for past 10 years in various States. Accordingly, the Commission has specified the plant load factor on the basis of the average crushing period in respective States for the purpose of determining the fixed charges and the same has been incorporated under final Regulations.

51. Auxiliary Consumption

51.1 In the draft regulations an auxiliary consumption factor of 8.5% has been specified.

51.2 A number of stakeholders have suggested considering an auxiliary consumption of 10% against 8.5% proposed in the draft regulations. IREDA has submitted that the auxiliary consumption is in range of 10%.

51.3 The Commission is of the view that in non-fossil fuel based cogeneration plants have some of the auxiliary equipments common between the sugar mill and the power generation unit. Also, the bagasse require less processing compared to the biomass. Keeping above fact into consideration the Commission has specified the norm for auxiliary consumption for cogeneration projects. Accordingly, the Commission has retained the norm as specified under Draft Regulations.

52. Station Heat Rate

52.1 In the draft regulation a Station Heat Rate of 4000 kCal/kWh has been specified for non-fossil fuel based cogeneration power projects. Further, for the purpose of determination of tariff the normative ratio of allocation of fuel cost between power and steam as 60:40 has been specified.

52.2 UP Sugar Mill Cogen Association & ISMA have suggested to consider the SHR as 3700 kCal/kWh by taking the ratio of fuel cost allocation between fuel and steam to be 75:25.

52.3 As regards to the Station Heat Rate for Non-Fossil fuel based cogeneration power projects, the Commission notes that the co-generation plant design depends on cane crushing capacity and steam requirement of host sugar mill. The eligibility criteria stipulated under Regulation shall ensure that cogeneration plants are designed to meet minimum cogeneration efficiency as stipulated under the Regulations. However, co-generation plant operates in co-generation mode during crushing season and in rankine cycle mode during off-season. The fuel consumption during crushing season (co-generation mode) is used for power generation as well as steam generation purposes, whereas fuel consumption during off-season is essentially used for power generation purposes. For the purpose of tariff determination, fuel consumption corresponding to power generation alone should be considered. Hence, allocation of fuel cost to power and steam was envisaged under Draft Regulations. However, the same effect can be achieved if normative Station Heat Rate for power component alone is specified. Thus, if Station Heat rate during rankine cycle mode (off-season) and station heat rate for power component alone (during co-generation mode) is specified then, formulation for fuel cost allocation to power and steam is not necessary. Further, the information furnished by MNRE and heat mass balance diagrams for a few co-generation projects have also been analysed before specifying the normative Station Heat Rate for non-fossil fuel based co-generation projects. Accordingly, the Commission has suitably modified the regulation and the same has been incorporated in the final regulations.

53. Fuel Cost

53.1 The comments received by various stakeholders in this regard are as under:

- To consider the fuel cost for Bagasse based Cogeneration Power Projects as Rs950/MT.
- To consider the price of bagasse to be Rs1378/MT considering 6% escalation.
- Fuel price should be actually around 20% higher than the prices achieved by the large thermal power plants and the fuel price escalation should be linked with the price of coal.
- To consider a fuel rate of Rs25/ltr with heat value of 8750kCal/ltr against Rs1/kg with heat value of 2250kCal/kg.
- To review the prices of bagasse as it does not reflect the market price.
- Cost of bagasse in some states such as M.P., A.P., and U.P. etc. appears to be on lower side.

53.2 The Commission would like to clarify that in order to compute the fuel price of bagasse for respective States the Commission has adopted ‘equivalent heat value’ approach for landed cost of coal for thermal Stations for respective States. For this purpose, the Commission has considered the landed cost and calorific values of coal as approved by the respective State Electricity Regulatory Commission while determining the generation tariff of the respective State Utility. As the approved fuel prices pertain to FY 2008-09 in most States, the bagasse prices so derived has been escalated based on fuel price indexation mechanism stipulated under the Regulation to derive fuel prices during first year of the Control Period (i.e. for FY 2009-10).

53.3 As suggested by the stakeholders, the Commission has reviewed the price of cogeneration for the respective States on the basis of available facts and the same has been reflected in the final regulations.

54. Operation and Maintenance Expenses

54.1 In the draft regulations it has been specified that the normative O&M expenses during first year of the Control period i.e. FY 2009-10 shall be 13.35 Lakh per MW.

54.2 UP Sugar Mill Cogeneration Association suggested to consider an O&M expenses of 4% of the capital cost. IREDA has submitted that specified O&M expenses are on the lower side and actual expenses are in the range of 4%-5% of the capital cost.

54.3 The Commission has observed that in case of cogeneration projects there are several common expenses between the host sugar factory and cogeneration unit. It is also to be noted that the bagasse is readily available in the premises of the sugar factory only, and hence does not require additional manpower in fuel transportation and hence associated handling charges are negligible. Further, such O&M expenses associated with fuel management chain are not significant in case of bagasse cogeneration plants. Accordingly, the Commission has fixed the norms for operation and maintenance for the non-fossil fuel based cogeneration projects. Keeping this in view the Commission has considered the O&M norm as 3.5% of the Capital Cost.

54.4 Accordingly, the Commission has retained the normative O&M expense as specified under Draft Regulations.

Solar Photovoltaic Power Projects

55. Definition of Technology Aspects

55.1 In the draft regulations it has been specified that the Norms for Solar Photovoltaic (PV) power under these Regulations shall be applicable for grid connected PV systems that directly convert solar energy into electricity and are based on the technologies such as crystalline silicon or thin film as may be approved by MNRE.

55.2 Dalmia Cement (Bharat) Ltd has submitted to suitably modify the regulations as,

> **"***Norms for Solar Photovoltaic <u>and Solar Dish Sterling Engine Power</u> under these regulations shall be applicable for grid connected PV <u>and Dish Sterling Engine systems</u> that directly convert solar energy into electricity and are based on technologies such as crystalline silicon/thin film <u>and Dish Sterling Engine</u> as may be approved by MNRE".*

55.3 The Commission would like to clarify that the plants which utilises the Solar Dish Stirling Engine technology qualifies as Solar Thermal Power Plants and are not part of Solar Photovoltaic Technology. The norms for solar thermal power plants have been specified separately under Chapter-8 of the Regulations.

56. Capital Cost

56.1 The draft regulations has the following provisions for the Capital Cost as regards to Solar PV:

The normative capital cost for setting up Solar Photovoltaic Power Project shall be Rs.1800 Lakh/MW for FY 2009-10.

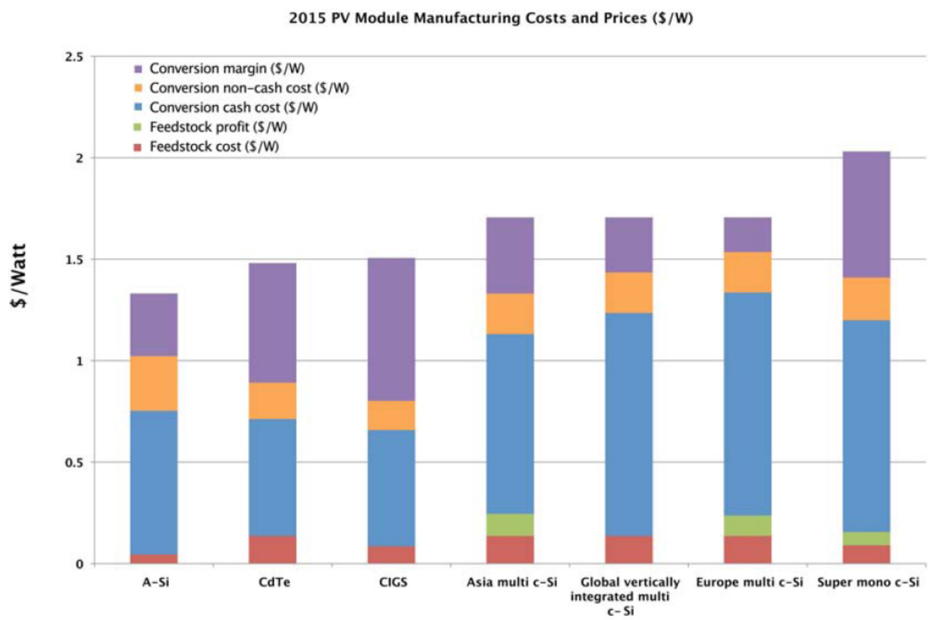
56.2 Various stakeholders have submitted that the normative capital cost varies for technologies with different PLF i.e. higher PLF higher capital cost requirement and vice versa and the same may be considered. The capital cost should be linked with foreign currency exchange rate variation.

56.3 With regards to the Capital Cost consideration of Solar PV power projects, the Commission has re-examined and analysed the market development of Solar PV in the countries that have announced any supporting law/regulation. The Commission finds that in case of Germany, which is also recognised as the world's largest solar PV market, with an installed base of over 3.8 GW, after announcing Renewable Energy Sources Act, 2000 significant solar capacity was added. Similar examples can be seen in the Countries like Spain and Greece which are leading in the installation of Solar PV projects.

56.4 Further, the Commission has taken into consideration the recommendations of the stakeholders which mentions that, the economies of scale will drive down the cost curve from USD 3.4/Watt (approx Rs17Cr/MW) in 2010 to USD 2.4/Watt (approx Rs12Cr/MW) in 2012. The Commission finds that the project cost of recently commissioned first phase of Solar PV project in Asansol, West Bengal is also in the range of approximately Rs17Cr/MW to Rs18Cr/MW. The capital cost for second phase is expected to reduce further. Last year Karnataka Power Corporation had also tendered two plants of 3 MW each, which were in the range of Rs. 16-17 Crore per MW.

56.5 International study[1] has projected PV module manufacturing costs to fall to US$ 1.5 – 2/Watt (2015) as per chart below.

Figure E-10: PV Module Manufacturing Costs and Prices – 2015



56.6 While the Commission notes that capital costs for PV modules are expected to fall in future, it cannot be ignored that the development of Solar Power projects in India are still at its nascent.

56.7 The Commission has also observed that the project proponents have stated, in their petitions submitted to SERCs for determination of tariff of Solar PV plants, the project cost to be around Rs17Cr/MW whereas few developers have indicated the project cost in the range of Rs.20Cr/MW.

56.8 Keeping the above facts into consideration the Commission envisages that the fast pace technological development and the economies of scale would ensure that the

[1] PV technology Production and Cost, 2009 Forecast:The Anatomy of shakeout, Greentech Media Inc

capital cost for Solar PV installations to decrease over a period of time. Therefore, the Commission has revised the capital cost for solar PV projects. The same has been incorporated in the final regulations. Further the Commission has set the applicability of the norms during the 'first year on the control period' and the benchmark capital cost for Solar PV shall be reviewed annually by the Commission. Pertinently, a project developer also has the option of approaching the commission for determination of project specific tariff if it wants any deviation from the benchmark capital cost norms provided in the regulations.

57. Capacity Utilisation Factor

57.1 The draft regulations has the following provisions for the Capacity Utilisation Factor as regards Solar PV power projects:

The Capacity utilisation factor for Solar PV project shall be 19%.

Provided that the Commission may deviate from above norm in case of project specific tariff determination in pursuance of Regulation 7 and Regulation 8.

57.2 The comments received by various stakeholders in this regards are as under:

- Annual performance degradation factor should be considered.
- For site specific insolation database maintained by USA's NASA may be considered.
- Range of CUF may be specified instead of specifying fixed CUF.
- The CUF of 19% for Solar PV plants is on the higher side. The CUF should be in range of 15% to 18%.
-

57.3 The Commission notes that the NASA's Atmospheric Science Data Center maintains the Surface Meteorology and Solar Energy Data and is recognised as one of the authentic sources for collecting the Solar Irradiance parameter. However, it may be noted that the Solar Energy Center, MNRE has also been maintaining the solar irradiance incident over different cities of India.

57.4 As regards providing the range of capacity utilisation factor in correlation with the capital cost of the project, the Commission is of the view that with technological improvement, the efficiency of the cell/module and the capacity utilisation factor may improve. However, till such time the technology reaches its maturity and operating parameters of projects commissioned in India are available, it is not advisable to devise formulation linking the capacity utilisation factor with capital cost at this stage.

57.5 The Commission also observes that the capacity utilisation factor is a function of the incident solar radiation. The Commission notes that the clear sunny days of around 290 days to 320 days are available in most of the parts of the country. Keeping this in view while devising the capacity utilisation factor an average clear sunny days of 300 days have been considered. Further the mean monthly global solar radiation incident over India is found to of the order of 5.5 to 6 kWh/sqm/day and the same has been considered. Keeping the above facts into consideration the Commission has specified a CUF of 19% for Solar PV based power projects.

58. Operation and Maintenance Expenses

58.1 The Commission has proposed a norm for Operation and Maintenance as under:

The O&M Expenses shall be Rs.9 Lakhs/MW for the 1st year operation.

Normative O&M expenses allowed at the commencement of the Control Period under these Regulations shall be escalated at the rate of 5.72% per annum.

Some of the stakeholders have sought O&M expenses to be 0.7% to 1% instead of 0.5% as proposed. The Commission observes that in case of solar PV power projects, repairs and maintenance expenses are not significant due to limited wear and tear and mainly pertain to replacement of parts for control system or power conditioning systems. Significant part of manpower related expense would pertain to inspection/testing/cleaning array systems etc. However, there is hardly any operational experience of MW scale PV power system in India to ascertain norms for O&M expenses. The objectors have also not provided any supporting documentation to substantiate their claim for higher O&M expenses. Accordingly, the Commission has considered normative O&M expense as proposed under draft Regulations.

Solar Thermal Power Projects

59. Technology Aspect

59.1 In the draft regulations following definition has been specified as under:

"Norms for Solar thermal power under these Regulations shall be applicable for Concentrated solar power (CSP) technologies viz. solar trough or solar tower, as may be approved by MNRE and uses direct sunlight, concentrating it several times to reach higher energy densities and thus higher temperatures whereby the heat generated is used to operate a conventional power cycle to generate electricity."

59.2 Many stakeholders have suggested specifying the applicability of regulations on Solar Thermal plants without thermal storage whereas some stake-holders have also preferred to specify norms with thermal storage.

59.3 With regard to definition of technology aspects and applicability of the norms, based on the views of MNRE, the Commission has modified the definition to cover all solar thermal power technologies with line focus or point focus applications. The same has been incorporated in the final regulations. The Commission recognises that while thermal storage would provide flexibility in operations and shall also improve capacity utilisation factor for the solar thermal power plant, it would also have corresponding cost implications. The generic norms under these Regulations have been provided for solar thermal power plants without thermal storage. In case a developer chooses to develop the system with thermal storage, the tariff determination for such system could be taken up on case-to-case basis under 'project specific' tariff determination route. As design of thermal storage, extent and type of thermal storage would be unique, it is preferred to deal with such project cases on case to case basis.

60. Capital Cost

60.1 The draft regulations had the following provision for the capital cost of solar thermal:

"The normative capital cost for setting up Solar Thermal Power Project shall be Rs.1300 Lakh/MW for FY 2009-10."

60.2 The comments received on this provisions are,

- Acme Group and FAST has submitted that the Capital Cost for Solar Thermal Power Plants should not be less than Rs.15Cr/MW. The capital cost considered is on lower side. Entegra and Rudraksh Energy has submitted to link the capital cost with the CUF which varies from 22% to 50% depending on technology and with or without storage facility.

- FAST has further submitted that Solar thermal projects are land intensive and the cost of land may be taken into account while mentioning the capital cost. Clean Energy Research Centre, University of South Florida has submitted that the capital costs of CSP plants presently under construction are in the range of Rs 18-20 Cr/MW.

60.3 The capital cost of a plant may vary according to the solar radiation. Clinton foundation has suggested that, for Indian Solar Sites, with direct normal radiation of approximately 2200 kWh/m2/annum, the capital cost requirement should be in the range of approximately Rs13.5Cr/MW to Rs18Cr/MW and with 2000 kWh/m2/annum the capital cost requirement may vary in the range of Rs14Cr/MW to Rs19Cr/MW (without thermal storage) with PLF varying from 24% to 26% (without thermal storage). The above capital cost requirement is for projects which are not utilising any storage medium. MNRE, in line with the submissions made by the stakeholders, has suggested that the norms for capital cost (Rs13Cr/MW) are on the lower side.

60.4 The Commission finds that the Stakeholders have generally argued for enhancement for capital cost based on the capital cost of Solar Thermal Projects being developed in countries like Spain, USA etc.

60.5 ACME have submitted a petition before CERC seeking approval for their proposed Solar Thermal Project in Rajasthan wherein they have quoted capital cost of Rs.13.03 crore per MW.

- In their justification for the project cost ACME have argued in the context of the capital cost of Solar Thermal Projects in other countries that “the engineering cost, development cost and construction cost is very high in those countries. With indicated costs received from the major components for the Solar Block, and doing the engineering through ourselves / domestic sources, the cost of Solar Block can be done at Rs.9.5 crore per MW. This makes the total plant cost in the range of Rs.12 crore per MW”
- ACME have further argued that “it is expected that through local manufacturing for critical components or sourcing from Indian Vendors to the extent possible, cost of Solar Block can be brought down to Rs. 6-7 crore per MW and the cost of the plant can be retained at around Rs.10 crore per MW”.

60.6 In view of the above, the commission has decided to retain the provision of Capital Cost of Rs.13 crore/MW for Solar Thermal Project

61. Capacity Utilisation Factor

In the draft regulations a Capacity utilisation factor of 25%has been specified.

61.1 The comments received on this provision are as under:

- Energy and Petrochemical Department, Government of Gujarat and Acme Group have submitted considering normative CUF as 23%. Rudraksh Energy, Entegra Limited has suggested providing a CUF range varying from 22% to 50%.
- FAST has submitted that CUF of 21% is the maximum possible limit to be considered for Kutch in Gujarat, Western Rajasthan and Andhra Pradesh and the same shall be kept under consideration.

61.2 MNRE has suggested that normative capacity utilisation factor of 23% for solar thermal power plants without storage may be considered.

61.3 As regards norms for Capacity Utilisation Factor for Solar Thermal Power Plant, the Commission has taken into consideration the submissions made by the developers of the prospective projects and recommendation of MNRE. Accordingly, the Commission has revised the norm for capacity utilisation factor for Solar Thermal Power Projects (without storage) and the same has been incorporated in the final regulations.

62. Operation and Maintenance

62.1 The Commission has made following provision under draft regulation:

The O&M Expenses shall be Rs 13 Lakhs/MW for 1st year operation.

62.2 The comments received in this regard are as under:

- Rudraksh Energy submitted that a range of normative O&M expenses may be specified as percentage of Capital Cost which may vary from 1.25% to 1.5% linked with CUF and Storage Capacity. Entergra Ltd. submitted that the proposed O&M norms are on the lower side and it may be specified in the range of 1% to 1.25% of the capital cost. Further the O&M norms for with and without thermal storage are different and same may be considered. Clean Energy Research Centre, University of South Florida submitted that O&M cost of Rs22Lakhs/MW/annum may be considered.

62.3 The Commission observes that in case of solar thermal power projects, repairs and maintenance expenses related to solar field operations are not significant due to limited wear and tear and mainly pertain to operation and maintenance for power block components. Significant part of manpower related expense would pertain to inspection/testing/cleaning solar panels/array tracking systems etc. However, there is hardly any operational experience of MW scale thermal power projects in India to ascertain norms for O&M expenses. The objectors have also not provided any supporting documentation to substantiate their claim for higher O&M expenses. Accordingly, the Commission has considered normative O&M expense as proposed under draft Regulations.

63. Auxiliary Consumption

63.1 In the draft regulations the Commission has adopted an auxiliary consumption factor shall be 10%,

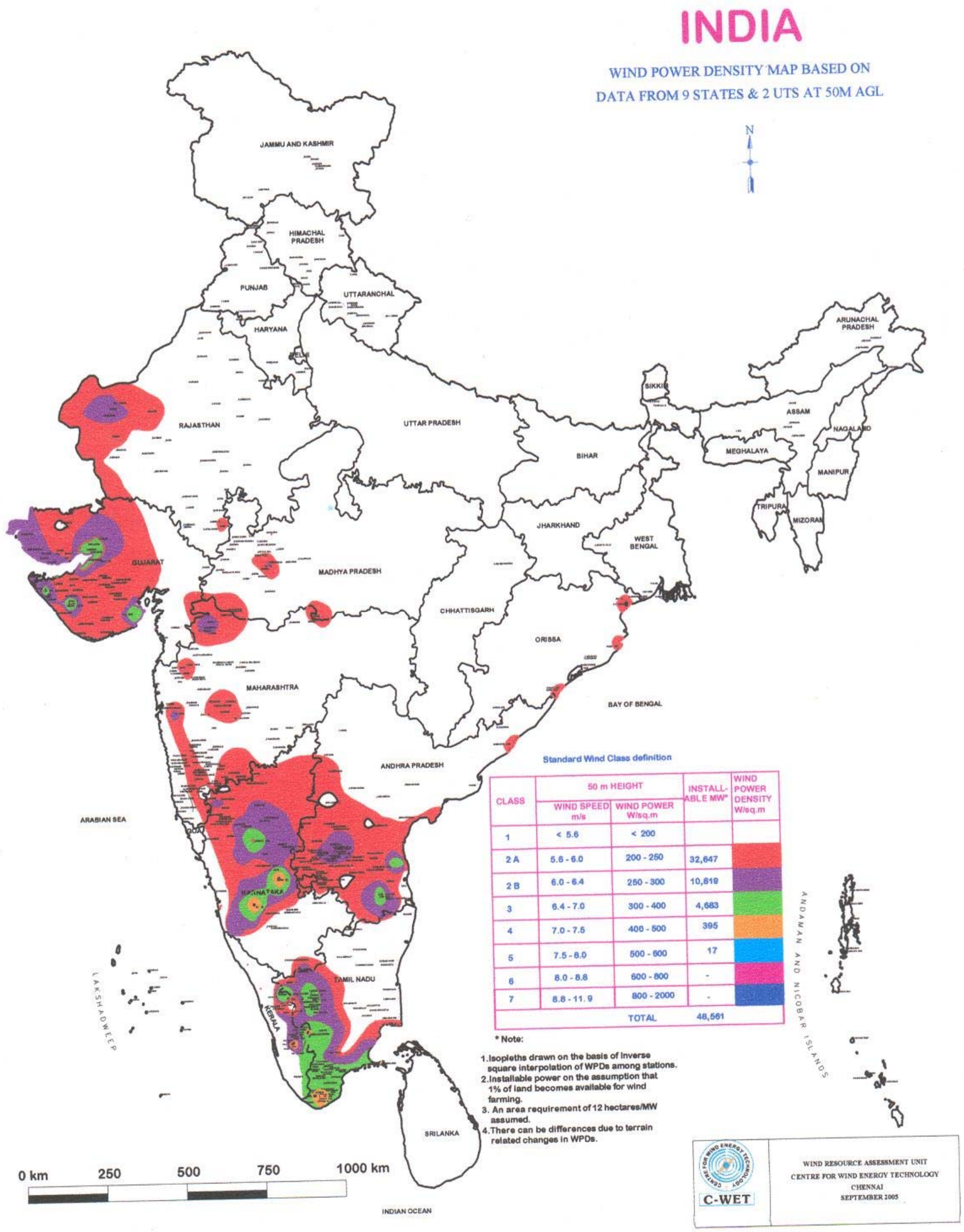
63.2 The Commission would like to clarify that the above norms are applicable to plants without storage and no modification has been proposed from that specified under draft Regulations.

Sd/-	Sd/-	Sd/-	Sd/-	Sd/-
(V.S. Verma)	(S. Jayaraman)	(R. Krishnamoorthy)	(Rakesh Nath)	(Pramod Deo)
Member	Member	Member	Ex-Officio Member	Chairperson

Dated:- 07th October, 2009

Schedule-1

State-wise Wind Power Density Map



<u>Annexure – 1</u>

Summary of Comments received from various Stakeholders

<u>Draft Regulation 2:</u> Definitions

1. In the definition of Installed capacity, mechanism needs to be devised for name plate capacity on the basis of type certification for different models of WTGs. In Definition of 'Non-Firm Power', the non-firm should be replaced with less firm power because with the present technology, generation can be reasonably predicted. ***(Shri M.P. Ramesh, Ex-ED, C-WET)***
2. All type of hydro power plants, irrespective of their capacity should be considered as renewable power sources as they help in reducing the carbon footprint. ***(Torrent Power Limited)***
3. Word 'mini hydro' mentioned in the definition of Renewable Energy Sources may be replaced with the word 'small hydro' ***(Power Trading Corporation and Himachal Small Hydro Power Association)***
4. Sub-classification of small hydro projects into mini Hydel plant with capacity in the range of 1MW and 250 kW, and micro hydro with capacity less than 250 kW may be made. ***(PMC Power Pvt. Ltd.)***
5. Industrial wastes of all types i.e. solid, liquid and gaseous should be included in the definition of Renewable Energy Sources ***(Transparent Energy Systems Private Limited)***
6. The word 'non-conventional energy sources' should also be defined and heat energy generated from the chemical reaction of NCES sources may also be included in the scope of Regulations. ***(Tamil Nadu Electricity Regulatory Commission)***
7. Definition of 'Non-Firm Power' should also include electricity generation from biomass power plants ***(Maharashtra Biomass Energy Developers Association)***
8. Inter-connection point may also be defined for solar power plant and municipal waste power plant. ***(Shri Shanti Prasad)***
9. The word 'at the wind farm site' may be added after the definition of inter-connection point for wind projects. ***(Consolidated Energy Consultants Limited (CECL))*** Definition of 'Interconnection Point' shall be in accordance with the definition mentioned by GoI under Case I bidding guidelines "*Interconnection Point" shall mean the point where the power from the Power Station switchyard bus of the seller is injected into the interstate/intrastate transmission system (including the dedicated transmission line*

connecting the Power Station with the interstate/intrastate transmission system). ***(BEST Undertaking)***

10. Useful life for wind project should be 20 years ***(GFL, IWPA, Accoina Wind Energy Pvt Ltd., CLP, IWTMA, CECL)***
11. IEC Standard specifies useful life of 20 years. 25 years useful life is possible with certain safety related clearances after 15 years. ***(Shri M.P. Ramesh)***
12. Useful life of biomass plant should be kept at 15 years instead of 20 years due to lot of wear and tear caused by stones, sand, mud etc present in Biomass ***(Abellon Clean Energy Limited, Auro Mira Energy Group (AMEG))***
13. Useful life for Solar Power Plants and Municipal Solid Waste Projects should also be specified. ***(Shri Shanti Prasad)***

Draft Regulation 3: Scope and Extent

14. Tariff norms for industrial waste to energy based projects may also be specified. ***(NEDCAP)***
15. Regulations should provide incentives for promotion of the renewable energy sources rather than providing disincentives and regulating the tariff like conventional power plants. ***(HSHPA)***
16. Regulations shall not prohibits other modes of sale of power i.e. inter-state or intra-state sale through open access ***(GFL)***
17. Clarification should be given whether these Regulations would work as guidelines as contemplated in Tariff Policy for pricing of Non-firm power. ***(IWPA, IWTMA)***
18. Tariff based on CERC regulations is more attractive, new generation based on RE may have a tendency to contract for power with two or more States. ***(PGCIL)***
19. The Regulations should have separate section for existing projects which come up for tariff revision after 10 years, 25 years and so on. Related provisions from Tariff Regulations, 2009 may be incorporated in the draft Regulations. ***(Energy Development Company Limited (EDCL))***

Draft Regulation 4: Eligibility Criteria

20. Self identified small hydro project get approval from State Nodal Agency or State Govt. MNRE plays no role in approving the small hydro sites. ***(NEDCAP, HSHPA, Polyplex Corporation Limited, Kaplan Hydro, NTPC, IREDA)***
21. Relationship between the wind power density and wind velocity may either be incorporated in the Regulations or annexure to the Regulations. ***(Shri Shanti Prasad)***

22. Eligibility criteria and norms should also be specified for process waste heat driven power plants, process waste heat cogeneration plants, and non-fossil fuel based power plants***. (Transparent Energy Systems Pvt. Ltd.)***
23. Hub-height should also be considered along with wind power density for computation of CUF for wind projects. ***(IWPA)***
24. Wind power density depends upon hub-height, measurement period and location of wind mast etc. Therefore, all these parameters should also be considered. ***(IWTMA)***
25. It should be mentioned that wind power density should be minimum 200 Watt/ m^2 at 50 m. hub-height. ***(Shri M.P. Ramesh CECL)***
26. MNRE/IREDA permits up to 25% of fossil fuels in the biomass based projects while in the draft Regulations, this limit has been kept as 15%. Further, the word '15% of total fuel consumption' should be replaced with '15% of the total fuel consumption expressed in kCal' for more clarity. ***(TNERC, PTC)***
27. Nodal Agency for certification of wind sites may also be specified in the Regulations. ***(GETCO)***
28. Biomass gasification, Solar Thermal, Solar PV & roof top should also be included in these Regulations. ***(NTPC)***
29. Eligibility criteria for Non-Fossil Fuel based Cogeneration plants are theoretical and difficult to monitor. ***(IREDA)***

General Principle

Draft Regulation 5: Control Period

30. Control Period should be of 5 years as SHP has gestation period of more than 3 years. ***(HSHPA, Polyplex Corporation Limited, PTC)***
31. Process for revision of norms should be initiated at least 12 months before the expiry of Control Period for certainty and predictability of Regulatory Framework. ***(IWPA and Accoina Wind Energy Pvt.)***
32. Control period of two years is most desirable. ***(MBEDA)***
33. For regulatory certainty, Control period should be of 5 years. ***(NTPC)***

Draft Regulation 6: Tariff Period

34. Tariff Period should be of 20 years as it will help in making the projects bankable and reducing the uncertainty and unpredictability about the tariff, investment risk after 13 year period. ***(GFL, IWPA, Tata Power and Accoina Wind Energy Pvt, CECL)***

35. Tariff period of 5 years may be specified for SHP so that review of situation due to any forced meajure condition could take place. ***(PMC Power Pvt. Ltd.)***
36. Tariff period should be of ten years as loan repayment period is not more than 10 years. ***(Greenko Energies Pvt. Ltd., Biomass Energy Developers Association (BEDA))***
37. Tariff should be specified for the complete useful life of the project. ***(Torrent Power, NTPC, GETCO)***

Draft Regulation 7: Project Specific Tariff

38. Project specific tariff for wind projects in excess of 100 MW to be developed by a single project developer at one location may be determined. ***(IWPA and Accoina Wind Energy Pvt. Ltd)***
39. The Commission should specify a minimum project capacity, above which only, a developer can file petition for project specific tariff. ***(IWTMA)***
40. Tariff based on normative capital cost, O&M expenses, interest rate, subsidy by central government etc. should be specified upfront for each financial year of the control period. ***(PGCIL)***

Draft Regulation 9: Tariff Structure

41. Two part tariff may be specified for small hydro projects as it will ensure the recovery of fixed cost component like interest cost in case generation is affected due to poor monsoon. ***(PMC Power Pvt. Ltd.)***

Draft Regulation 10: Tariff Design

42. Levellised tariff as proposed in the Regulations is not a practical proposition as generating company may face the cash flow problems. Therefore, the tariff mechanism as close to the cost of generation may be specified. ***(Shri Shanti Prasad, Polyplex Corporation Limited, HSHPA, Indian Sugar Mills Association)***
43. Front Loaded Tariff should be specified ***(HSHPA)***
44. Discounting factor of 10.29%, as considered by CERC for competitive bidding projects, should be specified for levellisation purpose. ***(GFL)***
45. For avoiding the burden on consumers, tariff should be back loaded tariff. ***(GETCO)***
46. Discounting factor should be specified upfront at the time of finalisation of Regulations as discounting factor on the basis of cost of capital may vary year on year basis. ***(Tata Power)***

47. Process of determining the discount factor for the purpose of levellisation and determination of tariff should be elaborated with illustration. ***(BEST, PTC)***
48. Levellisation to be carried out for the useful life of the RE project, while tariff to be specified only for 13 years, would affect the revenue stream of the project during the tariff period ***(Uttar Pradesh Sugar Mill Cogen Association, PTC)***
49. Levellised tariff should be applicable for entire life of the project. ***(NTPC)***
50. Levellised tariff is detrimental to the interest of the projects. ***(BEDA and Greenko Energies Pvt. Ltd)***

<u>Draft Regulation 11</u>: Scheduling of electricity generated from RE sources

51. All renewable energy plants, irrespective of the installed capacity, should be given 'MUST RUN' status. The term 'collective basis' needs to be further elaborated. ***(Shri Shanti Prasad)***
52. Draft Regulations would create hindrance in allowing the open access by the State utilities to the renewable energy sources as State utilities would be hostile in paying the UI charges for deviation in the energy generation from RE sources. ***(HSHPA)***
53. It is not possible to declare the availability on inter-connection point basis due to co-ordination problem among the project developers. ***(Polyplex Corporation Limited, and HSHPA)***
54. It should be clearly specified in the Regulations that the Open Access to renewable energy projects shall be allowed however, while preparing the UI accounts for a State, the deviations due to renewable energy transactions shall not be considered. ***(HSHPA)***
55. SHP below 1 MW should be exempted from furnishing the tentative day-ahead generation schedule. ***(PMC Power Pvt. Ltd.)***
56. UI mechanism should not be made applicable to non-firm renewable energy sources. ***(IWPA and Accoina Wind Energy)***
57. In normal conditions, RE plants may be given 'Must Run' status but in case of contingency or grid constraint, those plants should be guided by the real time instructions issued by SLDC. ***(GETCO)***
58. Scheduling charges should not be made applicable to renewable projects as they are just submitting their tentative forecast. ***(Tata Power)***
59. UI charges due to deviation in schedule and actual energy generation from RE sources should be considered as part of ARR and passed on to the consumers in retail tariff. ***(Guttaseema Wind Energy Company Private Limited (GWECL))***
60. Cap for scheduling of biomass power plant should be raised to 25 MW. ***(Abellon)***

61. Any size of bagasse cogeneration plants should be brought under Must Run category. ***(UP Sugar Mill Cogen Association, ISMA)***
62. It is to be clarified that responsibility for forecasting of generation lies with developer not on individual generator/owner, as they have no expertise for such forecast. ***(Torrent Power)***
63. Biomass and non-fossil fuel cogeneration plants with installed capacity of 10 MW and above would not able to maintain generation as per scheduling and despatch code as there is no established fuel supply chain or institutional mechanism. ***(NTPC)***
64. Biomass power plants and non fossil fuel based cogeneration even below 10 MW should not be accorded MUST RUN status and should be covered under merit order despatch principle and UI charges mechanism. ***(GUVNL)***
65. Commercial mechanism for incentive/disincentive based on deviation from forecast may be specified for better generation forecast. ***(PGCIL)***
66. Exempting RE generators from UI mechanism may be correct at low penetration level however, at high penetration level operational planning may go haywire because of such non-firm generation. Therefore, penetration level may be specified beyond which ABT mechanism would be applicable. ***(PGCCIL)***
67. SLDC may not approve inter-state OA on the grounds that the forecast is tentative and hence it cannot be scheduled. ***(PTC)***
68. MUST RUN compulsion should be limited to the ceiling percentage on energy consumption from renewable sources. ***(Kerala State Electricity Board***
69. No initiative for wind energy forecasting has been taken in India and therefore, it will not be possible to provide forecast in near future. ***(CECL)***

Draft Regulation 12: Grid Connectivity

70. The term ‘Concerned licensee’ needs to be defined in the Regulations. ***(Shri Shanti Prasad)***
71. Maximum distance of the inter-connection point from the power house should be clearly mentioned in the Regulations. ***(HSHPA)***
72. Proper regulatory support to remove the bottleneck for grid connectivity should be provided. ***(IWPA, IWTMA)***
73. Grid connectivity may be delinked from payment of OA charges as providing grid connectivity is responsibility of respective state or central transmission utility irrespective of nature of sale of power. ***(InWEA)***
74. Renewable energy projects should be exempted from payment of transmission and wheeling charges. ***(GWECL)***

75. Inter-connection point is far located from nearest grid sub-station therefore, development of evacuation infrastructure from inter-connection point to grid sub-station and cost thereof should be borne by the project developer and be a part of capital cost. ***(KSEB)***

76. The cost for development of evacuation infrastructure or strengthening of existing system beyond the inter-connection point may be shared by the project developers and concerned licensee on proportionate basis. ***(HPSEB)***

77. For sale to utility, no payment for transmission and wheeling charges should be applicable for wind energy projects. ***(CECL)***

Financial Principle

Draft Regulation 14: Evacuation Infrastructure

78. Wheeling or transmission charges, other taxes, duties and other costs that may be levied by the governmental or other regulations should be considered as 'pass-on' cost. (Greenko Energies Pvt. Ltd.)

79. Cost for grid connectivity should be borne by the licensee and not by the project developer. (Tata Power)

80. It would not be economical to connect cluster of small plants at 200kV or 400kV level. STU/Distribution Company should be declared as 'concerned licensee'. (PGCIL)

81. Cost of providing inter-connection for wind and SHP should also be factored in project cost. (PTC)

82. Project developer should be made responsible for development of evacuation infrastructure up to nearest grid sub-station and the cost should be included in capital cost. (GETCO)

83. Licensee should be made responsible for development of evacuation infrastructure beyond 10 kms. (IWPA and Acciona ***Wind Energy Pvt. Ltd)***

Draft Regulation 15: Debt : Equity Ratio

84. Debt equity ratio for non-recourse financed wind projects is 3:2. Considering equity cost at lending rate for equity above 30% will not be true reflective of weighted average capital cost. (Acciona Wind Energy Pvt.)

85. Debt equity ratio of 50:50 may be adopted due to higher risk perceived by the banks. (NTPC)

86. IPP RE project would not be able to achieve a gearing in excess of 60:40 at a minimum DSCR of 1.4. Therefore, D: E ratio should be 60:40 instead of 70:30. ***(CLP)***

Draft Regulation 16: Loan and Finance Charges

87. Banks provide for loans for tenure not more than 8 years, especially for the biomass power plants which are funded on project specific basis. ***(Abellon Clean Energy Limited)***

88. Loan tenure of 10 years should be considered. ***(UP Sugar Mill Cogen Association, Greenko Energies Pvt. Ltd., IREDA, BEDA, GFL, HSHPA, GWECL)***

89. Loan tenure of 7 years should be considered. ***(Indo Greenfuel Private Limited)***

90. Interest charges on loan may be determined on normative average outstanding loan during the year considering quarterly repayments schedule. ***(Shri Shanti Prasad)***

91. For small hydro projects, the interest rate should be considered as 200 points above SBI LTPLR due to higher hydrology and geological risk. ***(GFL, Polyplex Corporation Limited, HSHPA)***

92. Interest rate offered by IREDA may be considered as normative interest rate. ***(TNERC)***

93. Interest rate should be at least 300 basis points above the SBI PLR. ***(Greenko Energies Pvt. Ltd, BEDA)***

94. Interest rate should be 200 basis points above the SBI PLR. ***(NTPC, Indo Greenfuel Private Limited)***

Draft Regulation 17: Depreciation

95. No provision for advance against depreciation would result in severe financial crisis for small hydro projects. ***(Polyplex Corporation Limited)***

96. Depreciation should be allowed to the extent of 95% of the asset value, in line with the prevailing accounting and taxation norms in India. Further, depreciation should be written off in first 10 years of project life itself as would ensure the better cash flow. ***(GFL)***

97. Land is not a depreciable asset therefore, should not be considered while computing the depreciation charges. ***(GETCO)***

98. Salvage value of wind projects is not more than 2% therefore salvage value of 10% may be reviewed. ***(IWPA)***

99. Depreciation rate may be revised to 7% per annum. ***(GWECL, UP Sugar Mill Cogen Association, ISMA)***

100. 95% of the assets over 10 year period should be considered for computation of depreciation. ***(Greenko Energies Pvt. Ltd., BEDA)***

101. Asset should be depreciated 75% in the first 5 years and balance 20% in next 10 years. ***(Indo Greenfuel Private Limited)***

102. Depreciation rate during initial years is on higher side. ***(GETCO)***

<u>Draft Regulation 18: Return on Equity</u>

103. Benefit of MAT under Section 80IA of Income Tax Act is available for the power stations to be commissioned till March 31, 2010. ***(Shri Shanti Prasad, Torrent Power)***
104. Differential return of 2% for Renewable Energy plants should be allowed over and above the RoE considered for conventional generation projects. ***(Auro Mera Energy Group, Accoina Wind Energy Pvt., GWECL)***
105. Post tax base RoE of 17% should be considered which may be grossed up by the applicable tax rate. ***(NTPC)***
106. For RE projects, the risk and gestation period is less as compared to the thermal power projects and hence RoE should be kept on lower side. ***(GUVNL)***
107. ROE of 16% on post tax basis should be considered. ***(CLP)***
108. SHP projects should get additional ROE of 5%, in addition to the normal ROE of 16% due to higher risk. (HSHPA)
109. For SHP, pre-tax 23% ROE should be provided during the first 10 years, and 30% ROE should be provided from 11th year onwards. ***(Polyplex Corporation Limited)***
110. For attracting the investment in small hydro sector, ROE of at least 25% on post-tax basis should be specified. ***(PMC Power Pvt. Ltd.)***
111. Normative ROE for wind projects should be 23% throughout the project life. ***(GFL)***

<u>Draft Regulation 19: Interest on Working Capital</u>

112. Receivables equivalent to 3 months should be considered. Interest rate for working capital loan should be 2-3% higher than the SBI average short term PLR ***(Auro Mira Energy Group).***
113. LTPLR + 100 basis points for loan towards working capital. ***(Indo Greenfuel Private Limited)***
114. Receivables equivalent to 2 months of energy charges and fuel cost for 6 months equivalent to normative PLF should be considered in computing working capital. ***(NTPC)***
115. 2 months of fuel costs equivalent to normative PLF shall be considered for biomass and non fossil fuel based cogeneration. ***(GUVNL)***
116. Interest on working capital may be linked to the SBI Short Term PLR+2%. ***(IREDA)***
117. Receivables should be equivalent to 2 months. ***(Polyplex Corporation Limited)***

118. For wind projects, O&M expense for six months, receivables equivalent to three months and maintenance spare equivalent to 2% of capital cost should be considered as normative working capital requirement. ***(GFL)***

119. 4 month fuel stock as working capital for biomass projects is on higher side. ***(TNERC)***

<u>Draft Regulation 20: Operation and Maintenance Expenses</u>

120. For small hydro projects, O&M expenses are on lower side. On realistic basis, it works to Rs 92.1 Lakh/MW for a 1 MW plant. ***(Polyplex Corporation Limited)***

121. Escalation rate for wind projects should be less than 5% considering the prevalent inflation rate. ***(GETCO)***

122. Due to lack of past experience in case of RE projects, O&M expenses should be as per actuals for first 5 years from the commercial operation and subsequently O&M norms may be fixed. ***(NTPC)***

<u>Draft Regulation 21: Sharing of CDM Benefits</u>

123. CDM benefit should not be shared as entire risk is borne by the project developers. Further, CDM benefit is available only to the projects which are not economically viable with normal means. ***(MBEDA, NEDCAP, UP Sugar Mill Cogen Association, Shalivahana Green Energy Limited and Shalivahana (MSW) Green Energy Limited, SR Renewable Energy Limited, Indo Greenfuel Private Limited, Seoni Renewable Energy (P) Limited, Bhanu Prakash Power Projects Pvt Ltd, Yuvaraj Power Projects Private Limited, Hema Sri Power Projects Ltd, Hyma Sri Distilleries Private Ltd., Hyma Sri Biomass Power Projects Private Ltd., Hyma Sri NCE Projects Pvt. Ltd., Hyma Sri Energy projects Pvt. Ltd., Hyma Sri Agro Farms Pvt. Ltd., Hema Sri Agro Power Projects Ltd., and Solid Waste to Energy Developers Association, NTPC, CLP, ISMA, BEDA, Polyplex Corporation Limited, HSHPA, GFL, Kaplan Hydro, IWPA, InWEA and Accoina Wind Energy Pvt. Ltd)***

124. Revenue generated from CDM to be first adjusted against the eligible RoE for the generator and the balance shall be shared as proposed. ***(Auro Mira Energy Group)***

125. Minimum RoE from the power generation should be ensured to the project developers before sharing the CDM benefits. ***(Greenko Energies Pvt. Ltd.)***

126. Mechanism for apportionment of CDM benefits in case of more than one beneficiary should be specified. ***(Torrent Power)***

127. CDM benefits should be shared from the 1st year of commissioning itself. ***(GUVNL)***

128. CDM benefit should not be shared for first 5 years. From sixth year onwards, the CDM benefit can be shared between the generating company and beneficiary on 50:50 basis. ***(Shri Shankar Prasad Banarjee)***

Draft Regulation 22: Subsidy or Incentive by Central/State Government

129. Subsidy/incentives should not be considered while computing the tariff as these are extended by the Governments for fast growth of RE sector. ***(BEDA, NEDCAP, HSHPA, Polyplex Corporation Limited, Himurja, Auro Mira Energy Company, Greenko Energies Pvt. Ltd., PTC)***
130. If State/Central Government subsidies/incentives are in addition to the tariffs then the same shall not be considered. ***(IREDA)***
131. It should clarify whether incentive/ subsidy would go towards reduction in equity, loan or both. ***(PGCIL)***

Wind Energy Projects

Draft Regulation 23: Capital cost for Wind Projects

132. Based on the proposals invited from different WTG manufactures for development of wind projects, the average capital cost works out to Rs 6.67 Cr/MW. ***(GFL)***
133. Capital cost for wind projects should be considered as Rs 6.075 Cr/MW. ***(Tata Power)***
134. Price of wind turbine in market ranges between Rs6.0Cr/MW to Rs 6.5Cr/MW. Hence, capital cost for wind projects should be Rs 6.5 Cr/MW. ***(CLP)***
135. Capital cost should be Rs 630 Lakh/MW. ***(EDCL)***
136. Capital cost of Rs 575 Lakh/MW should be specified for wind projects. ***(Accoina, IWPA, InWEA, IWTMA)***
137. Capital cost for wind project should be 540 Lakh per MW in which 515 lakh per MW for project cost upto inter-connection point and Rs 25 Lakh per MW as grid extension and evacuation cost. ***(CECL)***

Draft Regulation 24: Capital cost Indexation mechanism for Wind Projects

138. It may be specified in the Regulations that norms for capital cost, capital cost indexation formula, technical and financial parameters will be reset during the next Control Period. ***(Shri Shanti Prasad)***
139. Value of P&M(0) has not been specified in the Regulations. ***(Tata Power)***
140. Value of Factor F1 and F2 for wind projects should be 0.10 and 0.09, similar to biomass projects. ***(IWPA and Accoina Wind Energy Pvt. Ltd)***

141. Capital cost is influenced by the cost of imported items like blade, bearings, control panel items etc. which all depends on foreign supplier prices and also by the foreign exchange rate variation. These factors should also be considered in indexation mechanism ***(CECL)***

Draft Regulation 25: Capacity Utilisation Factor for Wind projects

142. CUF norms should be flat 20%. Improvement in CUF should be considered as incentive to the project developers for identifying and investing in the viable wind sites. ***(GFL)***
143. Deration in CUF should also be specified, @ 1.25% of CUF from 6th, 10th, 14th and 18th year. ***(IWPA)***
144. CUF norms do not consider sites with Wind Power Density below 200 W/sq.m. However, with latest WTGs even these sites can be potential sites for development of wind projects. Further, co-relation between hub-height and WPD may also be considered while specifying CUF norms for wind projects. ***(InWEA)***
145. Basis of deriving the slabs of Capacity Utilisation Factor and correlating it with Mean Wind Power Density should be clarified. ***(Torrent Power)***
146. Actual CUF for the considered wind densities range is lower than the proposed norms, ranges from 15% to 22%. ***(NTPC)***
147. Wind power density for different areas as specified by C-WET in advance may be considered for CUF. ***(PGCIL)***
148. Uniform CUF in each state should be considered. (CECL)
149. Range of CUF should be specified for a particular wind zone instead of providing single value. CUF can be specified on WPD zoning based on Wind Atlas by identifying the areas of different WPDs. ***(Shri M.P. Ramesh)***

Draft Regulation 26: Operation and Maintenance Expense for Wind projects

150. O&M expense for wind projects should be revised to Rs 23 Lakh/ MW, as 15 Lakh/MW are required for O&M activities and Rs 8 Lakh/MW towards the machine breakdown insurance. ***(GFL)***
151. O&M expense should be 1% of project cost with an escalation linked to prevailing inflation rate. ***(GETCO)***
152. O&M expense should be Rs10lakh/MW+5.72% escalation per annum. ***(CLP)***
153. O&M expenses are on higher side. It should be 1% of capital cost. ***(KSEB)***

Small Hydro Power Projects

<u>Draft Regulation 27:</u> Capital cost for Small Hydro Projects

154. Capital cost for SHP varies from Rs.5.82Cr/MW to Rs.6.95Cr/MW depending upon location, capacity, head available, length of transmission lines etc. ***(IREDA)***

155. Capital cost norms on the basis of historical data may not necessarily be correct approach. For realistic capital cost, assessment of individual items of capital cost needs to be done. Capital cost for SHP varies from Rs 7.0 Cr per MW to Rs 16.67 Cr/MW. ***(Polyplex Corporation Limited)***

156. Capital cost of Rs 630 Lakh/ MW as proposed for SHP projects in Himachal Pradesh, Uttarakhand and North Eastern region should be specified for SHP in other States. ***(Sileru Power Generation Pvt. Ltd.)***

157. Capital cost for mini and micro hydro projects may be specified as Rs 650 Lakh/MW. (PMC Power Private limited)

158. Benchmark capital cost of Rs 8.0 Crore/MW should be specified for SHP or alternatively, project cost for small hydro projects may be determined on case to case basis. ***(HSHPA)***

159. Capital cost of Rs 700 Lakh/MW may be considered for SHP located in Northern and North Eastern States while for other States, it may be specified as Rs 600 Lakh/MW. ***(Kaplan Hydro)***

160. Capital cost data considered from UFCCC and IREDA source is based on historical cost and therefore, it doesn't reflect the capital cost for the projects to be commissioned in next Control Period. Capping of capital cost has been proposed for SHP but no such limit has been considered for large hydro projects. ***(Himurja)***

161. Capital cost for SHP located in Himachal Pradesh and other hilly areas are in the range of Rs 6.50 Cr/MW to Rs 7.50 Cr/MW, depending upon the topography and tunnelling involved. The capital cost in other States varies from Rs 5.50 Cr/MW to Rs 5.75 Cr/MW. ***(Greenko Energies Pvt. Ltd.)***

162. Capital cost is site specific parameter and therefore, it shall not be realistic to assume uniform price throughout the country. ***(KSEB)***

163. Normative capital cost may be revised to Rs 850 Lakh/ MW and Rs 700 Lakh/ MW against the capital cost of Rs 630 Lakh/ MW and Rs 500 Lakh/MW proposed under the draft Regulations ***(EDCL)***

<u>Draft Regulation 28:</u> Capital cost Indexation mechanism for Small Hydro Projects

164. Capital cost factor may be modified to 50% towards plant and machinery, 36% for land and civil works, 10% for erection and commissioning, and 10% for IDC and Financing. ***(PMC Power Private Limited)***

165. Flat rate of indexation should be specified to avoid any further calculations and different interpretations. ***(Kaplan Hydro)***

166. Civil cost constitutes around 50-65% of total project cost while in proposed indexation mechanism, it is taken as 16%. ***(Himurja)***

167. Civil works accounts more than 50% of the total project cost while in the Regulations, it has been assigned the value of 0.16. ***(KSEB)***

Draft Regulation 29: Capacity Utilisation Factor for Small Hydro Projects

168. CUF of 40% should be considered for Northern and North Eastern States and 25% for other States, which should be net of free power. ***(Kaplan Hydro)***

169. Generation above the normative PLF is purchased by the licensees at very low price while there is no provision for mitigating contingencies during low generation period. Therefore, tariff for small hydro projects should be based on cumulative CUF basis i.e. even if the CUF achieved falls short of the normative CUF in one year then the loss can be recovered in subsequent years. ***(PMC Power)***

170. Sikkim and J&K may also be clubbed with Himachal Pradesh, Uttrakhand and NER. ***(PGCIL)***

Draft Regulation 30: Auxiliary Consumption

171. Realistic assessment of auxiliary consumption should be done on the basis of auxiliary load assessment, and operational period of various loads. The auxiliary consumption and transformation losses for SHP work out to 3.80% and 3.60% respectively. ***(Polyplex Corporation Limited)***

172. Transmission losses of 0.5% should be considered in addition to the auxiliary consumption norms. ***(Kaplan Hydro)***

173. For small hydro projects, it should be at least 2%, including the transformation losses. ***(PMC Power)***

174. Auxiliary consumption for SHP having surface power house should be specified as 1.5% while for SHP having underground power house, it should be fixed at 2.5%. ***(HSHPA)***

175. Normative auxiliary consumption of 1.5% should be considered. ***(Auro Mira Energy Company)***

176. Normative auxiliary consumption including the transformation losses may be revised to 1.25% energy generation. ***(Greenko Energies)***

Draft Regulation 31: Operation and Maintenance Expense

177. O&M expense for small hydro project ranges from 1.5% to 4.0% of the capital cost. ***(IREDA)***

178. Proposed O&M expense is on lower side. ***(Himuraja)***

179. O&M expense of Rs 20 Lakh/MW should be considered. ***(Kaplan Hydro)***

180. O&M expenses should be at least 3.5% of capital cost for small hydro projects. ***(HSHPA)***

181. Proposed O&M expenses are on lower side and realistic assessment should be done after assessing the individual items for operation and maintenance expense. ***(Polyplex Corporation Limited)***

182. Normative O&M expense of 3.5% of capital cost with 6% annual escalation or linked to Consumer Price Index (CPI) may be specified. ***(PMC Power)***

183. O&M expenses are on higher side. It should be 1.5% of capital cost. ***(KSEB)***

Draft Regulation 32: Water Royalty charges

184. Water royalty charges should be paid by the distribution company, which is purchasing power from SHP, directly to the State Government. ***(PMC Power)***

185. State Government is awarding the Small hydro projects through bidding process wherein project developer is required to quote water royalty and the developer who is quoting highest royalty shall be awarded the project site for development. In case water royalty is a pass-on to beneficiary in addition to tariff, it will put additional burden on beneficiary. ***(GUVNL)***

Biomass Power Projects

Draft Regulation 33: Technology Aspect

186. Specify norms for biomass power plants based on technology other than Rankine cycle **(GUVNL)**

Draft Regulation 34: Capital Cost Benchmarking

187. Benchmark capital cost should be Rs 5.5Cr/MW since pre-processing equipment itself cost 1Cr/MW.***(Abellon)***

188. Request to consider capital cost norm of Rs 500Lakhs/MW for (FY 2009-10 during first year of Control Period).***(MBEDA)***

189. Project cost of at least Rs.5.00 Cr/MW for the 1st year of the order with necessary escalation.***(AMEG)***

190. Capital cost quotation received from EPC contractors are in the range of Rs7Cr/MW and the same shall be considered for the purpose of tariff computation.***(CLP)***

191. The benchmark project costs (with Water Cooled Condenser) per MW are in the range of Rs.4.70Cr/MW to Rs.5.03Cr/MW depending on the location, transmission system etc.***(IREDA)***

Draft Regulation 35: Capital Cost Indexation Mechanism

192. Three separate tariffs shall be specified for each category based on their commissioning during first, second and third year of the control period.**(RERC)**

193. Basis and methodology adopted for deriving weightages and rationale for linking the cost of such factors, land and civil works, erection and commissioning and IDC and financing cost, at the indexed cost of P&M may be provided.**(TPL)**

Draft Regulation 36: Plant Load Factor

194. For the purpose of determination of tariff the first year of operation should be termed as the stabilisation period.***(MBEDA)***

195. PLF of 70% against 80% should be considered***(AMEG)***

196. To avoid dispute, Stabilisation Period should be specified.***(TPL)***

197. PLF norms for biomass need to be relaxed as fuel supply chain is not established and no institutional supply mechanism is available.***(NTPC)***

198. PLF norms are dependent on the age of the equipment.***(BEDA)***

Draft Regulation 37: Auxiliary Consumption

199. Auxiliary consumption comes out to be 12% and same should be considered.***(Abellon)***

200. Since the biomass power plants after stabilisation runs at maximum load of about 70%-80% PLF, the auxiliary consumption should be assumed as 11.50%.***(MBEDA)***

201. An auxiliary consumption of 11% should be considered.***(AMEG)***

202. Auxiliary consumption may be 13% while factoring the transmission losses.***(BEDA)***

Draft Regulation 38: Station Heat Rate

203. To consider the actual fuel consumption data collected over a period of time to arrive the SHR.***(Shalivahana Green Energy Limited & MBEDA)***

204. SHR of 4100 kCal/kWh should be adopted considering the boiler pressure and temperature.***(AMEG)***

205. SHR of 3650kCal/kWh may be difficult.***(IREDA & BEDA)***

206. Station heat rate for biomass projects are too high as these plants uses waste product and the revenue has already been earned on the main product. Therefore, higher SHR will give undue benefit to the biomass project developer.***(GETCO)***

<u>Draft Regulation 39: Operation and Maintenance Expenses</u>

207. O&M may be fixed at reasonable level between 2.5% to 3.0% of the capital cost.*(GUVNL)*
208. Since the project equipment damage frequently due to corrosion/erosion due to usage of variety of biomass fuels , O&M expenses in the range of 6%-7% should be considered.*(IREDA)*
209. An O&M cost of 9% should be considered to compensate the steep increases in manpower cost, prices of steel and metals.*(BEDA)*

<u>Draft Regulation 40: Fuel Mix</u>

210. Waiving the condition of establishing the fuel management plan since it is not feasible to ensure fuel management supply chain on a long term basis and short term contracts are not binding as there is no price guarantee in biomass fuel market**.*(Shalivahana Green Energy Limited)***

<u>Draft Regulation 41: Use of Fossil Fuel</u>

211. Allowing usage of fossil fuel for 20% of total fuel consumption on annual basis.***(Abellon)***
212. Increasing the fossil fuel consumption from 15% to 25% considering the non-availability of the fuel.***(Shalivahana Green Energy Limited)***
213. To allow the use of fossil fuel of at least 25% of the total fuel consumption on annual basis.***(MBEDA & BEDA)***

<u>Draft Regulation 42: Monitoring Mechanism for the use of fossil fuel</u>

214. To clarify the tariff to be applied and the action to be taken if the project developer continues to exceed the use of fossil fuel than stipulated 15% limit.***(BEST)***
215. In case of the default from developer, with-drawl of tariff should be to extent use of fossil fuel in excess of 15% in the year and penalty should not be complete withdrawal of tariff.***(NTPC)***
216. Mentioning the consequences in case of breach of compliance of the condition of usage of fossil fuel.***(GUVNL)***

Draft Regulation 43: Calorific Value

217. The weighted average calorific value of biomass fuel mix is in the range of 3228 kCal/kg and Gujarat should not be clubbed in other States category.***(Abellon)***

218. The Calorific Values (CV) of most of the biomass fuel undergo unpredictable change from high moisture/low CV to low moisture/high CV.***(Shalivahana Green Energy Limited)***

219. CV should be 3300 kCal/kg in accordance with the recommendations of CEA.***(MBEDA & BEDA)***

220. Provide clarity on variation in calorific value from state to state as these are dependent on fuel specific characteristics.***(IREDA)***

221. Provide clarity whether the norms are of gross calorific value or net calorific value.***(Transparent Energy Systems Private Limited)***

Draft Regulation 44: Fuel Cost

222. The base fuel cost of biomass for Gujarat should not be clubbed under other States since the cost of biomass procured by them is in the range of Rs2500 per tonnes against Rs 1685 per tonnes as notified in the draft regulations.***(Abellon)***

223. The base fuel cost of biomass for Andhra Pradesh should be considered at Rs 2000 per tonnes as notified by APERC in its tariff order dated March,2009.***(NEDCAP)***

224. Average fuel cost of Rs 2600/MT (including biomass & coal) should be assumed. This cost will include the expenses incurred on account of site handling/processing & storage losses etc.***(MBEDA)***

225. Methodology adopted for computation of the fuel cost should be reviewed as it appears that cost of coal is exclusive of transportation charges.***(TPL)***

226. To adopt transparent price fixation mechanism for biomass fuel instead of linking it to the price of coal in equivalent heat terms and the mechanism should be reflected in tariff.***(NTPC)***

227. The landed cost of fuel for some states, like AP, as presented is on lower side.***(IREDA)***

228. In order to achieve a CV of 3300kCal/kg the moisture content should be 25%. Keeping this in view the price of the fuel figures out to be Rs.2200/MT and hence to be considered.***(BEDA)***

Non fossil fuel based Cogeneration projects

Draft Regulation 47: Capital Cost

229. To consider the Transmission cost of evacuation of power as a part of Capital Cost.***(UP Sugar Mill Cogen Association & ISMA)***

230. To benchmark the capital cost for cogeneration plants at Rs545Lakhs/MW.***(Indo Greenfuel Private Limited)***

231. To consider the capital cost of Rs550lakh/MW against Rs445lakh/MW as proposed in draft regulations for biogas/biodiesel.***(Acme Tele Power Limited)***

232. The capital cost are in the range of Rs 4.33Cr/MW to Rs 5cr/MW.***(IREDA)***

Draft Regulation 49: Plant Load Factor

233. PLF should correspond to 124 days per annum of crushing period operation as bagasse may not be available from in house operation and need to be purchased from other sources. ***(UP Sugar Mill Cogen Association)***

234. To consider the PLF based on actual operating days for each State and therefore the load factor should be considered as 85% as against 90%.***(Indo Greenfuel Private Limited)***

235. To consider a PLF of 80% against 60% as proposed in draft regulations biogas/biodiesel.***(Acme Tele Power Limited)***

236. State wise PLF should be used which actually reflects the working days of crushing season.***(ISMA)***

237. PLF of 60% appears to be on lower side.***(IREDA)***

Draft Regulation 50: Auxiliary Consumption

238. To consider an auxiliary consumption of 10% against 8.5% proposed in the draft regulations. ***(UP Sugar Mill Cogen Association)***

239. To consider an auxiliary consumption of 10% against 8.5% for biogas/biodiesel.***(Acme Tele Power Limited)***

240. Auxiliary consumption is in range of 10%.***(IREDA)***

Draft Regulation 51: Station Heat Rate

241. To consider the SHR as 3700 kCal/kWh by taking the ratio of fuel cost allocation between fuel and steam to be 75:25.***(UP Sugar Mill Cogen Association & ISMA)***

242. To consider the SHR based on the operating days of the 'cogen plant'. ***(Indo Greenfuel Private Limited)***

243. To consider the SHR of 3185kCal/kWh against 4000kCal/kWH as proposed in draft regulations biogas/biodiesel and the allocation of fuel cost in power and heat should be in the ratio of 80:20. ***(Acme Tele Power Limited)***

244. The SHR for cogeneration should not be higher than 2716kCal/kWh if the boiler efficiency is 85% and in this view the station heat rate should be reviewed. ***(PTC)***

Draft Regulation 53: Fuel Cost

245. To consider the fuel cost for Bagasse based Cogeneration Power Projects as Rs950/MT.***(NEDCAP)***

246. To consider the price of bagasse to be Rs1378/MT considering 6% escalation.***(UP Sugar Mill Cogen Association)***

247. Fuel price should be actually around 20% higher than the prices achieved by the large thermal power plants and the fuel price escalation should be linked with the price of coal.***(Indo Greenfuel Private Limited)***

248. To consider a fuel rate of Rs25/ltr with heat value of 8750kCal/ltr against Rs1/kg with heat value of 2250kCal/kg biogas/biodiesel.***(Acme Tele Power Limited)***

249. To review the prices of bagasse as it does not reflect the market price.***(ISMA)***

250. Cost of bagasse in some states such as M.P., A.P., and U.P. etc. appears to be on lower side.***(IREDA)***

Draft Regulation 55: Operation and Maintenance Expenses

251. To consider an O&M expenses of 4% of the capital cost.***(UP Sugar Mill Cogen Association)***

252. To consider an O&M of 2%for plants utilising biogas/biodiesel.***(Acme Tele Power Limited)***

253. Propose O&M expense translates to be 3% which is on the lower side and actual expenses are in range of 4-5%.***(IREDA)***

Solar Photovoltaic Power Projects

Draft Regulation 56: Technology Aspect

254. Dalmia Cement (Bharat) Ltd has submitted to suitably modify the regulations as,

"*Norms for Solar Photovoltaic* <u>*and Solar Dish Sterling Engine Power*</u> *under these regulations shall be applicable for grid connected PV* <u>*and Dish Sterling Engine systems*</u> *that directly convert solar energy into electricity and are based on technologies such as crystalline silicon/thin film* <u>*and Dish Sterling Engine*</u> *as may be approved by MNRE".*

<u>Draft Regulation 57: Capital Cost</u>

255. The normative capital cost varies for technologies with different PLF i.e. higher PLF higher capital cost requirement and vice versa and the same shall be considered. The capital cost should be linked with foreign exchange variation. **(Dalmia Cement (Bharat) Ltd., Moserbaer Photovoltaic Ltd., Rudraksh Energy)**
256. India can challenge developers to install at USD 3.4/Watts driving down to USD 2.4/Watts by 2012. **(Astonfield Renewable Resources Limited)**

<u>Draft Regulation 58: Capacity Utilisation Factor</u>

257. Annual performance degradation factor should be considered. **(Sri Power, Lanco Solar Power Limited)**
258. Tariff determination form templates for Solar PV and Solar Thermal plants in lines with Form 1.1, 1.2 and 2.2 should be provided. **(Sri Power)**
259. For site specific insolation database maintained by USA's NASA shall be considered. **(Astonfield Renewable Resources Limited)**
260. Range of CUF shall be specified instead of specifying fixed CUF. **(Rudraksh Energy**)
261. The CUF of 19% for Solar PV plants is on the higher side. The CUF should be in range of 15% to 18%. **(Acme Power, LSPL)**
262. Capital Cost and CUF determined in the regulations needs to be reviewed with a view to compare all available options and cost economics of individual technology at common platform.**(GL Somani)**

<u>Draft Regulation 59: Operation and Maintenance Expenses</u>

263. Rs 9 lakh/MW may not be sufficient and the figure should also be increased by nominal inflation year on year. **(Moser Baer Photovoltaic Limited)**
264. O&M expenses should be in the range of 0.7% to 1.0% of capital cost depending on the de-ration factor varying from 0.25% to 1.00% and should be linked accordingly. **(Rudraksh Energy)**

265. O&M expenses shall be fixed as a percentage of installed capacity cost which may range between 1.2% to 1.5% depending on the PLF claimed by the relevant technology. **(Dalmia Cement (Bharat) Ltd)**

Solar Thermal Power Projects

Draft Regulation 60: Technology Aspect

266. Specify the applicability of regulations on Solar Thermal plants with or without thermal storage. **(Rudraksh Energy)**

Draft Regulation 61: Capital Cost

267. The Capital Cost for Solar Thermal Power Plants should not be less than Rs.15Cr/MW. The capital cost considered in on lower side. (**Acme Group, FAST)**
268. Central commission to specify that the State Commission while determining the project specific tariff may consider the project cost duly taking into account various parameters like, Solar Radiation, Cost of Land, Technology, Installed Capacity, Unit Size of Equipment. **(Energy and Petrochemical Department, Government of Gujarat)**
269. Link the capital cost with the CUF which varies from 22% to 50% depending on technology and with or without storage facility.**(Rudraksh Energy, Entegra Limited)**
270. Solar thermal projects are land intensive and the cost of land shall be taken into account while mentioning the capital cost. **(FAST)**
271. The capital costs of CSP plants presently under construction are in the range of Rs 18-20 Cr/MW. They further requested to revise the capital cost to Rs 18 Cr/MW as the "Normative" cost of a CSP plant. **(Clean Energy Research Centre, University of South Florida)**

Draft Regulation 62: Capacity Utilisation Factor

272. Normative CUF to be considered as 23%. **(Acme Group, Energy and Petrochemical Department, Government of Gujarat)**
273. Provide a CUF range varying from 22% to 50%. **(Rudraksh Energy, Entegra Limited)**

274. CUF of 21% is the maximum possible limit to be considered for Kutch in Gujarat, Western Rajasthan and Andhra Pradesh and the same shall be kept under consideration. **(FAST)**

275. The actual capacity factors for both CSP and PV are below 20% because of lower solar radiation and the monsoon season and the CUF shall be revised accordingly.**(Clean Energy Research Centre, University of South Florida)**

276. The Capital Cost and CUF determined in the regulations needs to be reviewed with a view to compare all available options and cost economics of individual technology at common platform. He further suggested that the CSP plants are run with a provision of auxiliary fossil fuel firing and in such a case use of fossil fuels shall be permitted to the extent of 25% of energy output on annual basis.**(Shri GL Somani)**

Draft Regulation 63: Operation and Maintenance

277. O&M charges to be specified in terms of percentage of Capital Cost only which vary from 1.25% to 1.5% linked with CUF and Storage Capacity. **(Rudraksh Energy)**

278. Proposed O&M norms are on the lower side and it should remain in the range of 1% to 1.25% of the project capital cost. Further the O&M norms for with and without thermal storage are different and same shall be considered. **(Entegra Limited)**

279. O&M cost of Rs22Lakhs/MW/annum should be considered. **(Clean Energy Research Centre, University of South Florida)**

Draft Regulation 64: Auxiliary Consumption

280. The auxiliary consumption factor varies for the projects with or without storage capacity and hence the same shall be considered. **(Rudraksh Energy)**

Annexure – 2

List of Stakeholders participated in Public Hearing conducted on July 22, 2009

SR. No	Name of the Organization (requested for presentation)
1	Indian Sugar Mills Association, New Delhi U.P. Gogen Association (Indian Sugar Mills Association, New Delhi)
2	Abellon CleanEnergy Limited, Ahmedabad
3	World Institute of Sustainable Energy, Pune
4	AMR Infrastrutures Limited, New Delhi
5	ACME Tele Power Limited, Gurgaon
6	Astonfield Managements Consultancy Pvt. Ltd., Mumbai
7	Greenko Energies Pvt. Ltd., Hyderabad
8	Indo Greenfuel Private Limited, New Delhi
9	Kalpan Hydro Company (I) Pvt. Ltd., Noida
10	Tata BP Solar India Limited, New Delhi
11	Indian Wind Energy Association (InWEA), New Delhi
12	Polyplex Corporation Ltd., Gautam Budh Nagar (U.P.)
13	Indian Wind Turbine Manufacturers Association (IWTMA), Chennai
14	Ramky Enviro Engineers Ltd., Hyderabad
15	Future Computing & Energy Solutions (P) Ltd. (Haryana Vidyut Prasaran Nigam Ltd.
16	Future Computing & Energy Solutions (P) Ltd. (M/o New & Renewable Energy)
17	Sri City Power Gen. (TN) Pvt. Ltd., Hyderabad
18	Himachal Pradesh Hydro Power Association
19	Haryana Power Purchase Centre, Panchkula
20	Moser Baer Photo Voltaic Ltd
	Anil Lakhna , FAST
	SunBorne Energy, Aseem Sharma
	Name of organisation for commenting w/o ppt
	N. Venkatraman
	C.R. Vishwanathan, KENERSYS India Pvt. Ltd., Pune
	R.K.Grover M/s A.B. Sugars Ltd, Dasuya, Panjab
	Inidian wind power Association, U.B. Reddy

	Padamjit Singh , Individual
	GUVNL
	NTPC
	Name of organosation participated in hearing
1	Shyam Indus Power Solutions Pvt. Ltd., New Delhi
2	BGR Energy Systems Limited, Chennai
3	Biomass Energy Developers Association, Hyderabad
4	New Energy Finance, New Delhi
5	Power Grid Corporation of India Limited, Gurgaon
6	Belgaum Wind Farms Pvt. Ltd., Mumbai
7	Chhattisgarh State Power Generation Company Ltd., Raipur
8	GMR Energy Trading Limited, Bangalore
9	Lanco Solar Pvt. Ltd., Hyderabad
10	North Delhi Power Limited (NDPL)
11	Satluj Jal Vidyut Nigam Limited, New Delhi
12	Torrent Power Ltd., ahmedabad
13	Central Electricity Authority, Delhi
14	Infraline Energy, New Delhi
15	Mr. Padamjit Singh – **As an Individual**
16	Integrated Search and Action for Development, New Delhi
17	
18	Uttar Haryana Bijli Vitran Nigam Ltd., Panchkula