Statement of Objects and Reasons

CERC (Terms and Conditions for Tariff determination from Renewable Energy Sources) Regulations, 2012

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CENTRAL ELECTRICITY REGULATORY COMMISSION (CERC), NEW DELHI

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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 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 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 above referred powers conferred under Section 61 read with Section 178 (2) (s) of the Act, the Commission framed the Central Electricity Regulatory Commission (Terms and Conditions for Tariff determination from Renewable Energy Sources) Regulations, 2009 (herein after “RE Tariff Regulations-2009”) dated 16.09.2009. The Control Period specified was of three years ending on 31.03.2012. The said Regulations also state that the Commission shall undertake the exercise of revision in Regulations for next Control Period at least six months prior to the end of the first Control Period.

1.5. Hence, the Commission initiated the exercise of framing RE Tariff Regulations for the next Control Period and issued, vide public notice No.1/8/2011-Reg. Aff. RE (TR 2012-15)/ CERC dated 18.11.2011, the draft of Central Electricity Regulatory Commission (Terms and Conditions for Tariff determination from Renewable Energy Sources) Regulations, 2012 (hereinafter referred to as the draft Regulations) along with explanatory memorandum for inviting comments/ suggestions/ objections thereon. Last date of submission of comments / suggestions /objections was kept on date 15.12.2011. A list of stakeholders who submitted comments is enclosed as **Annexure-I.**

1.6. Subsequently, public hearing was held on 22.12.2011 to hear views of all the stakeholders, if any.

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

2. DEFINITIONS

2.1 REGULATION 2 (aa): DEFINATION: USEFULL LIFE

Draft Regulation provides following definition of "Useful Life"

> **"aa) 'Useful Life'** in relation to a unit of a generating station including evacuation system shall mean the following duration from the date of commercial operation (COD) of such generation facility, namely:-
>
> | | |
> |---|---|
> | (a) Wind energy power project | 25 years |
> | (b) Biomass power project with Rankine cycle technology | 20 years |
> | (c) Non-fossil fuel cogeneration project | 20 years |
> | (d) Small Hydro Plant | 35 years |
> | (e) Solar PV/Solar thermal power project | 25 years |
> | (f) Biomass Gasifier based power project | 20 years |
> | (g) Biogas based power project | 20 years" |

2.1.1 THE COMMENTS RECEIVED ON THIS PROVISIONS:

RE New Power Pvt. Limited has submitted that the Useful life of the wind energy projects cannot be 25 years because the design life certified by C-WET or other internationally acclaimed testing agency is only 20 years and likely technology obsolescence including availability of spares etc. This is evidenced from many old wind turbines lying idle.

Torrent Power limited has suggested that the Useful Life for wind and solar energy projects should be kept at 20 years as the manufacturers of wind turbines and solar panels are usually providing test certificate of 20 years and willing to commit that their equipments will work in techno-commercially feasible manner post 20 years

InWEA has suggested that useful life for wind power plant should be considered as 20 years for determination of Tariff.

2.1.2 COMMISSION'S DECISION

According to the 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. 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.

Regarding Useful Life of Solar Power project, manufacturers offer warranties cover for solar modules for 25 years and more, and so the life is usually expected for 25 years. Considering the above, the Commission has decided to retain the definition as provided in the draft Regulations.

2.2 REGULATION 2 (m): DEFINATION: INSTALLED CAPACITY

Draft Regulation provides following definition of "Installed capacity""

> *"(m) **'Installed capacity'** or 'IC' means the summation of the name plate capacities of all the units of the generating station or the capacity of the generating station (reckoned at the generator terminals),*

approved by the Commission from time to time;"

2.2.1 THE COMMENT RECEIVED ON THIS PROVISION:

NTPC Limited has submitted that in case of Solar PV, there is some confusion over installed capacity of the plant. We propose that definition on Installed Capacity should be revised as under:

> **"Installed capacity'** or 'IC' means the summation of the name plate capacities of all the units (modules in case of Solar PV) of the generating station or the capacity of the generating station (reckoned at the generator terminals), approved by the commission from time to time;"

2.2.2 COMMISSION'S DECISION

The Commission does not find any substance in the argument advanced and hence decided to retain the same in the final Regulation.

2.3 REGULATION 2 (n): DEFINITION: INTER CONNECTION POINT

Draft Regulation provides following definition of "Inter-connection Point" wherein the phrase : ***"pooling sub-station***" used:

> *"**(n) 'Inter-connection Point'** shall mean interface point of renewable energy generating facility with the transmission system or distribution system, as the case may be:*
>
> *i. in relation to wind energy projects and Solar Photovoltaic Projects, inter-connection point shall be line isolator on outgoing feeder on HV side of the **pooling sub-station;***
>
> *ii. in relation to small hydro power, biomass power and non fossil fuel*

based cogeneration power projects and Solar Thermal Power Projects the, inter-connection point shall be line isolator on outgoing feeder on HV side of generator transformer;”

2.3.1 THE COMMENT RECEIVED ON THIS PROVISION:

NTPC Limited has suggested that the Pooling sub-stations as indicated in definition may be defined as:

> **“Pooling sub-station** shall be the first sub-station where pooling of power is done. This shall be generator sub-station, in case generator or developer has a sub-station in its premises where pooling is done or else it shall be the sub-station of local distribution utility where power from wind mills and solar PV panels is pooled first.”

2.3.2 COMMISSION’S DECISION

The definition as suggested by the stakeholder is not appropriate and rather more confusing. The term “Pooling sub-station” is very commonly understood in the industry meaning a sub-station developed by the developer /generator where pooling of generation from individual turbine is done for interface with receiving sub-station. The Commission has decided not to incorporate the suggestion received in this regard.

2.4 REGULATION 4: ELIGIBILITY CRITERIA

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

2.4.1 THE COMMENT RECEIVED ON THIS PROVISION:

Phillips Carbon Black Limited has submitted that the scope and ambit of the RE Tariff Regulations, be extended to all types of cogeneration irrespective of fuel.

Kalptaru Power Transmission Limited has submitted that the eligibility criteria for biomass power plants should be amended to cover plants located at sites approved by State Nodal Agency/State Government as being done for Wind power plants.

Greenergy Renewables Pvt. Limited has suggested to specify and define the words 'new wind turbine generator' so as to be clear whether which make of turbines should be considered as new for investment purposes.

InWEA has suggested removing the condition of approval by SNA/State Government as eligibility criteria for wind power projects.

PTC India Ltd. has suggested that following definition of "topping cycle" to be incorporated:

> "Cogeneration process in which thermal energy produces electricity followed by useful heat application in industrial activities".

CESC Limited has suggested fixing a lower limit on capacity of a Solar Power plant for selling power through grid.

2.4.2 COMMISSION'S DECISION

Cogeneration from fossil fuel

The CERC draft RE Tariff Regulations-2012 seek to determine tariffs only for those renewable energy sources/technologies which are recognized /approved by MNRE. Co-generation based on fossil fuel is not recognized as renewable energy source/ technology by MNRE. In view of the above these Regulations provide for tariff determination for co-generation based on non-fossil fuels only;

Biomass

As regard, the suggestion of Kalptaru Power Transmission Limited on eligibility criteria for biomass power plants, the Commission is of the view that the concern behind the suggestion should be addressed at the level of the State Nodal Agency(SNA) /State Government. Specific provision in this regard is not required in these Regulations.

Wind

As regard, the suggestion received from InWEA for removing the condition of requiring approval of SNA/State Government for wind power projects, it is to be clarified that the approval of SNA is required for only zoning purpose as the CUF is linked with the zone. However, the apprehension of InWEA is that it may be interpreted that the prior approval of SNA is required for eligibility. The Commission has noted the suggestion and decided to modify the eligibility criteria as under to avoid any confusion in the final Regulation:

> *"Wind power project – using new wind turbine generators."*

Co-generation

The Commission has decided to incorporate the definition of "topping cycle" under the eligibility criteria of "Non-fossil fuel based co-generation project" as suggested for the sake of greater clarity:

> "topping cycle" means a cogeneration process in which thermal energy produces electricity followed by useful heat application in industrial activities".

Accordingly, the final Regulations have been modified.

Solar

The Commission does not consider it necessary to fix a lower limit on capacity of a Solar Power plant for selling power through grid as suggested by CESC Limited as any such limit might discourage smaller sized grid connected Solar PV (including Rooftop) generation.

3. GENERAL PRICIPLES

3.1 REGULATION 5: CONTROL PERIOD

In the draft Regulations, it was proposed that Control Period under these Regulations would be of 5 years.

3.1.1 THE COMMENTS RECEIVED ON THIS PROVISION:

Acciona Energy has submitted that the Control period of **5 years** is acceptable but the revision for the next control period should be undertaken at least prior to the end of the control period to enable investors and developers to plan ahead accordingly.

GUVNL has suggested that the shorter control period of **2 years** will ensure benefit to the end consumers for technology development, reduction in project cost, economy of scale and efficiency and at the same time it also help developers to get adequate return on investment since such project cost determination is to be considered nearest to time of setting up of project.

Indian Biomass Power Association has suggested that the control period should be with **revision annually for variable costs** of biomass as it significantly affects viable operation of biomass plants.

Maharashtra Biomass Energy Developers Association has submitted that for the last few years the fuel markets have remained very volatile and biomass projects may become unviable within a short time if a provision to review cost within a reasonable period is not allowed, therefore a control period of **2 years** is most desirable.

GMR Energy Ltd. has suggested that the capital cost benchmarking be done for a longer period, say **10 years**, since 50% depreciation of the project would be recovered in 9th year.

3.1.2 COMMISSION'S DECISION

The Stakeholders expressed different views on the tenure of Control Period, ranging from 2 years to 10 years. Further, some stakeholders expressed that review of biomass price should be undertaken annually.

Since all the renewable energy technologies are in maturity stage except solar, the Commission has decided to keep control period of five years with a provision that the biomass price will be reviewed at the end of third year of the Control period in order to take care of any price volatility in the biomass fuel market and will capture market price correctly. Accordingly, the final Regulation has been modified.

3.2 REGULATION 6: TARIFF PERIOD

In the draft Regulations, following provisions made for Tariff Period for all RE technologies:

"a) The Tariff Period for Renewable Energy power projects except in case of Small hydro projects below 5 MW, Solar PV, Solar thermal, Biomass Gasifier and Biogas based power projects shall be thirteen (13) years.

b) In case of Small hydro projects below 5 MW, the tariff period shall be thirty five (35) years.

c) In case of Solar PV and Solar thermal power projects the Tariff Period shall be twenty five years (25) years.

d) In case of Biomass gasifier and Biogas based power projects the Tariff Period shall be twenty years (20) years.

e) Tariff period under these Regulations shall be considered from the date of commercial operation of the renewable energy generating stations.

f) Tariff determined as per these Regulations shall be applicable for

Renewable Energy power projects, only for the duration of the Tariff Period as stipulated under Regulation 6 (a), (b), (c), (d) and (e)."

3.2.1 THE COMMENTS RECEIVED ON THIS PROVISION:

Prayas has submitted that it is prudent to make PPAs for all RE with tariff periods equal to their lifetime, since on a life-cycle basis that would prove far more cost effective to the consumers. Opening of the REC market allows renewable energy developers to reap in much higher profits even after the 13 year PPA and the benefit of lower wind costs is not passed on to the consumers as is anticipated.

GUVNL has suggested to consider the Tariff Period equal to Useful life of wind power projects and small Hydro projects above 5 MW as to give long term certainty to end consumers in terms of cost of power and continuous availability of power throughout the useful life of the project.

Acciona Energy has submitted that the Tariff Period should be 20 years for Wind Energy Projects instead of 13 years.

RE New Power Pvt. Limited has submitted that Since the Tariff Period is of 13 years only it leads to tariff uncertainty after the 13th year, and requested that the Commission should either to extend the Tariff Period to 25 year or arrive at the levellised tariff considering only 13 year period.

Shri Shanti Prasad has suggested that the Commission may specify that after the expiry of 13 years wind power projects shall not be bound by PPA and shall be free to supply to third party directly or through exchange or under REC mechanism or to quote against competitive bidding.

Energy Infratech has submitted that the useful life for small hydro projects be uniformly taken as 35 years. They have further submitted that the difference between the tariff period and control period with reference to its effect on regulations may be clarified.

3.2.2 COMMISSION'S DECISION

The stipulation of13 years of Tariff period was kept considering the provisions of the Tariff Policy which outline preferential treatment to renewable energy projects till such time that RE technologies are able to compete in the market. The Commission is of the view that 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, considering the above suggestions received from the stakeholders, the Commission has decided to provide flexibility for PPA beyond 13 years. Accordingly, the Regulation 6 (a) has been modified in the final Regulations to substitute the expression "shall be thirteen (13) years" by the expression "shall be for a minimum period of thirteen (13) years".

3.3 REGULATION 7: PROJECT SPECIFIC TARIFF

In the draft Regulations, the provision for determining project specific tariff for new technologies was provided.

3.3.1 THE COMMENTS RECEIVED ON THIS PROVISION:

DVC has submitted that in some special cases if a developer approaches to work out tariff based on actual capital cost the same may be allowed.

TATA Power Company Ltd. has submitted that Tariff Regulation related to other smaller generation systems like Rooftop solar should be formulated.

A2Z Maintenance & Engineering Services Limited has suggested to determine

Technology specific tariff for RDF (derived from MSW) Power Projects based on Rankine Cycle.

3.3.2 COMMISSION'S DECISION

It is to be noted that the Project Specific tariff has been envisaged in the draft Regulations in the cases of any new RE technologies approved by MNRE, waste to energy projects, solar power projects, hybrid projects and biomass projects other than that based on Rankine Cycle technology application with water cooled condenser. Such projects may approach the Commission for determination of project specific tariff. The Commission can consider specifying generic norms for such technologies once adequate data is available for arriving at the norms.

3.4 REGULATION 10 (1): TARIFF DESIGN: GENERIC TARIFF

In the draft Regulations, it was proposed to determine the generic tariff on levellised basis for all RE technologies for tariff period and for RE technologies having single part tariff with two components, tariff shall be determined on levellised basis considering the year of commissioning of the project for fixed cost component while the fuel cost component shall be specified on year of operation basis.

3.4.1 THE COMMENTS RECEIVED ON THIS PROVISION:

CESC Limited has submitted that the appropriate Commission may specify cap price and distribution licensee may negotiate between developers of such sources within the cap price as specified and may purchase at a price higher than the cap price with prior approval of appropriate Commission. They further submitted that the Power purchase cost of the licensee being a pass-through, there would be an upward revision of tariff for the end consumers for procurement of power at such high price. The issue is more pertinent in cases where majority of licensee's consumers are consuming less than 50 units a month and pay at lower tariff.

A2Z Group has submitted that the Fixed Cost component of the levellised tariff may be determined on the formula already adopted by the Commission on the basis of year of commissioning and should be fixed for the entire period of PPA while Variable Cost Component should be determined on year to year basis depending on the prevalent market price of fuel and should be applicable for all old and new Biomass/Non-fossil fuel based co-gen projects, as the fuel cost would be same for all new/old projects.

3.4.2 COMMISSION'S DECISION

It is clarified that there is no prohibition for a distribution company to invite competitive bids. In such a case the tariff determined under these Regulations will not apply.

As regard to biomass price, the Commission has decided to specify in the final Regulation that the biomass base price would be revised at the end of third year of the Control period and the revised biomass price will apply prospectively to both old and new projects. Accordingly, the same tariff structure as specified for the next Control Period in the draft Regulations has been retained in the final Regulations.

3.5 REGULATION 10 (2): TARIFF DESIGN: DISCOUNT FACTOR

In the draft Regulations, it is specified that for the purpose of levellised tariff computation, the discount factor equivalent to Post Tax Weighted Average Cost of Capital (WACC) shall be considered.

3.5.1 THE COMMENTS RECEIVED ON THIS PROVISION:

InWEA has submitted that the returns under RE tariff regulations are proposed to be regulated in Pre-Tax terms. Hence, the time value should also be factored in pre-tax terms of weighted average cost of capital (WACC), as was computed under earlier first control period regime. They have further suggested that in order to work out “Post Tax Cost of Debt” consideration of applicable tax as Weighted Average of MAT and Corporate Tax Rate would be the right approach.

Reliance Power Ltd. has suggested that WACC should be considered on the basis of Pre-tax and do away with the suggestion for Post tax till clarity is evolved on the DTC and applicable tax regime. They further submitted Shift from Pre-Tax to Post Tax should not hamper returns due to any change in tax regimes. The Cost of Equity is higher for CSP projects and these projects commensurately need a higher ROE.

NTPC Limited has submitted that Pre Tax WACC should be considered as discount factor for levellised tariff computation in line with previous control period.

Greenergy Renewables Pvt. Limited has submitted that since Return on Equity is on pre-tax basis and also income tax is not part of the tariff, for the purpose of levellised tariff computation, discount factor equivalent to Pre Tax weighted average cost of capital shall be considered.

3.5.2 COMMISSION’S DECISION

While taking the investment decisions, the developer considers post tax WACC as the discount rate to post tax incremental cash flows to arrive at NPV of the project. Considering the same, the Commission has decided to retain the provisions made in the draft Regulations.

3.6 REGULATION 11: DESPATCH PRINCIPLES FOR ELECTRICITY GENERATED FROM RENEWABLE ENERGY SOURCES

In the draft Regulations, it was provided that 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. Further draft Regulation also provides scheduling requirement of wind and solar energy as per IEGC-2010.

3.6.1 THE COMMENTS RECEIVED ON THIS PROVISION:

Wind

Prayas has suggested that old wind energy generators be also required to be IEGC-2010 complaint and further suggested that Commission should give some longer term clarity on what would be the allowable forecasting error bands and how soon these would be tightened.

Torrent Power Limited has suggested that scheduling should be introduced on an experimental basis as scheduling of wind and solar power is at a nascent stage in India and error margin would be higher than +/- 30% during most of the times.

Greenergy Renewables Pvt. Limited has suggested that energy generated beyond 150% may be considered for REC benefits so that the impact of scheduling may have equal impact on RE Generators selling power to Distribution Licensees under CERC draft RE Tariff Regulations, 2012 and RE Generators exercising various options of sale of power (i.e. captive consumption or sale to third party under open access route and availing REC benefits).

Acciona Energy has suggested that the procedure of implementation of RRF, dispatch principles should not be applicable for wind energy projects which have signed PPA with Utilities.

Reliance Power has suggested that considering the lack of data and effective techniques for wind forecasting and low contribution of wind generation (in proportion to conventional power) to the grid, Commission should defer the expansion of the provisions of IEGC-2010 to next Control Period.

CLP Wind Farms has suggested that the wind projects should be allowed to submit the generation forecast on best endeavour basis without any commercial implication for deviation from schedule and also should the Hon'ble Commission find merit in retaining the UI linked settlement mechanism, returns to the investor should be commensurate with the additional risk associated under the scheduling and forecasting regime.

Biomass

GUVNL has suggested that Small biomass projects should also be subject to scheduling so that they help Utilities to plan the power requirement in more appropriate manner and effective utilization of fuel.

Gujarat Biomass Energy Developers Association submitted that even 10 MWs and above may be allowed variation in power generation to an extent of 20-30 % as achieving consistent generation is not a reality due to uses of different fuels with varying characteristics such as moisture content, chemical composition etc. manual feeding of biomass, during monsoon season the fuel characteristics further vary due to high moisture.

IL&FS RE Ltd and PTC Bermaco Green Energy Systems Ltd. have suggested that Biomass projects of more than 15 MW, instead of 10 MW, should be subjected to 'Scheduling'.

Indian Biomass Producers Association has requested to reconsider the basis for Scheduling the power on merit order basis for biomass power which is subject to availability of biomass from unorganized sector.

Solar

Shri Shanti Prasad has submitted that the solar projects of smaller capacity may be kept out of the purview like wind power projects.

3.5.2 COMMISSION'S DECISION

In view of the large scale integration of Renewable Energy sources in the future, the IEGC-2010 specifies the technical and commercial aspects for integration of the renewable sources into the grid. While specifying the philosophy and responsibilities for planning and operation of Indian power system, the Indian Electricity Grid Code (IEGC) -2010 has specified specific provisions for proper scheduling and despatching of power from the renewable energy sources for grid discipline and same is required to be followed.

As regards scheduling of biomass power, the Commission is of the view that it is a firm power as compared to wind energy and amenable to scheduling for day-to-day operations. 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.

In accordance with the IEGC -2010, solar generating plants with capacity of 5 MW and above and connected at the connection point of 33 KV level and above shall be subjected to scheduling and despatch code as specified under Indian Electricity Grid Code (IEGC) -2010.

Accordingly, the Commission has decided to retain the provisions as specified in the draft Regulations.

4. FINANCIAL PRINCIPLES

Under this section, comments received on the financial principles such as Benchmarking of Capital Cost, Debt: Equity, Loan and Finance Charges, Depreciation, Return on Equity, Interest on Working Capital have been discussed along with Commission's findings.

4.1 REGULATION 13: DEBT EQUITY RATIO

In the draft regulations, debt to equity ratio of 70:30 has been specified for generic tariff.

4.1.1 THE COMMENTS RECEIVED ON THIS PROVISION:

Abhiram Reddy has submitted that the Debt-equity ratio of 70:30 considered by CERC is reasonable as most of the banks are offering the same.

Acciona Energy has suggested that a 60:40 benchmark may be used for non-recourse financed wind IPPs as projects are getting 60% to 65% debt.

Rajasthan Biomass Power Developers Association has proposed to continue with the debt to equity ratio of 70:30 in line with RE Tariff Regulations- 2009 for the determination of renewable energy tariff in the next control period.

3.5.2 COMMISSION'S DECISION

The Tariff Policy notified by the Government of India, stipulates consideration of debt equity ratio of 70:30 for financing all future projects. Further, with maturity of renewable energy technologies, the risk perception of the lenders and stakeholders for RE projects is undergoing change even for the IPP projects. Accordingly, the Commission has decided to retain the normative debt to equity ratio of 70:30 as proposed in the draft Regulations.

4.4 LOAN AND FINANCE CHARGES

4.4.1 REGULATION 14(1): LOAN TENURE

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

4.4.1.1 THE COMMENTS RECEIVED ON THIS PROVISION:

Majority of Stakeholders have suggested considering 10 years as loan tenure for Renewable Energy projects. Abhiram Reddy has suggested that though RE technologies have achieved maturity level, most of the RE projects have not performed as per the expectations and in view of this even now most banks do not offer a 12 year loan repayment period. He further suggested that even IREDA does not offer a term loan repayment period of 12 years. Hence, CERC may consider 10 years only as the term loan repayment period.

GMR Energy Ltd has suggested that the loan repayment period for such long term investments should be 15 years in order to allow comfort to the developers during initial years of operation

EMCO Limited has submitted that Loan tenure needs to be reduced as it is on higher side as banks are reluctant to give loan tenure beyond 10 years and even if tenure beyond 10 years is offered then it comes with additional interest rate.

ACME has submitted that the Solar PV is still considered a nascent technology in

Indian context, loan repayment tenure of 10 years should be considered with proportionate increase in depreciation so as to ensure loan repayment as per envisaged repayment period.

4.4.1.2 COMMISSION'S DECISION

Since, most of the RE technologies have achieved maturity level, it is now possible for the developers to get loan from lenders/financial institutions for longer duration of say 12 years. Considering the same, the Commission has decided to retain proposal of normative loan tenure of 12 years, as proposed in the draft Regulations, for the purpose of determination of tariff in the final regulations.

4.4.2 REGULATION 14(2): INTEREST RATE

In the draft Regulations the Commission has proposed the normative interest rate as average State Bank of India (SBI) Base rate prevalent during the first six months of the previous year plus 300 basis points.

4.4.2.1 THE COMMENTS RECEIVED ON THIS PROVISIONS ARE,

Abhiram Reddy has suggested that the proposal for normative interest rate for the determination of tariff for the next Control period is justified

GUVNL has suggested that upper limit of interest on loan may be kept at 12% and interest on working capital at 11.5% for the control period as over last 10 years the interest rate on working capital is found lower than long term interest rate and gap is around 50 to 100 basis points.

DVC has submitted that the average rate of interest may be calculated on the basis of actual loan portfolio so that the RE company does not get any extra profit/loss from the tariff element of notional interest.

Harsil Hydro limited has suggested that instead of IREDA data, the SBI PLR be used as the normative rate for determination of tariff or actual interest rate received on a per project basis be used since it is verifiable.

Torrent Power Limited has suggested that interest rate of 350 basis points above SBI Base rate may be considered in view of recent inflationary situation and based on the recent experience, banks are financing RE projects at atleast base rate plus 350 basis points.

InWEA, IWTMA, Kenersys have suggested retaining the same interest rate basis linked to SBI LTPLR + 150 bps.

RE New Power Pvt. Limited has requested to make required modification in Interest rate for determination of RE Generator's Tariff considering the following rationale:

- Interest Rate charged by IREDA is lowest among any lenders in India lending to Renewable Generators.
- Even PFC lending rate, whose reference CERC's Explanatory Memorandum mentions, has an interest rate 50 to 75 basis point more than IREDA against equivalent grade of investors.
- IREDA has a limited balance sheet and cann't cater to the requirement of entire Renewable Industry.
- On account of faster and less tedious appraisal process followed by many other lenders, developers still sometimes prefer to explore options other than IREDA.
- Most of investors/borrowers are falling under Grade IV category of IREDA, and there are very limited investors in Grade I and Grade II; and Schedule A/Rated PSU/ State Sector category. This means that Interest rate even in most competitive lender IREDA for most of the players is in the range of 12.5% to 13.5% as against the interest proposed in the Draft Regulations is about 12.28% (weighted average of first 6 months of interest rate of previous year i.e. FY12).

- In the current environment, most of the projects are able to achieve financial closure at an interest rate of 13.5 to 14% which is equivalent to 425 basis point above the average SBI Base Rate, during the first six months of the previous year.

Infraline Energy Research has suggested that the normative interest could be fixed at 'average State Bank of India (SBI) base-rate for the just preceding six months' instead of 'average SBI base rate prevalent during the first six months of the previous year plus 300 basis points'.

Energy Infratech has submitted that the spread over SBI Base Rate should be atleast 450 basis points.

Reliance Power Ltd. has submitted that infrastructure projects are being financed in the range of 14-15% in India and requested that the Commission accounts for actual cost of financing and revises normative interest rate to a minimum of 500 basis points above base rate.

Surabhi Akshay Urja Pvt. Ltd has suggested that the allowable interest rates is to be reflective of the real market conditions that currently range from 14.75% to 16.50%

Hetero Wind Power Ltd. has suggested that the general inflationary trends coupled with high interest rate etc. shall be taken into account in determining tariff for wind power.

4.4.2.2 COMMISSION'S DECISION

The Commission has taken note of the interest rates charged by IREDA and PFC to various renewable energy projects. Considering that the matured technologies, like: wind, co-gen and Small hydro projects, are being financed around the normative rate as proposed in the draft Regulations, the Commission has decided to retain the norms as proposed in the draft Regulations.

4.5 REGULATION 15: DEPRECIATION

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 5.83% per annum and the remaining depreciation shall be spread over the remaining useful life of the project from 13th year onwards.

4.5.1 THE COMMENTS RECEIVED ON THIS PROVISION:

Many stakeholders have suggested that that there is no such change in scenario that the Depreciation rate must be decreased and have demanded that the earlier clause of depreciation may be retained.

Chhattisgarh Biomass Energy Producers Association has submitted that the Loan Repayment should be considered at 10 years and accordingly depreciation should be allowed as due to non performance of RE projects in the country and increasing NPA in power sector, banks, even IREDA is not allowing a term loan repayment period of 12 years.

Grameena Abhivrudhi Mandali has submitted that depreciation rate of 7% may be considered as in case of biogas based plant the life of high speed shredders, submerged agitators, corrosion resistant gas holders/roofs etc. for biogas based power plants would all be of the order of 10 years.

Ankur Scientific Energy has suggested that the key component of Biomass Gasifier power plant is Producer Gas Engine which is prone to very high maintenance cost and its life is typically not more than 10 years so total cost should be depreciated over 10 years only.

Gujarat Fluoro has suggested that the salvage value of the asset should be considered as 5%.

Acciona Energy has suggested that the salvage value of wind assets after 20 years is nil.

4.5.2 COMMISSION'S DECISION

The Commission has considered loan tenure of 12 years. Considering the same, the Commission has decided to retain the norm of depreciation as proposed in the draft Regulations. Accordingly, the normative depreciation rate shall be 5.83 % per annum as for initial period of 12 years i.e. equivalent to the loan tenure and the remaining depreciation, to cover 90% depreciable value, shall be spread over balance useful life of the project beyond the initial period of 12 years.

4.6 REGULATION 16: RETURN ON EQUITY

In the draft Regulations normative Return on Equity has been proposed as,

a) 20% per annum for the first 10 years.

b) 24% per annum 11th years onwards.

4.6.1 THE COMMENTS RECEIVED ON THIS PROVISION:

Matrix Private Power Limited suggested that there is no preferential treatment for biomass based power plants.

GUVNL has submitted that since RE projects have gestation period less compared to the thermal power projects it is suggested to consider ROE at 14% post tax.

A2Z Maintenance & Engineering Services Limited has suggested that in order to attract investment in RE projects a suitable ROE may be provided so that investor may get Post tax return of 20%, as such projects require long term equity commitment, high payback period as compared to other infrastructure projects and risk involved in biomass power projects on account of availability of biomass and its price.

Harsil Hydro limited has suggested that that SBI charges 15% interest after securing the money that it lends for the projects, the normative ROE should be revised to reflect the higher monetary rates prevailing in the markets as is reflected in the internationally accepted CAPM method.

RE New Power Pvt. Limited has suggested that it is unfair to keep the RoE unchanged under following background:

- An equity investor typically expects a return which is much better than interest rate, as he is taking far more risk than the lender and the Interest rate in last 3 years, have moved up by more than 3%.
- With the current level of volatility in the Indian stock exchange, the beta is much higher and accordingly if we go by Capital Asset Pricing Methodology (CAPM), the RoE should be much higher than proposed.

Torrent Power Limited has suggested that the impact of any change in the direct tax may be factored in tariff by issuing suo-moto order as Direct Tax Code is expected to be implemented from FY2012-13 onwards.

Shri Shanti Prasad, Rajasthan Biomass Power Developers Association, InWEA and Energy Infratech have submitted that the Return on Equity shall be adjusted for any variation in MAT / Corporate tax.

GFL has suggested that the ROE should be flat 23% per annum.

CLP Wind Farms (India) Pvt. Ltd.) has suggested to tabulate the tariff on a post-tax basis by fixing the ROE and assuming the present rate of Income tax; and permit tax to be a pass through item. They have further submitted that the KERC in its Wind Tariff Order dated 11.12.2009 allowed Income Tax as pass through with the intent of protecting the post-tax ROE for the investors.

4.6.2 COMMISSION'S DECISION

It is clarified that that the returns for renewable energy generation projects have been specified in pre-tax terms alone and 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 20% per annum (pre-tax) for initial 10 years and at 24% per annum (pre-tax) for subsequent period.

It is also clarified that any 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.

As regards providing additional return on equity to RE projects, the Commission is of the view that 16% post tax return seems to be adequate for attracting investment considering the maturity of technology and lower gestation period. Accordingly, the Commission has decided to retain the provisions as specified under draft Regulations.

4.7 REGULATION 17: INTEREST ON WORKING CAPITAL

The draft regulations provided following provisions related to Interest on Working Capital:

"17. Interest on Working Capital

(1) The Working Capital requirement in respect of wind energy projects, Small Hydro Power, Solar PV and Solar thermal power projects shall be computed in accordance with the following:

<u>Wind Energy / Small Hydro Power /Solar PV / Solar thermal</u>

a) Operation & Maintenance expenses for one month;

b) Receivables equivalent to 2 (Two) months of energy charges for sale of electricity calculated on the normative CUF;

c) Maintenance spare @ 15% of operation and maintenance expenses

(2) The Working Capital requirement in respect of biomass power projects and non-fossil fuel based co-generation projects shall be computed in accordance with the following clause :

Biomass, Biogas Power and Non-fossil fuel Co-generation

a) Fuel costs for four months equivalent to normative PLF;

b) Operation & Maintenance expense for one month;

c) Receivables equivalent to 2 (Two) months of fixed and variable charges for sale of electricity calculated on the target PLF;

d) Maintenance spare @ 15% of operation and maintenance expenses

(3) Interest on Working Capital shall be at interest rate equivalent to the average State Bank of India Base Rate prevalent during the first six months of the previous year plus 350 basis points".

4.7.1 THE COMMENTS RECEIVED ON THIS PROVISION:

Receivables

IWTMA, Acciona Energy, Greenergy Renewables Pvt. Limited and GFL have submitted that with the present financial position of many of the State Utilities, the generator has been receiving money for the electricity sold after a considerable delay. They have suggested that receivables equivalent to **3 months** of energy charges for sale of electricity be assumed.

Orient Green Power suggested that for the purpose of arriving at the working capital requirement, receivables equivalent to four months of energy charges for sale of electricity be assumed.

Fuel cost

Kalptaru Power Transmission Limited has submitted that as per study conducted by M/s DSEL on behalf of RREC, the Biomass plants procure more than 70% requirement in season therefore **6 months fuel cost** should be considered for working capital requirement.

PTC Bermaco Green Energy Systems Ltd. has suggested to consider working capital requirement of fuel stock of paddy straw based biomass power projects for **10 months** instead of 4 months.

O&M Cost

Kalptaru Power Transmission Limited has suggested that the O&M cost is 6.5% of Capital cost of ₹ 540 Lakh/MW. Thus working capital for spares allowed is 57.89 Lacs considering an escalation of 5.72% on O& M expenses.

GFL has suggested that O & M expenses for six months may be considered.

Maintenance spare

Kalptaru Power Transmission Limited has suggested that the maintenance spares considered by RERC at 20%. Further it submitted that CERC for conventional power plants allows the maintenance spares at 20% of operation and maintenance expenses, therefore, 20% should be considered instead of 15%.

GFL has suggested that maintenance spares @ 2% of capital cost of project may be considered.

Rajasthan Biomass Power Developers Association has submitted that the maintenance spares may be taken as ₹ 9 Lakh/MW.

Interest on Working Capital

Matrix Power Private Limited has submitted that the proposal for normative interest rate for the determination of tariff for the next Control period is justified.

IWTMA has submitted that the proposed formula for arriving at the interest rate may not reflect the reality in the market and suggested that it should be specified at SBI BR + 550 basis points as interest rate on Working capital.

Rajasthan Biomass Power Developers Association suggested that the interest rate may be taken higher by 2% of the rate of interest for term loan.

Energy Infratech has suggested that the spread over SBI Base Rate should be at least 600 basis points.

4.7.2 COMMISSION'S DECISION

Regarding Receivables, O&M cost and Maintenance spares, the provisions made in the draft Regulations are in line with the conventional power projects. As regards Fuel cost, the Commission is of the view that the provision made of four months seems appropriate as not all the biomass power plants procure biomass for more than six months. Considering the same the Commission has decided to retain the provision as specified under the draft Regulations.

4.8 REGULATION 18: OPERATION AND MAINTENANCE EXPENSES

The draft Regulations made the following provisions related to Operation and Maintenance Expenses:

"18. Operation and Maintenance Expenses

(1) 'Operation and Maintenance or O&M expenses' shall comprise repair and maintenance (R&M), establishment including employee expenses,

and administrative and general expenses.

(2) Operation and maintenance expenses shall be determined for the Tariff Period based on normative O&M expenses specified by the Commission subsequently in these Regulations for the first Year of Control Period.

(3) Normative O&M expenses allowed during first year of the Control Period (i.e. FY 2012-13) under these Regulations shall be escalated at the rate of 5.72% per annum over the Tariff Period."

4.8.1 THE COMMENTS RECEIVED ON THIS PROVISION:

Greenergy Renewables Pvt. Limited has submitted that the escalation factor of 5.72% was derived considering inflation data (i.e., based on Wholesale Price Index (WPI) and Consumer Price Index (CPI) data) for the period from 2003-04 to October-2008.

Greenergy and InWEA has submitted that the escalation factor may be considered based on the escalation rate (i.e., based on WPI and CPI data) for the period from 2003-04 to November 2011 considering weightages of 60% for WPI and 40% for CPI.

RE New Power Pvt. Limited suggested adjusting the escalation rate of 5.72% considered in line with the trend in escalation of the Wholesale Price Index in last year which is around 9%.

GMR Energy Ltd. suggested that the escalation factors should be generic as decided by the CERC from time to time.

4.8.2 COMMISSION'S DECISION

The Commission would like to clarify that, the escalation factor specified of 5.72% per annum is in line with the escalation factor considered for conventional power projects as per CERC (Terms and Conditions for Tariff) Regulation, 2009 for the Control period FY 2009 to FY 2014. If the provision in the said 2009 Regulations is amended, during the new Control period of the Renewable Energy Tariff, the Commission may consider extending the same prospectively to all the RE projects as well.

4.9 REGULATION 21: SHARING OF CDM BENEFITS

The draft Regulations provided following provisions related to Sharing of CDM Benefits:

"21. Sharing of CDM Benefits

(1) The proceeds of carbon credit from approved CDM project shall be shared between generating company and concerned beneficiaries in the following manner, namely-

a) 100% of the gross proceeds on account of CDM benefit to be retained by the project developer in the first year after the date of commercial operation of the generating station;

b) In the second year, the share of the beneficiaries shall be 10% which shall be progressively increased by 10% every year till it reaches 50%, where after the proceeds shall be shared in equal proportion, by the generating company and the beneficiaries."

4.9 THE COMMENTS RECEIVED ON THIS PROVISION:

Stakeholders have requested to revisit the sharing of CDM benefits with any other beneficiaries as the entire risk in obtaining carbon credit is taken by the generating company.

EMCO Limited and CLP Wind Farms have suggested that the beneficiary should share **Net CDM Benefit** instead of Gross CDM benefits due to high initial cost for registration, recurring cost and income tax to be paid on CDM benefits.

CLP Wind Farms has further submitted that the MERC RE Tariff Regulations allowed investors to retain entire proceeds from sale of CERs and requested to permit investors to retain 100% of the revenue from sale of CER.

InWEA has submitted that Commission needs to clarify that the sharing of CDM benefit, if any, shall be applicable only after the sale proceeds from CERs are received by Project Developer and not from date of commissioning. Further it suggested that it should be applicable only after considering transaction costs borne by the CDM project proponent and taking into account risks borne by CDM proponent while formulating CDM sharing mechanism.

GMR Energy Ltd. has suggested that first three years' 100% gross proceeds of CDM benefits be allowed to be retained by the project developer and fourth year onwards it could be reduced yearly 10% till it reaches 50%.

4.9.2 COMMISSION'S DECISION

As regards sharing of CDM benefits, the Commission has considered 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. Accordingly the Commission has decided to retain the same as proposed in the draft Regulations.

The Commission would, however like to clarify that the sharing of CDM benefit, if any, shall be applicable only after the sale proceeds from CERs are received by Project Developer and not from date of commissioning.

4.10 REGULATION 22: SUBSIDY OR INCENTIVE BY THE CENTRAL / STATE GOVERNMENT

The draft Regulations provided the following provisions related to subsidy or incentive by the Central / State Government:

"22. Subsidy or incentive by the Central / State Government

The Commission shall take into consideration any incentive or subsidy offered by the Central or State Government, including accelerated depreciation benefit if availed by the generating company, for the renewable energy power plants while determining the tariff under these Regulations.

Provided that the following principles shall be considered for ascertaining income tax benefit on account of accelerated depreciation, if availed, for the purpose of tariff determination:

i) 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.

ii) Capitalization of RE projects during second half of the fiscal year. Per unit benefit shall be derived on levellised basis at discount factor equivalent to weighted average cost of capital."

4.10.1 THE COMMENTS RECEIVED ON THIS PROVISION:

Energy Infratech has submitted that the accelerated depreciation benefit if any available under the Income Tax Act should not be adjusted while determining the tariff as, such an approach would run counter to the objective of the Govt. to give incentive to Renewable Energy Projects.

IWTMA submitted that the Generation Based Incentive (GBI) being provided by the Government should not be considered for arriving at the tariff.

InWEA has submitted that there is no provision for treatment of GBI under the draft RE tariff regulations and suggested to incorporate the following proviso in the RE Tariff regulation:

> “Provided further that in case any Central Government or State Government notification specifically provides for any Generation based Incentive over and above tariff, the same shall not be factored in while determining Tariff.”

GUVNL has suggested that any benefit on account of subsidy/GBI shall also be considered for determination of tariff

Harsil Hydro limited has submitted that MNRE Capital subsidy is an incentive for developers and should not be used for reducing tariff.

A2Z Maintenance & Engineering Services Limited submitted that the capital costs arrived for various technologies are net of the subsidy and hence no reduction on account of subsidy will be applicable.

Prayas has submitted that there are capital subsidies available for bagasse cogeneration and Small Hydro power project should also to be factored in Capital cost.

Greenergy Renewables Pvt. Limited suggested has submitted that the situation where sale of power to one or other distribution licensee may lead to differential/ additional benefit or cost to the generator will be considered as a pass through and also requested to clarify whether the same also be considered by the SERCs while approving the power purchase cost for such distribution licensee or not.

Shri Shanti Prasad has suggested that there is a need to specify, the incentive/subsidy to be considered and subsidies such as cost of land should not to be considered under this regulation. He has further suggested that following may be added at the end of first para:

> "provided that incentive or subsidy in respect of parameters specified on normative basis will not be considered".

4.10.2 COMMISSION'S DECISION

Under 'Preferential Tariff' approach based on cost plus regime, the tariff is determined upon ascertaining normative costs and performance parameters. 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, accelerated depreciation benefit or generation based incentive (which is a substitute for accelerated depreciation benefits) be factored in while determining tariff.

As regards the capital subsidies available for biomass, bagasse cogeneration and Small Hydro power projects in the 11th Plan i.e. upto 31st March 2012, are as under:

Small Hydro

According to the Ministry of New and Renewable Energy letter No. 1491)/2008-SHP dated 11.12.2009, the Central Financial Assistance (CFA) for setting up new SHP Projects in private/co-operative /Joint sector are as under:

Areas	**upto 1000 KW**	**Above 1 MW & upto 25 MW**
N.E. States, J & K, H.P & Uttarakhand (Special Category States)	₹ 20,000 per KW	₹ 2.00 Crores for 1st MW + ₹ 30 lakhs for each addl. MW
Other States	₹ 12,000 per KW	₹ 1.20 Crores for 1st MW + ₹ 20 lakhs for each addl. MW

According to the Ministry of New and Renewable Energy letter No. 1491)/2008-SHP dated 11.12.2009, the Central Financial Assistance (CFA) for setting up new SHP Projects in the Government sector are as under:

Areas	Above 100 KW & upto 1000 KW	Above 1 MW & upto 25 MW
N.E. States, J & K, H.P & Uttarakhand (Special Category States)	₹ 50,000 per KW	₹ 5.00 Crores for 1st MW + Rs. 50 lakhs for each addl. MW
Other States	₹ 25,000 per KW	₹ 2.50 Crores for 1st MW + ₹ 40 lakhs for each addl. MW

Biomass Power Project and Bagasse Cogeneration Projects

According to the Ministry of New and Renewable Energy letter No. 3/19/2006-CPG dated 28.4.2010, the Central Financial Assistance (CFA) for setting up Grid interactive Biomass Power and Bagasse Cogeneration Projects remaining period of the 11th Five Year Plan i.e. upto 31st March 2012, are as under:

A. CFA for Biomass Power Project and Bagasse Cogeneration Projects by Private/Joint/Coop./Public Sector Sugar Mills are as under:

	Special Category States (NE Region, Sikkim, J&K, HP & Uttaranchal)	**Other States**
Project Type	Capital Subsidy	Capital Subsidy
Biomass Power projects	₹ 25 lakh X (C MW)^0.646	₹ 20 lakh X (C MW)^0.646
Bagasse Co-generation by Private sugar mills	₹ 18 lakh X (C MW)^0.646	₹ 15 lakh X (C MW)^0.646

Bagasse Co-generation projects by cooperative/ public sector sugar mills 40 bar & above 60 bar & above 80 bar & above	₹ 40 lakh * ₹ 50 lakh * ₹ 60 lakh * Per MW of surplus power@ (maximum support ₹ 8.0 crore per project)	₹ 40 lakh * ₹ 50 lakh * ₹ 60 lakh * Per MW of surplus power@ (maximum support ₹ 8.0 crore per project)

*For new sugar mills, which are yet to start production and existing sugar mills employing backpressure route/seasonal/incidental cogeneration, which exports surplus power to the grid, subsidies shall be one-half of the level mentioned above.

@ Power generated in a sugar mill (-) power used for captive purpose i.e. net power fed to the grid during season by a sugar mill.

Note: CFA and Fiscal Incentives are subject to change.

B. CFA for Bagasse Cogeneration Project in cooperative/ public sector sugar mills implemented by IPPs/State Government Undertakings or State Government Joint Venture Company / Special Purpose Vehicle (Urja Ankur Trust) through BOOT/BOLT model

PROJECT TYPE	MINIMUM CONFIGURATION	CAPITAL SUBSIDY
Single coop. mill through BOOT/BOLT Model	60 bar & above 80 bar & above	₹ 40 L/MW of surplus power * ₹ 50 L/MW of surplus power* (maximum support ₹ 8.0 crore/ sugar mill)

* Power generated in a sugar mill (-) power used for captive purpose i.e. Net power fed to the grid during season by a sugar mill.

C. CFA for Bagasse Cogeneration Project in existing cooperative sector sugar mills employing boiler modifications

PROJECT TYPE	MINIMUM CONFIGURATION	CAPITAL SUBSIDY
Existing Cooperative Sugar Mill	40 bar & above 60 bar & above 80 bar & above	₹20 L/MW of surplus power * ₹25 L/MW of surplus power* ₹30 L/MW of surplus power*

* Power generated in a sugar mill (-) power used for captive purpose i.e. Net power fed to the grid during season by a sugar mill. CFA will be provided to the sugar mills who have not received CFA earlier from MNRE under any of its scheme.

It can be seen from the above that the CFA is available to the biomass, bagasse based co-generation and small hydro projects. Such CFA is available per MW basis and in some cases maximum limit is imposed, while in cases of Bagasse based co-generation projects CFA is linked to the boiler pressure configuration. Considering the same the Commission has decided to determine tariff on the basis of normative capital cost exclusive of capital subsidy available from MNRE, as may be specified for such technologies. However, capital subsidy/CFA available to the developer from the appropriate Government shall require to be passed on to the utilities on actual disbursement basis.

4.11 REGULATION 23: TAXES AND DUTIES

The draft Regulations provided following provisions related to Taxes and Duties:

"23. Taxes and Duties

Tariff determined under these regulations shall be exclusive of taxes and duties as may be levied by the appropriate Government:

Provided that the taxes and duties levied by the appropriate Government shall be allowed as pass through on actual incurred basis."

The Commission proposed that the tariff determined under these Regulations is exclusive of taxes (other than corporate tax and minimum alternative tax) and duties, including water royalty charges in case of Small Hydro Power Plant, as may be levied by the appropriate Government:

4.11.1 THE COMMENTS RECEIVED ON THIS PROVISION:

Abhiram Reddy has submitted that the proposal that taxes and duties levied by the appropriate Government shall be allowed as pass through on actual incurred basis is justified.

Tamilnadu Biomass Power producers Association has requested not to levy any electricity tax/duty for renewable power.

DVC has submitted that instead of taking taxes and duties as a pass through element, rate of return on equity computed may be considered to be grossed up with normal tax rate of the RE company.

Rajasthan Biomass Power Developers Association has submitted that it is not clear whether this provision is applicable to capital cost of the project. They have submitted that the excise duty, sales tax, works contract tax and other levies charged by appropriate Government may be allowed as pass through on the estimated capital cost also.

4.11.2 COMMISSION'S DECISION

The Commission would like to clarify that this provision is not applicable to excise duty, sales tax, works contract tax and other levies charged by appropriate Government which form part of the capital cost of the project as normative Capital Cost specified by the Commission is inclusive of the same. The taxes, duties levies etc. imposed by the appropriate Government and which are generally not factored into determinations of tariff are allowed as a pass through as per this provision. Accordingly, the Commission has decided to retain the provisions as specified under draft Regulations.

5. TECHNOLOGY SPECIFIC NORMS: WIND ENERGY

5.1 REGULATION 24: CAPITAL COST

The draft regulations had the following provision for the Capital Cost norm for Wind Energy Plant:

"24. Capital Cost

(1) The capital cost for wind energy project shall include Wind turbine generator including its auxiliaries, land cost, site development charges and other civil works, transportation charges, evacuation cost up to inter-connection point, financing charges and IDC.

(2) The capital cost for wind energy projects shall be ₹ 525 Lakhs/MW (FY 2012-13 during first year of Control Period) and shall be linked to indexation formula as outlined under Regulation 25."

5.1.1 THE COMMENTS RECEIVED ON THIS PROVISION:

Torrent Power Limited, NTPC, Orient Green Power Company Ltd. and IWTMA have suggested that the capital cost should be specified at ₹ **650 Lakhs/ MW** if new WPD-CUF matrix as proposed in the draft Regulations are to be implemented**.**

Rationales given for an increase in the capital cost are:

- In order to maximize generation in a low wind regime, the turbine heights and rotor diameter need to be increased substantially;
- Transportation of these components has become a challenge and the cost associated with this has also gone up as we have to use longer trailers which are available fewer in numbers;

- The technology has also undergone changes with a view to maximize output in low wind regime with electrical drive pitch control, battery backup, SCADA etc.
- With the introduction of the Indian Electricity Grid Code, there are capital costs associated with satellite connectivity, special energy meters, software associated with scheduling etc.
- Land becoming a scarce commodity, the cost of the land for putting up a wind farm has increased many folds.

Prayas has submitted that significant cost reduction can be achieved through competitive bidding in large orders for utility or captive consumption as has been seen in the solar sector. that there can be variation in these CUFs in different wind zones based on turbine technology and wind regime and since tariffs will not be adjusted for actual field performance (as in the case of Germany), it would be best not to continue with the feed in tariff mechanism but to go in for competitive reverse bidding with the ERC tariff as the ceiling.

Greenergy Renewables Pvt. Limited has submitted that with increase in turbine heights substantially from the prevailing height of 50 meters and also the rotor diameter will require to increase in cost for transportation of these machines as well as the cost of the machines itself and suggested to consider such additional expenses as well while specifying the norm for Capital Cost for the turbines.

Acciona Energy has submitted that the proposed Capital cost is not reflective of the actual situation and it should be ₹ **575 Lakh/ MW** plus evacuation cost.

RE New Power Pvt. Limited has **s**uggested that proposed rates are of Class II machines, not very suited for the low wind speeds in India. If we go with more suitable Class III machines the prices are not lower than ₹ **630 Lakh/ MW** and for the better ones like Vestas V-100, prices go up to ₹ **720 Lakh/ MW**.

Infraline Energy has suggested that the capital cost for wind energy projects may be kept at ₹ **580-590 Lakh/MW** instead of ₹ **525 Lakh/MW** for FY 2012-13, considering the inflationary trends.

InWEA has suggested to specify normative capital cost for wind power projects during 2012-13 as ₹ **575 Lakh/MW** instead of ₹ **525 Lakh/MW** as based on the indexation mechanism, the normative capital cost for wind power project during 2012-13 works out as ₹ **595 Lakh/MW**. They also suggested to consider a normative capital cost of at least ₹ **625 Lakh/MW** for wind turbines falling in WPD zone of less than 200 W/m2.

Vestas Wind Technology India Pvt. Ltd. has submitted that the weighted average Capital cost of WTGs under various approach works out to ₹ **654 Lakh/MW**.

Axis Wind Energy Ltd. has submitted that the cost per MW of the turbine has gone upto about ₹ **700 Lakh/MW** and suggested to consider the capital cost ₹ **525 Lakh/MW** considering the WTGs of 50 meters hub-height or alternatively, capital cost of ₹ **700 Lakh/MW** at 80mtrs hub-height.

GFL has suggested that the average capital cost of wind turbines are ₹ **600 Lakh/MW**.

Reliance Power Ltd. has submitted that the project costs are in the range of ₹ **635-670 Lakh/MW** for Wind projects

Hetero Wind Power Ltd. has submitted that the turbines with higher hub-heights of 80 meters and above, the cost per MW of turbine has gone beyond ₹ **700 Lakh/MW**.

Torrent Power Limited has suggested that the cost towards construction of transmission lines should be included in the Capital cost and based on our experience and estimates the evacuation cost for large RE project would be approximately ₹ 38 Lakh per MW.

NTPC Limited has submitted that NTPC in its tenders for two wind projects has got the cost ₹ 630 Lakh/MW and ₹ 636 Lakh/MW (Excluding IDC) and suggested to consider ₹ 650 Lakh/MW.

5.1.2 COMMISSION'S DECISION

It is evident that per MW capital cost has a very wide range from ₹ 575 - 700

Lakh/MW as suggested in various submissions. The submissions received by the Commission have also linked the cost to the technology and the CUF used for wind projects.

Project cost consists of four important parameters, as follows

1) Plant & Machinery cost
2) Land
3) Extra High Voltage (EHV) Pooling station
4) Associated Service Tax

Unlike conventional power projects, it is tough to arrive to capital cost benchmarks for wind energy projects. Alternatively, one can take the lowest price achieved in the tendering process carried out by state and central government Public Sector Undertakings (PSUs). The average capital costs for a delivered wind energy projects can show project cost variance ranging from ₹ 585 Lakh per MW to as high as ₹ 625 Lakh per MW. The project cost varies with the technology, size of the projects, cost of the infrastructure (i.e. land, EHV infrastructure), statutory charges/fees etc. The same is also evident in the "explanatory memorandum" put forward by the Commission on the draft Regulations.

The Commission has considered the fact that the technologies employed in India (i.e. Class III and IV wind turbine technology) have never been in a phase of oversupply. Moreover the wind farm projects in India have significant impact on the increase of commodity price, Euro-Rupee & USD- Rupee parity for import of certain critical components from Europe (viz. gear box, control systems, yaw mechanisms), increasing land price and EHV costs and specialty commodity items (i.e. steel used in towers). All these parameters have potential of influencing the Capital cost of the wind energy equipment shown in the table as follows:

Cost break-up for 1 MW unit size wind energy project in ₹ Lakh

No	Components	Prevailing Market Conditions
1	Nacelle	197
2	Hub	31
3	Blade	45
4	Power panel	25
5	Hardware + Cables	26
	Sub-total (A)	324
6	Tower + Tower Logistics	79
7	Transformer (690 V/ 33 kV)	12
8	Logistics / Transportation expenditure	30
	Sub-total(B)	121
9	Foundation	25
10	Electrical (33 kV lines + DP yard)	14
11	Erection & Commissioning	26
12	EHV + Road + Area Development	24
13	Land	25
14	State Nodal Agency charges	2
15	Cost of hardware for forecasting	2
16	Associated expenditure for Forecasting	2
17	Consulting fees	5
	Subtotal Total (C)	125
18	Service Tax at 10.33%	12.91
	Grant Total - A + B + C (rounded) (₹ Lakh/MW)	583

Considering the above aspect, the Commission has decided to revise the Capital cost at ₹ 575 Lakh per MW in the final regulations.

5.2 REGULATION 26: CAPACITY UTILISATION FACTOR (CUF)

The draft Regulations had the following provision for the Capacity Utilisation Factor norms for Wind Energy Plant:

"26. Capacity Utilisation Factor (CUF)

(1) CUF norms for this control period shall be as follows:

Annual Mean Wind Power Density (W/m^2)	***CUF***
Upto 200	*20%*
200-250	*22%*
250-300	*25%*
300-400	*30%*
> 400	*32%*

(2) The annual mean wind power density specified in sub-regulation (1) above shall be measured at 80 meter hub-height.

(3) For the purpose of classification of wind energy project into particular wind zone class, as per MNRE guidelines for wind measurement, wind mast either put-up by C-WET or a private developer and validated by C-WET would be normally extended 10 km from the mast point to all directions for uniform terrain and limited to appropriate distance in complex terrain with regard to complexity of the site. Based on such validation by C-WET, state nodal agency should certify zoning of the proposed wind farm complex."

5.2.1 THE COMMENTS RECEIVED ON THIS PROVISION:

IWTMA and Kenersys India Pvt. Ltd. have submitted that the Annual Mean WPD equal to or below 250 watt/m^2 should be linked to 20% CUF. They have further submitted that the proposed zoning scheme contradicts the existing regulatory regime and to avoid such contradiction and for the sake of consistency following

WPD linked CUF zoning is suggested:

Annual Mean WPD (W/m^2)	CUF
Upto 250	20%
251-300	23%
301-350	25%
351-400	27%
>400	30%

Kenersys India Pvt. Ltd has also suggested to consider the subjective factors such as complexity/terrain/altitude etc. while finalising this regulation. Further suggested that there will be no necessity of the nodal agency issuing any wind zone certificate as it is available in public domain or nodal agency has a copy of CWET validation.

RE New Power Pvt. Limited has suggested that the only required change is to include <250 W//m2 in Zone 1 and the CUF assumed in the 2009 regulations were very reasonable corresponding to a WPD. They have further mentioned that measuring a WPD at 80 meter hub-height and convincing CWET/ local energy development authorities on the WPD is not an easy task as many of the CWET old mast doesn't have a temperature and pressure reading along with wind speed data and accordingly it is difficult to extrapolate the lower height wind speed data in these masts to 80 m hub-height, in line with proposed Draft Regulations. They also suggested that inter annual variations in the wind speed should be taken into consideration during WPD zone determination as historical generation data shows 4% to 5% variation in plant load factor over a period of 10 years.

Prayas has submitted that there can be variation in these CUFs in different wind zones based on turbine technology and wind regime and since tariffs will not be adjusted for actual field performance (as in the case of Germany), it would be best not to continue with the feed in tariff mechanism but to go in for competitive reverse bidding with the SERC tariff as the ceiling.

Prayas has also suggested that the standard feed-in tariff practices applied globally should be followed where in actual CUF and performance is taken into account while payments are made. In Germany, a preferential feed in tariff for wind power is calculated for a standard wind site (Expected generation at this site is called the Reference Yield). This tariff is guaranteed initially only for 5 years. Depending on the actual performance in these five years the future time period for which this preferential tariff is applicable is varied proportionately.

Prayas has further submitted that in a recent submission to MERC, M/s Gamesa Wind Turbines Pvt Ltd. sought amendment of Annual Mean Wind Power Density criteria for Wind Power Projects under Wind Zone-I category wherein results of the analysis estimated PLF of 27.7% at the site of less than 200 WPD.

PTC India Ltd. has submitted that for clarity, the values of average wind power diversity limits may be tabulated as: Up to 200, >200≤250, >250≤300, >300≤400, >400.

InWEA has suggested that till such time CWET issues validated data regarding WPD and wind speed at 80 m hub heights, Commission should continue to with CUF norms at 50 meter hub height as provided under the Renewable Energy Tariff Regulations, 2009, Or If the Commission wishes to continue with the hub height of 80m, then the CUF should not be changed. They have further requested to provide the co-relationship between WPD and Capacity Utilization factor and to provide basis for increase in CUF by around 2% across the 4 wind zones from RE Tariff Regulation, 2009.

Axis Wind Energy Ltd. has suggested to consider to specify the range of CUF for different wind zones based on the WPD at 80 meters level which is extrapolated from the Matmast data at 50 meters level based on WPD map of C-WET to avoid confusion on classification of sites and zones.

GFL has suggested that the CUF norms may be a flat 20%.

Reliance Power Ltd. has suggested that no change in method of calculation of base

CUF should be done at this stage.

NTPC Limited has submitted that 50 meter hub height data extrapolated to 80 m may be considered (C-WET is extrapolating data upto 75m only). Further, international accredited agencies should be allowed for validation and certification of zone for tariff consideration in addition to C-WET.

GE Energy has submitted that they support revised Wind Power Density (WPD) characterization, as they believe that this would spur additional development in the wind energy sector. They further suggested that the tariff level to support low and medium wind speed turbines would be ₹ 4.40- 6.92 per kWh for WPD range of 400-200 /sq. meter.

Hetero Wind Power Ltd. has suggested that it is appropriate to group the wind zones based on WPD at 50 meter hub-height only.

Axis Wind Energy Ltd. has suggested that wind energy tariff should be determined for different hub-heights of the machine with suitable cost parameters.

Acciona has suggested that de-rating of the wind power plant efficiency at the rate of 1% after the first 10 years should be considered.

InWEA has suggested that annual deration factor of 0.25% p.a. after 5 years of operation and normative auxiliary consumption factor of at least 0.5% should be specified.

5.2.2 COMMISSION'S DECISION

CUF represents important parameter that influences the economics of a wind project at a particular wind site. CUF depends on prevailing wind regime at particular site.

The Commission does not find any merit in submissions that the WPD zones should be defined at 50m when most of the wind turbines being installed in India are having hub heights of about 80m. Moreover, some of the stakeholders including manufacturers of wind turbine are also in agreement with the Commission's proposal. Further, no wind energy developers have submitted any evidence of actual

CUF of their wind turbines having hub height of 80 meters, to substantiate their argument.

Considering the same, the Commission has decided to retain the provisions as mentioned in the draft Regulations with following modifications in WPD range to give more clarity:

Annual Mean Wind Power Density (W/m2)	CUF
Upto 200	20%
201-250	22%
251-300	25%
301-400	30%
> 400	32%

It has also been submitted that the annual deration factor and the auxiliary consumption be considered while tariff estimation. The Commission would like to clarify that the CUF considered for wind projects is a net CUF for the entire life of the project and thus includes the effects of ageing and resultant reduction in performance, and there is no need for providing the deration as well as auxiliary consumption.

5.3 REGULATION 27: OPERATION AND MAINTENANCE (O&M) EXPENSES

The draft Regulations had the following provision for the Operation and Maintenance norm for Wind Energy Plant:

"(1) Normative O&M expenses for the first year of the Control Period (i.e. FY

2012-13) shall be ₹ 9 Lakh per MW.

(2) Normative O&M expenses allowed under these Regulations shall be escalated at the rate of 5.72% per annum over the tariff period to compute the levellised tariff.”

While proposing the above norm, the Commission considered 5.72% annual escalation over the normative Operation and Maintenance Cost allowed for FY 11-12 along with additional insurance cost was considered at 0.25% of capital cost as well as forecasting Cost.

5.3.1 THE COMMENTS RECEIVED ON THIS PROVISION:

IWTMA has submitted that with increased capital cost as suggested by them, the charges payable towards insurance get increased and generally the insurance charges payable would be 0.75% of capital cost. They have suggested that same should be factored in O&M expenses.

RE New Power Pvt. Limited has submitted that the proposed O&M Expense of ₹ 9 lakhs/ MW for FY13 is much lower than the current O&M Expense quoted by most of the turbine vendors and in the background of high inflation factor, the O&M Expense in FY13 should be at least ₹ 13 lakhs per MW. Further suggested that the O&M Expenses will substantially go up for not only meeting the IEGC requirement of forecasting but also for REC trading whereby an RE Generator has to either become a member of exchange themselves or to appoint a trader/consultant to bid for REC.

Acciona Energy has suggested that the spare part cost has not been included and as per present scenario O&M Expense is around ₹ 12-13 lakh per MW.

InWEA has suggested that the Commission should define and elaborate the forecasting cost component. They have further suggested that the capital cost and O&M expenses attributable to forecasting and scheduling of infirm wind power should be determined and allocated.

GFL has suggested that the O & M expenses do not take into consideration the 'machine breakdown insurance' which is usually 1.25% of the project cost.

Hetero Wind has suggested that the normative O & M cost should be considered at least ₹ 12 Lakh/MW.

GUVNL has suggested to consider O&M expanses for wind energy project at ₹ 7.75 Lakh/Mw

DVC has suggested that the draft Regulations propose different normative O&M expenses for different States and for different technologies. Charging a State-wise uniform rate for specific RE technology may be considered so that investors are not inclined to invest in a particular region or State.

5.3.2 COMMISSION’S DECISION

The Commission is of the opinion that the O&M costs of ₹ 9 lakh/MW would cover all the maintenance costs as well as the insurance costs of the wind project. The additional cost as a result of forecasting has been included in the above cost which has been increased from ₹6.5 lakh/MW in 2009. This increase would cover all the escalations and additional costs and hence we do not consider it necessary to make any change on account of O&M costs.

6. TECHNOLOGY SPECIFIC NORMS: SMALL HYDRO POWER

6.1 REGULATION 28: CAPITAL COST

The draft Regulations had the following provision for the Capital Cost of Small Hydro Power plant:

*"**28. Capital Cost***

(1) The normative capital cost for small hydro projects during first year of Control Period (FY 2012-13) shall be as follows:

Region	***Project Size***	***Capital Cost (₹ Lakh/ MW)***
Himanchal Pradesh, Uttarakhand and North	*Below 5 MW*	*700*
	5 MW to 25 MW	*630*
Other States	*Below 5 MW*	*550*
	5 MW to 25 MW	*500*

(2) The capital cost for subsequent years shall be determined on the basis of indexation formula as outlined under Regulation 29."

6.1.1 THE COMMENTS RECEIVED ON THIS PROVISION:

Energy Infratech submitted that even large hydro projects currently cost approx ₹ 800 -1000 Lakh per MW.

NTPC Limited has suggested that following capital cost should be considered:

Region	Project Size	Capital Cost (₹ Lakh/ MW)
Himanchal Pradesh, Uttarakhand and North Eastern States	Below 5 MW	1000
	5 MW to 25 MW	950
Other States	Below 5 MW	900
	5 MW to 25 MW	850

Harsil Hydro limited has submitted that the Capital Cost of the projects located in the hilly regions of HP, Uttarakhand and the North East are currently between ₹ 800 -1000 Lakh per MW and the same is also acknowledged in the draft that the projects funded by IREDA in 2011-12 is ₹ 817 Lakh per MW. They suggested that the proposed project cost is unfair, unrealistic and completely ignores the financial reality of implementation. They further suggested that the implementation agreements executed with Government of Uttaranchal in September 2011 upon approval of DPR with an average capital cost of ₹ 1000 Lakh per MW. They further submitted that the cost of canal based SHPs is also unrealistic as the project cost of 30 projects prepared by the IIT Roorkee/Kanpur for NEDA had average capital cost of ₹ 800 Lakh per MW and the cost can be verified from PEDA where majority of canal based projects have been constructed. Harsil Hydro limited also suggested that the transmission line cost should be added separately depending upon the distance and the voltage of the line to be constructed.

6.1.2 COMMISSION'S DECISION

The Commission agrees with the views expressed by the stakeholders that small hydro projects cost has increased as the sites are located in remote areas. On the basis of the above recommendations and analysis of project database, the norms for capital cost have been modified as follows:

Region	Project Size	Capital Cost (₹ Lakh/ MW)
Himanchal Pradesh, Uttarakhand and North Eastern States	Below 5 MW	770
	5 MW to 25 MW	700
Other States	Below 5 MW	600
	5 MW to 25 MW	550

6.2 REGULATION 30: CAPACITY UTILISATION FACTOR (CUF)

The draft Regulations had the following provision for the Capacity Utilisation Factor of Small Hydro Power plant:

"Capacity Utilisation factor for the small hydro projects located in Himachal Pradesh, Uttarakhand and North Eastern States shall be 45% and for other States, CUF shall be 30%.

Explanation: For the purpose of this Regulation normative CUF is net of free power to the home state if any, and any quantum of free power if committed by the developer over and above the normative CUF shall not be factored into the tariff."

6.2.1 THE COMMENT RECEIVED ON THIS PROVISION:

Harsil Hydro limited has submitted that the Secondary energy rate to be at par with the primary energy as higher efficiency should not be penalized.

6.2.2 COMMISSION'S DECISION

The Commission would like to clarify that the generation, over and above the normative PLF as specified in the Regulation would also be payable at the same levellised tariff as may be determined by the Commission.

6.3 REGULATION 32: OPERATION AND MAINTENANCE EXPENSES

The draft Regulations had the following provision for the Capacity Utilisation Factor of Small Hydro Power plant:

"(1) Normative O&M expenses for the first year of the Control period (i.e. FY 2012-13 shall be as follows.

Region	***Project Size***	***O&M Expense (₹Lakh/ MW)***
Himachal Pradesh, Uttarakhand and North Eastern States	*Below 5 MW*	*25*
	5 MW to 25 MW	*18*
Other States	*Below 5 MW*	*20*
	5 MW to 25	*14*

(2) Normative O&M expenses allowed under these Regulations shall be escalated at the rate of 5.72% per annum for the Tariff Period for the purpose of determination of levellised tariff."

6.3.1 THE COMMENT RECEIVED ON THIS PROVISION:

Harsil Hydro limited has submitted that several projects are located in highly seismic zones and require higher insurance cost, the proposed O & M cost should add 1% for comprehensive insurance covering natural disasters.

6.3.2 COMMISSION'S DECISION

As per CERC (Terms and Conditions for Tariff) Regulation, 2009, in case of the hydro generating stations declared under commercial operation on or after 1.4.2009, operation and maintenance expenses should be fixed at 2% of the original project cost (excluding cost of rehabilitation & resettlement works) and should also be subject to annual escalation of 5.72% per annum for the subsequent years. It also covers the insurance cost. Proposed norm of the O & M expenses as a percentage of the capital cost are shown as under;

Region	**Project Size**	**Capital Cost (₹ Lakh/ MW)**	***O&M Expense (₹Lakh/ MW)***	**O&M Exp. as % of CC**
Himanchal Pradesh, Uttarakhand and North Eastern States	Below 5 MW	770	*25*	*3.2%*
	5 MW to 25 MW	700	*18*	*2.6%*
Other States	Below 5 MW	600	*20*	*3.3%*
	5 MW to 25 MW	550	*14*	*2.5%*

Considering the same, the Commission has decided to retain the provision as proposed in the draft Regulations.

7. TECHNOLOGY SPECIFIC NORMS: BIOMASS PROJECTS RANKINE CYCLE

7.1 REGULATION 34: CAPITAL COST

The draft Regulations had the following provision for the Capital Cost of Biomass Power plant:

"The normative capital cost for the biomass power projects based on Rankine cycle shall be ₹ 445 Lakh/MW (FY 2012-13 during first year of Control Period) and shall be linked to indexation formula as outlined under Regulation 35."

7.1.1 THE COMMENTS RECEIVED ON THIS PROVISION:

Matrix Private Power has submitted that the proposed normative capital cost for the first year of the control period and capital cost indexation mechanism is justified for plants above 10 MW capacities. They further submitted that for plants below 10 MW, the capital cost is around ₹ 550 Lakh/MW which could be established from Banks

Kalptaru Power Transmission Limited has suggested that separate Capital Cost for biomass power project with Air Cooled Condenser plant should be specified and the same may be given as ₹ 50 Lakh/MW extra as considered by the Rajasthan Electricity Regulatory Commission (RERC). They have also submitted the rationale for suggesting the same is that the RERC has allowed ₹ 45 Lakh/MW extra in 2009-10 and with 5% escalation per annum the cost of air-cooled, condensers will become ₹ 52 Lakh/MW in 2012-13.

Chhatisgarh Biomass Association has suggested that the capital cost is on lower side as it has gone up to steep increase in the prices of Steel, Cement, Equipment and Transportation. They have further submitted that the construction of power evacuation system is too high for the plants which are located remotely.

PTC Bermaco Green Energy Systems Ltd. has suggested to consider the Capital Cost of paddy straw based biomass power projects being implemented with Water-Cooled Condenser and Air Cooled Condensers for minimum Project Cost as ₹ 705 Lakh/MW and ₹ 740 Lakh/MW respectively, for deciding the tariff rate for our specific fuel based project.

A2Z Maintenance has suggested that there should be separate norm for smaller project.

Dalkia Energy Services has suggested that the Capital cost for biomass should be reviewed once again.

IL&FS RE Ltd. has suggested that there should be separate norm for the projects with water cooled and air cooled condensers, in order to promote such projects and to conserve the water resource of the country. IL&FS RE Ltd. has suggested that the capital cost of biomass projects for the water-cooled and air-cooled condensers at ₹ 600 Lakh/MW and ₹ 640 Lakh/MW respectively.

Transtech Green Power Pvt. Ltd has submitted that their project cost of plant commissioned in July 2010 is ₹ 72.12 crore for 12 MW, which is ₹ 601 Lakh/MW. They have further submitted that the cost currently taken by CERC as fixed cost is not reasonable and beyond execution in current financial scenario in Rajasthan or to some extent other places as well.

NTPC Limited has suggested that the capital cost should be fixed in the range of ₹ 570 – 650 Lakh/MW.

Rajasthan Biomass Power Developers Association has submitted that the Capital cost of biomass based power plant with air cooled condenser may be taken as ₹ 650 Lakh/MW.

Konark Power Project Ltd. has submitted that the biomass project cost needs to be increased to ₹ 650 Lakh/MW.

Biomass Power Producers Association, Tamilnadu has submitted that even if nominal annual escalation of 5% to be applied to the capital cost assumed in FY 2009 by CERC then the capital costs in 2012-13 would stand at ₹ 579 Lakh/MW. They have further suggested that the indexation mechanism can be applied as guided.

7.1.2 COMMISSION'S DECISION

The Capital Cost as proposed in the draft Regulations was based on the detailed analysis of the actual project cost approach as well as the benchmark norm developed by the IREDA for financing the biomass based projects for FY 2011-12, and accordingly proposed normative capital cost at ₹ 445 Lakh/MW for first year of the Control Period. The Commission has decided to retain the provision as proposed in the draft Regulations.

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.

The Commission is of the view that the generic norms for determination of the tariff may be differentiated based on project-specific factors. These factors can be included for the biomass based power plants with rankine cycle are: technology type (air cooled condensers, water cooled condensers etc.), the fuel type (rice husk, straw, stalks), the size of the project (to account for economies of scale), the quality of the resources at that particular site and the specific location of the project. In order to specify generic norms for a biomass based power projects, the Commission has considered a representative project size of 10 MW. CERC RE Tariff Regulation may also be a guiding norm for States and they may go for different norms to accommodate above factors. Considering the above, the Commission has decided to retain the provision as specified in the draft Regulations.

7.2 REGULATION 36: PLANT LOAD FACTOR (PLF)

The draft regulations had the following provision for the Plant Load factor of Biomass Power plant:

"36

(1) Threshold Plant Load Factor for determining fixed charge component of Tariff shall be:

a) During Stabilisation: 60%

b) During the remaining period of the first year (after stabilization): 70%

c) From 2nd Year onwards: 80 %

(2) The stabilisation period shall not be more than 6 months from the date of commissioning of the project."

7.2.1 THE COMMENTS RECEIVED ON THIS PROVISION:

Matrix Power Private Limited, based on the actual performance of 6 Biomass Power plants in Andhra Pradesh (4.5 MW to 9 MW size), from 2004-05 to 2008-09, suggested that the threshold PLF for fixed cost coverage be considered at 75%. They have submitted following Rationale for lower PLF:

1. Super Heater tube corrosion due to presence of sodium salt in fuel;
2. Increase in moisture content in the fuel in rainy season to an extent of 35%;
3. Plant runs on mixed fuel with varying GCV and maintaining ideal air fuel ratio at all times is impossible and leads to constant fluctuation in temperature and pressure of flue gas across the boiler ultimately leads to the inefficiency and failures; and
4. Grid failure.

PTC Bermaco Green Energy Systems Ltd. and **Dalkia Energy Services** have submitted that for straw fired plants, PLF should be considered 10% lower. PTC further suggested that PLF of 60% to 70% in the first year and 70% to 75% from 2nd year onward and for straw fired plants PLF should be considered 10% lower.

Chhatisgarh and Rajasthan Biomass Energy Developers Association suggested that the normative PLF should be considered at 75% due to following reasons:

1. Frequent trappings of 33 kV Grid
2. Frequent tripping of Boilers due to Silica deposits on Bed Coil /Super Heaters
3. High moisture content in fuel in rainy seasons

MP Biomass Energy Developers Association has submitted that the Stabilization period should not be more than 6 months from the commissioning of the project and the PLF determined by CERC seems more realistic and practical.

Energy Infratech has suggested that a PLF of 60% would be reasonable and fair for biomass based power plants.

Maharashtra Biomass Energy Development Association has suggested that for the purpose of tariff determination the first year of operation should be termed as the period of stabilaisation and thereafter the PLF for 2nd year of operation should be kept at 70% and 3rd year onward as 80%.

7.1.2 COMMISSION'S DECISION

Some stakeholders are in agreement with the Commission's proposal. The Commission does not find any material reason for changing the norms as provided in the draft Regulations.

7.3 REGULATION 37: AUXILIARY ENERGY CONSUMPTION

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

7.3.1 THE COMMENTS RECEIVED ON THIS PROVISION:

Matrix Power Private Limited has suggested that the Auxiliary Consumption should be considered at 12%.

PTC Bermaco Green Energy Systems Ltd. has suggested that for straw fired plants, Auxiliary Consumption should be considered at 14% for Water Cooled Condenser and 16% for Air Cooled Condenser.

Dalkia Energy Services has suggested that an additional allowance should be given for straw fired plants as it requires additional high power consuming fuel preparatory devices.

Kalptaru Power Transmission Limited has submitted that the RERC in its Tariff Regulation-2009 has considered 12% auxiliary consumption for project with water cooled condenser and 12.5% auxiliary consumption for project with air cooled condenser plants. The same should be considered by CERC

Chhatisgarh Biomass Energy developers Association has suggested that the normative Auxiliary Consumption should be considered at 12% as suggested by National Productivity Council as frequent re-startup of power plant consuming higher Auxiliary Consumption due to following reasons:

1. Frequent trappings of 33 kV Grid
2. Frequent tripping of Boilers due to Silica deposits on Bed Coil /Super Heaters
3. High moisture content in fuel in rainy seasons

IL&FS RE Ltd. has submitted that their experience in operation of projects indicates that the auxiliary consumption is 12%, even at 80% PLF with water-cooled condensers. They have further suggested that the PLF should be fixed at 12% for the water-cooled condenser and 14% for the air-cooled condenser.

Kalpataru Power Trans. Ltd. has suggested that as considered by RERC in Tariff Regulations-2009, auxiliary consumption should be specified as 12% and 12.5% for project with water and air-cooled condenser plants respectively.

Rajasthan Biomass Power Developers Association has suggested that during stabilization period auxiliary consumption may be increased by 0.5% and in case of air cooled condenser, auxiliary consumption may be taken as 12.5% during stabilization period and 12% thereafter.

Madhya Pradesh and Orissa Biomass Developers Association have submitted that the auxiliary consumption on an average is found in the verge of 12% of the gross generation.

Maharashtra Biomass Energy Development Association has suggested that since the biomass plants after stabilization period perpetually run at maximum about 70-80% PLF, auxiliary consumption should be assumed as **11.5%.**

Konark Power Project Ltd. has suggested that auxiliary consumption may be fixed at around 13%.

Biomass Power Producers Association, Tamilnadu has submitted that assuming 10% aux. consumption will not be adequate and is likely to affect the viability for the generators.

7.3.2 COMMISSION'S DECISION

The auxiliary consumption factor is one of the key performance factors and is in dependent of the size of the plant. Further, it may vary according to the need of pre-processing requirement of the biomass fuel. The Commission also notes that the auxiliary energy consumption is a function of plant efficiency and the energy conservation methods adopted by the developers. 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.

7.4 REGULATION 38: STATION HEAT RATE (SHR)

In the draft Regulations the station heat rate of 4000 kCal/kWh for biomass power project has been specified.

7.4.1 THE COMMENTS RECEIVED ON THIS PROVISION:

Matrix Power private Ltd. has suggested that the SHR norm as suggested by CEA i.e. 4500 kCal/kWh should be considered. They have further submitted that based on the actual performance of 6 Biomass Power plants in Andhra Pradesh, ranging from 4.5 MW to 9 MW size, from 2004-05 to 2008-09, the achievable average specific fuel consumption is found at 1.63 kg/kWh. They have further submitted that the APERC study team in 2004 also determined that specific fuel consumption was above 1.64 kg/kWh.

PTC Bermaco Green Energy Systems Ltd. has suggested to consider Station Heat Rate of 4400 kcal/kwh for paddy straw fired biomass power plant instead of 4000 kcal/kwh.

Dalkia Energy Services has recommended to consider SHR as 4100, 4400 and 4150kCal/kWh for rice husk based (> 5MW), straw based and other fuel based biomass power plants.

GUVNL has submitted that the Commission may continue with SHR norm of 3800 kCal/kWh as actual design SHR range of 3400-3600 kCal/kWh.

Gujarat Biomass Energy Developers Association has submitted that in Gujarat all the power plants are based on Travelling Grate Boiler using fuel such as stalks and ground nut shell where SHR found at 4500 kCal/kWh since cotton stalk has moisture content of 60%.

Chhatisgarh Biomass Energy Developers Association has submitted that due to inferior quality of fuel increases the specific fuel consumption and unburnt carbon in fly ash leads to higher SHR.

Orissa, Maharashtra and Madhya Pradesh Biomass Association have requested to consider the SHR as 4500kCal/kWh as per CEA norms for the long term sustainability of this sector.

Tamilnadu Biomass Power Producers Association has suggested fixing the SHR at 4200kCal/kWh.

IL&FS RE Ltd. has suggested that SHR of 4200kCal/kWh and 4400kCal/kWh should be considered for project with water-cooled condensers and air-cooled condensers respectively.

Rajasthan Biomass Power Developers Association has submitted that the SHR may be taken as under:

Parameter	**Water Cooled Condenser**	**Air Cooled Condenser**
During stabilization	4300 kcal/kWh	4540 kcal/kWh
After stabilization	4200 kcal/kWh	4440 kcal/kWh

7.4.2 COMMISSION’S DECISION

While specifying the SHR norm in the draft regulations, the Commission considered the norms as suggested in the report of National productivity Council as well as by MNRE which are as under:

NPC suggested norm:

Project with Boiler Type	Station Heat Rate kCal/KWh
AFBC	4000 – 4100
Traveling Grate	4150 – 4250

MNRE suggested SHR for plant greater than 5 MW:

Biomass Source	Station Heat Rate kCal/KWh
Rice Husk	4100
Straw	4400
Others	4150

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. Considering the same the Commission has decided to retain the norm of Station Heat Rate at 4000 kCal/kWh and the same has been reflected in the final regulations.

7.5 REGULATION 39: OPERATION AND MAINTENANCE EXPENSES

In the draft Regulation normative O&M expenses has been specified as under:

"(1) Normative O&M expenses for the first year of the Control period (i.e. FY 2012-13 shall be ₹ 24 Lakh per MW.

(2) Normative O&M expenses allowed at the commencement of the Control Period (i.e. FY 2012-13) under these Regulations shall be escalated at the rate of 5.72% per annum."

7.5.1 THE COMMENTS RECEIVED ON THIS PROVISION:

Matrix Power Private Limited has submitted that the O&M may be considered at 7% of the project cost for the first year of operation and for subsequent years needs to be escalated at 5% per annum as deduced by CEA otherwise CERC should recommend the various ways by which O&M cost could be reduced from 7% as recommended by CEA to 4.5% as recommended by CERC. Further submitted that as per actual operation of six plants in Andhra Pradesh, from five years of operation data, it is found that average O&M expens is 9.39% of the project cost as cost of consumables, salaries and operating expenses increased sharply over years.

Chhatisgarh Biomass Energy Developers Association has suggested that the normative O & M expenses should be specified at 7% as suggested by CEA which is reasonable and practical.

PTC Bermaco Green Energy Systems Ltd. has suggested that the O & M expenses should be fixed at ₹ 35 Lakh/MW with an annual escalation at the rate of 7% instead of ₹ 23.4 Lakh/MW with an annual escalation of 5.72%.

Dalkia Energy Services has submitted that both straws fired and tail end projects would need higher expenses.

A2Z Maintenance has suggested that separate norm may be determined by CERC for smaller project.

Kalptaru Power Transmission Limited has submitted that O&M charges allowed by CERC in tariff regulation for various sizes of thermal power plants are as under for 2012-13:

1. 600 MW sets: ₹ 13.82L/MW,
2. 500 MW sets: ₹ 15.36L/MW,
3. 300 MW sets: ₹ 18.91L/MW,
4. 200 MW sets: ₹ 21.51 Lac/MW,
5. Tanda: ₹ 31.02 Lac/MW,
6. Badarpur: ₹ 34.12 Lac/MW
7. Talchar : ₹ 38.70 Lac/MW

They further submitted that lower the size of plant, higher the O&M expenses approved by the Commission and suggested to consider the same at ₹ 50 Lakh/MW with following rationale:

- The wear and tear in boiler tubes is more in the boilers using Musard Crop Residue and Boiler tubes have to be changed every two years.
- Being prone to fire hazards the insurance premium is also more as compared to conventional plants.
- The salary and wage of engineers and technical man power have also increased as there is shortage of experienced personnel required to operate the biomass power plants.
- The RERC has allowed O&M @ 6.5% on Base Capital cost of ₹ 540 Lakh/MW which means ₹ 35 Lakh/MW.
- Escalation of 5.72% per annum is low looking to the present rate of inflation. This should be increased to 10%.
- Average cost of fuel feeding expenses for last three years (excluding F.Y 2011-12) come to ₹ 11.06 Lakh/ MW and for four years comes to ₹ 11.55 Lakh/ MW.
- Average cost of store, spares & consumables for last three years inclusive of fuel additives (excluding F.Y 2011-12) come to ₹ 13.50 Lakh/ MW and for four years (including 2011-12) comes to ₹ 15.26 lakh/ MW. Fuel additives are used for reducing erosion of super heater tubes of the boiler. Average cost for last three years exclusive of fuel additives (excluding F.Y 2011-12) come to ₹ 9.51 Lakh/ MW and four years(including 2011-12) comes to ₹ 11.35 Lakh/ MW. We have to replace the tubes at least once in two- three years costing approximately Rs.1.0 Crore each time.
- Average cost of employee emoluments for last three years (excluding F.Y 2011-12) come to ₹ 18.61 Lakh/ MW and four years(including 2011-12) comes to ₹ 19.51 Lakh/ MW. Expenses are higher to have and retain qualified, skilled & professional persons at remote rural locations of the small plants.
- Average Cost of insurance other than material stored at collection centres for last three years (excluding F.Y 2011-12) come to ₹ 4.64 Lakh/ MW and four years (including 2011-12) comes to ₹ 5.28 Lakh/ MW.

IL&FS RE Ltd has submitted that the O & M expenses may be considered with determining at ₹ 35 Lakh/MW with annual escalation of 7% instead of ₹ 24 Lakhs/MW with annual escalation of 5.72%.

Rajasthan Biomass Power Developers Association has submitted that the O&M expenses may be taken as 6.5% of the total capital cost.

Maharashtra, Madhya Pradesh Biomass Energy Developers Association has suggested to consider O&M expenses at ₹ 32.4 Lakh/MW and ₹ 34.56 Lakh/MW for water-cooled and air-cooled condensers respectively.

Tamilnadu Biomass Power Producers Association has suggested to consider O&M expenses at ₹ 48 Lakh/MW with an escalation as guided at 5.72%/year

Konark Power Project Ltd. has suggested that the O&M cost needs to be factored at around 8%.

7.5.2 COMMISSION'S DECISION

Arguments have been put forward by many stakeholders that the size of biomass power plant is small compared to the conventional power projects and that 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.

The Commission has already recognized all this and accordingly, for the purpose of determination of tariff the normative O&M expenses at ₹ 24 Lakh/MW has been specified.

7.6 REGULATION 41: USE OF FOSSIL FUEL

In the draft Regulations the usage of fossil fuel of 15% has been specified.

7.6.1 THE COMMENTS RECEIVED ON THIS PROVISION:

Rajasthan Biomass Developers Association has submitted that the use of fossil fuel may be permitted up to 30% and its actual cost may be allowed for calculation of variable tariff.

Maharashtra Biomass Energy Developers Association has submitted that the use of fossil fuels of at least 25% of total fuel consumption on annual basis should be allowed and a proposal to MNRE may be sent to review their notification in this regard.

7.6.2 COMMISSION'S DECISION

The Commission has kept the usage of fossil fuel in line with the stipulation made by the MNRE. As and when the MNRE reviews 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. In view of the above, the Commission does not find any need to modify norm as specified under draft Regulations.

7.7 REGULATION 42: MONITORING MECHANISM FOR THE USE OF FOSSIL FUEL

In the draft Regulations the monitoring mechanism for the usage of fossil fuel it has been specified as under:

"(1) 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. The statement shall cover details such as -

a) Quantity of fuel (in tones) for each fuel type (biomass fuels and fossil fuels) consumed and procured during the month for power generation purposes,

b) Cumulative quantity (in tones) of each fuel type consumed and procured till the end of that month during the year,

c) Actual (gross and net) energy generation (denominated in units) during the month,

d) Cumulative actual (gross and net) energy generation (denominated in units) until the end of that month during the year,

e) Opening fuel stock quantity (in tones),

f) Receipt of fuel quantity (in tones) at the power plant site and

g) Closing fuel stock quantity (in tones) for each fuel type (biomass fuels and fossil fuels) available at the power plant site.

(2) 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."

7.7.1 THE COMMENTS RECEIVED ON THIS PROVISION:

GUVNL has suggested that consequences in case of breach of compliance should be specified clearly in detail. They further submitted that a separate tariff should be specified in case of use of fossil fuel exceeding the limit and penalty equivalent to atleast 1.5 times of difference between cost paid by Utility for sourcing RE power from alternate sources to meet its RPO obligation minus preferential tariff determined by the Commission.

Tamilnadu Biomass Power Producers Associations has submitted that the fuel mix, use of fossil fuel and monitoring mechanism for the use of fossil fuel are acceptable to the members of our association.

Maharashtra Biomass Energy developers Association has suggested that a detailed regulation may please be passed by the Commission to restrict the fossil fuel usage by a biomass project developer. Further, suggested that the condition of furnishing a bank guarantee covering penalty amount (i.e. amount equivalent to annual generation corresponding to 80% PLF, multiplied by penalty of Rs.0.30 per unit) in case of non-compliance of fossil fuel usage imposed by Discoms shall required to be waived completely.

PTC India Ltd. Has submitted that the penalty seems harsh and suggested that either 'non compliance' may be replaced by 'Deliberate non compliance' or 'shall' may be replaced by 'is liable to'.

Shri Shanti Prasad has suggested that this Regulation may provide for payment at weighted average cost of power purchase till violation is remedied and that generation by fossil fuel in excess of specified limit shall be paid at pooled cost of power purchase. He further suggested that the generating company not utilizing fossil fuel during the month will also furnish 'nil' return.

7.7.2 COMMISSION'S DECISION

As regards consequences in case of breach of compliance is concerned, remedies are specified in the in the Electricity Act, 2003. If a biomass generator fails to comply with provisions made in the Regulations it is liable for penalty under Section 142 of the Electricity Act, 2003. Therefore, the Commission has decided to retain the provision as provided in the draft Regulations.

7.8 REGULATION 43: CALORIFIC VALUE

In the draft Regulations the Commission has specified the norms for calorific valueas under:

The Calorific Value of the biomass fuel used for the purpose of determination of tariff shall be at 3300 kCal/kWh.

Above referred norm has been specified by the Commission based on the suggestions received from MNRE, a study carried out by NPC, a study carried out by CEA as well as norms specified by the SERCs.

7.8.1 THE COMMENTS RECEIVED ON THIS PROVISION:

Matrix Private Limited has submitted that the CEA, National Productivity Council and MNRE recommended GCV should be fixed between 3000 to 3400 kCal/kg, however, due to degradation normative GCV should be considered at **2760 kCal/kg.**

Chhattisgarh Biomass Energy developers Association has suggested that GCV should be considered at 3100 kCal/kg as in the State of Chhattisgarh, only rice husk is available as fuel for biomass power project and actual GCV in rice husk is between **3000-3100 kCal/kg.**

GUVNL has suggested that the GCV of cotton stalk available in Gujarat is around 3600-3700 kcal/kg and average GCV of the biomass would be around **3500 kCal/kg.**

Orissa & Madhya Pradesh Biomass Energy Developers Association has suggested that the GCV of 3300kCal/kg may kindly be determined much closer to the realistic integer as **3000kCal/kWh.**

Transtech Green Power P. Ltd has submitted that the average GCV should be taken as **3000 kCal/kg** considering loss of GCV during storage, which is a practical requirement.

Tamilnadu Biomass Power producers Association has suggested that the GCV of **2200 kCal/kg** may kindly be determined in as received condition resulting in specific fuel consumption of 2.17kg/kWh on exported power.

7.8.2 COMMISSION’S DECISION

While specifying the GCV norm in the draft Regulations, the Commission considered the norms as suggested in the report of National productivity Council, Central electricity Authority (CEA) as well as by MNRE which are as under:

MNRE recommended following norms as under:

Biomass	GCV (kCal / kg)
Rice husk	3200
Straw/Stalks/Other husks	3300
Plantation	2800

CEA in its report on “Operation Norms For Biomass based Power Plants” - September 2005 assumed GCV of 3300 kCal/kg based on the calculation of weighted average GCV for 16 biomass power plant and also taking into account large variation in quality and variety of biomass used including variation in moisture content due to weather conditions.

The National Productivity Council (NPC) in its study mentioned that based on the fuel analysis report from the different plants, GCV & moisture variation could be as under:

Biomass	GCV (kCal / kg)	Variation in Moisture (%)
Rice husk	3000-3200	12-18
Maize Bhutia	3500	21
Cotton Stalk (Air Dried Basis)	3250	8

Some of the stakeholders have submitted that none of the above referred organizations has conducted a study about the degradation of these seasonal fuels over the non-seasonal period. They have further submitted that due to the rains, storage, contamination by fuel suppliers and inherent mud in agricultural residues there is a significant reduction in GCV of biomass fuels.

Based on the recommendation of MNRE, NPC and CEA, the Commission has considered the GCV of biomass at 3250 kCal/kg and after taking into account, use of 15% of coal (average coal GCV at 3600 kCal/kg and 85% uses of Biomass fuel of 3150 kCal/kg), the weighted average GCV has been considered at 3300 kCal/kg. The Commission has decided to retain the norm as proposed in the draft Regulations.

7.9 REGULATION 44: BIOMASS FUEL PRICES FOR FY 2012-13

The draft Regulations had the following provision for the Capital Cost of Non-fossil fuel based Cogeneration Projects:

> *"Biomass fuel price during first year of the Control Period (i.e. FY 2012-13) shall be as specified in the table below and shall be linked to index formulae as specified under Regulation 45. Alternatively, for each subsequent year of the Tariff Period, the normative escalation factor of 5% per annum shall be applicable at the option of the biomass project developer.*

State	FY2012-13 (₹ /MT)
Andhra Pradesh	2315
Haryana	2635
Maharashtra	2116
Madhya Pradesh	1507

Punjab	2756
Rajasthan	2300
Tamil Nadu	2277
Uttar Pradesh	2355
Other States	2283

7.9.1 THE COMMENTS RECEIVED ON THIS PROVISION:

A2Z Maintenance & Engineering Services Limited has suggested that the approach adopted for determination of biomass price does not reflect the true value of the cost as some of the SERCs have carried out a detailed exercise and some of the states adopted lower cost. It is suggested that more realistic cost of fuel may be taken by CERC.

Andhra Pradesh

Matrix Private Limited has submitted that the methodology adopted is totally flawed and irrational, as the coal being supplied to the power stations was at a subsidized rate whereas biomass that is purchased is in the open market and there is no subsidy in the biomass procurement. They further submitted that average rate of the e-auction prices for the coals in the respective states should be considered.

Chhattisgarh

Chhattisgarh Biomass Energy Developers Association has suggested that Chhattisgarh being the largest producer of Biomass power and State has only rice husk as fuel for biomass based power plants, there should be separate norms determination of tariff. Further suggested that in Chhattisgarh, landed price of fuel is quite high as compared to cost of coal and therefore **prices of e-auction coal** needs to be considered as prices of biomass.

Rajasthan

Kalptaru Power Transmission Limited suggested that CERC should consider following points while deciding prices of Biomass in particular reference to Rajasthan:

(i) Rajasthan is different from other states, as half of the area is desert and the Biomass availability therefore is very limited.

(ii) In Rajasthan, we do not have many alternate non fodder Biomass fuel available in the entire state other than Mustard Crop Residue (MCR) and Juliflora.

(iii) In Rajasthan availability of non fodder Biomass is also not there in all seasons like Kharif, Rabi and others.

(iv) Because of the Geographical condition even the availability of surface water & ground water both are becoming scarce day by day.

(v) Bio-mass trade is highly disorganized with multiple uses and multiple players.

(vi) Bio-mass availability is also subject to overall cropped area and the production in the State.

(vii) The demand from various other users puts pressure on the prices and this pressure itself is subject to availability and prices of other energy sources, which in itself are highly volatile.

(viii) There is wide variation in prices depending upon the season and months of purchase and also among districts.

(ix) CERC is considering ₹ 2756/MT and ₹ 2635/MT in Punjab and Haryana respectively having 3 crop cycles therefore the availability of biomass is more as compared to that at Padampur in Rajasthan. The farmers in Sriganganagar also prefer to sell their MCR to plants in Punjab because they get better price.

(x) Based on the average purchase price of biomass during 2011-12 at Padampur plant is ₹ 2500 per ton, it is suggested that to allow ₹ **2756** per ton for Rajasthan as of Punjab.

(xi) Additional allowances of ₹ **250** per ton should be allowed for Biomass feeding cost in addition to fuel cost considering storage and shifting of biomass, labour at sub center and field collection, land rent and insurance cost.

Surya Chambal Power Ltd. has suggested that the price of ₹ **3025** per ton may be considered for Rajasthan.

Transtech Green Power P. Ltd. has suggested that for Rajasthan the fuel cost assigned for FY 2012-13 should be fixed at ₹ **2415** per ton, which should be factored by giving a 5% increase to the current figure of ` 2300 per ton.

Maharashtra

IL&FS RE Ltd. has suggested that the fuel prices in particularly for the state of Maharashtra a price of atleast ₹ **3000** per ton with a normative escalation factor of 10% per annum instead of ₹ 2116/MT with annual escalation of 5%.

Maharashtra Biomass Energy Developers Association has suggested that biomass fuel price should be fixed at ₹ **3800** per ton considering the actual market position with annual escalation of 10% p.a.

Orissa

Orissa Biomass Developers Association has submitted that the biomass availability has come down and prices have gone up with the result of shortage created due to usage by cement plants & power plants. They have requested to consider biomass fuel rate at ₹ **3000** per ton with annual escalation of 10% in the state of Odisha.

Madhya Pradesh

New and Renewable Energy Department, Madhya Pradesh has submitted that the average rate for biomass fuel price in Madhya Pradesh works out to ₹ **2864** per ton for FY 2012-13 based on the information from District Collectors and MD, MP Urja Vikas Nigam. They have requested that biomass fuel price for FY 2012-13 for the State of Madhya Pradesh may please be fixed at ₹ **2864** per ton.

Shri M.P. Bansal has submitted that the M.P. Government carried out a detailed study of biomass prices survey by forming an expert committee at district level and same was conveyed to CERC vide letter dated 4/10/2011. Government of MP took notice of the Biomass price considered for MP State at Rs. 1507/MT and send the letter dated 8.12.2011 to CERC certifying that average cost of biomass price in MP is ₹

2864 per MT. CERC should consider that rate as certified by Govt. of MP while finalizing the draft. He further submitted that the biomass price works out to be ₹ 2864/MT as mentioned in the Govt. of MP letter F-3-17/2011/60 dated 08/12/2011, this may be considered as direction under Section 108 of Electricity Act-2003 for MPERC and CERC should also consider the biomass price for Madhya Pradesh at ₹ **2864** per ton.

Madhya Pradesh Biomass Energy Developers Association has submitted that a minimum price of ₹ **3200** per ton should be taken into account as a realistic price for biomass with an annual escalation of 10% instead of ₹ 1507 per ton with an annual escalation of 5% per annum.

Gujarat

Gujarat Biomass Energy Developers Association has suggested that clubbing Gujarat under other states will not bring justice to the developers of Gujarat in tariff fixation as the biomass available in Gujarat is basically ground nut shell, Juliflora and cotton stalks. They have further requested that the biomass fuel should be specified as the average cost of the two fuels which works out to ₹ **3000** per ton (Groundnut shell ₹ 3500/- per ton & Cotton Stalks/ Juliflora ₹ 2500 per ton

Karnataka

Konark Power Project Ltd. has suggested that the cost of biomass on as received basis with high moisture works out to upto ₹ **3200** per ton including transportation.

Tamilnadu

Tamilnadu Biomass Power producers Association has suggested that a minimum price of ₹ **2500** per ton should be taken into account as a realistic price for biomass.

Punjab

PTC Bermaco Green Energy Systems Ltd. has suggested that the fuel prices in the state of Punjab should be redetermined at a price of at least ₹ **3000/MT.**

7.9.2 COMMISSION’S DECISION

The stakeholders expressed their views on fuel cost and are ranging from as under:

State	As proposed in draft RegulationFY2012-13 (₹ /MT)	Comments received (₹ /MT)
Andhra Pradesh	2315	e- auction coal price
Haryana	2635	-
Maharashtra	2116	3000-3800
Madhya Pradesh	1507	2864-3000
Punjab	2756	3000
Rajasthan	2300	2415-3215
Tamil Nadu	2277	2500
Uttar Pradesh	2355	-
Other States	2283	Karnataka: 3200, Gujarat 3000, Orissa: 3000

As suggested by the stakeholders, the Commission has reviewed the price of biomass fuel mix for some States. The commission has also considered the latest norm as specified by the Maharashtra Electricity Regulatory Commission. As far as Madhya Pradesh State is concerned, in the absence of any detailed analysis on average biomass price arrived based on the district wise study carried out by the Government, the Commission has decided to bring them in the Other States category. As regards request for separate norms for Chhattisgarh and Gujarat, in the absence of any authentic data, the Commission decided that till such time such States would be covered under the Other States category. 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 as under:

	Biomass Price
Andhra	**2315**
Haryana	**2635**
Maharashtra	**2695**
Punjab	**2756**
Rajasthan	**2300**
Tamil Nadu	**2277**
UP	**2355**
Other States	**2476**

7.10 REGULATION 45: FUEL PRICE INDEXATION MECHANISM

"(1) In case of biomass power projects, the following indexing mechanism for adjustment of fuel prices for each year of operation will be applicable for determination of applicable variable charge component of tariff, in case developer wishes to opt for indexing mechanism:

$$P_{(n)} = P_{(n-1)} * \{a * (WPI_{(n)}/WPI_{(n-1)}) + b * (1+IRC)_{(n-1)} + c * (Pd_{(n)}/Pd_{(n-1)})\}$$

Where,

$P_{(n)}$ = Price per ton of biomass for the n^{th} year to be considered for tariff determination

$P_{(n-1)}$ = Price per ton of biomass for the $(n-1)^{th}$ year to be considered for tariff determination. P_1 shall be Biomass price for FY 2012-13 as specified under Regulation 44.

a = Factor representing fuel handling cost

b =Factor representing fuel cost

c = Factor representing transportation cost

$IRC_{(n-1)}$ = Average Annual Inflation Rate for indexed energy charge component in case of captive coal mine source (in %) to be applicable for $(n-1)^{th}$ year, as may be specified by CERC for 'Payment purpose' as per Competitive Bidding Guidelines

Pd_n = Weighted average price of HSD for nth year.

Pd_{n-1} = Weighted average price of HSD for $(n-1)^{th}$ year.

WPI_n = Whole sale price index for the month of April of n^{th} year

WPI_{n-1} = Wholesale price index for month of April of $(n-1)^{th}$ year.

Where a, b & c will be specified by the Commission from time to time. In default, these factors shall be 0.2, 0.6 & 0.2 respectively.

(2) Variable Charge for the nth year shall be determined as under:

i.e. $VC_n = VC_1 x (P_n / P_1)$ *or* $VC_n = VC_1 x (1.05)^{(n-1)}$ *(optional)*

where,

VC_1 represents the Variable Charge based on Biomass Price P_1 for FY 2012-13 as specified under Regulation 44 and shall be determined as under:

$$VC_1 = \frac{\text{Station Heat Rate (SHR)}}{\text{Gross Calorific Value (GCV)}} \times \frac{1}{(1 - \text{Aux Cons. Factor})} \times \frac{P1}{1000}$$

7.10.1 THE COMMENTS RECEIVED ON THIS PROVISION:

Indian Biomass Power Producers Association has suggested that biomass price/tariff should be fixed annually.

Kalpataru Power Trans. has suggested that the average % increase in three years (2009-10 to 2012-13) in CERC tariff is 30.75%. We therefore request to consider 10% annual escalation rate instead of 5%, therefore suggested that annual escalation rate should be considered at 10% instead of 5%.

Konark Power Project Ltd. has suggested that the escalation may be fixed at 10%.

A2Z Maintenance & Engineering Services Limited suggested that the cost of fuel may be reviewed based on actual every year as 5% escalation may not be true reflection of cost in subsequent years.

Rajasthan Biomass Power development Association has suggested that escalation in biomass price may be linked with actual biomass price to be ascertained by engaging a consultant.

PTC Bermaco Green Energy Systems Ltd. suggested that normative escalation factor of should be 10% annum instead of 5% annually escalation.

Surya Chambal Power Ltd. has suggested that the price be escalated @10% per annum or linked with open market coal price.

Matrix Private Limited has submitted that in Andhra Pradesh the fuel cost increased at a rate of 11% year-on-year, hence, assuming a 9% increase in biomass price per year is justified

7.10.2 COMMISSION'S DECISION

The Commission has decided to review the biomass price at the end of third year of the control period. Considering the same, the Commission has decided to retain the norm for yearly escalation in the biomass fuel price as provided in the draft Regulations.

7.11 REGULATION 45 (3): REVIEW OF BIOMASS FUEL PRICES FOR THE PROJECTS COMMISSIONED IN THE EARLIER CONTROL PERIOD

The draft Regulations provides following provisions related to review of biomass fuel prices for the projects commissioned in the earlier control period.

(3) The biomass base price shall be revised at the end of the control period for the next Control Period and same shall also be applicable to project commissioned under this Control Period."

7.11.1 THE COMMENTS RECEIVED ON THIS PROVISION:

PTC Bermaco Green Energy Systems Ltd. has suggested that CERC should direct all SERCs to revisit the Biomass fuel cost on half yearly basis instead of review at the end of control period.

Indian Biomass Power Producers Association has suggested that indexation mechanism is agreeable. It is requested to consider fixing biomass price/tariff annually.

IL&FS RE Ltd. has submitted that CERC should direct all SERCs to revisit the biomass fuel cost on half yearly basis instead of the review at the end of control period.

Chhattisgarh Biomass Energy Developers Association has suggested that the prices need to be revised every quarter or half yearly instead of at the end of the Control Period.

A2Z Maintenance & Engineering Services Ltd. has suggested that cost adopted by SERCs based on actual studies may be adopted by CERC on year on year basis and where State has not carried out such exercise, the cost adopted by adjoining State may be adopted to stop cross boarder movement of biomass.

Matrix Private Ltd. has submitted that a more rational approach would be :

- Like for any thermal power plant a fuel pass-through approach should be adopted.
- A committee can be formed under CERC to determine the fuel costs in each of the States.

7.11.2 COMMISSION'S DECISION

The Control Period of 5 years has been specified in the final Regulations. Considering the comments received from the stakeholders, the Commission has decided to review the biomass price at the end of third year of the control period in order to capture the volatility in the biomass fuel market.

8. TECHNOLOGY SPECIFIC NORMS: NON-FOSSIL FUEL BASED CO-GENERATION

8.1 REGULATION 47: CAPITAL COST

The draft Regulations had the following provision for the Capital Cost of Non-fossil fuel based Cogeneration Projects:

"The normative capital cost for the non-fossil fuel based cogeneration projects shall be ₹ 420 Lakh/MW for the first year of Control Period (i.e. FY 2012-13), and shall be linked to indexation formula as outlined under Regulation 48."

8.1.1 THE COMMENT RECEIVED ON THIS PROVISION:

IL&FS RE Ltd. has suggested that the capital cost of bagasse based co-generation projects should be ₹ 550 Lakhs/MW. IL&FS has further submitted that the Capital Costs of two projects (36 MW and 44 MW) commissioned by IREL under Urjankur Nidhi initiative on BOOT basis were ₹ 530 Lakh/MW and ₹ 550 Lakh/MW respectively for projects with 110 ata pressure and 540^0 C temperature.

Indian Sugar Mills Association submitted that the capital cost depends on boiler pressure/temperature, capacity of projects and utilization of high pressure boilers to increase generation of power which attracts huge capital investment. Further mills also have to construct transmission lines from sugar mill to the nearest 132 kV sub-station which also involves capital investment.

8.1.2 COMMISSION'S DECISION

With the advancement in the technology for generation and utilization of steam at high temperature and pressure, sugar industry can produce electricity and steam for their own requirements. It can also produce significant surplus electricity for sale to the grid using same quantity of bagasse. The sale of surplus power generated through optimum cogeneration would help a sugar mill to improve its viability, apart from adding to the power generation capacity of the country.

While proposing the normative capital cost of ₹ 420 Lakh / MW for first year of the next Control Period in the draft Regulations, the Commission has considered the capital cost norm developed by IREDA for financing the project during FY 2011-12 considering the typical size of the project for 2500 TCD with 66 bar / 480 ^{o} C configuration.

Pressure Configuration (Kg/ cm^2)	Bagasse based Cogeneration Project Cost (₹ Crore/MW)			
	2500 TCD	3500 TCD	5000 TCD	>5000 TCD
44	3.70	3.58	3.53	3.46
66	**4.13**	4.06	4.00	3.93
86	4.77	4.70	4.66	4.60
102	5.42	**5.12**	4.83	4.77
110	5.53	5.22	**4.93**	4.87

It can be seen that higher capital cost is justified if one opts for higher temperature and pressure configuration. Further the Commission has also considered the impact of Steam generation pressure on power generation in a 2500 TCD Sugar Mill as under:

Steam Pressure/ Temperature	Gross Electricity Generation (MW)	In-house Consumption (MW)	Surplus to Grid (MW)
21 bar / 300 °C	2.0	2.5	-0.5
33 bar / 380 °C	3.5	3.5	0
45 bar / 440 °C	6.0	4.0	2.0
64 bar / 480 °C	13.5	4.5	9.0
85 bar / 510 °C	17.0	6.0	11.0
110 bar / 540 °C	21.0	8.0	13.0

Source: MNRE

Based on analysis of the actual project cost, benchmark capital cost norm developed by IREDA for financing the project during FY 2011-12 and considering the typical size of the project for 2500 TCD with 66 bar / 480 °C configuration, the Commission has decided to retain the normative capital cost of ₹ 420 Lakh / MW for first year of the next Control Period as proposed in the draft Regulations.

8.2 REGULATION 50: AUXILIARY CONSUMPTION

The draft Regulations had the following provision for the Auxiliary Consumption of Non-fossil fuel based Cogeneration Projects:

> *"The auxiliary power consumption factor shall be 8.5% for the computation of tariff."*

8.2.1 THE COMMENT RECEIVED ON THIS PROVISION:

IL&FS RE Ltd. has suggested that the normative auxiliary consumption for the bagasse based cogeneration projects should be considered as 10% instead of 8.5%.

Based on their experience, IL&FS further submitted that it is difficult to achieve an auxiliary consumption of 8.5%, for projects with technical configuration of 110 ata steam and 540^{0} C temperature parameters.

8.2.2 COMMISSION'S DECISION

Since the 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 requires less processing compared to the biomass. Keeping above fact into consideration the Commission has decided to retain the norm for auxiliary consumption for cogeneration projects specified in the draft Regulation.

8.3 REGULATION 53: FUEL PRICE

The draft Regulations had the following provision for the Fuel Price for Non-fossil fuel based Cogeneration Projects:

"(1) The price of Bagasse shall be as specified in the table below and shall be linked to indexation formula as outlined under Regulation 54. Alternatively, for each subsequent year of the Control Period, the normative escalation factor of 5% per annum shall be applicable at the option of the project developer.

State	***Bagasse Price (₹ / MT)***
Andhra Pradesh	*1307*
Haryana	*1859*

Maharashtra	*1327*
Madhya Pradesh	*946*
Punjab	*1636*
Tamilnadu	*1408*
Uttar Pradesh	*1458*
Other States	*1420*

For use of biomass other than bagasse in co-generation projects, the biomass prices as specified under Regulation 44 shall be applicable."

The Commission computed the abovementioned fuel price of bagasse for respective States for the base year 2012-13 on 'equivalent heat value' approach for landed cost of coal for thermal stations for respective States.

8.3.1 THE COMMENT RECEIVED ON THIS PROVISION:

IL&FS RE Ltd. has suggested that considering both crushing season and off-season, average price of bagasse delivered at project site is ₹ 1750-2000 for the FY 2010-11 in Maharashtra. IL&FS has further suggested that the fuel prices in particularly for the state of Maharashtra should be specified at a price of at least ₹ 1850/MT with normative escalation factor of 10% per annum instead of ₹ 1327/- with annual escalation of 5%.

8.3.2 COMMISSION'S DECISION

Analysis of the bagasse price and related discussion in the tariff setting exercise undertaken by different SERCs in establishing the tariff for bagasse power plant are shown as under:

States	Uttar Pradesh	Gujarat	Tamil Nadu	Maharashtra	Haryana
Date of Order/Regulation	9.9.2009	31.5.2010	6.5.2009	7.6.2010	3.2.2011
Fuel Cost (in ₹/MT)	1178/- (2009-10) with 6% escalation	1200/- (2010-11) with 5% escalation	1000/- (2009-10) with 5% escalation	1832/- during first three years of the Control Period and thereafter linked to indexation	600/- (2010-11) Indexation as per CERC
Approach	equivalent heat value of coal	equivalent Cost of lignite	Based on prevailing prices of bagasse	Based on prevailing prices of bagasse	Based on prevailing price of bagasse

The Commission has decided to retain the approach as proposed in the draft Regulations i.e. 'equivalent heat value' approach for landed cost of coal for thermal Stations for respective States with a variation in order to take into account State specific prevailing prices of bagasse as may be considered by the respective Commission if the same is higher than the price.

The Commission has decided to bring Madhya Pradesh State in the category of "Other States" with a view to discouraging arbitrage between adjoining States due to price differential.

Accordingly, the same has been incorporated in the final Regulations. The fuel price for each State has been specified in the final regulations as under;

State	Bagasse Price (₹/MT)
Andhra Pradesh	1307
Haryana	1859
Maharashtra	1832
Punjab	1636
Tamil Nadu	1408
Uttar Pradesh	1458
Other States	1583

8.4 REGULATION 51: STATION HEAT RATE

In the draft Regulation the Station Heat Rate has been proposed at 3600 kCal/kWh for power generation component alone for computation of tariff for nonfossil fuel based Cogeneration projects.

8.4.1 THE COMMENT RECEIVED ON THIS PROVISION IS,

Indian Sugar Mills Association has suggested to consider the Station Heat Rate norm at 3700 kCal/kWh as the bagasse is having very high moisture content in comparison to other conventional/fossil fuels.

8.4.2 COMMISSION'S DECISION

As regards to the Station Heat Rate for Non-Fossil fuel based cogeneration power projects, the Commission has considered that the co-generation plant design depends on cane crushing capacity and steam requirement of host sugar mill. Co-generation plant operates in co-generation mode during crushing season and in rankine cycle mode during off-season. For the purpose of tariff determination, fuel consumption corresponding to power generation alone should be considered. In the RE Tariff Regulations-2009, the information furnished by MNRE and heat mass balance diagrams for a few co-generation projects have also been analyzed before specifying the normative Station Heat Rate for non-fossil fuel based co-generation projects. Accordingly, the Commission has decided to retain the norm as specified in the draft Regulations.

8.4 REGULATION 55: OPERATION AND MAINTENANCE EXPENSES

The draft Regulations had the following provision for the Operation and maintenance Expenses for Non-fossil fuel based Cogeneration Projects:

"(1) Normative O&M expenses during first year of the Control period (i.e. FY 2012-13) shall be ₹ 16 Lakh per MW.

(2) Normative O&M expenses allowed at the commencement of the Control Period (i.e. FY 2012-13) under these Regulations shall be escalated at the rate of 5.72% per annum."

8.5.1 THE COMMENT RECEIVED ON THIS PROVISION:

GUVNL has suggested that O&M expenses should be considered at ₹ 14.75 Lakh/MW as considered by the SERCs with annual escalation at 5.72%.

8.4.2 COMMISSION'S DECISION

Considering the current inflation trend the Commission has decided to retain the normative O&M expenses as proposed in the draft Regulations.

9. TECHNOLOGY SPECIFIC NORMS: SOLAR PV POWER PLANT

9.1 REGULATION 57: CAPITAL COST

The draft Regulations had the following provision for the Capital Cost of Solar Photovoltaic power plant:

"(1) The normative capital cost for setting up Solar Photovoltaic Power Project shall be ₹ 1000Lakh/MW for FY 2012-13.

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

9.1.1 THE COMMENTS RECEIVED ON THIS PROVISION:

Prayas has suggested that, due to limited reliable public data and information asymmetry, to limit the financial impacts on retail tariffs and to get all the benefits from innovative financial engineering and possible technology improvements, procurement of solar power should be only through the **competitive based reverse bidding process** with the feed-in-tariff acting as a ceiling.

CESC Limited has suggested that the recent developments in case of second round of bidding under National Solar Mission show the tariff of electricity from solar PV power projects about ₹ **10/kWh** as against the financial principles and the parameters as assumed for solar PV power project in the draft Regulations would indicate much higher tariff.

Torrent Power Limited has suggested that the Capital Cost should be considered at ₹ **1100** Lakh/MW including evacuation cost up to nearest grid sub-station.

ACME has suggested that a capital cost of ₹ **1152** Lakh/MW be considered for solar PV projects.

EMCO Limited has suggested that the Capital cost for MW size solar project should be considered at ₹ **1200** Lakh/MW as reduction in cost of various items considered is not achievable in actual practice. They have further submitted that the exchange rate for US$ should be considered as ₹ 54 and in order to take care of fluctuation in the rate of US $ a suitable mechanism is needed to be devised and it may be made pass through.

Reliance Power Ltd. has suggested that the project costs are in the range of ₹**1300 - 1400** Lakh/MW for PV projects.

SDS Solar Private Limited has submitted that only module cost has gone down and other non module cost components have gone up. They have further submitted that Solar PV project cost should be considered under two heads: (1) Project upto Max of 2 MW and (2) bigger projects.

9.1.2 COMMISSION'S DECISION

Analysis as carried out in the Explanatory Memorandum shows that the thin film module prices per watt were in the range of $0.8 to $1.20 and crystalline module prices were in the range of $1.0 to $1.5. Considering the same, the Commission proposed module cost at $1.00 per watt with the exchange rate of ₹ 49/US$. Current trend as shown below reveals that the prices of crystalline and thin film module available in India are in the range of 0.7 to 1.0 US$/Watt and the same is expected to decline in future.

PV Spot Price	High	Low	Avg	% Change
Poly Price (Per KG)	29.00	20.00	23.790	-0.79%
Multi-Si Wafer (156mm x 156mm)	1.25	1.00	1.120	0.09%
Mono-Si Wafer (156mm x 156mm)	1.80	1.48	1.570	0.00%
Cell Price (Per Watt)	0.64	0.43	0.505	-1.17%
Multi-Si Cell (156mm x 156mm)	2.06	1.84	2.040	-1.17%
Mono-Si Cell (156mm x 156mm)	2.36	2.19	2.286	-1.17%
Module Price (Per Watt)	1.30	0.70	0.861	0.00%
Thin Film Price (Per Watt)	1.20	0.70	0.829	0.00%
CPV Price (Per Watt)	2.55	2.09	2.303	0.00%
PV Inverter Price (Per Watt)	0.35	0.17	0.235	0.00%

Source: EnergyTrend

China/Taiwan PV-Spot Price in US$ (week of Dec 12)

	Avg	% Change
Poly Price (Per KG)	25.69	*-4.02%*
Multi-Si Wafer (156mm x 156mm)	1.12	*-1.44%*
Cell Price (Per Watt)	0.50	*-0.20%*
Module Price (Per Watt)	0.89	*-2.06%*
Thin Film Price (Per Watt)	0.80	*-0.68%*

Data derived from: Digitimes/EnergyTrend/PVinsights

Mercom Capital Group, llc

Therefore, the Commission has decided to consider the module cost at $ 0.85$/W, with the current exchange rate of ₹ 53/US$. The module cost thus comes out to be ₹ 450 Lakh/MW. The non-module cost has been considered as ₹ 484 Lakh per MW. The detailed breakup is as under:

Sr. No.	Particulars	Capital Cost Norm FY 2012-13 (` Cr/MW)
1	Land Cost	0.16
2	Civil and General Works	0.90

3	Mounting Structures	1.00
4	Power Conditioning Unit	0.98
5	Evacuation Cost up to Inter-connection Point (Cables and Transformers)	1.00
6	Preliminary and Pre-Operative Expenses including IDC and contingency	0.80
	Total Non Module Cost	**4.84**

Taking into account degradation in the module output over a period of time as well as the auxiliary power consumption requirement, the Commission has decided to consider the additional cost towards degradation and auxiliary in the capital cost. Accordingly, it has been decided to retain the capital cost of the project at ₹ 1000 Lakh per MW as proposed in the draft Regulations.

9.2 REGULATION 58: CAPACITY UTILISATION FACTOR (CUF)

The draft Regulations had the following provision for the Capacity Utilisation factor Solar Photovoltaic power plant:

"(1) 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."

9.2.1 THE COMMENTS RECEIVED ON THIS PROVISION:

EMCO Limited suggested that the normative CUF should be considered at 17-18 % as only few States like Rajasthan and Gujarat are able to achieve a CUF of 19%.

EMCO Limited has further suggested that the auxiliary consumption for solar PV projects should be considered as 1% of the total generation as the energy consumption by inverters, air conditioning, and water treatment and pumping, lighting is high. GERC draft Sola PV Tariff order has also considered the same.

Torrent Power Limited has suggested that the actual data from the operating site should be collected, analyzed and be used as the basis for determination of CUF for Solar PV projects. They have further suggested that the annual degradation of 1% in CUF annually should be considered in the Regulation.

GUVNL has suggested that CUF should be specified on zonal basis as in case of wind energy which will ensure benefit to consumers in areas where high solar radiation are received

NTPC Limited has suggested that while determining tariff of Solar PV, the country may be divided into 4-5 solar zones based on MNRE data (similar to wind energy project zone). They have further suggested that degradation of solar modules with age should be considered. NTPC Limited has also suggested Auxiliary Consumption of 5.5% for solar PV stations should be considered while determining tariff. Break up of 5.5% are as under:

- Transformer losses = 3.0% (remain charged for 24 hrs)
- Station facilities, lighting, washing arrangement, etc = 2.5%.

ACME has suggested that CUF should be considered at 17% for Solar for Crystalline Technology & 19% for Thin Film Technology as a reference point to reflect the all India average. They have further suggested that for such projects where interconnection point is at the end of transmission line, an additional provision of 2.5% towards transmission losses be considered. ACME also recommended that 1.1% as auxiliary consumption factor should be taken in account various loads at the project site such as lighting, inverter auxiliary as well as some common facilities.

Shri Shanti Prasad has submitted that in respect of solar PV power plants there is small auxiliary consumption of lighting during night for watch and ward to prevent theft and damages and during non-sunshine period for cleaning of the modules. Solar PV modules also undergo duration with time. A discussion paper (dated 2.11.11) on determination of tariff for procurement of power by distribution licensees and others from solar energy projects issued by GERC may be referred.

9.2.2 COMMISSION'S DECISION

A study carried out by the Commission on "Performance of Solar Power Plants In India" reveals that the average CUF at more than 80% locations works out to be more than 19% for solar PV plant based on thin film technology. Similarly, the average CUF at more than 50% locations works out to be more than 19% for solar PV plants based on crystalline technology. Considering the same and in the absence of actual data of full one year, the Commission has decided to retain the benchmark CUF as proposed in the draft Regulations for the next Control Period for determination tariff. Regarding degradation, the above referred study analyzed as under:

> *"One can conclude from all available data that the manufacturers provide a guarantee with a definite margin of safety and for design purpose a lower degradation percentage can be employed. Further, the length of warranty period is continuously increasing, indicating the increase in confidence among manufacturers, as they realise durable quality of their products, due to technology improvements and quality assurance practices. And lastly, this has important consequences in calculation of electricity cost from the power plant and with increased lifetimes, one can expect better returns on investment. The quality of module is of immense importance. It is safe to assume no degradation for the first three years and then a maximum of 0.5% per year over the life of modules."*

The Commission in its Explanatory Memorandum considered the additional cost towards degradation in the module cost while arriving at total module cost.

As regards the norms for Auxiliary Consumption for Solar PV Power Plant, we may consider the submissions made by the stakeholders. Auxiliary power may be required for air-conditioning in inverter and control rooms, cleaning water softening and pumping system, security night lighting and general office lights and fans. The Commission has considered the additional cost towards degradation in the capital cost.

9.3 REGULATION 59: OPERATION AND MAINTENANCE EXPENSES

The draft Regulations had the following provision for the Operation and Maintenance Expenses of Solar Photovoltaic power plant:

"(1) The O&M Expenses shall be ₹ 11 Lakhs/MW for the 1st year of operation.

(2) 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."

9.2.1 THE COMMENTS RECEIVED ON THIS PROVISION:

GUVNL has suggested that O&M expenses should be considered at ₹ 8.35 Lakh/MW as considered by other SERCs with annual escalation at 5.72%.

9.2.2 COMMISSION'S DECISION

Considering the current inflation trend, the Commission has decided to retain the normative O & M Expenses as proposed in the draft Regulations.

10. TECHNOLOGY SPECIFIC NORMS: SOLAR THERMAL TECHNOLOGIES

10.1 REGULATION 61: CAPITAL COST

The draft Regulations had the following provision for the Capital Cost of Solar Thermal based power plant:

"(1) The normative capital cost for setting up Solar Thermal Power Project shall be ₹1300 Lakh/MW for FY 2012-13.

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

10.1.1 THE COMMENTS RECEIVED ON THIS PROVISION:

ACME Energy Solutions Private Ltd. has suggested that

a. There are no significant technical advancements for establishing a trend in the capital cost reduction for Solar Thermal projects,
b. An exchange rate of USD/INR of ₹ 53 be considered for the purpose of determining Capital Cost,
c. Usage of Air Cooled Condensers (ACC) will entail higher Capital Cost.

10.1.2 COMMISSION'S DECISION

Based on the market information of EPC contracts signed by the solar thermal projects developer under phase-1 of the National Solar Mission and estimated plant load factor on standalone plants, the Commission has decided to retain the total project cost at ₹ 1300 Lakh/MW as benchmark capital cost for determination tariff for solar thermal projects as specified in the draft Regulations.

10.2 REGULATION 62: CAPACITY UTILIZATION FACTOR (CUF)

The draft Regulations had the following provision for the Capacity Utilisation Factor of Solar Thermal based power plant:

"The Capacity Utilisation Factor shall be 23%.

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

10.2.1 THE COMMENTS RECEIVED ON THIS PROVISION:

ACME Energy Solutions Private Ltd. has suggested

a. To recalculate CUF values using SAM model with actual DNI data for standalone plants as DNI considered based on NREL data is on higher side than the values actually recorded at sites,
b. Usage of Air Cooled Condensers (ACC) will cause fall in CUF considering the lower efficiency of the power block operating with ACC.

10.2.2 COMMISSION'S DECISION

In the absence of access to the actual DNI data of locations in which Solar Thermal Plants are likely to be located, the Commission has used NREL projected incident solar irradiation data, which are based on satellite modeling, of Rajasthan, Gujarat and Andhra Pradesh States used for determination of solar field size corresponding to target CUF of 23% and Capital cost. Considering the same, the Commission decided to retain the norm as specified in the draft Regulations.

11. TECHNOLOGY SPECIFIC NORMS: BIOMASS GASIFIER

11.1 REGULATION 66: CAPITAL COST

The draft Regulations had the following provision for the Capital Cost of Biomass Gasifier based power plant:

"The normative capital cost for the biomass gasifier power projects shall be ₹ 550 Lakh/MW (FY 2012-13 during first year of Control Period) and shall be linked to indexation formula as outlined under Regulation 67. After taking into account of capital subsidy net project cost shall be ₹ 400Lakh/MW for FY 2012-13."

11.1.1 THE COMMENTS RECEIVED ON THIS PROVISION:

Ankur Scientific Energy Technologies Pvt. Ltd. has suggested that the total project cost should be specified at minimum of ₹ 650 Lakh/MW as it is also supported by MNRE vide its letter dated 30th September 2011 addressed to the Commission. They have also suggested that the project cost should include cost of evacuation system up to nearest grid sub-station. They have further submitted that based on their own experience, the total project cost for 1 MW is ₹ 700 Lakh (including cost for power evacuation system) as the cost of Gas Engine is the biggest cost element in the total project cost and as of now very limited indigenous options available.

A2Z Maintenance & Engineering Services Ltd. has submitted that that normative capital cost of ₹` 550 Lakh per MW may be taken for determination of tariff as MNRE Capital Subsidy Scheme is available for 11th Plan i.e. upto March 2012 and continuation of Scheme has not yet been announced by MNRE.

GE Energy recommended that the Capital cost should be in the range of 7-8 Crore/MW.

11.1.2 COMMISSION'S DECISION

Keeping the suggestions received into consideration, the Commission has decided to retain the norms for Capital Cost for Biomass Gasifier based Power Plant as proposed in the draft Regulations.

11.2 CAPITAL SUBSIDY FROM MNRE

Considering the Capital subsidy available from MNRE, which as per the prevailing norms for Biomass Gasifiers is ₹ 150 Lakh /MW or part thereof for grid connected power plants, the Commission decided the net project cost at @ ₹ 400 (₹ 550 Lakh - ₹ 150 Lakh) Lakh/MW for the FY 2012-13 for the determination of tariff.

11.3 REGULATION 68: PLANT LOAD FACTOR (PLF)

The draft Regulations had the following provision for the Plant Load Factor of Biomass Gasifier based power plant:

> *"Threshold Plant Load Factor for determining fixed charge component of Tariff shall be 80%."*

11.3.1 THE COMMENTS RECEIVED ON THIS PROVISION:

Ankur Scientific Energy Technologies Pvt. Ltd. has suggested that the PLF as mentioned in Regulation 36 (for biomass power plant based on rankine cycle) should be applicable for Biomass Gasifier based power plant as well.

11.3.2 COMMISSION'S DECISION

As regards norms for Plant Load Factor for Biomass Gasifier based Power Plant, the Commission has decided to revise the norm for Plant Load Factor at 85% as per the report available with the Indian Institute of Science, Bangalore where it is mentioned that many of these plants are operated round the clock and the availability of the plant has been as high as 85-90%. Accordingly, the revised norm has been incorporated in the final Regulations.

11.4 REGULATION 69: AUXILIARY CONSUMPTION

The draft Regulations had the following provision for the Auxiliary Consumption of Biomass Gasifier based power plant:

> *"The auxiliary power consumption factor shall be 10% for the determination of tariff."*

11.4.1 THE COMMENTS RECEIVED ON THIS PROVISION:

Ankur Scientific Energy Technologies Pvt. Ltd. has suggested that due to small size of power plant as well as additional equipment such as Engine, auxiliary consumption of power should be considered at 12% which is also supported by MNRE through its letter to the Commission.

11.4.2 COMMISSION'S DECISION

Since the stakeholder has not submitted any evidence to substantiate their argument, the Commission has decided to retain the provision as mentioned in the draft Regulations.

11.5 REGULATION 69: SPECIFIC FUEL CONSUMPTION

The draft Regulations had the following provision for the Specific Fuel Consumption of Biomass Gasifier based power plant:

"Normative specific fuel consumption shall be 1.1 kg per kWh."

11.5.1 THE COMMENTS RECEIVED ON THIS PROVISION:

Ankur Scientific Energy Technologies Pvt. Ltd. has submitted that draft Regulations propose Specific Fuel Consumption at 1.1 kg/kWh with less than 20% moisture level, however, actual moisture level is not less than 35%. They have further submitted that since biomass price has been considered same for all the technologies, consumption should be revised based on actual moisture level i.e. 1.25-1.30 kg/kWh. Further even in Rankine cycle, consumptions have been considered at 1.25 Kg approx and requested to consider the biomass consumption at 1.30 kg / kWh.

TATA Power Company Ltd. has submitted that the basis for specific consumption for 1.1 Kg/KWh proposed for gasifier based power could be further reviewed with actual consumption parameters (for example: specific fuel consumption of fine fuels like rice husk can be at times as high as 1.8 Kg/KWh based on GCV of about 3000 Kcal/Kg). They have further suggested that to arrive at more market reflective price, a sample survey can be carried out by a reputed agency like CPRI.

11.5.2 COMMISSION'S DECISION

As regards norms for Specific Fuel Consumption for Biomass Gasifier based power plant, the Commission has decided to take into consideration the submissions made by the Stakeholder and revise the norm for Specific Fuel Consumption for Biomass Gasifier based power plant at 1.25 kg/kWh and the same has been incorporated in the final Regulations.

11.6 REGULATION 70: OPERATION & MAINTENANCE EXPENSES

The draft Regulations had the following provision for the Operation & Maintenance expenses of Biomass Gasifier based power plant:

"(1) Normative O&M expenses for the first year of the Control period (i.e. FY 2012-13 shall be ₹ 35 Lakh per MW.

(2) Normative O&M expenses allowed at the commencement of the Control Period (i.e. FY 2012-13) under these Regulations shall be escalated at the rate of 5.72% per annum."

11.6.1 THE COMMENTS RECEIVED ON THIS PROVISION:

Ankur Scientific Energy Technologies Pvt. Ltd. has submitted that considering the fact that Engines maintenance cost is high and cost of manpower does not get reduced proportionately as compared to large biomass based power plant, O & M expenses should be considered at minimum of ₹ 46 Lakh/MW. They have further submitted that the normal operation and maintenance cost of a typical biomass Gasifier based power plant of 1 MW will be as under:

Description	Annual Amount ₹ Lakh
Gasifier & Accessories Maintenance	8.00
Engine Maintenance including lube oil etc.	21.00
Operation: 1 supervisor 4 Technicians 10 Labours 1 Accountant/admn. 3 Security person	 3.00 4.80 6.00 1.20 2.25
Grand Total	46.25

They have further submitted that there should be a separate cost between ₹ 200 - 400/ton (₹14-28 Lakh per MW) for drying and pre-processing/sizing cost of biomass as it is very specific to Biomass Gasifier based power plant only.

TATA Power Company Ltd. has submitted that the tariff for lower capacity ranges should factor in higher proportionate capital costs, O&M cost along with operating parameters based on the existing plant performance of these ranges in order to provide the right economic signal towards better exploitation of bio-fuel through a larger base of smaller micro-generation units based on bio-fuels.

11.6.2 COMMISSION'S DECISION

As regards norms for Operation & Maintenance expenses for Biomass Gasifier based power plant, the Commission has decided to consider the submissions made by the stakeholders and revise the norm for Operation & Maintenance expenses for Biomass Gasifier based power plant at ₹ 40 Lakh/MW considering the engine maintenance cost and cost of manpower which does not get reduced proportionately as compared to large biomass based power plant.

12.TECHNOLOGY SPECIFIC PARAMETERS: BIOGAS BASED POWER PROJECTS

12.1 REGULATION 76: CAPITAL COST

The draft Regulations had the following provision for the Capital Cost of Biogas based power plant:

> *"The normative capital cost for the biogas based power shall be ₹ 1000 Lakh/MW (FY 2012-13 during first year of Control Period) and shall be linked to indexation formula as outlined under Regulation 77. After taking into account of capital subsidy net project cost shall be ₹ 700Lakh/MW for FY 2012-13."*

12.1.1 THE COMMENTS RECEIVED ON THIS PROVISION:

Grameena Abhivrudhi Mandali has submitted that ₹ 1000 Lakh/MW would be the Cost for Biogas power plant and it should also include additional cost of digester effluent treatment plant, which would be in range between ₹ 120 to 80 Lakhs/MW for Biogas plants rating of 400 kW to 2000 kW.

Surabhi Akshay Urja Pvt. Ltd. has submitted that the capital cost of a typical biogas plant implemented in FY 2011 -12 ranged between ₹ 1100 – 1300 Lakh/MW. They have further submitted that due to high inflation, devaluation of INR against USD and high interest rates have led to an overall increase in project cost by 12-15% over the last year. They have suggested that the project cost for such plants is to be increased as ₹ 14 crore/MW.GE Energy recommended that the capital cost should be in the range of 10-12 Crore /MW.

12.1.2 COMMISSION'S DECISION

The Commission has decided to revise the norm for Capital Cost for Biogas based Power Projects at ₹ 1100 Lakh/MW as the cost of digester effluent treatment plant was not considered in the Explanatory Memorandum and the same has been incorporated in the final Regulations.

12.1.2 CAPITAL SUBSIDY FROM MNRE

Considering the Capital Subsidy of ₹ 300 Lakh/MW available from MNRE, as per their circular F.No.10/1/2011-U&I dated 2.5.2011, for Biogas Plants with feedstock mix of cattle dung, vegetable market & slaughter house waste along with agriculture wastes/residues, the commission has revised the norm of net Capital Cost as ₹ 800 Lakh/MW for the FY 2012-13 for determination of tariff.

12.2 REGULATION 78: PLANT LOAD FACTOR

The draft Regulations had the following provision for the Plant Load Factor of Biogas based power plant:

> *"Threshold Plant Load Factor for determining fixed charge component of Tariff shall be 90%."*

The above referred norms in the draft Regulations were based on the MNRE letter dated 7.12.2010 submitting a request from Gramin Abhirudhi Mandli, Banglore for determining generic tariff for the biogas based power plant wherein Plant Load Factor was proposed at 90%.

12.2.1 THE COMMENTS RECEIVED ON THIS PROVISION:

Surabhi Akshay Urja Pvt. Ltd. has submitted that the threshold Plant Load Factor for determining fixed charge component of tariff should be 85% considering 330 days of operation in a year. They have submitted that owing to sand and other inorganic contents that enter the digester and post digester, clean up and preventive maintenance of the same is recommended once every 24 months for a minimum period of 4 days and after such preventive maintenance the digester and post digester would take 26 days to reach full capacity. They have further submitted that during the period of 24 months the plant would operate at full capacity for 550 days and partial capacity for a period of 180 days.

12.2.2 COMMISSION'S DECISION

As regards norms for Plant Load Factor for Biogas based Power Plant, the Commission has decided to retain the norm for Plant Load Factor as proposed under draft Regulations.

12.2 REGULATION 79: AUXILIARY POWER CONSUMPTION

The draft Regulations had the following provision for the Auxiliary Power Consumption of Biogas based power plant:

> *"The auxiliary power consumption factor shall be 12% for the determination of tariff."*

12.2.1 THE COMMENTS RECEIVED ON THIS PROVISION:

The Grameena Abhivrudhi Mandali has submitted that it would be appropriate to consider 13% as auxiliary consumption.

12.3.2 COMMISSION'S DECISION

The Commission has decided to retain the provision as proposed in the draft Regulations.

12.3 REGULATION 80: OPERATION AND MAINTENANCE EXPENSES

The draft Regulations had the following provision for the Operation and Maintenance Expenses of Biogas based power plant:

"(1) Normative O&M expenses for the first year of the Control period (i.e. FY 2012-13 shall be ₹ 30 Lakh per MW.

(2) Normative O&M expenses allowed at the commencement of the Control Period (i.e. FY 2012-13) under these Regulations shall be escalated at the rate of 5.72% per annum."

12.3.1 THE COMMENTS RECEIVED ON THIS PROVISION:

Grameena Abhivrudhi Mandali has submitted that the O&M costs would have to be ₹ 66 Lakhs/MW.

Surabhi Akshay Urja Pvt. Ltd. submitted that the O&M expenses for the first year should be ₹ 1000 Lakh per MW with the escalation as considered in the Draft Regulations. In support of the above argument they have submitted that:

a. to ensure optimum plant operation and utilization regular tests are required on a continual basis which necessitates the additional requirement for laboratory infrastructure, technicians and consumables;

b. Cost of trained technical personnel is high;

c. Components need to be replaced as per the periodic maintenance schedule including gas engine and stators and in case of imported components (constituting 35-38% of the project cost), the cost of replacement has further increased due to depreciating rupee.

Based on DPR submitted by a Project Developer to MNRE for 2 MW Biogas Power Plant wherein O&M cost is considered as 6% of the total project cost. The detailed break up is reproduced as under:

Description	1st Year ₹ in Lakh
Biogas Plant & Digester Effluent Treatment maintenance	36.30
Engines Maintenance including Lube Oil**	58.80
Manpower Cost	36.90
Total O & M Cost	132.00
Total Project Cost	2200
O & M Cost as %age of Project Cost	6%
O & M Cost /MW	66

** Engine annual maintenance cost provided by Notable Engine manufacturer MWM is given below;

All in ₹ Lakh

Year	1	2	3	4	5	6	7	8	9	10	Av. of 10 yrs.
2 MW	14.48	29.20	36.02	30.10	103.62	22.95	80.69	29.20	211.59	30.10	58.80

12.3.2 COMMISSION'S DECISION

As regards norms for Operation & Maintenance expenses for Biogas based power plant, the Commission has decided to consider the submissions made by the Stakeholders and revise the norm for Operation & Maintenance expenses for Biogas based power plant at ₹ 40 Lakh/MW considering the engine maintenance cost and cost of manpower which does not get reduced proportionately as compared to large biomass based power plant.

Keeping the above facts into consideration the Commission has decided to specify Operation & Maintenance expenses for Biogas based Power Plant have been specified at ₹ 40 Lakh/MW.

12.4 REGULATION 81: SPECIFIC FUEL CONSUMPTION

The draft Regulations had the following provision for the Specific Fuel Consumption of Biogas based power plant:

"Normative specific fuel consumption shall be 3 kg of substrate mix per kWh."

12.4.1 THE COMMENTS RECEIVED ON THIS PROVISION:

Surabhi Akshay Urja Pvt. Ltd. submitted that the normative Specific Fuel Consumption for biogas based plants using cow dung should be considered as 4.67 kg of substrate mix per kWh. They have further submitted that such plants using cow dung as fuel the specific fuel consumption is much higher than those using only agricultural residues.

12.4.2 COMMISSION'S DECISION

As regards norms for Specific Fuel Consumption for Biogas based power plant, the Commission has taken into consideration that on a Pan India basis, the manure would be typically cow manure and substrate mix would be 60 % agriculture residues and 40% cow manure. Accordingly, the normative Specific Fuel Consumption proposed at 3 kg of substrate mix per kWh in the draft Regulations.

In view of the above, the Commission has decided to retain the normative Specific Fuel Consumption as proposed under draft Regulations.

12.5 REGULATION 82: FEED STOCK PRICE

The draft regulations had the following provision for the Feed Stock Price of Biogas based power plant:

> *"Feed stock price during first year of the Control Period (i.e. FY 2012-13) shall be ₹ 990/MT for FY 2012-13."*

As regards norms for Feed Stock Price for Biogas based power plant, the Commission has taken into consideration the suggestions of MNRE which was based on request from Gramin Abhirudhi Mandli, Banglore to CERC for determining generic tariff for the biogas based power plant as under:

Cost of Different Substrate (Agriculture Waste + Manure)			
Sr. No.	Feedstock	Dry Solid %	Cost /MT In ₹
1	Cow Dung	18	565
2	Agri Residues (Maize Stalks, Paddy Straw, Cane Trash)	55	1350
Typical Feedstock Mix for 1 MW Biogas Plant			
Sr. No.	Typical Feedstock Mix	Total MT	Average Cost/MT In ₹
1	Agri Residues (12400 MT) + Cow Dung 9000 MT)	21400	1020

Prior to discharge of Biogas Plant digester effluent needs to be treated and separated solids can be used as organic manure. Taking the by-product cost recovery at around 10% of the feedstock cost, the Commission proposed the average feedstock mix cost, net of by-product cost recovery, as ₹ 990/MT for FY 2012-13.

12.5.1 THE COMMENTS RECEIVED ON THIS PROVISION:

Grameena Abhivrudhi Mandali has submitted that in order to avoid ambiguity it may be clarified that the Feed stock Price ₹ 990/MT is net of any cost recovery from digester effluent.

Surabhi Akshay Urja Pvt. Ltd. submitted that the cost of fuel should be reflective of the real market conditions as it is highly influenced by local demand/supply & pricing, seasonal variation in case of agricultural residues and low energy density of feed stock.

12.5.2 COMMISSION'S DECISION

As regards norms for Feed Stock Price for the Biogas based plant, the Commission has decided to retain the normative Feed Stock Price as proposed under draft Regulations. In addition, in order to avoid ambiguity the Commission has decided to clarify that the Feed stock Price ₹ 990/MT for the FY 2012-13 is net of any cost recovery from digester effluent. Accordingly, the same has been incorporated in the final Regulations.

Sd/-	Sd/-	Sd/-	Sd/-
[M. Deena Dayalan] Member	[V. S. Verma] Member	[S. Jayaraman] Member	[Dr. Pramod Deo] Chairperson

ANNEXURE-I

Sr. No.	Name of Stakeholders Submitted Comments on RE Tariff Regulation-2012
1	Shri Shanti Pradsad
2	Infraline Energy researcha nd Information System
3	Transtech Green Power Private Limited
4	IL&FS Renewable Energy limited
5	Rajasthan Biomass Developers Association
6	Orissa Biomass Developers Association
7	Madhya Pradesh Biomass Energy Developers Association
8	Biomass Power Producers Association Tamilnadu
9	Maharashtra Biomass developers Association
10	Konark Power Project Ltd.
11	Kenersys
12	InWEA
13	VESTAS
14	Energy InfraTech Pvt. Limited
15	M.P. Government, New and Renewable Energy Department
16	Ankur Scientific Energy Technologies pvt. Limited
17	Axis Wind Energy Limited
18	Amreli Power
19	CLP Wind Farms (India) Private Limited
20	NTPC Limited
21	Indian Biomass Power Association
22	Reliance Power Limited
23	RE New Power Pvt. Limited
24	Greenergy Renewables Pvt. Limited
25	Prayas (Energy Group)
26	Gujarat Fluorochemicals Limited

27	A2Z Maintenance & Engineering Services Limited
28	PTC India Limited
29	Chhattisgarh Biomass Energy Developers Association
30	Gujarat Biomass Energy Developers Association
31	Kalptaru Power Transmission Limited
32	Indian Wind Turbine manufacturers Association (IWTMA)
33	EMCO Limited
34	Shri M. C. Bansal
35	Abhiram Reddy, Matrix Private Limited
36	Phillips Carbon Black Limited
37	Acme Energy Solutions Private Limited
38	Orient Green Power Company limited
39	Tata Power Company Limited
40	SDS Solar Private Limited
41	Acciona energy Private Limited
42	Hetero Wind Power Limited
43	Damodar Valley Corporation (DVC)
44	Grameena Abhivrudhi Mandali
45	Surachambal Power Limited
46	Harsil Hydro limited
47	Gujarat Urja Vikas Nigam limited
48	Torrent power Limited
49	Dalkia Energy Services
50	PTC BERMACO Green Energy Systems limited
51	Power System Operation Corporation Limited
52	CESC Limited
53	Indian Sugar Mills Associations
54	GE Energy