Explanatory Memorandum

For

Draft Terms and Conditions for Determination of Tariff

For

Renewable Energy Sources

November, 2011

CENTRAL ELECTRICITY REGULATORY COMMISSION (CERC), NEW DELHI

[Pick the date]

1. BACKGROUND

In exercise of powers conferred under Section 61 read with Section 178 (2) (s) of the Electricity Act, 2003 (36 of 2003) (herein after "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. Hence, the Commission has initiated the exercise of framing RE Tariff Regulations for the next Control Period.

2. SCOPE OF RE TARIFF REGULATIONS

2.1 APPLICABILITY OF REGULATIONS

In accordance with Section 79 read with Section 62 of the Act, the Commission is required to determine the tariff for the central sector generating stations or the generating stations with composite scheme for sale of electricity to more than one State. Accordingly, it is proposed that RE Tariff Regulations shall be applicable in all cases where tariff for a generating station or a unit thereof based on renewable sources of energy. Further, in cases of wind, small hydro, biomass, non-fossil fuel based cogeneration, biomass gasifier based, biogas based power projects and solar power projects these Regulations shall apply subject to the fulfillment of eligibility criteria as specified under the Regulations. Para 6.4 (3) of National Tariff Policy empowers the Commission to lay down the guidelines for pricing of non-firm power. The Para 6.4 (3) reads as under,

> *"(3) The Central Commission should lay down guidelines for pricing non-firm power, especially from non–conventional sources, to be followed in cases where such procurement is not through competitive bidding".*

CERC RE Tariff Regulations are also a guiding factor for the State Electricity Regulatory Commissions in terms of Section 61(a) of the Act and the aforesaid provision of the Tariff Policy.

2.2 ELIGIBILITY CRITERIA

The tariff determined under these Regulations shall be applicable in respect of RE technologies meeting specific Eligibility Criteria. The Commission proposes to retain the Eligibility Criteria as specified in the RE Tariff Regulations-2009 for the small hydro, biomass power project based on rankine cycle technology, non-fossil fuel based co-generation, Solar PV and Solar Thermal Power Projects. The Ministry of New and Renewable Energy (MNRE), vide its circular dated 27.06.2002, had issued a guideline to consider Wind Power Density (WPD) of 200 watt/m2 at 50 meter hub height as the minimum requirement for suitability of wind power project development. Accordingly, RE Tariff Regulations - 2009 specified the same as eligibility criteria for the wind energy projects. With change in wind turbine technology and better efficiency, even the lower wind regimes have become exploitable. Considering the same, the MNRE, vide its circular dated 01.08.2011, had issued a new guideline wherein it has been decided that hereafter, no restriction will exist for Wind Power Density criteria as far the development of wind power project is concerned. Therefore, the Commission proposes eligibility criteria for wind energy projects accordingly. The Commission also proposes to specify eligibility criteria for the Biomass Gasifier and biogas based power projects.

Eligibility Criteria for the next Control Period are as under:

(a) **Wind power project -** using new wind turbine generators, located at the sites approved by State Nodal Agency/ State Government only for zoning purpose.

(b) **Small hydro project -** located at the sites approved by State Nodal Agency/ State Government using new plant and machinery, and installed power plant capacity to be lower than or equal to 25 MW at single location.

(c) **Biomass power project based on Rankine cycle technology -** using new plant and machinery based on Rankine cycle technology and using biomass fuel sources, provided use of fossil fuel is restricted only to 15% of total fuel consumption on annual basis.

(d) **Non-fossil fuel based co-generation project** using new plant and machinery and is in accordance with the definition and also meets the qualifying requirement outlined below:

TOPPING CYCLE MODE OF CO-GENERATION – Any facility that uses non-fossil fuel input for the power generation and also utilizes the thermal energy generated for useful heat applications in other industrial activities simultaneously.

Provided that for the co-generation facility to qualify under topping cycle mode, the sum of useful power output and one half the useful thermal output be greater than 45% of the facility's energy consumption, during season.

EXPLANATION- For the purposes of this clause,

(i) 'Useful power output' is the gross electrical output from the generator. There will be an auxiliary consumption in the cogeneration plant itself (e.g. the boiler feed pump and the FD/ID fans). In order to compute the net power output it would be necessary to subtract the auxiliary consumption from the gross output. For simplicity of calculation, the useful power output is defined as the gross electricity (kWh) output from the generator.

(ii) 'Useful Thermal Output' is the useful heat (steam) that is provided to the process by the cogeneration facility.

(iii) 'Energy Consumption' of the facility is the useful energy input that is supplied by the fuel (normally bagasse or other such biomass fuel).

(e) **Solar PV and Solar Thermal Power Project** – Based on Technologies approved by MNRE.

(f) **Biomass Gasifier based Power Project** – using new plant and machinery and having a Grid connected system that uses 100% producer gas engine, coupled with gasifier technologies approved by MNRE.

(f) **Biogas based Power Project** –using new plant and machinery and having grid connected system that uses 100% Biogas fired engine, coupled with Biogas technology for co-digesting agriculture residues, manure and other bio waste as may be approved by MNRE.

2.3 APPROACH FOR DEVELOPMENT OF TARIFF NORMS

While determining the tariff norms following aspects have been considered:

(a) Detailed review of the Tariff Orders / Regulations notified by the various SERCs and the approaches considered in determining the norms for tariff for a specific RE technology.

(b) Scrutiny and analysis of the actual project cost details and information about performance parameters in respect of existing RE projects based on information gathered from financial institutions and also available in the public domain.

(c) Comparative analysis of project cost and performance parameters in respect of similar RE technology applications in the international context.

(d) Feedback/views/comments of the various stakeholders received on the RE Tariff Regulations-2009 in the subject matter.

The tariff norms have been categorized broadly under three sections, namely General Principles, Financial Principles and Technology specific Principles. On the basis of RE technologies covered under the Regulations, the Explanatory Memorandum has been divided into the following sections:

i. General Principles

ii. Financial Principles

iii. Technology specific Principles: Wind Energy

iv. Technology specific Principles: Biomass based generation with Rankine cycle technology

v. Technology specific Principles: Non-fossil fuel based Cogeneration

vi. Technology specific Principles: Small Hydro Power

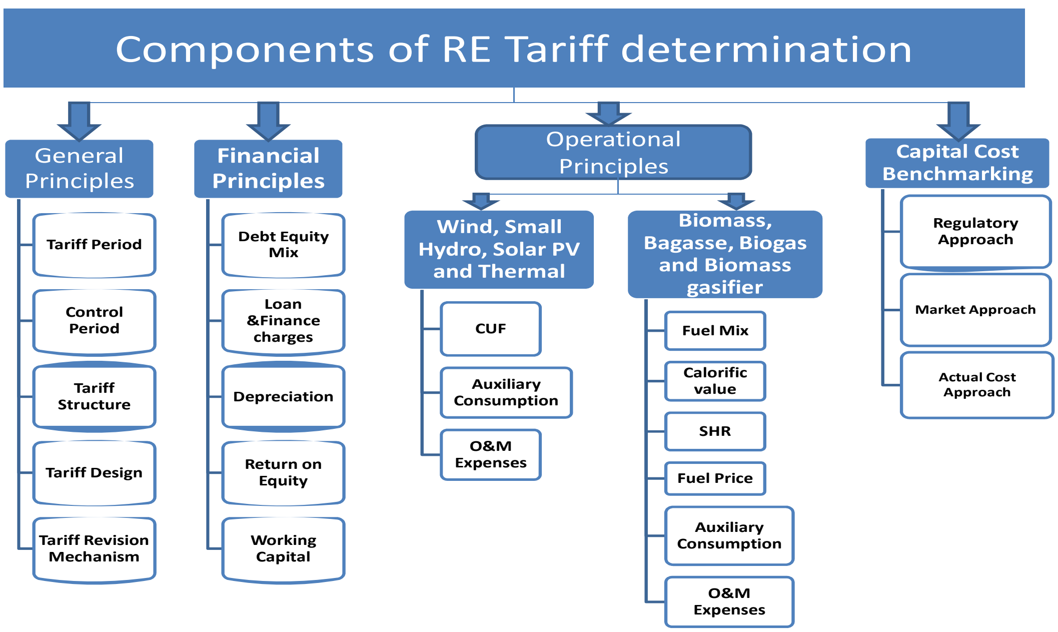
vii. Technology specific Principles: Solar PV

viii. Technology specific Principles: Solar Thermal

ix. Technology specific Principles: Biomass Gasifier based power generation

x. Technology specific Principles: Biogas based power generation

Broad approach adopted for development of norms for the purpose of RE Tariff determination in respect of various RE technologies has been presented diagrammatically below and the same has been elaborated under subsequent sections.



3. GENERAL PRICIPLES

Under this section, the general principles for RE tariff determination such as Control Period, tariff period, tariff structure, tariff design, tariff review mechanism etc. have been discussed.

3.1 CONTROL PERIOD

In the RE Tariff Regulations-2009, three (3) years Control Period was specified.
While specifying the same, the Commission had considered the advantages and disadvantages of specifying a short duration Control Period of 2 years or long duration Control Period of 5 years.

The Commission was of the view that the short duration Control Period would lead to frequent revision of tariff. However, regulatory concern could be easily addressed due to close regulatory monitoring and on the other hand, while long duration Control Period would offer long term certainty of regulatory principles, it might lead to situation when the underlying tariff parameters would hold valid through the long duration of the Control Period. The Commission had also considered the gestation period of different RE technologies for specifying the Control Period so that project conceptualized on the basis of these norms could receive the same tariff.

Considering the maturity level of the non solar technologies, the Commission now proposes to keep second Control Period of five years. The tariff determined for the RE projects commissioned during the Control Period, shall continue to be applicable for the entire duration of the Tariff Period. It is however, also proposed that the benchmark capital cost for Solar PV and Solar Thermal projects may be reviewed annually by the Commission.

The Commission also proposes that the revision in Regulations for next Control Period would be undertaken at least six months prior to the end of the present Control Period and in case Regulations for the next Control Period are not notified until commencement of next control period, the tariff norms as per these Regulations shall continue to remain applicable until notification of the revised Regulations subject to adjustments as per revised Regulations.

3.2 TARIFF PERIOD

In the RE Tariff Regulations-2009, it is specified that Tariff Period for Renewable Energy power projects except in case of Small Hydro Projects below 5 MW, Solar PV, and Solar thermal power projects shall be thirteen (13) years. In case of Small hydro projects below 5 MW, the tariff period shall be thirty five (35) years and in case of Solar PV and Solar thermal power projects the Tariff Period shall be twenty five years (25) years.

While specifying above mentioned Tariff Period of 13 years for some technologies, the Commission took balanced approach based on the provisions of the Act and the Tariff Policy which outline preferential treatment to renewable energy projects till such time that RE technologies are allowed to compete in the market. The Commission also considered that the regulatory support during the 13 year tariff period will provide certainty to the project developer to meet its debt service obligations and 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, different dispensation provided to small hydro projects below 5 MW and useful life of 35 years was considered as tariff Period because of smaller size and such projects might not be able to explore other market models after tariff period of 13 years and would have to depend on local distribution licensee for sale of power. For solar technologies which are at nascent stage of development in India, the Commission specified Tariff Period of 25 years (useful life) to ensure adequate regulatory support is available to Solar Power projects till such time enough confidence is generated amongst all stakeholders about solar power technologies. The Commission proposes to retain the Tariff Period as specified for the various renewable energy technologies in the RE Tariff Regulations-2009 for the next Control Period.

The Commission proposes that in case of Biomass Gasifier and biogas based power projects useful life at 20 years for determination of Tariff as suggested in the MNRE letter dated 7.12.2010, referring request letter of Gramin Abhirudhi Mandli, Banglore. It is also in line with the useful life specified for biomass based power projects with rankine cycle technology and bagasse based cogeneration projects. The Commission proposes the tariff period for such project equal to the useful life of 20 years because such projects are smaller in size (upto 2

MW) and such projects might not be able to explore other market models after tariff period of 13 years and will have to depend on local distribution licensee for sale of power.

3.3 TARIFF STRUCTURE

The RE Tariff Regulations-2009 specifie that the tariff for renewable energy technologies not having fuel cost component shall be single part tariff consisting of the following fixed cost components:

i. Return on equity;
ii. Interest on loan capital;
iii. Depreciation;
iv. Interest on working capital;
v. Operation and maintenance expenses.

For renewable energy technologies having fuel cost component, like biomass power projects and non-fossil fuel based cogeneration, single part tariff with two components, fixed cost component and fuel cost component, was specified. The Commission considered that single part tariff structure for RE technologies involving no fuel cost component is the simplest method to operationalise considering number of projects and unit size of each project and the same has been in practice for RE technologies for long time.

In case of RE technologies involving fuel cost components single part tariff with two components representing fixed cost component and variable cost component was specified. Any generation beyond threshold PLF shall also receive same tariff since risk and cost associated with project sizing, project location etc is expected to be borne by project developer.

The Commission proposes to continue with the same tariff structure for the next Control Period.

3.4 TARIFF DESIGN

In the RE Tariff Regulations-2009, it was specified that the tariff would be determined on levellised basis for all RE technologies for tariff period. While specifying the same the Commission considered that Levellised tariff approach is a balanced approach amongst various tariff determination mechanisms like front loaded tariff, back loaded tariff etc.

The Commission was of the view that the front loaded tariff meets the requirement of the RE project developer at the same time it leads to significant cash flow impact for the utilities during initial period and in addition, there would be little incentive for the RE developer to continue with the existing energy purchase agreement with the Utility once the debt service obligations are over. On the other hand, back-loaded tariff structure meets with the requirement of utility but, significant back-ending would impact project cash flow and may not meet requirement of the project lenders/investors.

The Commission also considered that Levellised tariff with appropriate discount rate representing weighted average cost of capital on the basis of normative debt: equity ratio specified in the Regulations or time value of money yields necessary balance between front-loaded or back-loaded tariff. The discount rate used for renewable energy tariff determination was the pre-tax Weighted Average Cost of Capital (WACC). The WACC was computed as under:

WACC = Cost of Debt + Cost of Equity

Where,

Cost of Debt = Normative Debt X (Normative Rate of Interest)

Cost of Equity= Normative Equity * (Pre Tax Return on Equity)

Now it is proposed to use post tax WACC for the determination of levellised tariff in the next Control Period. This is based on the understanding that 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.

Post Tax WACC = Cost of Debt + Cost of Equity

Where,

Cost of Debt = Normative Debt X (Normative Rate of Interest) X (1-Corporate Tax Rate)

Cost of Equity= Normative Equity X (Post Tax Return on Equity)

The Commission in the RE Tariff Regulations-2009 also addressed the debt service coverage /cash flow related concern during the initial year by specifying the higher depreciation rate of 7% per annum for first 10 years has been specified. The Commission is of the view that since most of the RE technologies have achieved maturity level, it would be possible for the developers to get loan from lenders /financial institution for longer duration of say 12 years. Considering the same, Commission now proposes depreciation rate of 5.83% per annum for first 12 years and balance depreciation to be spread during remaining useful life of the RE projects.

3.5 PROJECT SPECIFIC TARIFF

RE Tariff Regulations-2009 specified that the project specific tariff would be determined by the Commission on case to case basis, for new RE technologies like: Municipal Solid Waste Projects, Hybrid Solar Thermal Power plants, Biomass project other than that based on Rankine Cycle technology application with water cooled condenser, any other new renewable energy technologies as approved by MNRE.

It was also specified in the RE Tariff Regulations-2009 that the financial norms as may be specified except for capital cost, would be ceiling norms while determining the project specific tariff.

The Commission proposes to retain the said provision in the Regulations for the next Control Period and also proposes to include hybrid options (i.e. renewable–renewable or renewable–conventional sources) for which RE technology is approved by MNRE.

3.6 SCHEDULING OF RENEWABLE ENERGY

In the RE Tariff Regulations-2009, it was specified 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. For the biomass power generating station (rankine cycle technology) with an installed capacity of 10 MW and above and non-fossil fuel based co-generation projects it was specified that such projects be subjected to scheduling and despatch code as specified under Indian Electricity Grid Code (IEGC) and Central Electricity Regulatory Commission (Unscheduled Interchange and related matters) Regulations, 2009 including amendments thereto.

While specifying the above provision, the Commission considered that generation from renewable energy sources such as wind, solar, small hydel etc. are non-firm in nature as critically dependent on vagaries of nature. The Commission also considered that the use of the same needs to be maximised as and when such resources are available in order to optimally utilise the assets and maximise generation from such assets already installed.

For the biomass power and non-fossil fuel cogeneration projects of 10 MW and above, the Commission considered that such projects are amenable to scheduling for day-to-day operations, as it has established fuel management chain. However, for such projects with installed capacity of lower than 10 MW, in view of their smaller size and complexities of ensuring visibility at SLDC the Commission considered that such projects are not amenable to scheduling and despatch requirement unlike their counterparts with installed capacity in excess of 10 MW.

With significant increase in share of renewable energy in total energy portfolio, frequent increase or reduction in energy injection within short duration may not be in the interest of safe, smooth and reliable grid operations. In order to have fair idea to system developer of possible energy injection to the system operator from such renewable energy sources, the Commission investigated and deliberated the feasibility of scheduling of wind and solar energy projects for imposing forecasting requirements on such RE sources and covered this aspect in the Indian Electricity Grid Code (IEGC) 2010.

According to the IEGC-2010, with effect from 1.1.2012, scheduling of wind power generation plants would have to be done for the purpose of Unscheduled Interchange (UI) where the sum of generation capacity of such plants connected at the connection point to the transmission or distribution system is 10 MW and above and connection point is 33 KV and above. The schedule by wind power generating stations may be revised by giving advance notice to SLDC/RLDC, as the case may be. Such revisions by wind power generating stations shall be effective from 6th time-block, the first being the time–block in which notice was given. Further, eight (8) revisions are allowed for each 3 hour time slot starting from 00:00 hours during the day.

IEGC-2010 also specifies that the schedule of solar generation to be given by the generator based on availability of the generator, weather forecasting, solar insolation, season and normal solar generation curve and same will be vetted by the RLDC in which the generator is located and incorporated in the inter-state schedule. If RLDC is of the opinion that the schedule is not realistic, it may ask the solar generator to modify the schedule.

Considering the above provisions related to scheduling of wind and solar energy in the IEGC-2010, scope of the relevant Regulation in the RE Tariff Regulation for the next Control Period is proposed to be expanded.

4. FINANCIAL PRINCIPLES

Under this section, 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.

4.1 CAPITAL COST

For development of benchmark capital cost in respect of different RE technologies, the Commission considered inter alia, the capital cost norms as approved by various SERCs in last three years. Such capital cost norm approved by SERCs varied from State to State. Most of the SERCs have not considered the year on year basis variation in capital cost during the

Control Period which means that project commissioned at the beginning of Control Period will have same capital cost as the projects to be commissioned at the end of Control Period, providing no mechanism for considering the inflation impact in the capital cost.

The Commission also compared capital cost for installation of renewable energy projects awarded through competitive tender process in last three years by public and private entities particularly, wind energy projects. Information about capital cost of projects awarded through competitive route could reflect real cost towards capacity addition rather than any notional cost as assumed under regulated approach. However, under supply shortage scenario, with limited number of equipment manufacturers, market based approach, is likely to reflect influence of demand-supply gap rather than underlying costs.

The Commission has also collected capital cost information for RE projects as provided by IREDA and PFC. Further, capital cost information submitted by the project developers to Executive Board of United Nations Framework Convention for Climate Change (UNFCCC) under the Project Design Document (PDD) for projects registered as CDM projects are also considered.

The analysis for benchmark capital cost formulation for each RE technology has been elaborated separately under Technology specific section.

4.2 CAPITAL COST INDEXATION FORMULA

The Commission in its RE Tariff Regulations-2009 specified capital cost indexation formula to consider the year on year variation for the underlying capital cost parameters for each RE technology except Solar PV and Solar Thermal.

Capital cost for each RE technology has been specified as function of site- independent parameters mainly plant and machinery cost and other factors (F1, F2 and F3) representing site specific factors such as land/civil works, erection and commissioning and financing cost and Interest During Construction (IDC) as outlined below:

$C\ C\ (n) = P\ \&\ M\ (n) \times (1+F_1+F_2+F_3)$

F_1 = Factor for Land and Civil Works

F_2 = Factor for Erection and Commissioning

F_3 = Factor for IDC and Financing Cost

The capital cost breakup as furnished by the developers and available in public domain had been considered and separate factors specified for each RE technology depending on its percentage component within overall capital cost as summarized below.

Technology	Plant & Machinery	Land and Civil Work (F1)	Erection and commissioning (F2)	IDC and financing (F3)
Wind	80%	0.08	0.07	0.10
Biomass/Biogas	75%	0.10	0.09	0.14
Bagasse	80%	0.10	0.08	0.07
Small Hydro	70%	0.16	0.10	0.14

Indices influencing Plant and Machinery across projects have been identified as material indices which constitute underlying cost parameters for plant and machinery. Indices considered were whole sale index for steel and whole sale index for electrical machinery for indexation purpose as these two elements constitute major part of plant and machinery cost. Appropriate weightage for each index had been considered. Following formulation specified in the RE Tariff Regulation-2009 to arrive at Capital Cost for second year and third year of Control Period.

P&M (n) = P&M(0) * (1+d(n))

d (n) = [a*{(SI(n-1)/SI(0))– 1} + b*{(EI(n-1)/EI(0)) – 1}]/(a + b)

Where,

CC (n) = Capital Cost for nth year

P&M (n) = Plant and Machinery Cost for nth year

P&M (0) = Plant and Machinery Cost for the base year

d (n) = Capital Cost escalation factor for year (n) of Control Period

SI (n-1) = Average WPI Steel Index prevalent for fiscal year (n-1) of the Control Period

SI (0) = Average WPI Steel Index prevalent for fiscal year (0) at the beginning of Control Period i.e. April 2008 to March 2009

EI (n-1) = Average WPI Electrical Machinery Index prevalent for fiscal year (n-1) of the Control Period

EI (0) = Average WPI Electrical and Machinery Index prevalent for fiscal year (0) at the beginning of the Control Period i.e. April 2008 to March 2009

a = Constant to be determined by Commission from time to time, for weightage to Steel Index

b = Constant to be determined by Commission from time to time, for weightage to Electrical Machinery Index

The Commission proposes to continue with the above formulation of indexation in the Capital cost for the next Control Period for the wind, bagasse based cogeneration, small hydro projects, biomass power projects including biomass gasifier and biogas based power projects. The Commission proposes the following formulation to arrive at Capital Cost for second year and third year of the next Control Period.

P&M(n) = P&M(0) * (1+d(n))

d(n) = [a*{(SI(n-1)/SI(0))– 1} + b*{(EI(n-1)/EI(0)) – 1}]/(a + b)

Where,

CC(n) = Capital Cost for nth year

P&M(n) = Plant and Machinery Cost for nth year

P&M(0) = Plant and Machinery Cost for the base year

d(n) = Capital Cost escalation factor for year (n) of Control Period

SI(n-1) = Average WPI Steel Index prevalent for fiscal year (n-1) of the Control Period

SI (0) = Average WPI Steel Index prevalent for fiscal year (0) at the beginning of Control Period i.e. April 2011 to March 2012

EI (n-1) = Average WPI Electrical Machinery Index prevalent for fiscal year (n-1) of the Control Period

EI(0) = Average WPI Electrical and Machinery Index prevalent for fiscal year (0) at the beginning of the Control Period i.e. April 2011 to March 2012 a = Constant to be determined by Commission from time to time, for weightage to Steel Index

b = Constant to be determined by Commission from time to time, for weightage to Electrical Machinery Index

4.3 DEBT EQUITY RATIO

The Commission in its RE Tariff Regulations-2009 specified that the generic tariff to be determined based on *suo- motu* petition, the debt equity ratio shall be 70:30.

For Project specific tariff, it was specified that if the equity actually deployed is more than 30% of the capital cost, equity in excess of 30% shall be treated as normative loan and where equity actually deployed is less than 30% of the capital cost, the actual equity shall be considered for determination of tariff. CERC RE Tariff Regulations-2009 also provided for normative debt-equity ratio of 70:30 for Generating Company/licensee.

It is 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.

4.4 LOAN AND FINANCE CHARGES

4.4.1 LOAN TENURE

In the RE Tariff Regulation-2009, the Commission after considering the suggestions from stakeholders specified a normative loan tenure of 10 years for the purpose of determination of tariff. The Commission is of the view that since most of the RE technologies have achieved maturity level, it should be possible for the developers to get loan from lenders /financial institution for longer duration of say 12 years. Considering the same, Commission now proposes normative loan tenure of 12 years for the purpose of determination of tariff.

4.4.2 INTEREST RATE

Considering the perceived higher risk profile of Renewable energy projects as compared to conventional power projects normative interest rate of 150 basis points above State Bank of India long term prime lending rate (SBI-LTPLR), as on 1st April of the relevant year of the Control Period was specified in the RE Tariff Regulations-2009.

With effect from 01.07.2010, SBI replaced Benchmark Prime Lending Rate (BPLR) regime with new regime of Base Rate. However, SBI has still continued with the Benchmark Prime Lending Rate (BPLR) (also referred to as SBAR) and prevailing BPLR is 14.75 %.

Base Rate %	Effective from Date	Benchmark Prime Lending Rate (BPLR) %
07.50	01.07.2010	12.25
07.60	21.10.2010	12.35
08.00	03.01.2011	12.75
08.25	14.02.2011	13.00
08.50	25.04.2011	13.25
09.25	12.05.2011	14.00
09.50	11.07.2011	14.25
10.00	13.08.2011	14.75

The Commission took note of the interest rates charged by IREDA and PFC to various renewable energy projects. IREDA classifies borrowers/investors into four grades and depending on the grade, charges interest rate from 11 to 13.25% depending upon the renewable energy technology. The matured technologies, like: wind, co-gen and Small hydro projects, are being financed at lower interest rate compared to solar PV and solar thermal projects.

	Grade I	Grade II	Grade III	Grade IV
Schedule-A, AAA. Rated PSU	11.00			
State Sector	11.00	11.25	11.50	11.75
Wind, Cogen, Hydro	11.75	12.00	12.25	12.5
Solar PV	12.25	12.50	12.75	13.00
Solar Thermal	12.50	12.75	13.00	13.25
Other Sectors	13.50			

In view of the above, the Commission proposes normative interest rate of three hundred (300) basis points above the average State Bank of India Base Rate prevalent during the first six months of the previous year of the relevant year of the Control Period for the determination of tariff for the next Control Period.

4.5 DEPRECIATION

In the RE Tariff Regulations-2009 the Commission specified depreciation per annum based on 'Differential Depreciation Approach' over loan tenure and beyond loan tenure over useful life computed on 'Straight Line Method'. The depreciation rate specified for the first 10 years of the Tariff Period shall be 7% per annum and the remaining depreciation shall be spread over the remaining useful life of the project from 11th year onwards.

While specifying the same, the Commission had considered the concern of the investors/lenders about debt service coverage needs as more renewable energy capacity is envisaged to be funded by way of non-recourse finance basis. The Commission is of the view that since most of the RE technologies have achieved maturity level it should be possible for the developers to get loan from lenders /financial institution, for longer duration of say 12 years. The therefore, Commission now proposes depreciation rate of 5.83% per annum for first 12 years and balance depreciation to be spread during remaining useful life of the RE projects.

4.6 RETURN ON EQUITY

In the RE Tariff Regulations-2009, the Commission specified that the normative Return on Equity of pre-tax 19% per annum for the first 10 years and pre-tax 24% per annum 11th years onwards. It was further specified that the value base for the equity shall be 30% of the capital cost or lower, in case of actual equity is less than 30% of the capital cost (in case of project specific tariff determination).

The Commission while specifying the Return on Equity of pre-tax 19% per annum for the first 10 years had considered tax holiday benefit available under the Section 80-IA of Income Tax Act, 1961. Renewable energy project developers are exempted from income tax on all earnings generated from the project for any 10 year consecutive assessment year during the first 15 years of the project life and the Minimum Alternate Tax (MAT) would be applicable on book profit of such undertaking.

The Commission proposes to continue with the same proposition with prevailing MAT and Corporate Tax rate. The Commission proposes to consider normative Return on Equity of 20% per annum for the first 10 years considering 16% post tax return on equity grossed up with prevailing MAT Rate 20% (Normal rate18.5% + Surcharge 5% + Education Cess 3% (2%+1%), =16%/(1- 20%))
and 24% per annum 11th years onwards considering prevailing corporate tax rate 32.445%(Normal rate 30% + Surcharge 5% + Education Cess 3% (2%+1%))

4.7 INTEREST ON WORKING CAPITAL

The Working Capital requirement in respect of wind energy projects, Small Hydro Power, Solar PV and Solar thermal power projects are proposed to be computed in accordance with the following:

Wind Energy / Small Hydro Power /Solar PV / Solar thermal

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.

The Working Capital requirement in respect of biomass power projects with rankine cycle technology, non-fossil fuel based co-generation projects, Biomass Gasifier based power projects and biogas based power projects are proposed to be computed in accordance with the following clause:

Biomass Power (with rankine cycle technology), Non-fossil fuel Co-generation, Biomass Gasifier based power projects and Biogas based power projects

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.

Interest on Working Capital is proposed to be kept at interest rate equivalent to average State Bank of India Base Rate prevalent during the first six months of the previous year plus 350 basis points of the relevant year of the Control Period, for the determination of tariff for the next Control Period.

4.8 SUBSIDY AND INCENTIVE

Regulation 22 of the RE Tariff Regulations-2009, specifie that 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. It also provide principles to be considered for ascertaining income tax benefit on account of accelerated depreciation, if availed, for the purpose of tariff determination which is reproduced as under:

> *"a) Assessment of benefit shall be based on normative capital cost, accelerated depreciation rate as per relevant provisions under Income Tax Act and corporate income tax rate.*
>
> *b) Capitalisation of RE projects during second half of the fiscal year.*
>
> *c) Per unit benefit shall be derived on levellised basis at discount factor equivalent to weighted average cost of capital.*
>
> *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."*

The Commission proposes to continue with the same principles during the next control period.

4.9 TAXES AND DUTIES

The Commission proposes that the tariff determined under these Regulations is exclusive of taxes (other than corporate tax and minimum alternative tax) and duties as may be levied by the appropriate Government:

Provided that the taxes (other than corporate tax and minimum alternative tax) and duties levied by the appropriate Government shall be allowed as pass through on actual incurred basis.

5. TECHNOLOGY SPECIFIC NORMS: WIND ENERGY

Under this section, technology specific parameters such as Capital Cost norm, capital cost indexation mechanism, Capacity Utilization Factor (CUF), O&M Expenses for wind energy projects have been discussed.

5.1 CAPITAL COST

The Commission in its RE tariff Regulations-2009 specified capital cost for wind energy projects at ₹ 515 Lakhs/MW (FY 2009-10 during first year of Control Period) and linked to the indexation formula as outlined under Regulation 25 of the said Regulations. The Capital costs considered for each year of the control period are as under:

Year	Date of Regulation / Order	Capital cost ₹ Lakh / MW
2009-10	17.09.2009	515.00
2010-11	26.02.2010	467.13
2011-12	09.11.2010	492.52

Wind projects require a capital investment comprised of a number of other costs beyond the turbines alone. However, as shown in the table below, approximately 75% of the total investment cost is associated with the cost of the wind turbines. Other costs include grid connection, foundations, installation, and construction-related expenses, summarized as percentages. These are based on a selection of data from Germany, Denmark, Spain, and the UK.

Parameters	Share of the total cost (%)
Turbine , tower, blades (ex works)	68 - 84
Grid connection	2 - 10
Foundation	1 - 9
Electric installation	1 - 9
Land	1 -5
Financial Costs	1 - 5
Road construction	1 – 5
Consultancy	1 - 5

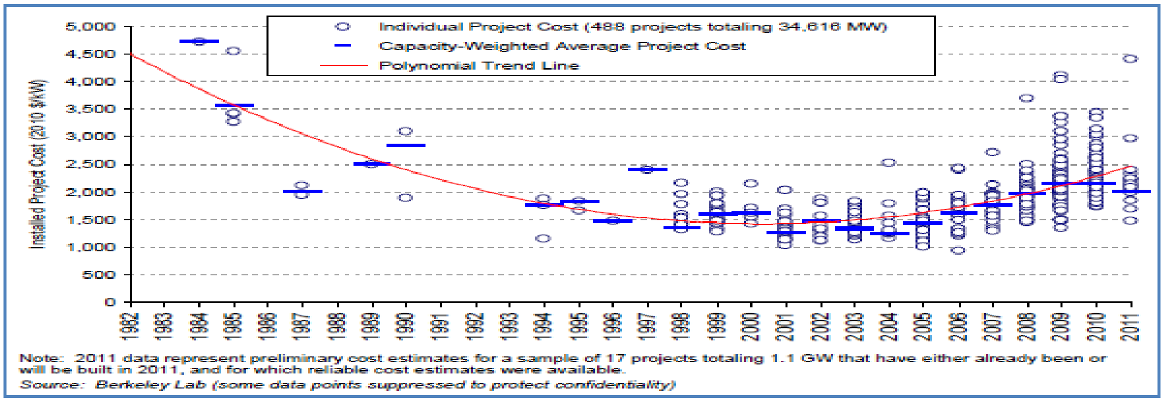
Source: IEA Wind Task 26: Multi-national Case Study of the Financial Cost of Wind Energy: March 2011

Before we go into details of wind power project cost of, let's have a look at the international trend.

5.1.1 INTERNATIONAL TREND: INSTALLED WIND POWER PROJECT COST

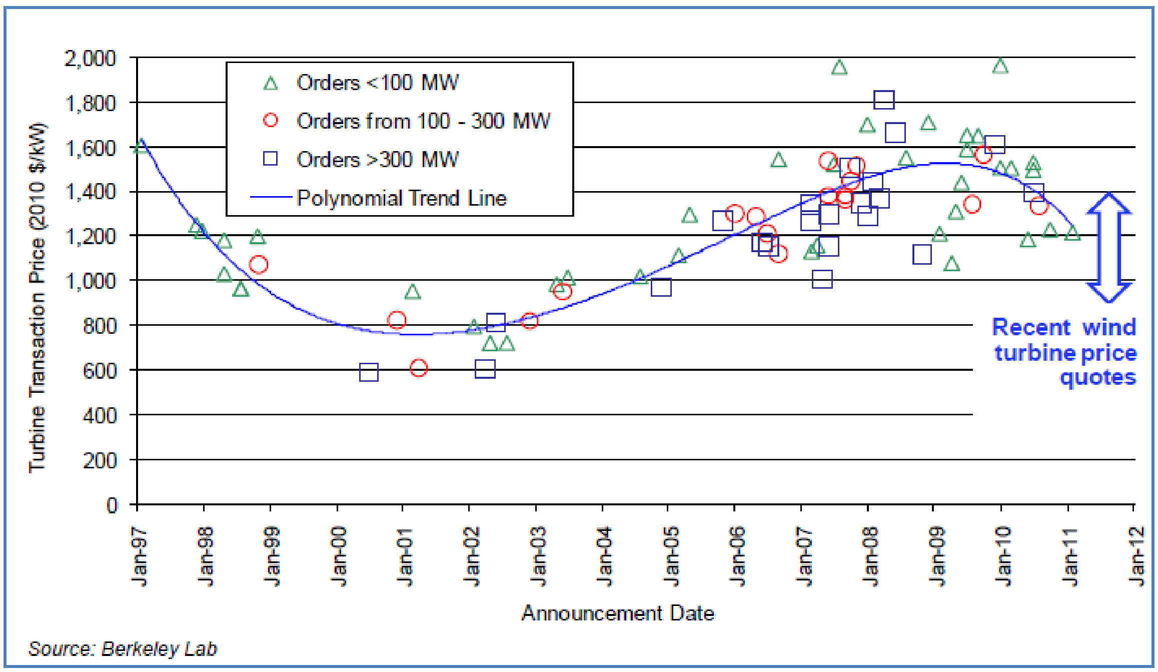
U.S. Department of Energy's in June - 2011 published a report on "2010 Wind Technologies Market Report", prepared by the Lawrence Berkeley National Laboratory (LBNL), which reveals that the total Project costs which were bottomed out in 2001-04; rose by $850/kW on average through 2009; held steady in 2010 at around $2,160/kW and appear to be dropping in 2011 at around $2000/kW. Similar trend was also observed in the turbine costs which were bottomed out in 2001-04; rose by $0.70m /MW on average through 2009; held steady in 2010 at around $1.5m/MW and appear to be dropping in 2011 at around $1.20 m/MW.

Installed Wind Power Project Costs over Time



Source: U.S. Department of Energy's in June - 2011 published a report on "2010 Wind Technologies Market Report"

Turbine Costs over Time



The Bloomberg New Energy Finance's Wind Turbine Price Index – February, 2011 which also shows that the global turbine contracts signed in late 2010 for delivery in H1 2011 and H2 2011 display pricing, with average values at €0.98m/MW ($1.33m/MW).

However in Indian context the total installed cost is lower in comparison to US and Europe market which is around $1.30m/MW. Reason of variance could be shipping cost, terrain, cheaper labour cost, insurance etc. Wind energy sector in India registering 50% growth in the last financial year and with a trend of 25-30% growth in the coming period, the cost economics in the country seems to be a bit different from the international market.

In order to derive benchmark capital cost for wind energy projects for the year 2012 - 13, following approaches have been considered viz. regulatory approach, actual project cost approach, and market based approach. The analysis of various approaches and summary result have been detailed in following paragraphs.

5.1.2 REGULATORY APPROACH

The Commission, under Regulation 24 (2) of the RE Tariff Regulations-2009 dated 17.9.2009, specified the normative capital cost for wind energy projects as ₹ 515 Lakh / MW for FY 2009-10 which was linked to the indexation mechanism specified under Regulation 25 of the RE Tariff Regulations-2009. The Commission determined the normative capital cost of the Wind Energy Projects as ₹ 467.13 Lakh / MW for FY 2010-11 (Order No. 53/2010 dated 26.02.2010) and ₹ 492.52 Lakh / MW for FY 2011-12 (Order No. 256/2010 dated 9.11.2010). After the notification of CERC RE Tariff Regulations-2009, the OERC, MPERC, MERC and KERC came out with the wind energy Tariff Regulations/Orders. Details of the capital cost specified are as under:

Name of the Commission	Date of Order /Regulation	Capital cost ₹ Lakh / MW
RERC	23-01-2009	525.00
TNERC	15-05-2009	535.00
CERC (FY 09-10)	17.09.2009	515.00
KERC	11.12.2009	470.00 (inc. evacuation cost)
GERC	31-01-2010	462.00
CERC (FY 10-11)	26.02.2010	467.13
MPERC	14.05.2010	500.00 (inc. evacuation cost)
OERC (FY 10-11 to FY 12-13)	14.09.2010	467.13
CERC (FY 11-12)	09.11.2010	492.52
MERC (FY 10-11)	29.04.2011	489.53

The MPERC, OERC and KERC have not considered the year on year basis variation in capital cost during the Control Period. The MERC and OERC have followed CERC specified norm for capital cost of the project. The KERC and MPERC have included evacuation/grid connectivity cost as part of Capital Cost.

5.1.3 ACTUAL PROJECT COST APPROACH

Under this approach, the capital cost data has been collected from two sources namely projects sanctioned by IREDA and PFC as well as projects registered with UNFCCC. The capital cost data for around 41 projects which translates into 1127.24 MW of capacity addition have been analyzed under this approach.

Technology	IREDA		PFC		UNFCC	
	Nos.	MW	Nos.	MW	Nos.	MW
Wind	14	790.00	03	124.20	28	429.24

IREDA has financed 14 projects of total 790 MW during FY 2010-11 and FY 2011-12. Capital cost per MW ranges from ₹ 5.53 to ₹ 6.45. Weighted average cost works out to ₹ 5.90 Cr./ MW

PFC financed 3 wind energy projects of total capacity of 124.2 MW in 2007-08. Capital cost per MW ranges from ₹ 5.45 Cr./ MW to ₹ 7.10 per MW. Weighted average cost works out to ₹ 6.15 Cr./ MW. However, since such capital cost data are prior to the CERC RE Tariff Regulations-2009, the same is not considered for the determination of capital cost benchmark norm.

The Capital cost data of 19 projects of total 221 MW registered with UNFCCC commissioned during FY 2009-11 have been analyzed. Capital cost per MW ranges from ₹ 4.43 to ₹ 6.62 Cr./ MW. The weighted average cost of the same works out to ₹ 5.32 Cr./ MW

5.1.4 MARKET BASED APPROACH

In case of wind energy projects, the various private and public entities have set up wind farms by inviting the tenders from various wind project developers. The total 34.20 MW capacity awarded through tender process during the FY2010-11 of total 5 wind projects. Capital cost per MW ranges from ₹ 5.82 Cr./ MW to ₹ 6.18 per MW. Weighted average cost works out to ₹ 6.00 Cr./ MW.

5.1.5 CAPITAL COST FORMULATION FOR WIND ENERGY

It appears from the table below that the per MW capital cost has increased over the period. However, such increase was significant between the years FY 2010 and FY 2011, mainly due to steep rise in material/equipment cost.

Source	No. of Projects	MW	Capital Cost ₹ Crore per MW
IREDA (FY 10-11)	10	570	5.90
IREDA (FY 11-12)	4	220	5.90
UNFCCC (FY 09-10)	14	137	5.23
UNFCCC (FY 10-11)	5	84	5.47
Tender (FY 10-11)	5	34	6.00
Total	38	1045	

The average wind energy project cost in the industry stands higher at around ₹ 5.23 to 6 Crore / MW depending upon the size, capacity, sites as against the CERC's normative ₹ 4.92 Crore /MW for 2011-12. Considering the above, Commission proposes the normative capital cost for first year of the next Control Period at ₹ 5.25 Cr. /MW (without evacuation infrastructure from pooling sub-station to nearest grid sub-station).

5.2 CAPITAL COST INDEXATION MECHANISM FOR WIND ENERGY

The Commission proposes indexation mechanism, as mentioned in the para 4.2, to be applicable in case of wind energy projects for adjustments in capital cost over the Control Period with the changes in Wholesale Price Index for Steel and Electrical Machinery.

5.3 CAPACITY UTILISATION FACTOR (CUF)

The RE Tariff Regulations-2009 specified following CUF norms on the basis of wind resource assessment carried out by C-WET in four groups of annual mean wind power density range measured at 50 meter hub-height:

Annual Mean Wind Power Density (W/m^2)	CUF
200-250	20%
250-300	23%
300-400	27%
> 400	30%

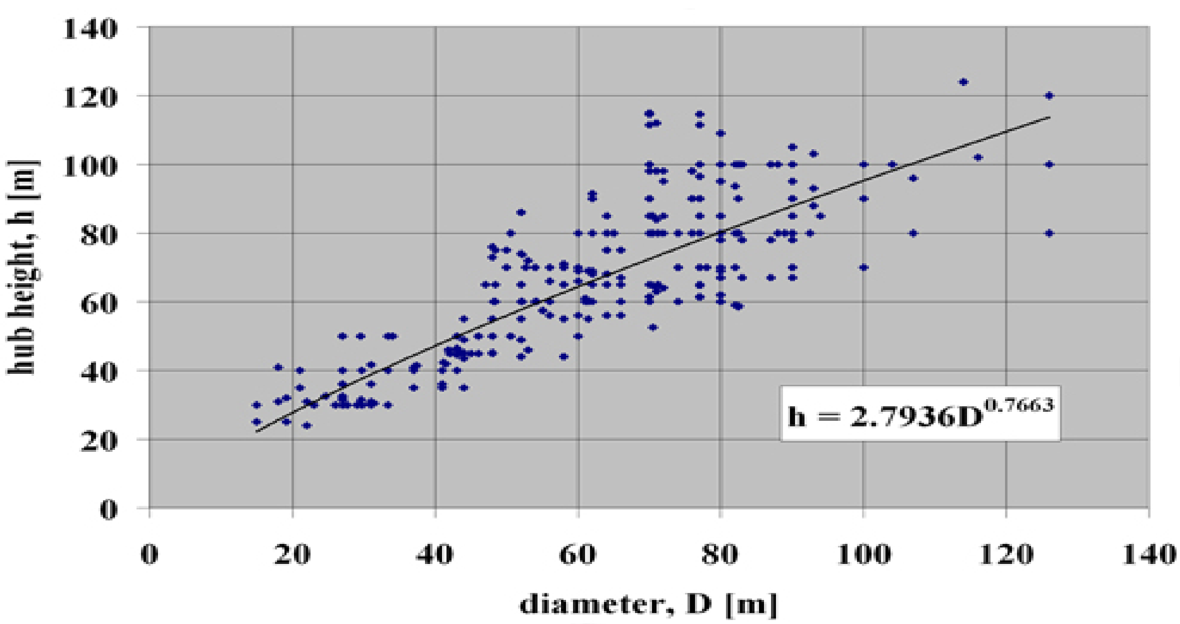
It was also specified that 'Wind Atlas' as and when prepared by C-WET would be basis of categorization of wind sties. It also mentions that as it might take some time to get this Atlas completed, the Wind Power density map provided by C-WET (as annexed under Schedule - 1 of RE Tariff Regulations-2009) would be the basis for categorization of wind sites as an interim arrangement. Further, a provision was incorporated in the RE Tariff Regulations-2009 which enabled the Commission, by notification in Official Gazette, to amend such Schedule from time to time based on the inputs provided by C-WET/ MNRE.

C-WET has published Indian Wind Atlas in February 2010. According to the inputs provided by C-WET, the assessment was done through Mesoscale modeling with 5 kM resolution, and that there would be huge uncertainty in WPD values at boundary lines where 250 becomes 251 or 300 becomes 301. C-WET suggested that it is not advisable to use Atlas for tariff fixation and the same is also mentioned in the preface of atlas. Further, C-WET has also communicated that the theoretical energy in the WPD cannot really represent the power getting out from today's model of wind turbine as actual performance depends on the power curve and efficiency of machine.

With change in wind turbine technology and better efficiency, even the lower wind regimes have become exploitable. Considering the same, the MNRE, vide a circular dated 1.08.2011, issued a new guideline, wherein it is decided that hereafter, no restriction will exist for Wind Power Density criteria as far the development of wind power project is concerned.

In accordance with the MNRE guidelines for wind measurement, the 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 at the desecration of C-WET. The Commission proposes that based on such validation by C-WET, state nodal agency should certify zoning of the proposed wind farm complex.

There is a clear trend of linearly increasing hub height in proportion to rotor diameter. Most manufacturers offer a range of tower heights with any given turbine model, to suit varying site conditions.



Source: http://www.wind-energy-the-facts.org, Garrad Hassan

In general trend is towards steadily growing hub heights, with most major wind turbine manufacturers now routinely offering turbines with hub heights around 80 meters. While fixing the capital cost related norm based on the prevailing market price of wind turbines having average hub height of 80 meters, it is vitally essential to understand the impact of increase in turbine height from 50 meters to 80 meters on the wind speed which rationally defines capacity factor of wind turbine which requires extrapolation of above referred wind class at 50 meters to 80 meters hub heights.

The Commission approached C-WET in this regard. C-WET, vide letter dated 14.10.2011 informed us that C-WET will not able to provide authentic data in this regard as measurements at 80 m hub height are available only at some locations and they do not have turbine wise generation data for any state.

The Lawrence Berkley National Laboratory (LBNL) did a study "Reassessing Wind Potential Estimates for India: Economic and Policy Implications" wherein wind potential at higher hub heights – i.e. 80, 100 and 120 meters has been estimated. Wind power class, density and capacity utilization factor at such higher hub heights are as under:

Wind Power Class	50 m		80 m			100 m			120 m		
	WPD	WS	CF	WPD	WS	CF	WPD	WS	CF	WPD	WS
1	0-200	0-5.6	-	0 - 200	0-5.6	-	0-200	0-5.6	-	0-200	0-5.6
1a	*NA*	*NA*	*20%*	*200 -251.3*	*5.6 -6.0*	*20.0%*	*200-220*	*5.6-5.7*	*20.0%*	*200-237.9*	*5.6-5.9*
1b	*NA*	*NA*	*NA*	*NA*	*NA*	*21.6%*	*220-276.5*	*5.7-6.2*	*23.3%*	*237.9-299*	*5.9-6.3*
2	200 -300	5.6-6.4	25%	251.3 - 375.1	6.0 -6.9	27.0%	276.5-412.7	6.2-7.1	29.0%	299-446.3	6.3-7.3
3	300 -400	6.4-7.0	32%	375.1 - 490.8	6.9-7.5	34.0%	412.7-540	7.1-7.7	35.5%	446.3-583.9	7.3-7.9
4	400 -500	7.0 -7.5	36%	490.8 - 603.6	7.5-8.0	37.5%	540-664.2	7.7-8.3	39.0%	583.9-718.2	7.9-8.5
5	500 -600	7.5-8.0	39%	603.6 - 732.6	8.0 -8.6	40.5%	664.2-806.1	8.3-8.8	42.0%	718.2-871.6	8.5-9.1
6	600 -800	8.0 -8.8	42%	732.6 - 975.1	8.6-9.4	43.5%	806.1- 1,072.9	8.8-9.7	45.0%	871.6- 1,160.1	9.1-10

WPD = Wind Power Density (W/m^2)
WS = Wind Speed (m/s)
CF = Capacity Factor

Wind turbines available in India having 80 meter hub-heights are considered for analysis. To estimate energy content of available wind resource at mast location, Weibull distribution approach is adopted which is well accepted in wind industry and is the basis for all high end wind flow modelling softwares. It gives a good representation of the variation in hourly mean speed over a year at many typical sites. It indicates fraction of time for which wind is at a given velocity V and is characterized by two parameters - “scale parameter” and “shape parameter”. Weibull parameters estimated at mast height are extrapolated to the hub height. In this method mast height and wind speeds are extrapolated to the hub height of a turbine.

Capacity Factor Analysis	
Air density	1.225 kg/m3
Shape factor k	1.95
Scale factor C	(WS/Gamma(1+1/k)

Height	10 m			50 m			80 m		
Wind class	Wind Power Density (W/m2)	Wind Speed (m/s)	Scale factor C	Wind Power Density (W/m2)	Wind Speed (m/s)	Scale factor C	Wind Power Density (W/m2)	Wind Speed (m/s)	Scale factor C
	0	0	0.00	0	0.0	0.00	0	0.0	0.00
1	50	3.5	3.92	100	4.4	4.93	122	4.7	5.27
	100	4.4	4.93	199	5.5	6.21	244	5.9	6.64
	112.5	4.5	5.13	224	5.7	6.46	274	6.1	6.91
2	125	4.7	5.31	249	5.9	6.69	305	6.3	7.15
	137.5	4.9	5.49	274	6.1	6.90	335	6.5	7.38
	150	5.0	5.65	299	6.3	7.11	366	6.7	7.60
3	175	5.3	5.95	349	6.6	7.48	427	7.1	8.00
	200	5.5	6.22	399	6.9	7.82	488	7.4	8.37
4	225	5.7	6.46	448	7.2	8.14	549	7.7	8.70
	250	5.9	6.70	498	7.5	8.43	610	8.0	9.01
5	275	6.1	6.91	548	7.7	8.70	670	8.2	9.30
	300	6.3	7.12	598	7.9	8.95	731	8.5	9.58
6	350	6.6	7.49	698	8.4	9.43	853	8.9	10.08
	400	6.9	7.83	797	8.7	9.86	975	9.3	10.54
7	700	8.4	9.44	1395	10.5	11.88	1707	11.3	12.70
	1000	9.4	10.63	1993	11.9	13.38	2438	12.7	14.31

The standard power curve of turbines is applied as input along with frequency distribution for determination of gross electricity generation/Capacity Utilization Factor (CUF) estimation at 80 meter hub-heights. The Net generation/CUF is determined by considering suitable discounting factors to the gross generation/CUF.

Based on the above analysis and LBNL study report, the Commission proposes to determine wind energy tariff at following CUF norms in five groups of annual mean wind power density range extrapolated at 80 meter hub-height:

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

5.4 OPERATION AND MAINTENANCE (O&M) EXPENSES

The Commission in its RE Tariff Regulations-2009 specified normative O&M expenses for the first year of the Control Period (i.e. FY 2009-10) at ₹ 6.50 Lakh per MW. The above norms for O&M expense had been proposed in the Regulations after considering the O&M expense norms specified by different SERCs in their Tariff Orders. It also provide that the normative O&M expenses for the first year of the Control Period (i.e. 2009-10) to be escalated at the rate of 5.72% per annum over the tariff period for determination of the levellised tariff. Accordingly, the Commission considered O&M cost norm for wind energy as ₹ 7.26 Lakh/MW for determination of tariff for FY 2011-12.

O&M expenses are a significant component of the overall cost of wind energy, but can vary substantially among projects depending upon the size of the project and technology of the turbine. O&M costs are related to a limited number of cost components, including: Insurance; Regular maintenance; Repair; Spare parts, and Administration. Some of these cost components can be estimated relatively easily. For insurance and regular maintenance, it is possible to obtain standard contracts covering a considerable share of the wind turbine's total lifetime. Conversely, costs for repair and related spare parts are much more difficult to predict. And although all cost components tend to increase as the turbine gets older, costs for repair and spare parts are particularly influenced by turbine age; starting low and increasing over time.

Wind energy developers generally offer O&M rates on annual basis with an escalation provision. Most of the developers are offering first year O&M free of cost and subsequently there is a compounded escalation of 5% percent. O&M agreements being signed between the wind farm developers and investors are in the range of ₹ 7 Lakh to ₹ 12 Lakh/MW. Gearless wind turbine has comparatively lower O &M cost than wind turbine with gear box. Additionally most of the wind energy projects also would end up spending 0.25% of the project cost as insurance, and the same needs to be added too. In addition, from 1.1.2012 wind energy generators are covered under ambit of scheduling requirement. Therefore, forecasting expenses are also needed to be added in the O&M expanses. The O&M cost norm approved by the State Electricity Regulatory Commissions are as under:

ERCs	O & M Cost	Escalation
CERC	Rs. 6.50 Lakh/MW (2009-10)	5.72 %
APERC	1.25 % of CC	5.00 %
GERC	1.5 % of CC	5.00 %
KERC	1.25% of CC	5.00 %
MPERC	1.0 % of CC for First 5 yrs	5.72 %
MERC	1.46% for first yr (6.87 Lakh/MW)	5.72 %
RERC	Power plant - 1.25 % Trans. Lines - 3% of lines cost	5.72 %
TNERC 15.05.2009	1.1% of CC , Insurance Cost 0.75% of m/c cost for 1st yr, reduced by .5% of previous yrs insurance cost every yr.	5.00 %

Considering the above, the Commission proposes the operation and maintenance cost for FY 2012-13 at ₹ 9 Lakh/MW (i.e. O&M cost for FY 11-12 escalated with 5.72% annual escalation + 0.25% of capital cost as insurance cost + forecasting Cost).

6. TECHNOLOGY SPECIFIC NORMS: SMALL HYDRO POWER

Under this section, technology specific parameters such as Capital Cost norm, capital cost indexation mechanism, Capacity Utilization Factor, Auxiliary Consumption and O&M Expenses for small hydro power projects have been discussed.

6.1 CAPITAL COST

The Commission in its RE Tariff Regulations-2009 specified normative capital cost for small hydro projects during first year of Control Period (FY 2009-10). Capital cost for subsequent years to be determined on the basis of indexation formula as outlined under Regulation 29 of the RE Tariff Regulations-2009.

In line with the indexation mechanism, the Commission determined the normative capital cost for FY 2010-11 (vide Order No. 53/2010 dated 26.2.2010) and FY 2011-12 (vide Order No. 256/2010) as shown below,

Region	Project Size	Capital Cost (FY 2009-10) (₹ Lakh/ MW)	Capital Cost (FY 2010-11) (₹ Lakh/ MW)	Capital Cost (FY 2011-12) (₹ Lakh/ MW)
Himachal Pradesh, Uttarakhand and North Eastern States	Below 5 MW 5 MW to 25 MW	700 630	634.94 571.44	669.42 602.48
Other States	Below 5 MW 5 MW to 25 MW	550 500	498.88 453.53	525.97 478.16

The Commission specified Capital Cost norms for SHP below 5 MW higher than SHP between 5 MW to 25 MW as small size hydro projects below 5 MW have higher capital cost and higher operating cost due to their small size, remote locations, grid connectivity issues etc.

6.1.2 COST CONSIDERED BY THE STATE REGULATORY COMMISSIONS

After notification of CERC RE Tariff Regulations-2009, KERC, UERC, MERC, HPERC and OERC have come out with the Small Hydro Tariff Regulations/Order. Details of the capital cost specified are as under:

	Karnataka	Himachal	Orissa	Maharashtra	Uttarakhand
Project Cost (₹ Cr/Mw)	4.75	6.50	6.70	1 to 5MW: 4.98 > 5 to 25 MW: 4.53	Up to 5 MW: 7.00 5 to 10 MW: 6.85 10 to 15 MW: 6.70 15 to 20 MW: 6.50 20 to 25 MW: 6.30
Order	December 2009	February 2010	May 2010	June 2010	July 2010

MERC and UERC have followed CERC specified norm for capital cost of the project. MERC has specified indexation mechanism in line with CREC RE Tariff Regulations-2009. UERC, OERC and KERC have not considered the year on year basis variation in capital cost during the Control Period which means that project commissioned at the beginning of Control Period will have same capital cost as the projects to be commissioned at the end of Control Period, providing no mechanism for considering the inflation impact in the capital cost. KERC has included evacuation/grid connectivity cost as part of Capital Cost.

6.1.3 ACTUAL PROJECT COST APPROACH

Capital cost information for 18 Small Hydro Projects (which translates into 153.60 MW) as provided by IREDA, PFC as well as capital cost information submitted by the project developers to Executive Board of United Nations Framework Convention for Climate Change (UNFCCC) in the Project Design Document (PDD) for projects to get registered under CDM activity have been analysed under this approach.

Source	No of Projects	Capacity, MW
IREDA	7	78.15
PFC	12	83.45
UNFCCC	1	15.00
Total	20	176.60

Under this approach, the capital cost data has been collected from two sources namely projects sanctioned by IREDA and PFC as well as projects registered with UNFCCC. The capital cost data for around 18 projects which translates into 153.60 MW of capacity addition have been analyzed under this approach. IREDA has financed 4 projects of total 63.75 MW during FY 2010-11. Capital costs per MW during FY 2010-11 are as under:

Region	Project Size	No. of projects	Capital Cost (FY 2010-11) (₹ Lakh/ MW)
Himachal Pradesh, Uttarakhand and North Eastern States	Below 5 MW 5 MW to 25 MW	1 2	796 743
Other States	Below 5 MW 5 MW to 25 MW	- 1	- 538

IREDA has financed 3 projects of total 14 MW during FY 2011-12. Capital costs per MW during FY 2011-12 are as under:

Region	Project Size	No. of projects	Capital Cost (FY 2010-11) (` Lakh/ MW)
Himachal Pradesh, Uttarakhand and North Eastern States	Below 5 MW 5 MW to 25 MW	- 2	- 817
Other States	Below 5 MW 5 MW to 25 MW	1 -	518 -

PFC financed 10 small hydro projects of total capacity of 72.75 MW in 2008-09. Capital cost per MW ranges from ₹ 7.89 Cr./ MW to ₹ 15.39 Cr./ MW. Weighted average cost works out to ₹ 9.59 Cr./ MW. However, since such capital cost data are prior to the CERC RE Tariff Regulations-2009, of is not considered for the determination of capital cost benchmark norm. PFC financed 2 small hydro projects in Kerala State of total capacity of 10.7 MW in 2009-10.

Region	Project Size	No. of projects	MW	Capital Cost (FY 2009 - 10) (` Lakh/ MW)
Other States	Below 5 MW 5 MW to 25 MW	1 1	3.2 7.5	594 458

Capital cost data of 1 projects of total 15 MW commissioned in Karnataka State registered with UNFCCC commissioned during FY 09-10 having per MW capital cost at ₹ 5.26 Cr./ MW.

6.1.4 CAPITAL COST FORMULATION FOR SMALL HYDRO

The weighted average capital costs under different categories under actual cost approach in FY 2009-10 are compared with the CERC considered cost in the same year as under:

Region	Project Size	Capital Cost (FY 2009-10)		Capital Cost (FY 2010-11)		Capital Cost (FY 2011-12)	
		No. of project	(₹ Lakh/ MW)	No. of project	(₹ Lakh/ MW)	No. of project	(₹ Lakh/ MW)
Himachal Pradesh, Uttarakhand and North Eastern States	Below 5 MW 5 MW to 25 MW	- -	- -	1 2	796 743	- 2	- 817
Other States	Below 5 MW 5 MW to 25 MW	1 2	594 503	- 1	- 538	1 -	518 -

From the above analysis it is found that the capital cost for small hydro projects varies significantly across the States, mainly due to variation in civil works and transportation etc. The Commission proposes to restore at the original level i.e. Capital cost specified for the FY-2009-10 in the TE Tariff Regulations-2009. The normative capital cost for first year of the next Control Period is proposed as under:

Region	Project Size	Capital Cost (FY 2012-13) (₹ Lakh/ MW)
Himachal Pradesh, Uttarakhand and North Eastern States	Below 5 MW 5 MW to 25 MW	700 630
Other States	Below 5 MW 5 MW to 25 MW	550 500

6.2 CAPITAL COST INDEXATION MECHANISM FOR SMALL HYDRO

The Commission proposed indexation mechanism, as mentioned in the para 4.2, to be applicable in case of small hydro projects for adjustments in capital cost over the Control Period with the changes in Wholesale Price Index for Steel and Electrical Machinery.

6.3 CAPACITY UTILISATION FACTOR (CUF)

The RE Tariff Regulations -2009 specifie that Capacity Utilization Factor (CUF) for the small hydro projects located in Himachal Pradesh, Uttarakhand and North Eastern States shall be 45% and for other States, CUF was 30%. It was further specified that the 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. The above norms for CUF were derived on the basis of CUF considered by the SERCs while approving the tariff for small hydro projects in their respective States. The CUF considered by various SERCs are as follows:

Andhra Pradesh	Uttaranchal	Maharashtra	Karnataka	Himachal	U.P.	Orissa
35%	45%	30%	30%	40%	35%	35%

The Commission proposes to retain the norm specified in the RE tariff Regulations-2009 as it is for the next Control Period.

6.4 AUXILIARY CONSUMPTION FACTOR

The Commission in its RE tariff Regulations-2009 specified the Normative Auxiliary Consumption for the small hydro projects of 1.0% for the determination of tariff. While specifying the above norm, the Commission considered that a typical SHP project has very few auxiliaries and pumping units as compared to large size hydro projects.

The Commission proposes to retain the normative auxiliary consumption including transformation losses of 1%.

6.5 O&M EXPENSE FOR SMALL HYDRO

The Commission in its CERC RE Tariff Regulations-2009 specified the normative O&M expenses for the first year of the Control period (i.e. FY 2009-10). While specifying the above norm the Commission considered the operation and maintenance expense norm of 2 % of Capital cost specified in the CERC (Terms and Conditions for Tariff) Regulations, 2009 for new large size hydro projects. It was further considered that the small hydro projects would not have the advantage of economies of scale therefore, O&M expense for these projects would be higher than that specified for large hydro projects.

Regulation 32 of RE Tariff Regulations-2009 provided for the normative O& M expenses for small hydro projects for the year 2009-10 which shall be escalated at the rate of 5.72% per annum over the tariff period for determination of the levellised tariff. Accordingly, the table below presents the normative O&M Expenses considered by the Commission in its RE Tariff Order for FY 2011-12,

Region	Project Size	FY09-10 O&M Expense (₹ Lakh/ MW)	FY11-12 O&M Expense (₹ Lakh/ MW
Himanchal Pradesh, Uttarakhand and North Eastern States	Below 5 MW	21	23.47
	5 MW to 25 MW	15	16.77
Other States	Below 5 MW	17	19.00
	5 MW to 25 MW	12	13.41

The Commission proposes the following O&M expenses norm for the first year of Control Period (i.e. FY 2012-13) which are determined by applying annual escalation factor of 5.72% per annum on the O&M cost norm applicable for FY 2011-12:

Region	Project Size	FY 12-13 O&M Expense (₹ Lakh/ MW)
Himanchal 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 MW	14

7. TECHNOLOGY SPECIFIC NORMS: BIOMASS PROJECTS RANKINE CYCLE

Under this section, technology specific parameters such as capital cost norm, capital cost indexation mechanism, plant load factor, auxiliary consumption, station heat rate, gross calorific value, biomass fuel price, biomass fuel price indexation mechanism and O&M Expenses, for biomass based power projects with rankine cycle technology have been discussed.

7.1 TECHNOLOGY ASPECT

The tariff norms for biomass power projects under these Regulations have been developed in respect of Biomass power projects based on rankine cycle technology and using biomass fuel sources and use of fossil fuel to limited extent, provided use of fossil fuel is restricted only to 15% of total fuel consumption on annual basis.

7.2 CAPITAL COST BENCHMARKING

The Commission under Regulation 34 of the RE Tariff Regulations-2009 specified the normative capital cost for the biomass power projects based on Rankine cycle technology application using water cooled condenser as ₹ 450 Lakh / MW for FY 2009-10 and linked to the indexation mechanism specified under Regulation 35 of the RE Tariff Regulations-2009. Accordingly, the Commission determined the normative capital cost as ₹ 402.54 Lakh /MW for FY 2010-11 and ₹ 426.03 Lakh / MW for FY 2011-12.

7.2.1 COST CONSIDERED BY THE STATE REGULATORY COMMISSIONS

After issuance of the CERC RE Tariff Regulations-2009, various SERCs have issued the Tariff Orders for biomass based generation projects. The latest cost data approved by the various States Commissions are as under:

SERCs	Capital Cost ₹ Cr./MW	Indexation Mechanism	Order/ Regulation	Remark
RERC	5.40 : Water Cooled Condenser 5.85 : Air Cooled Condenser	As per Formula	Regulations 23/01/2009	
GERC	4.25	Not provided	Order No.5 of 2010: 17.05.2010	Took note of CERC determined CC for FY10-11
UERC	4.50	Not provided	Regulations Dated 06.07.2010	As per CERC
MERC	4.03 (FY 10-11)	As per CERC	Regulations 07.06.2010	As per CERC
KERC	4.87 inclusive of transmission infrastructure costs	Not provided	Order No.5 of 2010: 11.12.2009	Took note of CERC specified CC for 2009-10
JSERC	4.50	Not provided	Regulations Dated 27.01.2010	As per CERC
HERC	4.50	Not provided	Order dated 27.5.2011	As per CERC

7.2.3 ACTUAL PROJECT COST APPROACH

Capital cost information for RE projects as provided by IREDA and capital cost information submitted by the project developers to Executive Board of United Nations Framework Convention for Climate Change (UNFCCC) in the Project Design Document (PDD) for projects to get registered under CDM activity are considered.

The capital cost data for around 10 projects which translates into 101.3 MW have been analysed under this approach. The table below summarises the average capital cost for the projects during various years.

	FY2009-10			FY2010-11			FY2011-12		
Source	No	Capacity MW	Capital Cost, ₹ Cr/MW	No	Capacity MW	Capital Cost, ₹ Cr/MW	No	Capacity MW	Capital Cost, ₹ Cr/MW
IREDA				2	19.90	4.79	1	9.90	5.00
UNFCCC	4	36.8	4.74	2	24.5	5.39			
Total	4	36.8	4.74	4	44.4	5.12			

IREDA has financed 3 projects of total 29.8 MW during FY 2010-12. Capital costs per MW are ranging from ₹ 4.79 Cr. to ₹ 5 Cr. / MW. The Cost Breakup for 9.9 MW project financed by IREDA having total project cost of around ₹ 50.0 Cr. (Including evacuation infrastructure cost beyond point of connection and with Air Cooled condenser) as confirmed by the project developer are as under:

Civil Works : 07.0 Cr.

Plant & Machinery : 34.0 Cr.(Including Trans. Line cost, 2 Crore and Air Cooled Condenser)

IDC : 03.5 Cr.

Preoperative Charges : 04.0 Cr.

Margin money for W/C : 01.5 Cr.

IREDA uses following benchmark capital cost norm for financing the biomass based power projects during FY 2011-12:

Pressure Configuration (ata)	Biomass Power project (₹ Crore/MW)		
	6 MW	7.5 MW	10 MW
44	4.03	3.93	3.79
66	5.38	5.19	**5.03**
86	5.59	5.37	5.15
102	5.93	5.77	5.61
110	6.05	5.89	5.72

MNRE vide its letter dated 30th September, 2011 submitted that the Capital cost of the biomass based power project depends upon the type of fuel, which in turn decides the plant configuration and technology type. MNRE recommended project cost for various biomass categories for IPP and tail end projects as given in the table below:

Cost Head	Project Cost – IPP (₹ Lakh /MW)				Project Cost – Tail End (₹ Lakh /MW)			
	Straw	Stalk	Plantation	Husk	Straw	Stalk	Plantation	Husk
Steam Pressure/ temperature (ata/ ^{0}C)	68/435	68/435	87/515	87/515	48/435	48/435	48/435	48/435
Land Civil and Equipment Cost	545.5	522.6	517.2	517.2	650.0	650.0	650.4	650.3
Fuel Logistics equipment	49.6	3.6	5.6	1.5	62.5	13.0	13.5	10.2
PDD Charges	4.6	4.2	4.1	4.1	2.8	2.8	2.8	2.8
Finance Charges	31.1	28.7	27.4	28.4	36.1	36.5	36.6	36.5
Margin Money	19.3	19.2	19.2	18.8	19.5	19.4	19.4	19.4
Total Project Cost	650.1	578.3	573.5	570	771.3	721.7	722.7	719.2

MNRE finally recommended normative capital cost as shown below:

₹ in Lakh

Biomass	IPP (>5MW)	Tail end (<2 MW)
Rice husk	570	720
Straw	650	770
Others	580	720

7.2.4 CAPITAL COST FORMULATION FOR BIOMASS POWER PROJECT

Based on 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, the Commission proposes normative capital cost at ₹ 4.45 Crore/MW (₹ 5.0 Crore – ₹ 0.20 (Evacuation infra. Cost beyond point of connection) – ₹ 0.35 (Difference between Air Cooled Condenser (ACC) and Water Cooled Condenser (WCC) = ₹ 4.45 Crore/MW) for first year of the Control Period.

7.3 CAPITAL COST INDEXATION MECHANISM FOR BIOMAS PROJECTS

The Commission proposes indexation mechanism, as mentioned in the para 4.1, to be applicable in case of biomass based power projects for adjustments in capital cost over the Control Period with the changes in Wholesale Price Index for Steel and Electrical Machinery.

7.4 PLANT LOAD FACTOR (PLF)

The Commission specified the threshold Plant Load Factor in its RE Tariff Regulations-2009 for the biomass based power projects with Rankine cycle technology for determining fixed charge component of Tariff as under:

1. During Stabilisation: 60%
2. During the remaining period of the first year (after stabilisation): 70%
3. From 2nd Year onwards: 80%

It was further, specified that the stabilization period shall not be more than 6 months from the date of commissioning of the project. The Plant load factor (PLF) being a critical performance parameter for any power plant installation and since it is dependent on factors such as reliable and quality fuel supply, plant availability and unconstrained off-take, while specifying the above norm, the Commission considered the information available from IREDA/UNFCCC in respect of biomass power projects. Most of the Projects assume capacity utilization at 60-70 % during the 1st year of operation, and 75 % to 80 % from the 2nd year onwards. The Commission proposes to retain the norm specified earlier for the threshold Plant Load Factor for determining tariff for the next control period.

7.5 AUXILIARY ENERGY CONSUMPTION

The Commission in the RE Tariff Regulations – 2009 specified the normative auxiliary power consumption factor at 10% for the determination of tariff for biomass based power generation projects with Rankine cycle technology.

While specifying the above norm the Commission considered that the auxiliary consumption factor is one of the key performance factors and is dependent of the size of the plant, need of pre-processing requirement of the biomass fuel and drive towards adopting energy conservation methods.

Auxiliary power consumption in a power plant influences the net power available for export from any power plant. Lower the auxiliary consumption, higher will be the power that can be exported. The major power plant auxiliaries in the power plant contributing to the auxiliary power consumption are,

- Boiler Feed water Pump
- Condensate Extraction Pump
- Cooling Water Pumps
- ID Fans
- FD Fans
- Cooling Tower Fans
- Air Compressor
- Fuel Handling Equipments
- Losses in the transformers

According to the study carried out by NPC it varies between 10% & 18%. They suggested that power plants should strive to maintain auxiliary consumption within **12%**, which can be achieved if operated under stable conditions.

The auxiliary consumption also depends on the plant availability and loading on the plant. Greater the plant availability & higher the plant loading, the lower will be the auxiliary consumption. The plant availability is largely dependent on the quality of fuel while the loading on the power plant is greatly influenced by the grid conditions.

The Commission proposes to retain the norm as it is for the next control period.

7.6 STATION HEAT RATE

The Commission specified the Station Heat Rate for biomass power projects based on Rankine cycle technology at 3800 kCal / kWh.

While specifying the above norm the Commission considered that although the design Station Heat Rate is of the order of 3400-3600 kCal / kWh, the operational efficiency is significantly lower and consequently operational station heat rate is higher due to several factors such as deterioration in quality of fuel due to storage, O&M practices etc.

The heat rate assessment of the biomass based power plants is required to be evaluated on the basis of the boiler efficiency and turbine performance. The Central Electricity Authority (CEA) came out with a report on operation norms for biomass based power plant in September 2005, wherein norm of 4500 kCal/kWh was suggested based on the analysis of data furnished by the 16 projects most of them having capacity ranging from 4 MW to 6 MW. From the design data provided by the biomass power plants, CEA calculated Turbine heat rate at 3094 kCal/kWh. Weighted Average Gross heat rate of 16 projects was arrived at 4033 kcal/kWh based on the design steam parameters and efficiency of the boiler derived from the performance curve adjusted based on the moisture content in the biomass fuel which is in the range of 77%.

CEA in its report mentioned that there are variation in parameters like: fuel quality, moisture content, fuel type, condenser vacuum and grid frequency etc. are observed during the actual operation of the plant. Biomass such as cotton stalk, chilly stalk and mustard stalk etc., create problem in the boiler tubes, thus affecting the performance of the boiler. Therefore, CEA suggested allowing 5% allowance over average gross heat rate. Further, noted that since biomass is stored in open, it is affected by climate changes. Certain percentage weight will get loss due to lost of moisture and degradation due to weather changes and loss during the strong wind. Therefore, CEA also suggested allowing additional 5% over 4234.65 to take care of fuel related losses like qualitative and quantative degradation of biomass which works out to 4446.38 kCal/kWh say 4500 kcal/kWh.

The National Productivity Council also conducted a field study for MEDA for assessment of heat rate of commissioned biomass power plants in Maharashtra. The observation and results of the study conducted are as under:

Sr. No.	Name of the Unit		Shalivahana Green Energy Ltd.	Rake Power Ltd.	Saradambika Power Plant Pvt. Ltd.	GAPS Power & Infra. Pvt. L
	Parameters	Unit	10 MW	10 MW	10 MW	10 MW
Turbine Inlet Condition						
1	Steam Flow	TPH	35.6	42.4	43.0	57.3
2	Steam Press.	Kg/cm2	64.9	63.7	61.3	42.3
3	Steam Temp.	Deg C	432	471	487	458
4	Steam Enthalpy	kCal/kg	775.7	799.6	809.6	798.9
5	Condensate Enthalpy	kCal/kg	56	61	75.4	43
Turbine Heat Rate						
6	Total Heat Input	kCal/Kg	25621320	31309254	31570600	43282834
7	Total Power Output	kWh	7850	9825	9250	12310
8	Turbine Heat rate	kCal/kWh	3264	3178	3413	3516
9	Steam rate	Kg/kWh	4.5	4.3	4.6	4.7
10	Boiler Efficiency	%	79.5	75.5	73.1	76.6
11	Station Heat Rate	kCal/kWh	4090	4221	4669	4590

Based on the acceptable Boiler Efficiency & Turbine Heat rate, the NPC suggested that SHR should be in following range:

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

MNRE submitted their recommendation for tariff guidelines vide letter dated 30th September, 2011 wherein it was stated that the SHR depends upon type of fuel which in turn decides the plant configuration and technology.

It is feasible to use very high pressure and temperature and superior combustion technology for rice husk fuel. However, it would not be cost effective to use such high end technology for rice straw as it has poor physical and chemical characteristics.

While mustard husks, stalks and plantation fuels are somewhat in between rice husk and straw. MNRE recommendations on SHR for different technology and fuel are shown in the following table:

Biomass Source	Technology	Gross Calorific Value	IPP (8 MW Capacity)			Tail-end (2 MW Capacity)		
			Steam Pressure (ata)	Steam Temperature (^{0}C)	Net Station Heat rate (kCal/kWh)	Steam Pressure (ata)	Steam Temperature (^{0}C)	Net Station Heat rate (kCal/kWh)
Mustard Stalk	Travelling Grate	3300	68	465	4401	48	435	5753
Paddy Straw	Travelling Grate	3300	68	435	4465	48	435	5753
Rice Husk	AFBC	3200	87	515	4127	48	435	5753
Plantation	AFBC	3200	87	515	4127	48	435	5753

MNRE finally suggested following SHR for biomass power plant greater than 5 MW:

Biomass Source	IPP (> 5 MW)	Tail End (< 2 MW)
Rice Husk	4100	5200
Straw	4400	5500
Others	4150	5200

The Commission is of the view that specifying different benchmark norms for different types of biomass fuel and size of the project for determination of generic tariff will not encourage project developer to use efficient system of converting biomass into electricity. Based on the acceptable Boiler efficiency and Turbine Heat rate, the Commission proposes norm for the Station heat rate at 4000 kCal/kWh for the purpose of determination of tariff for the next Control Period.

7.7 GROSS CALORIFIC VALUE (GCV)

The Commission specified calorific value for eight States in the RE Tariff Regulations-2009, which comprises around approximately 70% of estimated surplus biomass power potential in the country for the mix of biomass fuel available in particular State. Further, in order to determine the weighted average calorific value of biomass fuel mix, the calorific values of individual biomass have been considered as maintained by Indian Institute of Science, Bangalore. States wherein biomass potential is yet to be explored, have been considered under 'Other State' category. The Biomass Atlas prepared and maintained by the Indian

Institute of Science, Bangalore maps State-wise availability of the different type of biomass fuel and also presents the power generation potential using each of the biomass fuel. The following methodology was followed while specifying norm state-wise:

Type of Biomass	GCV kCal/kg	MAH	UP	AP	TN	KAR	RAJ	PUN	MP	HAR
Paddy	3000	6%	46%	56%		11%		49%	7%	34%
Wheat	3800	6%	37%				51%	28%	16%	33%
Mustard	3400						28%			
Bajra	3950	6%					9%			
Maize	3500		10%	10%		18%				
Cotton	3636	47%		5%		18%		21%	37%	23%
Groundnut	4200			12%		9%				
Coffee	4300					9%				
Coconut	3300			6%	13%	16%				
Jowar	3500	13%				10%			9%	
Gram	3810									
Soyabean	3700	9%							19%	
Sunflower	2800									
Share in Total Biomass Surplus Available		86%	93%	90%	13%	91%	88%	98%	89%	90%
Share in Total Biomass Surplus kT/Yr		12,107	11,696	4,235	1,091	7,652	6,878	24,395	8,957	9,215
Total Biomass Surplus Available kT/Yr		14,002	12,537	4,689	8,092	8,442	7,808	24,789	10,080	10,288
Wt. Avg. Calorific Value for State kCal/kg		3,611	3,371	3,275	3,300	3,576	3,689	3,368	3,612	3,458
CV of Biomass kCal/kg		3,476								

A comparison of CERC specified GCV of the biomass fuel in RE Tariff Regulations 2009 and Calorific Value used for the purpose of determination of tariff across various States are as under:

State	Calorific Value (kCal/kg) As specified by CERC	Calorific Value (kCal/kg) As specified by concerned SERC	Rational considered
Andhra Pradesh	3275	APERC: 3200	Based on the report of the expert committee: CV of 3250 kcal / kg which translates into 1.12 kg / kWh.
Haryana	3458	HERC: 3458	As per CERC
Maharashtra	3611	MERC: 3611	As per CERC
Madhya Pradesh	3612	MPERC:3325	Base on GCV of main biomass fuel 3400, supp. biomass fuel 2900 and coal 3600 In 50:25:25 proportion
Punjab	3368	PSERC: 3368	As per CERC
Rajasthan	3689	RERC: 3400	
Tamil Nadu	3300	TNERC: 3200	
Uttar Pradesh	3371	UERC: 3371	As per CERC
Other States	3467	JSERC :3467	As per CERC
		BERC: 3150	As per rice husk GCV
		KERC:3275	Specified based on Specific fuel consumption at 1.16 kg/unit.
		GERC: 3300	As suggested by SNA

MNRE vide its letter dated 30th September, 2011 suggested that GCV should be decided based on the biomass type and following table should be referred for GCV of various biomass:

Sr. No.	Name of Biomass	Moisture (%)	Dust (%)	GCV on as received basis (kCal/kg)
1	Groundnut Shell	4.60	4.00	3167
2	Jeera Residue	6.80	3.85	3690
3	Saw Dust	30.00	12.00	2139
4	Sindhi Saunf	16.97	4.66	3186
5	Asalia	6.69	6.31	3505
6	Isabgol	6.79	5.18	3588
7	Mustard Residue	10.00	4.00	3300
8	Juliflora	13.00	1.00	2800
9	Paddy Straw	10.00	4.00	3300
10	Rice Husk	12.00	1.50	3200

MNRE also mentioned that there are other losses which are being encountered during the storage and handling of biomass due to land settlement, loss of fuel during sand storm, GCV loss due to decaying of biomass. MNRE referred to a recent survey carried out by DESL under mandate from Rajasthan Renewable Energy Corporation Ltd. (RREC) to assess such losses which are in the range of 3.2 to 3.5%. MNRE recommended that there should be provision of loss of fuel during storage at around 2%. MNRE recommended that the following general principles can be adopted for the GCV 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 of 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

Considering the suggestions received from MNRE, a study carried out by NPC, a study carried out by CEA and norms specified by the SERCs, the Commission proposes normative GCV of biomass at 3250 kCal/kg. Taking into account, use of 15% of coal and 85% uses of Biomass fuel, weighted average GCV works out to 3300 kCal/kg (considering biomass GCV at 3250 kCal/kg and average coal GCV at 3600 kCal/kg in proportion of 85% and 15% respectively (3300= (0.85*3250+0.15*3600)).

7.8 FUEL PRICE RELATED ASSUMPTION

The Commission, in terms of Regulation 44 of the RE Tariff Regulations-2009, specified the biomass fuel price applicable during the period 2009-10 and specified fuel price indexation mechanism, in case developer wished to opt, for the remaining years of the Control Period.

The Commission while specifying the biomass fuel price for respective States,had adopted 'equivalent heat value approach for landed cost of coal for thermal power stations at respective States. For this purpose, the Commission had considered the landed cost and calorific values of coal as approved by the respective State Electricity Regulatory Commission while determining the generation tariff of the respective State Utility. The biomass fuel prices for different states specified/determined by the Commission are as under:

State	Biomass price (Rs/MT) 2009-10	Biomass price (Rs/MT) 2010-11	Biomass price (Rs/MT) 2011-12
Andhra Pradesh	1301	1,342.81	1,460.75
Haryana	2168	2,237.67	2,434.21
Maharashtra	1801	1,858.87	2,022.14
Madhya Pradesh	1299	1,340.74	1,458.50
Punjab	2092	2,159.23	2,348.88
Rajasthan	1822	1,880.55	2,045.72
Tamil Nadu	1823	1,881.58	2,046.84
Uttar Pradesh	1518	1,566.78	1,704.39
Other States	1797	1,854.75	2,017.65

Pricing of biomass power mainly depends on supply and demand of biomass. Availability of biomass (agro waste) is mostly dependent on production of the underlying crop which is subject to climatic conditions and cropping patterns. Therefore, its prices are facing seasonal variation. On demand side, biomass power plants face stiff competition from alternate users like: industries which use biomass as fuel for generation of steam, heat and power, feed stock application in paper industries, as a fuel by brick kiln and briquette manufacturers as well as by households for domestic fuel. Increased use of biomass by various users has resulted in to shortages of biomass for power generation and resulted into biomass prices shooting up in most of the states.

Spiraling of biomass price issue was also discussed in the Forum of Regulator Meeting held on 16th June, 2011 wherein the MNRE mentioned that the determination of biomass fuel price needs a detailed review as some of the biomass projects are closing down in Chhattisgarh, Punjab and Rajasthan because of increasing prices of Biomass fuel.

7.8.1 BIOMASS FUEL PRICES CONSIDERED BY THE STATE COMMISSIONS

Since cost of fuel is a critical parameter in determining tariff, the Commission has analysed the biomass prices determined by SERCs and rationale for fixing the same:

State	Biomass price (₹/MT) CERC 2011-12	Biomass price (₹/MT) As specified by concerned SERC	Rationale considered
Andhra Pradesh	1,461	2000	Date of Order: 31.3.09, based on the prevailing cost of biomass
Haryana	2,434	2390 (11-12)	Reviewed biomass price vide Order dated 27.05 2011 as directed by APTEL after detailed analysis and in line with the CERC norm
Maharashtra	2,022	2605 (10-13)	MERC Order dated 29.04.2011 Specified based on the prevailing cost of biomass
Madhya Pradesh	1,459	1181 (07-08)	Equivalent heat value of Coal in 50:25:25 proportion of main biomass, supplement biomass and coal
Punjab	2,349	2500 (10-11)	Collected information from various sources Like: MPL: 2469, DDL: 2845, Apex Co-operative Institutions 2773 - 3070, IREDA: 1800-2000

Rajasthan	2,046	1216 (09-10)	RERC assumed such price in the absence of adequate benchmark price for biomass, Further noted that stakeholders should submit documentary evidence in support of their claim so that RERC may review the base price
Tamil Nadu	2,047	2000 (09-10)	Based on prevailing prices
Uttar Pradesh	1,704	1675 (09-10)	Equivalent heat value of Coal
Other States	2,018	JSERC :1797	As per CERC (09-10)
		CSERC : 2018	As per CERC (11-12)
		BERC: 1050	Date of Order 21.5.2009
		KERC:1280	Took note of CERC specified price 1797 (09-10)
		GERC: 1600 (10-11)	As suggested by State Nodal agency i.e.1500 plus transportation / handling cost 100/MT

From the above table it appears from the above that MERC and PSERC have revised the norm of the biomass price based on the prevailing prices of biomass. GERC has specified on lower side as suggested by State Nodal Agency. HERC, JSERC and CSERC have followed CERC specified norm and rest of the states came out with an order prior to the CERC Re Tariff Regulations-2009.

MNRE vide letter dated 23rd September, 2011 submitted their findings on evaluation report on biomass price wherein prices of different types of biomass in different States for the current years given in table-4 of said report are as under:

State	Rice Husk	Mustard Residue	Stalks (Cotton/ Maize)	Wheat Straw	Paddy Straw	Juliflora	Wood Shavings
Haryana	3000	2200	2000	2500	1500		3500
Maharashtra	2400		1600	2000	1400		3500
Punjab	3200	2500	2000	2500	1500		4000
Rajasthan		1900	1800	2500		1900	
Orissa	2000				1500		2500
West Bengal	2400			2000	1400		3000
Chhattisgarh	2000				1500		3500

MNRE vide letter dated 30th September, 2011 submitted their recommendation on biomass price wherein it mentioned that the differences in the prices prevailing in different states are attributable to present demand supply situation and competitive uses and prices of alternative fuels. It is expected that as more power plants are developed in all states, prices will tend to converge and homogeneous market will develop. Accordingly, following prices can be considered for the current year as homogeneous price for all states.

Biomass	Price (₹ /MT-2011)
Rice husk	3000
Stalks / Other husks	2000
Straw	2400
Plantation	2000

7.8.2 BIOMASS FUEL PRICES FOR FY 2012-13

Considering the above, the Commission proposes normative price for the biomass fuel for the first year of the control period as median value of Equivalent heat value approach for landed cost of coal for thermal power stations at respective States, SERCs specified biomass norms escalated with 5% to bring at FY 2012-13 as well as MNRE recommended price with IISc suggested weightages of different biomass for different States For other States, average of eight states norm is considered.

(₹ /MT)

States	As specified by concerned SERC						MNRE suggested price applied on IISc specified weightages on surplus biomss	Landed Cost of Coal			GCV	Equ. Landed cost of coal	Median of SERC, MNRE & eq. heat approach
	FY07-08	FY08-09	FY09-10	FY10-11	FY11-12	FY12-13	FY12-13	FY10-11	FY11-12	FY12-13		FY12-13	FY12-13
Andhra Pradesh			2000	2100	2205	**2315**	**2650**			1917	3302	**1916**	2315
Haryana				2390	2510	**2635**	**2572**		2642	2774	3358	**2726**	2635
Maharashtra						**2605**	**2116**	1863	1956	2054	3483	**1946**	2116
Madhya Pradesh	1181	1240	1302	1367	1436	**1507**	**2313**		1546	1623	3860	**1387**	1507
Punjab				2500	2625	**2756**	**2805**		2730	2866	3943	**2399**	2756
Rajasthan			1216	1277	1341	**1408**	**2300**			2777	3613	**2536**	2300
Tamil Nadu			2000	2100	2205	**2315**	**2065**	2687	2821	2962	4292	**2277**	2277
Uttar Pradesh			1675	1759	1847	**1939**	**2645**	2169	2277	2391	3350	**2355**	2355
Other States													2283

State	Biomass 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

7.8.3 REVIEW OF BIOMASS FUEL PRICES FOR THE PROJECTS COMMISSIONED IN THE EARLIER CONTROL PERIOD

Since the present biomass based power generation tariff structure of CERC as well as SERCs have no provision to adjust the biomass price adequately to reflect the increased cost of biomass fuel price and in turn cost of generation for the biomass power projects commissioned in the previous control period. Many projects have been affected due to it and have been forced to shut down.

Considering the above, the commission is of the view that any revision either increase or decrease in biomass price is required to be suitably factored in for the viability of biomass power plants commissioned in the earlier control period. The Commission proposes that any revision in the biomass price for the next control period shall also be applicable to projects commissioned in the earlier Control Period with prospective effect.

7.10 FUEL PRICE ESCALATION

The Commission specified the following fuel price indexation formulae in the RE Tariff Regulations-2009 in order to take care of variation in prices of raw fuel, labour charges for storage and handling and transportation cost for the remaining year of the control period:

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

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.

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 nth 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.

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

$VC_n = VC_1 x (P_n / P_1)$ 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 2009-10 and shall be determined as under:

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

In the above formula the various components of base price of the biomass fuel have been linked to indices such as average 'Annual Inflation Rate' for domestic coal to be notified by the CERC from time to time, 'Wholesale Price Index' and 'Weighted Average Price of High Speed Diesel' to take care of fuel cost, fuel handling cost and transportation cost respectively. A normative fuel price escalation factor of 5% per annum shall be applicable at the option of the producer.

The Commission proposes to retain the above formula for Fuel Price Escalation during the Control Period. The Commission also proposes that as and when Commission determines the biomass cost for the next Control Period same will also be applicable prospectively to project commissioned under this Control Period.

7.11 OPERATION & MAINTENANCE EXPENSES

The Commission in its RE Tariff Regulations-2009 specified O&M expense at ₹ 20.25 Lakh/MW for the first year of the Control Period i.e. 2009-10 for the purpose of determination of tariff.

While fixing the said norm the Commission recognized that the size of biomass power plant is small compared to the conventional power projects and therefore the expenses towards manpower, other establishment and administrative expenses are higher as compared to the conventional power plants.

The Commission in its tariff Regulations, 2009-14, specified the norms for O&M expense for such plants at ₹ 18.20Lakhs/MW. Considering the same the normative O & M expenses for biomass based projects for the year 2009-10 was fixed at ₹ 20.25 lakh/MW (4.5% of the Capital Cost) and the same was escalated at the rate of 5.72% per annum to take care of increase in manpower and other related costs. For that reason, in the determination of generic tariff for the FY2011-12, the Commission considered O&M cost norm for biomass power as ₹ 22.63 Lakh/MW.

The Central Electricity Authority (CEA) came out with a report on operation norms for biomass based power plant in September 2005, wherein based on the analysis of data furnished by ten (10) biomass projects having capacity ranging from 4 MW to 8 MW following norm has been suggested:

O & M Cost elements	Suggested Norm in % of capital Cost
Salaries	1.5%
Admin Expenses	1.0%
Repairs & Maintenance	2.5%
Insurance	0.5%
Consumables	1.5%
Total	7 .0%

CEA suggested that 7% norm may be allowed presently and same may be reviewed after 2-3 years. While suggesting above norms, CEA observed that biomass power projects are labour oriented and maintenance requirement in boiler, fuel preparation side etc. comparatively higher than coal fired plants.

Most of the biomass based power projects have size in range of 4 to 6 MW. Large plants tend to have lower O&M costs due to economies of scale. Considering the moderate size of the projects, the Commission proposes the norm at ₹ 234Lakh/MW (which are determined by applying annual escalation factor of 5.72% per annum on the O&M cost norm applicable for FY 2011-12) for the first year of the next Control Period i.e. FY2012-13 and the same is proposed to be escalated at the rate of 5.72% per annum to take care of increase in manpower and other related costs.

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

Under this section, technology specific parameters such as capital cost norm, capital cost indexation mechanism, plant load factor, auxiliary consumption, station heat rate, gross calorific value, biomass fuel price, biomass fuel price indexation mechanism and O&M Expenses, for non-fossil fuel based co-generation projects have been discussed.

8.1 TECHNOLOGY ASPECT

The project may qualify to be termed as a co-generation project, if it is in accordance with the definition and also meets the qualifying requirement outlined below:

> ***Topping cycle mode of co-generation*** *– Any facility that uses non-fossil fuel input for the power generation and also utilizes the thermal energy generated for useful heat applications in other industrial activities simultaneously.*
>
> *For the co-generation facility to qualify under topping cycle mode, the sum of useful power output and one half the useful thermal outputs be greater than 45% of the facility's energy consumption, during season.*

8.2 CAPITAL COST BENCHMARKING

The Commission under Regulation 47 of the RE tariff Regulation-2009 specified the normative capital cost for the Non-Fossil Fuel Based Cogeneration Projects as ₹ 445

Lakh/MW for FY 2009-10 which was linked to the indexation mechanism specified under Regulation 48 of the RE Tariff Regulations-2009. In line with the indexation mechanism specified in Regulation 48 of the RE Tariff Regulations-2009, the Commission vide Order No. 53/2010 dated 26th April 2010 determined the normative capital cost of the Non-Fossil Fuel based Cogeneration power projects as ₹ 398.07Lakh/MW for FY 2010-11 and vide Order No. 256/2010 dated 9th November, 2010 determined the normative capital cost of ₹ 421.30 Lakh/MW for FY 2011-12.

Year	Date of Order/Regulation	Capital cost ₹ Lacs/MW
2009-10	17.09.2009	445.00
2010-11	26.02.2010	398.07
2011-12	09.11.2010	421.30

8.2.1 COST CONSIDERED BY THE STATE REGULATORY COMMISSIONS

Three SERCs have issued tariff Orders for bagasse based cogeneration projects after the issuance of RE Tariff Regulations-2009 by CERC. The cost data approved by such SERCs are as under:

	CERC	GERC	MERC	JSERC	HERC
Date of Order/ Regulation	17.9.09	31.5.10	7.6.10	27.01.10	3.2.11
Capital Cost ₹ In Cr./MW	4.45 (FY09-10) 3.98 (FY10-11) 4.21 (FY11-12)	4.15 (FY10-11)	3.98 (FY10-11) As per CERC	4.00 (FY10-11) As per CERC	4.45 (FY 10-11) As per CERC
Indexation provision	Provided	No indexation	Indexation as per CERC	Indexation as per CERC	Indexation as per CERC

Analysis of the Capital cost in the tariff setting exercise undertaken by different SERCs shows that the Capital Cost specified by above referred SERCs have considered CERC determined norm.

8.2.2 COST CONSIDERED BY THE FINANCINGF INSTITUTIONS

Capital cost information for bagasse based cogeneration projects as provided by IREDA and PFC are analysed as under:

Cost of bagasse based cogeneration projects sanctioned by IREDA during 2010-11 and 2011-12 are as below:

Sr. No.	Capacity in MW	Project Cost ₹ Lakh	Project Cost ₹ Lakh/MW
1	26	12850.00	494.23
2	10	4430.00	443.00
3	22	11019.00	500.86
4	20	8783.11	439.16
5	30	15945.00	531.50

Cost of bagasse based cogeneration projects sanctioned by PFC to TNEB for establishment of cogeneration plants at 10 Co-operative Sugar mills and 2 Public sector sugar mills with a total capacity of 183 MW having total project cost of ₹ 1034.69 Crore/MW. Per MW cost works out to ₹ 5.65 Crore/ MW. This project is going to employ boiler configuration of 87 Kg/ cm^2 and 515^0 C for 10 sugar mills and 110 Kg/ cm^2 and 540^0 C for 2 sugar mills.

The capital cost of installation of bagasse based co-generation projects depends upon boiler pressure/ temperature, capacity of power projects. Utilizing high-pressure technology more power can be generated. Following benchmark on capital cost is being considered by a financial institution:

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

Impact of Steam generation pressure on power generation in a 2500 TCD Sugar Mill

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

Source: MNRE

8.2.3 BASIS FOR FORMULATION OF CAPITAL COST BENCHMARK

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 ^{o} C configuration, the Commission proposes to consider normative capital cost of ₹ 420 Lakh / MW for first year of the next Control Period.

8.3 CAPITAL COST INDEXATION MECHANISM

The Commission proposes indexation mechanism, as mentioned in the para 4.1, to be applicable in case of bagasse based cogeneration projects for adjustments in capital cost over the Control Period with the changes in Wholesale Price Index for Steel and Electrical Machinery.

8.3 PLANT LOAD FACTOR (PLF)

The Commission specified the following plant load factor for different States in its RE Tariff Regulations-2009 for non-fossil fuel based cogeneration projects on the basis of inputs received from MNRE and IREDA regarding duration of crushing season in the state and additional off-season operation with stored/purchased bagasse with load factor of 92%.

State	Operating Days	Plant Load Factor (%)
Uttar Pradesh and Andhra Pradesh	120 days (crushing)+ 60 days (off-season) = 180 days operating days	45%
Tamil Nadu and Maharashtra	180 days (crushing)+ 60 days (off-season) = 240 days operating days	60%
Other States	150 days (crushing) + 60 days (off-season) = 210 days operating days	53%

Analysis of the PLF and related discussion in the tariff setting exercise undertaken by different SERCs in establishing the tariff for bagasse power plant shows that the PLF specified by most of the SERCs are in the range of 50% to 60%.

States	Uttar Pradesh	Andhra Pradesh	Gujarat	Tamil Nadu	Karnataka	Maharashtra
Date of Order/ Regulation	9.9.2009	31.3.2009 & 20.3.2004	31.5.10	6.5.09	11.12.09	7.6.10
Plant Load Factor	50%	55%	60%	55%	60%	60%

Considering the above, the Commission proposes to retain the plant load factor specified in the RE tariff Regulations-2009 on the basis of the average crushing period in respective States for the purpose of determining the fixed charges for the next Control Period.

8.5 AUXILIARY CONSUMPTION

The Commission specified auxiliary power consumption factor of 8.5% for the Control Period 2009-12. While fixing such norm the Commission considered that the non-fossil fuel based cogeneration plants have some of the auxiliary equipment common between the sugar mill and the power generation unit. It was also considered that the bagasse requires less processing compared to the biomass and hence comprises lesser auxiliary system.

Analysis of the Auxiliary Consumption and related discussion in the tariff setting exercise undertaken by different SERCs in establishing the tariff for bagasse power plant shows that the Auxiliary Consumption specified by the most of the SERCs in the range of 8 to 10 %.

States	Uttar Pradesh	Andhra Pradesh	Gujarat	Tamil Nadu	Karnataka	Maharashtra
Date of Order/ Regulation	9.9.2009	31.3.2009 & 20.3.2004	31.5.10	6.5.09	11.12.09	7.6.10
Auxiliary Consumption	8.5%	9%	8.5%	9%	8%	8.5%

Considering the same, the Commission proposes to retain the auxiliary consumption norm at 8.5%.

8.6 STATION HEAT RATE

The fuel consumption during crushing season (co-generation mode) is used for power generation as well as steam generation purposes, whereas fuel consumption during off-season is essentially used for power generation purposes. Considering the same, the Commission specified the normative Station Heat Rate of 3600 kCal / kWh for power generation component alone for computation of tariff for non-fossil fuel based Cogeneration projects for the Control Period 2009-12. The above norm was specified based on the information furnished by MNRE and analysis of the heat mass balance diagrams for a few co-generation projects.

States	Uttar Pradesh	Andhra Pradesh	Gujarat	Tamil Nadu	Karnataka	Maharashtra
Date of Order/ Regulation	9.9.2009	31.3.2009 & 20.3.2004	31.5.10	6.5.09	11.12.09	7.6.10
Station Heat Rate kCal/kWh	3650 for old plants 3100 for new plants	3700	3600	3518	3600	3600

Most of the SERCs have specified the norm for Station Heat Rate around 3600 kCal/kWh. UPERC allowed Station Heat Rate as 3650 Kcal/kWh for existing plants but a lower Station Heat Rate as 3100 Kcal/kWh for new plants considering that new plants will have higher efficiency due to advanced technology.

The Commission proposes to retain the Station Heat Rate norm at 3600 kCal/kWh.

8.7 GROSS CALORIFIC VALUE (GCV)

The Commission had specified the Gross Calorific Value for bagasse considered as 2250 kCal/kg for the Control Period 2009-12. This was based on the information collected for various projects, literature available on the gross calorific value of bagasse like, study of literature on 'By-products of the cane sugar industry' authored by Mr. J. Maurice Paturau, (consultant for cane sugar technology, Published by Elsvier Scientific Publishing Company, Amsterdam - Second Revised edition 1982), the comments received from the stakeholders on the discussion paper floated by the various SERCs as well as verification with agriculture research institutes the Gross calorific value of bagasse varies in the range of 2200kCal/kg to 2300kCal/kg on wet basis depending on the percentage of the moisture content and the soluble solids in the bagasse.

States	Uttar Pradesh	Andhra Pradesh	Gujarat	Tamil Nadu	Maharashtra
Date of Order/ Regulation	9.9.2009	31.3.2009 & 20.3.2004	31.5.10	6.5.09	7.6.10
GCV	2280	2312	2250	2300	2250

Gross Calorific Value specified by different SERCs is in the range of 2250 to 2300 kCal/kg. Considering the same the Commission proposes to retain the norm for Gross Calorific Value at 2250 kCal/kg.

8.8 FUEL PRICE

The Commission in its RE Tariff Regulations - 2009 computed the fuel price of bagasse for respective States for the base year 2009-10 on ‘equivalent heat value’ approach for landed cost of coal for thermal Stations for respective States.

State	Bagasse Price (2009-10) (₹/MT)	Bagasse Price (2011-12) (₹/MT)
Andhra Pradesh	899	1,009.39
Haryana	1411	1,584.26
Maharashtra	1123	1,260.89
Madhya Pradesh	809	908.34
Punjab	1398	1,569.66
Tamil Nadu	1243	1,395.63
Uttar Pradesh	1013	1,137.39
Other States	1163	1,305.80

Bagasse is a byproduct in the sugar industry and it also has alternate uses like, in paper industry. Alternative approach is the price that bagasse would otherwise get for other applications can be considered as cost of bagasse in short term.

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 in the state	Based on prevailing prices of bagasse in the state	Based on prevailing price of bagasse in the state

The Commission proposes to retain the approach followed in the RE Tariff Regulations-2009 i.e. 'equivalent heat value' approach for landed cost of coal for thermal Stations for respective States, for determination of the fuel price of bagasse for respective States for the base year 2012-13 considering the landed cost and calorific values of coal as approved by the respective State Electricity Regulatory Commission.

The State Electricity Regulatory Commission, while determining the generation tariff of the respective State Utility, approved the coal prices during the year FY 2010-11 and 2011-12. The bagasse prices so derived have been escalated based on fuel price indexation mechanism stipulated under the Regulation to derive fuel prices during first year of the Control Period (i.e. for FY 2012-13). The fuel price for each station in terms of ₹/MT equivalent to heat content of 2250kCal/kg is then derived, which is presented under following table.

State	Bagasse Price (₹/MT)
Andhra Pradesh	1307
Haryana	1859
Maharashtra	1327

Madhya Pradesh	946
Punjab	1636
Tamil Nadu	1408
Uttar Pradesh	1458
Other States	1420

8.9 FUEL PRICE INDEXATION MECHANISM

In case of bagasse based cogeneration 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 Bagasse/biomass for the nth year to be considered for tariff determination

P (n-1) = Price per ton of Bagasse/biomass for the (n-1)th year to be considered for tariff determination. In case of n=1, P (n-1) shall be equal to P0.

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 nth 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. By default, these will be 0.2, 0.6 & 0.2 respectively, unless otherwise specified.

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

$VCn = VC_0 \times (Pn / P_0)$ or $VC_0 = 1.05 \wedge (n-1)$ (optional)

Where,

VC_0 represents the Variable Charge based on bagasse Price P0 for FY 2012-13 (i.e. beginning of Control Period) and shall be determined as under:

$$VC_0 = 60\% \times \frac{\text{Station Heat Rate (SHR)}}{\text{Gross Calorific Value (GCV)}} \times \frac{1}{(1 - \text{Aux Cons. Factor})} \times \frac{P_0}{1000}$$

8.10 OPERATION AND MAINTENANCE EXPENSES

The Commission had specified the O&M cost norm as Rs 13.35 lakh per MW (3% of the Capital Cost ₹ 445 Lacs/MW) for the year FY 2009-10 with escalation rate of 5.72% per annum for remaining year of the Control Period for determination of the levellised tariff. Subsequently, the Commission, while determining the generic tariff for FY2011-12 considered the O&M cost norm for non-fossil fuel based co-generation as ₹ 14.92 Lakh/MW.

While specifying such norm, the Commission considered that in case of cogeneration projects there are several common expenses between the host sugar factory and cogeneration unit. It was further considered that the bagasse is readily available in the premises of the sugar factory only, and hence does not require additional manpower in fuel transportation and hence associated handling charges are negligible.

The O&M cost of bagasse power plants is on the higher side compared with the thermal power plants because of small size of the plant. Analysis of the O&M cost and related discussion in the tariff setting exercise undertaken by different SERCs in establishing the tariff for bagasse power plant shows that the O&M cost specified by the most of the SERCs at 3% except TNERC.

States	Uttar Pradesh	Andhra Pradesh	Gujarat	Tamil Nadu	Karnataka	Madhya Pradesh	Haryana	Maharashtra
Date of Order	9.9.09	31.3.09 & 20.3.04	31.5.10	6.5.09	11.12.09	9. 2008	3.2.11	7.6.10
O&M Expenses	3% of capital Cost	3% of capital Cost	3% of capital Cost	4.5% of capital Cost	3% of capital Cost	3% of capital Cost	₹ 13.35 Lakh/MW (3% of capital Cost)	₹ 14.11 Lakh/MW
Escalation	4%	4%	4%	5%	5%	5%	5.72%	5.72%

The Commission proposes the normative O&M expenses as ₹ 16 Lakh/MW for the year 2012-13 (FY11-12 norm escalated at 5.72%). The Commission further proposes that the operation and maintenance expenses for the year 2012-13 shall be escalated further at the rate of 5.72% per annum to arrive at permissible operation and maintenance expenses for the subsequent years of the Control Period.

9. TECHNOLOGY SPECIFIC NORMS: SOLAR PV POWER PLANT

Under this section, technology specific parameters such as capital cost norm, capacity utilization factor and O&M Expenses, for solar PV projects have been discussed.

9.1 TECHNOLOGY ASPECT

Norms for Solar Photovoltaic (PV) power would be applicable for grid connected PV systems that directly convert solar energy into electricity and are based on the technologies such as crystalline silicon or thin film etc. as may be approved by MNRE.

9.2 CAPITAL COST BENCHMARKING

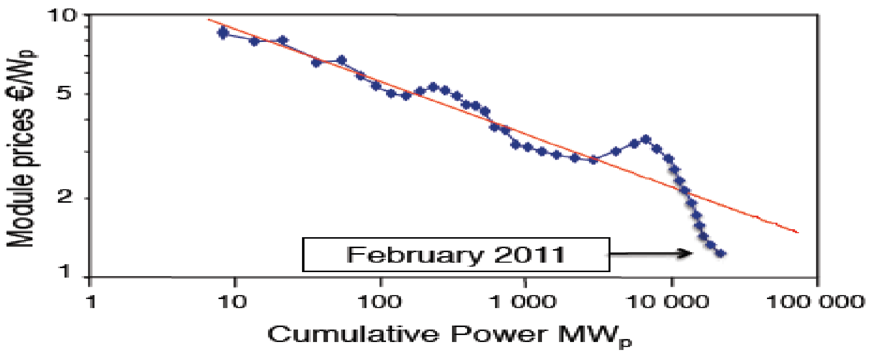
The capital costs for Solar Photovoltaic (PV) power projects fall into two broad categories; the module and the balance of system (BOS). The module is the interconnected array of PV cells and incorporates feedstock silicon prices, cell processing and module assembly costs. The BOS includes structural system costs viz. structural installation, racks, site preparation and electrical system costs, inverter, wiring and transformer.

In accordance with the first proviso under Regulation 5 of the RE Tariff Regulations-2009, the benchmark capital cost for Solar PV power projects is to be reviewed annually. The Commission, for FY 2009-10, specified the normative capital cost for MW scale Solar PV Power Projects as ₹ 1700 Lakh / MW. Subsequently, Commission had reviewed, benchmark capital cost for Solar PV power projects at ₹ 1690 Lakh / MW for the FY 10-11 (vide the Order dated 25.02.2010 in Petition no. 13/2010) and ₹ 1442 Lakh / MW for the FY 11-12 (vide the Order dated 15.9.2010 in Petition no. 255/2010).

Year	Benchmark Capital cost ₹ Lakh / MW
2009-10	1700
2010-11	1690
2011-12	1442

9.2.1 MODULE COST COMPONENT

PV modules cost represent the single-largest cost item of a PV system. Average global PV module factory prices dropped from about USD2005 22/W in 1980 to less than USD2005 1.5/W in 2010 (Bloomberg, 2010). Study about price experience curve (learning curve) focus on the silicon wafer based photovoltaic modules wherein world market prices are shown below as a function of the global cumulative shipment (logarithmic scales).



Source: Solar Energy Research Institute of Singapore (SERIS) ANNUAL REPORT2010

The above figure illustrates PV price decline over the last 20 years, with the price of PV modules decreasing by over 20% every time the cumulative sold volume of PV modules has doubled (learning factor). According to the Solar Energy Research Institute of Singapore (SERIS) the strong reduction of module prices is due to (i) economy of scale (ii) optimization of production in industry (iii) reduced company margins in the course of the economic crises and (iv) a multitude of highly essential incremental R&D results (almost throughout the whole curve).

The Energy Trend's survey which also shows that the Silicon Module's average weekly spot prices per watt as on 28th September 2011 was around US$ 1.124 per Watt.

PV Spot Price	High	Low	Avg	% Change
Poly Price (Per KG)	50.50	40.00	46.580	-4.18%
Multi-Si Wafer (156mm x 156mm)	2.00	1.61	1.814	-3.05%
Mono-Si Wafer (156mm x 156mm)	2.85	2.10	2.398	-1.52%
Cell Price (Per Watt)	0.83	0.66	0.704	-1.81%
Multi-Si Cell (156mm x 156mm)	2.88	2.57	2.844	-1.81%
Mono-Si Cell (156mm x 156mm)	3.10	2.74	3.050	-1.81%
Module Price (Per Watt)	1.69	1.04	1.124	0.00%
Thin Film Price (Per Watt)	1.20	0.85	0.927	0.00%
CPV Price (Per Watt)	2.55	2.09	2.303	0.00%
PV Inverter Price (Per Watt)	0.35	0.19	0.235	0.00%

According to the Pvinsight, the Silicon and Thin Film Module's weekly average spot prices per watt as on 28th September 2011 was around US$ 1.135 and US$ 0.895 per Watt respectively.

Tem	High US$	Low US$	Average US$
Silicon Module Price Per Watt	1.50	1.00	1.135
Thin Film Module Price Per Watt	1.20	0.80	0.895

Source: http://pvinsights.com/

The above analysis reveals that the current thin film module price per watt varies in the range of $0.8 to $1.20 and crystalline module price varies in the range of $1.0 to $1.5. Currently, modules suppliers are offering crystalline modules in India at around $1.15 per watt. Most of the international studies reveal that the prices are expected to decline in future. Considering the same, the Commission proposes to consider base module cost at $1.00 per watt (CIF) i.e. cost, insurance, taxes and freight price, for the determination of benchmark capital cost for solar PV projects for FY2012-13. With the exchange rate of Rs 49/US$, the module cost works out to ₹ 4.90 Crore/ MW.

9.2.2 NON-MODULE COST COMPONENT:

The non-module cost components (Balance of Supply) comprise cost towards land, civil & general works, ground mounting structures, power conditioning unit, cabling & transformer/ switchgears and preliminary/pre-operating expenses & financing costs. The non-module component together contributes to approximately 40% of overall capital cost requirement of solar PV based power projects.

There is great cost reduction potential for the BOS industry as it develops, and adopts similar principles to those followed in the module industry. An increased level of component standardisation can decrease cost and labour. This standardisation of components can help drive economies of scale, and lead to high volume manufacturing. Pre-assembled components realised through the standardisation and resulting economies, can also offer cost savings in the installation phase. High volume manufacturing has the potential to significantly reduce component costs, as it has in the module production industry. Significant cost savings opportunities remain, as the BOS component manufactures are typically small (with small market share), and utilise materials that are not specifically design for use in the solar industry. (Source: Renewable Energy Technology Cost Review – Melbourne Energy Institute, March 2011)

Each component of above referred non-module cost of Solar PV based power plant is estimated as under for the determination of benchmark capital cost of Solar PV projects for FY2012-13.

1.1 9.2.2.1 POWER CONDITIONING UNIT: INVERTER

The single largest of the BOS components the inverter. The Commission, while determining the benchmark capital cost for Solar PV projects for the year 2011-12, had considered the Inverter cost as ₹ 1.60 Crore/MW. According to IPCC Report-2011, the overall BOS experience curve was between 78 and 81%, or a 19 to 22% learning rate. Quite similar to the module rates, learning rates for inverters were just in the range of 10%.

Based on the Energy Tend survey as shown in the above table, the Commission proposes to consider base inverter price at $0.20 per watt for the determination of benchmark capital cost for solar PV projects for FY2012-13. With the exchange rate of Rs 49/US$, the module cost works out to ₹ 0.98 Crore/ MW.

9.2.2.2 LAND

The land requirement for Solar PV based power project depends upon the technology employed i.e. Crystalline or Thin film, conversion efficiency and solar radiation incident in respective area. The Commission, while determining the benchmark capital cost for Solar PV projects for the year 2011-12, had considered land requirement of 5 Acre/MW and its cost was considered as ₹ 3 Lakh/Acre or 0.15 Crore / MW. After allowing 5% escalation over the benchmark land cost for FY 2011-12, the Commission proposes to consider ₹ 16 Lakh/MW as the land cost for the determination of benchmark capital cost of Solar PV projects for FY2012-13.

9.2.2.3 CIVIL AND GENERAL WORKS

The cost associated with civil works includes roads and pathways, testing of soil, preparation of soil/ground with all necessary works like earthmoving, foundations and civil works for: transformers, HT panels, module mounting structures, fencing, earthing mat, main gate, security room, main control room, cable trenches, water system-sump with pump and water pipelines etc.

The Commission, while determining the benchmark capital cost for Solar PV projects for the year 2011-12, had considered the civil and general works together as ₹ 0.95 Crore/MW It was derived after allowing cost escalation of 5% over the last year's cost.

Considering the Civil Works rates being offered by the EPC contractors for MW size projects, the Commission proposes to consider 0.90 Crore/MW as the cost for Civil and General work for benchmark capital cost of Solar PV projects for FY2012-13.

9.2.2.4 MODULE MOUNTING STRUCTURES

This expenditure includes cost associated with manufacturing, delivery, installation and calibration of MS galvanized steel structures including all necessary material and works of erection and commissioning. The Commission, while determining the benchmark capital cost for Solar PV projects for the year 2011-12, had considered the cost of ground mounting structure as ₹ 1.05 Crore/MW.

Considering the module mounting structures rates quoted by the EPC contractors for MW size projects, the Commission proposes to consider 1.00 Crore/MW as the cost for Civil and General work for benchmark capital cost of Solar PV projects for FY2012-13

9.2.2.5 CABLES AND TRANSFORMERS AND EVACUATION SYSTEM

This expenditure includes EPC cost towards DC caballing between Solar PV panels & Inverters including junction boxes, AC cabling between Inverter & sub-station, Earthing arrangements and Transformer. The transformer cost includes the EPC cost of a step up outdoor type transformer, auxiliary transformers, 33 kV breaker, Current Transformers, Potential Transformers, Isolators, LAs, protection relay and TOD meter. It also includes electrical accessories like , MCCBs, MCBs, fuses, lugs, glands etc, plant and control room lighting system with supports, fixtures, SCADA system, battery set, earthing system.

The Commission, while determining the benchmark capital cost for Solar PV projects for the year 2011-12, had considered the cost of cables and transformers and other associated equipments as ₹ 0.90 Crore/MW. The Commission proposes ₹ 1.00 Crore / MW as expenditure towards cables, transformers and evacuation system for solar PV projects for the determination of benchmark capital cost of Solar PV projects for FY2012-13.

9.2.2.6 PRELIMINARY/PRE-OPERATING EXPENSES AND FINANCING COSTS

The preliminary/pre-operating expenses include transportation of equipment, storage of equipment at site, insurance, contingency, taxes and duties, IDC and finance charges etc. Detailed breakup of Preliminary and Pre-operative expenses and financing cost, lump sum in percentage of total capital cost is proposed as under:

i. Insurance Cost: 0.5%
ii. Contingency: 0.5%
iii. Interest during Construction (IDC): 4%
iv. Financing cost: 1%
v. Project management cost: 0.5%
vi. Pre-operative Cost: 1%

Preliminary/Pre-operating expenses and Financing Cost contribute to above 7.5% of total capital cost on average basis. Accordingly, ₹ 0.80 Crore /MW is proposed to be considered as preliminary /Pre-operating expenses and Financing cost.

The table below presents the breakup of benchmark capital cost norm for Solar PV projects for the FY 2012-13:

Sr. No.	Particulars	Capital Cost Norm for Solar PV project (₹ Lakh/MW)	% of total cost
1	PV Modules	494	54%
2	Land Cost	16	2%
3	Civil and General Works	90	9%
4	Mounting Structures	100	10%
5	Power Conditioning Unit	98	9%
6	Cables, Transformers and other misc.	100	10%
7	Preliminary and Pre-Operative Expenses including IDC and contingency	80	7.6%
8	Total Capital Cost	978	100%

Considering the above facts into consideration as well as taking care of degradation in the module output over a period of time, the Commission proposes the total cost of Solar Photo voltaic power projects for the FY2012-13 as ₹ 10.0 Crore/MW .

9.3 CAPACITY UTILISATION FACTOR

The Commission in its RE Tariff Regulations-2009 specified the Capacity Utilisation Factor for Solar PV project at 19%. Subsequently, the Commission had commissioned a study to assess as to whether the CUF of 19% for solar PV was adequate given the solar radiation in the country. The report suggests 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, the Commission proposes benchmark CUF of 19% for the next Control Period for determination tariff.

9.4 OPERATION AND MAINTENANCE EXPENSES

Regulation 59 of the RE Tariff Regulations-2009 provided the normative O&M expenses for solar PV projects for the year 2009-10 to be Rs 9.00 lakh/MW which shall be escalated at the rate of 5.72% per annum over the tariff period for determination of the levellised tariff. Accordingly, O&M expense norm for solar PV power project as Rs 10.06 Lakh/MW for FY 2011-12 has been considered.

According to Intergovernmental Panel on Climate Change (IPPC) working group report the O&M costs of PV electricity generation systems are low and are found to be in a range between 0.5 and 1.5% annually of the initial investment costs (Breyer et al., 2009; IEA, 2010c). Based on the capital cost proposed above it comes under the range of Rs 6.25 to 18.75 Lakh/MW depending upon the size of the projects.

The Commission has also considered the offers provided by the EPC contractors for Operation & Maintenance Support services to MW scale projects at Rs 10 lakh/year/MW with the escalation of 5-6 % per annum which includes maintaining the plant, replacement services & Cleaning manually of Modules for 10 years along with manpower support of engineers, technicians, workmen and security guard.

Considering the above, the Commission proposes the normative O&M expenses for solar PV projects for the year 2012-13 to be at ₹ 11 lakh/MW (Norm for FY2010-11 escalated at 5.72%) which shall be escalated at the rate of 5.72% per annum over the tariff period for determination of the levellised tariff.

10. SOLAR THERMAL TECHNOLOGIES

Under this section, technology specific parameters such as capital cost norm, capacity utilization factor, auxiliary consumption and O&M Expenses, for solar thermal projects have been discussed.

Solar Thermal technologies use systems of mirrored concentrators to focus direct beam solar radiation to receivers that convert the energy to high temperatures for power generation. There are four commercially available CSP technologies:

i. Parabolic Trough

ii. Central Receiver Tower

iii. Dish Engine

iv. Linear Fresnel

As per NREL Report the CSP projects of both parabolic trough and power tower technology, as of 2011, have been deployed mostly in Spain and U.S. Some projects are also operational and under development in the Middle East and North Africa region (MENA). CSP projects that use Linear Fresnel Reflector and Dish / Stirling Engine systems systems are very few and still under developmental stage.

10.1 CAPITAL COST AND CAPACITY UTILIZATION FACTOR (CUF)

As per Regulation 5 of the RE Tariff Regulations-2009, the Commission needs to review the benchmark capital cost for Solar Thermal Power projects every year. Accordingly the Commission reviewed the same and fixed it at ₹ 1500 Lakh/MW for the FY 2011-12 (Order dated 15th September, 2010 in the Petition No.255 /2010)

The Capital cost of solar thermal project is dependent on the solar irradiation level at a particular location. Variation of solar irradiation level at different locations would result in variation in electricity output, CUF and capital costs. For solar thermal power projects, the electricity output is computed by the formula:

Electricity Output = Annual average solar irradiation (KWh/m2/year) x Plant Efficiency (%) x Solar Field size (m^2)

Solar field size is one of the most decisive factors in deciding the cost of the project. The solar field, comprising of mirrors which concentrate the incident solar irradiation onto heat absorber tubes which absorb the thermal energy and transfers it to a heat transfer fluid. Heat exchangers transfer thermal energy to generate steam that drives a conventional turbine.

Designing the 'right' size of solar field to generate sufficient thermal heat required to drive the turbine continually throughout its operation depends on the solar irradiation level which varies according to the 'time of day' (maximum in the afternoon, low in the mornings and evenings) and 'month of year' (lower during monsoon, higher during summer months).

A larger than necessary (or a smaller) solar field may result in excess (or deficient) solar energy required to drive the turbine thereby causing solar energy to be dumped. Based on the solar field efficiency, hourly incident irradiation and the thermal to electric plant efficiency, solar simulation software is used to compute the thermal heat of steam required by the system to drive the steam turbine for different solar field sizes, along with electric output, capital costs and CUF.

The CUF is dependent on solar field size and number of hours of storage which are optimized for minimum Levelised energy cost (LEC, also commonly abbreviated as LCOE). Project cost is dependent on the CUF projected and corresponding solar field size. Solar irradiation varies from location to location across the country. Therefore field size requirement and in turn the project cost would also vary for a particular CUF across the country.

Parabolic Trough technology has achieved close to full commercial status while cost data for the power Tower, Fresnel and Dish Stirling technologies are in the process of being established. Therefore, available cost data of Parabolic Trough technology is considered for the determination of benchmark capital cost norm for solar thermal projects for the year 2012-13.

10.3 SYSTEM ANALYSIS MODELING (SAM)

SAM software (https://www.nrel.gov/analysis/sam/) for modeling and analysis has been developed by National Renewable Energy Labs, U.S. Department of Energy (NREL). SAM software is used extensively by project developers, policy makers and regulators in determining the project parameters (Electricity output, project cost, LCOE etc.) based on incident solar irradiation, standard solar component efficiencies and cost through the optimization of solar field size and no. of hours of thermal storage. NREL has also projected incident solar irradiation throughout India based on satellite modeling. (http://rredc.nrel.gov/solar/new_data/India/nearestcell.cgi)

CERC has not considered the optimization of solar field size and number of hours of thermal storage but assumed zero dump (neither excess nor deficient) of solar energy from the solar field. Optimization of these parameters based on incident irradiation would result in reduction of LCOE.

The Direct Normal Insonation (DNI) of different locations of solar resources rich states in the country is shown as under:

Year / States	Rajasthan Bhadla	Gujarat Aurum	Andhra Pradesh Megha
2002	2178	2180	2159
2003	2048	2167	2008
2004	2058	2136	2059
2005	2074	2236	1899
2006	1986	2164	2041
2007	2097	2180	1900
2008	2126	2084	2014

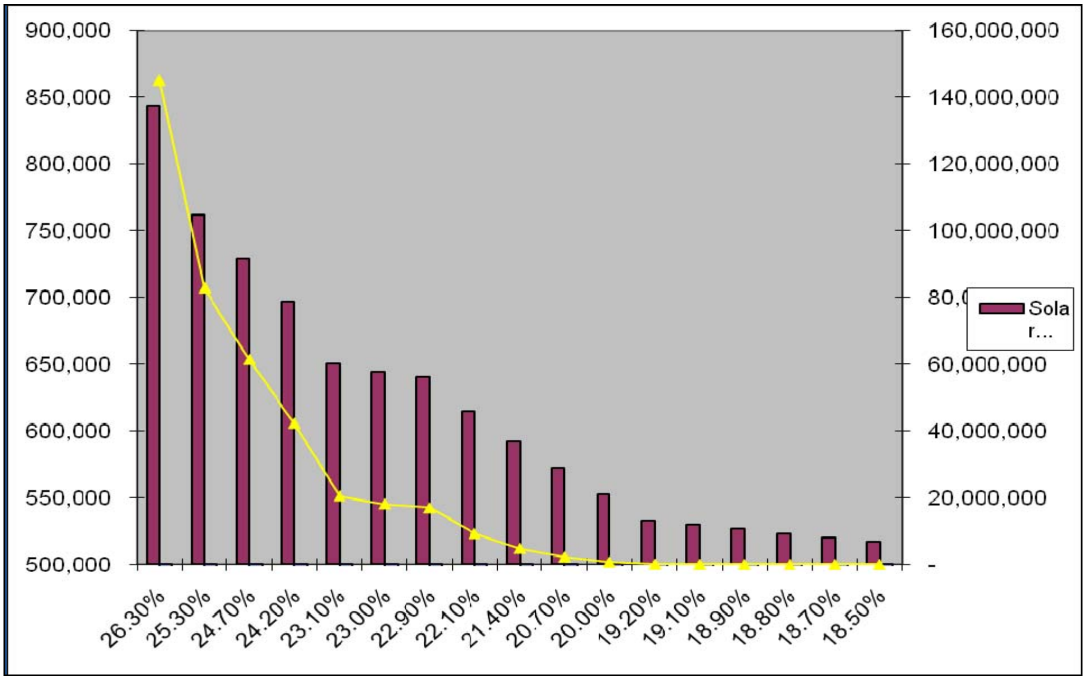
It appears from the above table that the solar irradiation level at different locations is different and also has yearly variation at the same location. In the RE Tariff Regulations-2009, a CUF of 23% has been specified. For determination of solar field size corresponding to target CUF of 23% and Capital cost, Rajasthan State, Jodhpur District DNI data of the year 2005 taken as representative irradiation (Direct Normal Insolation (DNI): 2074 kWh/m2/year) for the analysis.

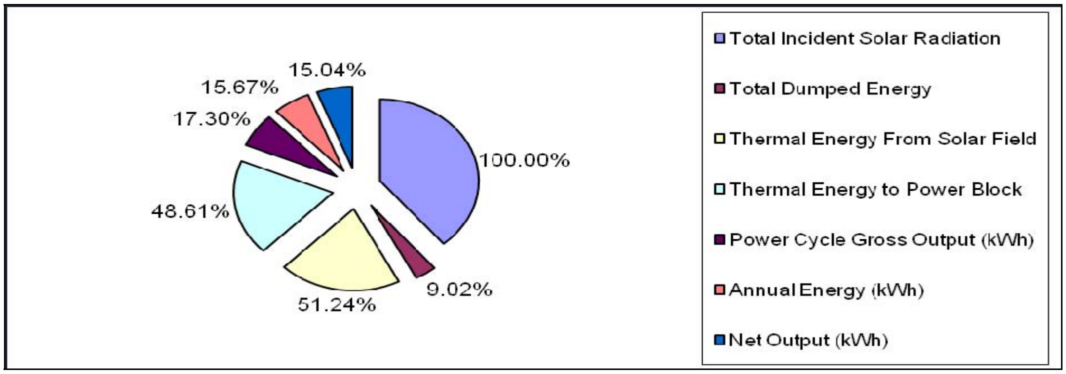
The table shown below calculates electricity output and CUF based on SAM modeling (for a 111 MW plant with net generation of 100 MW with standard component efficiency used is tabulated below) for Jodhpur District representative irradiation (Direct Normal Insolation (DNI): 2074 kWh/m2/year) with different size of solar field assuming nil thermal storage.

SM	Solar Field	Output	CUF	E-Dump	Dump/Output
1.64	843,660	229,802,081.00	26.30%	145,249,200	63.2062%
1.48	761,910	221,261,862.00	25.30%	83,002,880	37.5134%
1.415	729,210	216,570,205.00	24.70%	61,464,410	28.3808%
1.35	696,510	211,657,613.00	24.20%	42,340,810	20.0044%
1.26	650,730	202,454,388	23.10%	20,579,080	10.1648%
1.25	644,190	200,980,390	23.00%	18,134,440	9.0230%
1.245	640,920	200,233,277	22.90%	16,970,220	8.4752%
1.195	614,760	193,631,312	22.10%	9,262,562	4.7836%
1.15	591,870	187,090,149	21.40%	4,788,951	2.5597%
1.11	572,250	181,053,466	20.70%	2,215,236	1.2235%
1.07	552,630	174,750,605	20.00%	712,963	0.4080%
1.035	533,010	168,054,750	19.20%	78,549	0.0467%
1.03	529,740	166,854,200	19.10%	39,564	0.0237%
1.02	526,470	165,810,786	18.90%	13,534	0.0082%
1.015	523,200	154,522,901	18.80%	1,392	0.0009%
1.01	519,930	163,352,776	18.70%	-	
1	516,660	162,145,245	18.50%	-	

It has been found that for solar field size of 519930 m^2 for 110 MW projects results in nil solar energy dumped and provides an electricity output of 1.63 MUs with a CUF of 18.7 % based on standard component efficiencies.

Based on the above table and analysis, in order to achieve a CUF of 23%, solar field size of 5804 m^2 per MW would be required with an energy dump of 9%. The commission has therefore considered capital cost based on the solar field size of 5804 m^2 in determination of benchmark capital cost while maintaining CUF of 23%. The table shown below gives information about relation between solar field size, corresponding CUF and dumped energy for a 111 MW plant with net generation of 100 MW.





The parameters considered for benchmark capital cost are tabulated with the estimated cost of each sub-components as under: 1 € = ₹ 67

Solar Field (m2)/MW		5804
Sr. No.	**Particulars**	**€ per m2**
1	Structure	30
2	HCE (Absorber Tubes):	41
3	Mirrors	35
4	Labour charges for assembling, welding, alignment and topography	12
5	Solar Field Piping	20

6	HTF System (pumps, tanks, Heat exchangers etc.)		35
7	HTF Fluid		15
8	Electrical system		10
9	Control and Instrumentation		12
10	Civil Works		25
	Total Solar Field cost € /m2		235
A	**Total Solar Field cost**	**₹ Crore / MW**	**9.13**
	Power Block		
1	Steam Turbine and alternator € per kW		225
2	Balance of Plant* € per kW		175
	Total Power Block cost € per kW		400
B	**Total Power Block cost per MW**	**₹ Crore / MW**	**2.68**
	Other Cost elements		
1	Land cost: (6.25 Acre/MW ₹ 3 lakh/Acre) ₹ Crore /MW		0.19
2	Site development ₹ Crore/MW		0.40
3	Erection and commissioning charges: 2.5% of total A+B		0.29
4	Preliminary & Pre-Operative Expenses including IDC and contingency and other costs		1.00
C	**Other Cost elements**	**₹ Crore / MW**	**1.88**
	Total Project Cost: A+B+C	**₹ Crore / MW**	**13.69**
* Steam generation system, cooling tower, condensation system, auxiliary system, water treatment plant, cooling Tower, compressed air system, water pumping from catchment area, effluent treatment, fire protection, maintenance workshop, control and instrumentation, civil works, Electrical substation and installation			

Considering above cost estimates as well as based on the market information of EPC contracts signed by the solar thermal projects developer under phase-1 of the National Solar Mission, the Commission proposes total project cost at ₹ 13.00 Crore/MW as benchmark capital cost for determination tariff for solar thermal projects.

10.4 OPERATION & MAINTENANCE COST

There is hardly any operational experience of MW scale thermal power projects in India to ascertain norms for O&M expenses. Regulation 63 of the RE Regulations-2009 specified the normative O&M expenses for solar thermal power projects during the first year of operation i.e.2009-10 as ₹ 13.00 Lakh/MW to be escalated at the rate of 5.72% per annum over the tariff period for determination of the levellised tariff. Accordingly, O&M expense norm for solar thermal power project determined at ₹ 14.53 Lakh/MW for FY 2011-12.

The Commission while specifying norm of ₹ 13 Lakh /MW considered that the repairs and maintenance expenses related to solar field operations are not significant due to limited wear and tear and mainly pertain to operation and maintenance for power block components. Significant part of manpower related expense would pertain to inspection/testing/cleaning solar panels/array tracking systems etc.

Commission after taking into account the above and also considering the cheaper manpower cost in India compared to developed nations proposes ₹ 15 Lakhs/MW as O &M cost for the year 2012-13 (FY 11-12 norm escalated at 5.72%) which shall be escalated at the rate of 5.72% per annum over the tariff period for determination of the levellised tariff.

10.5 AUXILIARY CONSUMPTION

In the RE Tariff Regulations-2009, the Commission specified an auxiliary consumption factor at 10%. The Commission also specified that the above norms are applicable to plants without storage.

According to the CEA Report, Sub-group on integration of solar systems with Thermal/ hydro power stations, Solar thermal plant requires auxiliary power of about 8% when solar plant is in operation and about 1% during off sun hours. Besides, solar thermal plant will daily require start up power. Such power is required to tap off feeder from distribution licensee's feeder for auxiliary power/start up power requirement of solar plant at required voltage level. The Commission proposes to retain the said norm of 10% for the next Control Period.

11. TECHNOLOGY SPECIFIC NORMS: BIOMASS GASIFIER

Ministry of New and Renewable Energy (MNRE) has approached the Commission vide letter No. 202/3/2010-BM dated 7th December, 2010 with a request to amend the RE Tariff Regulations-2009 for incorporating Tariff norms for Biomass Gasifier and Biogas based power projects up to 2 MW in order to promote this technology considering the advantages of small megawatt size Biomass Gasification and Biogas based power plants connected at the tail end of 11 kV distribution system level and have enormous potential for contributing to sustainable development of rural India.

Considering the request from MNRE, the Commission has decided to evolve the norms for Biomass Gasifier based power projects and incorporate in the RE Tariff Regulations so that it could be applicable for the determination of tariff for generation of electricity from such renewable sources of energy and which could also act as guiding principle for State Electricity Regulatory Commissions in terms of Section 61(a) of the Act.

11.1 ELIGIBILITY CRITERIA

Norms for biomass gasifier power project would be applicable for grid connected system that uses 100% producer gas engine, coupled with gasifier technology as may be approved by MNRE.

11.2 BIOMASS GASIFIER TECHNOLOGY

11.2.1 BIOMASS FEEDSTOCK

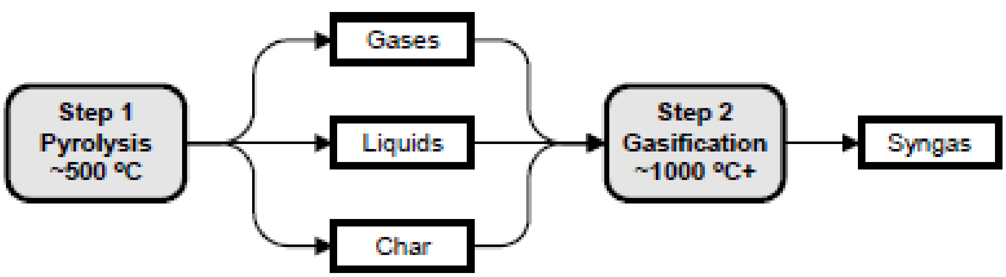
Biomass fuels available for gasification include charcoal, wood and wood waste (branches, twigs, roots, bark, wood shavings and sawdust) as well as a multitude of agricultural residues (maize cobs, coconut shells, groundnut shells, coconut husks, cereal straws, rice husks, cotton stalks, mustard stalks, stalks of various other crops etc.). The chemical composition of biomass varies among species, but basically consists of high, but variable moisture content, a fibrous structure consisting of lignin, carbohydrates or sugars, and ash. Biomass has an average composition of $C_6H_{10}O_5$, with slight variations.

11.2.2 BIOMASS GASIFICATION

Biomass gasification is the conversion of an organically derived, carbonaceous feedstock by partial oxidation into a gaseous product called synthesis gas or “syngas,” consisting primarily of hydrogen (H_2) and carbon monoxide (CO), with lesser amounts of carbon dioxide (CO_2), water (H_2O), methane (CH_4), higher hydrocarbons (C_2+), and nitrogen (N_2). Gasification relies on chemical processes at elevated temperatures 500-1400^{o}C, and atmospheric or elevated pressures up to 33 bar which distinguishes it from biological processes such as anaerobic digestion that produce biogas. The oxidant used can be air, pure oxygen, steam or a mixture of these gases.

11.2.3 GASIFICATION REACTIONS

Biomass gasification proceeds primarily via a two-step process, pyrolysis followed by gasification. Pyrolysis is the decomposition of the biomass feedstock by heat. This step, also known as devolatilization process and produces 75 to 90% volatile materials in the form of gaseous and liquid hydrocarbons. The remaining nonvolatile material, containing high carbon content, is referred to as char.



The volatile hydrocarbons and char are subsequently converted to syngas/producer gas in the second step known as gasification process. A few of the major reactions involved in this step are listed below:

Exothermic Reactions:

(1) Combustion {biomass volatiles/char} + $O_2 \rightarrow CO_2$

(2) Partial Oxidation {biomass volatiles/char} + $O_2 \rightarrow CO$

(3) Methanation {biomass volatiles/char} + $H_2 \rightarrow CH_4$

(4) Water-Gas Shift $CO + H_2O \rightarrow CO_2 + H_2$

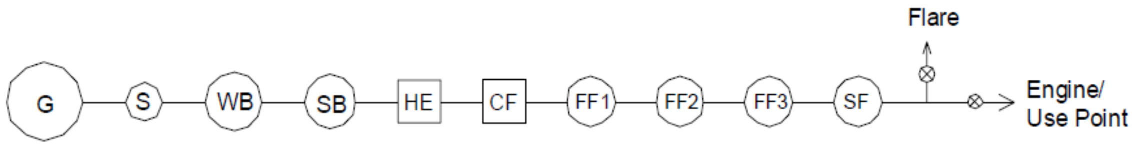
(5) CO Methanation $CO + 3H_2 \rightarrow CH_4 + H_2O$

Endothermic Reactions:

(6) Steam-Carbon reaction {biomass volatiles/char} + $H_2O \rightarrow CO + H_2$

(7) Boudouard reaction {biomass volatiles/char} + $CO_2 \rightarrow 2CO$

A typical gasifier plant based on technology consists of a reactor, which receives air and solid fuel and converts them into gas, followed by a cooling and washing/cleaning train where the impurities are removed. The clean combustible gas at a nearly ambient temperature is available for running gas engine generator sets suitable for running on producer gas alone. Indicative gasifier system schematic is as under:

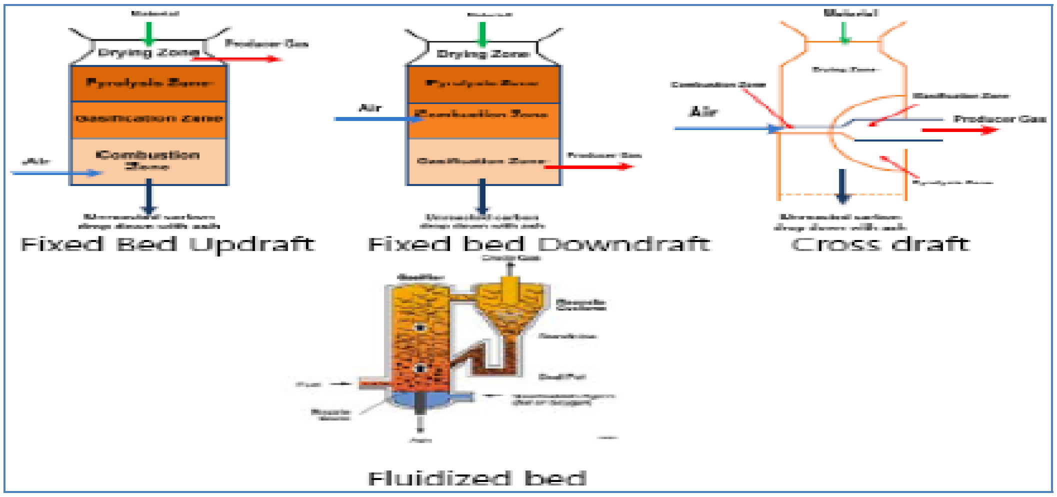


Legend:

• G – Gasifier, • S – Scrubber, • WB – Wet Blower, • SB – Separation Box, • HE – Heat Exchanger, • CF – Coarse Filter, • FF1 – Fine Filter 1, • FF2 – Fine Filter 2, • FF3 – Fine Filter 3, • SF – Safety Filter

11.2.4 GASIFIER TYPES

Biomass fuels differ greatly in their chemical, physical and morphological properties; they make different demands on the method of gasification and consequently require different reactor designs or even gasification technologies. The range of designs include up draught, down draught, cross draught and fluidized bed.



All systems have relative advantages and disadvantages with respect to fuel type, application and simplicity of operation, and for this reason each will have its own technical and/or economic advantages in a particular set of circumstances. Each type of gasifier will operate satisfactorily with respect to stability, gas quality, efficiency and pressure losses only within certain ranges of the fuel properties of which the most important are: energy content, moisture content, volatile matter, ash content & ash chemical composition, reactivity, size and size distribution, bulk density and charring properties.

Relative advantages and disadvantages

Gasifier	Advantages	Disadvantages
Updraft fixed bed	Mature for small-scale heat applications Can handle high moisture No carbon in ash	Feed size limits High tar yields Scale limitations Low heating value gas Slagging potential
Downdraft fixed bed	Small-scale applications Low particulates Low tar	Feed size limits Scale limitations Low heating value gas Moisture-sensitive
Bubbling fluid bed	Large-scale applications Feed characteristics Direct/indirect heating Can produce higher heating value gas	Medium tar yield Higher particle loading
Circulating fluid bed	Large-scale applications Feed characteristics Can produce higher heating value gas	Medium tar yield Higher particle loading
Entrained flow fluid bed	Can be scaled Potential for low tar Potential for low methane Can produce higher heating value gas	Large amount of carrier gas Higher particle loading Particle size limits

11.3 CAPITAL COST

The capital cost of the Biomass Gasification / Biogas based power plant based on the Otto cycle includes cost of two process units i.e. Gas Production Facility and Gas Fired Power Plant

11.3.1 CAPITAL COST NORMS AS APPROVED BY VARIOUS SERCS

GERC in 2007 determined tariff for biomass gasifier based power projects in 2007 at ₹ 4.5 Cr. / MW which also includes evacuation/grid connectivity cost from interconnection points to nearest grid sub-stations.

RERC in its order, in the matter of "Determination of tariff for sale of electricity from Bio-mass based power plants, in the State, to Distribution Licensees during the MYT control period 2009-14", dated 17.08.2009 ordered that the Bio-mass gasifier projects have the option of adopting the general tariff of water cooled projects or approach the Commission separately for specifying norms and for determining tariff. At present no benchmark capital cost approved by the SERCs are available.

TNERC came out with a consultative paper – August 2011, in which they have quoted IREDA letter dated 25.3.110 wherein they have suggested ₹ 5.82 Crore/ MW and based on the same the TNERC proposed that it is prudent to adopt the capital cost furnished by IREDA which is inclusive of the evacuation cost.

MNRE earlier referred to the Commission, vide letter dated 7.12.2010, a request letter of Gramin Abhirudhi Mandli, Banglore wherein project cost suggested at ₹ 6.50 Crore/ MW.

JSERC in its Regulations 'Terms and Conditions for Tariff Determination for Biomass and non-fossil fuel based co-generation projects) Regulations, 2010' (Dated 27.1.2010) specified Capital cost for Biomass gasifier based power project at ₹ 5.50 Cr. /MW.

11.3.2 INTERNATIONAL EXPERIENCE

In some countries like in Sri Lanka and European Countries, the biomass gasifier based power generation projects have significant presence. Equipment cost across the different countries can be used as a basis for cost benchmarking purpose. However, the capital cost in each of the countries is influenced by various local factors like competition, market size, material and labour cost, and local subsidy etc. Therefore, the underlying cost influencing parameters may be significantly different across the countries and it may have very limited relevance in Indian context.

11.3.3 ACTUAL PROJECT COST COLLECTED FROM VARIOUS SOURCES

According to a DPR submitted to MNRE in June 2009 for a project commissioned by M/s Sun Pharma, the cost for the captive project is INR 250 Lakhs for a 500 kW plant. Since it is a captive and off grid power plant located in the premises of M/s Sun Pharma, the cost for land has not been included here.

Capital cost information collected from a leading manufacturer/supplier in the country for 1.2MW biomass gasifier power plant along with gas engine are as under:

Sr. No.	Description	Qty.	₹ in Lakh
	Gasifier System		
1	Biomass Gasifier in ultra clean gas mode with basic accessories and auxiliaries	2 Nos.	
	Provision for parallel line of filters for continuous operation	2 Sets.	
2	Moisture meter (To check moisture content in the wood pieces)	3 Nos.	
3	Skip charger for biomass feeding with double door feed assembly	2 Nos.	
4	Gasifier Cooling Tower	Lump sum	
5	Ash /Char removal and water separation system	2 Nos.	
6	Heat Exchanger: to cool gas to 25^0 C	2 Nos.	
7	Water Treatment Plant	Lump sum	
	Total of above items (1 to 7)		160.82
	Engineering & erection and Commissioning Charges	Lump sum	5.50
	Total of all items		166.32
	Optional Items		
8	Chiller	1 No.	14.80
9	PLC based control panel	Lump sum	20.50
10	Biomass wood cutter/Chipper	Lump sum	2.40
	Total of optional items		37.70

Engine Cost			
1	Engine Genset equivalent to 1.2 MW : 3 No. 400 kW @ ₹ 95.0 lakh per Engine	Lump sum	285.00
2	Engine cooling tower	Lump sum	7.65
3	CST @ 2 % of material cost		7.10
	Total of all items of Engines equivalent to 1.2 MW		299.75
	Total cost of Biomass gasifier project with engines for 1.2 MW		**503.77**

Above cost are exclusive of the cost related to land, civil works, evacuation infra structure cost and other cost estimated as under:

1	Land : i. Acres for construction of plant @ ₹ 3Lakh/Acre : ₹3Lakh ii. 4 Acres for storage/ processing biomass @ Rs. 3lakh/Acre: ₹ 12 Lakh Civil work: iii. Plant shed of 19,000 sq.feet @Rs.400/sq. feet: ₹ 76 Lakh iv. Fencing, Road leveling, borewell, etc.: ₹ 12 Lakh Crane, chain pulley, labour, welding etc. for E&C and Boarding, lodging, power, transportation, insurance etc. First fill of lube oil, charcoal, biomass, coolant etc Agriculture Residue Processing Machine Including Threshers, tractors etc.: ₹ 12 Lakh	Lump sum	115.00
2	415 Volt / 11 kV transformer, DP structure, ABT Meter, Control/power Panel etc., Cabling from Engine control panel to transformer, earthling etc.	Lump sum	45.00
3	Interest capitalization, pre-operative cost DPR preparation cost etc.	Lump sum	20.00
	Total cost of project with engines for 1.2 MW		**683.77**

It appears from the above that Capital Cost is around ₹ 5.70 Cr/MW.

MNRE vide its letter dated 30Th September 2011 recommended that capital cost of MW sized biomass gasifier has been estimated at ₹ 5 Crore / MW by one of the gasifier makers and project cost would be about ₹ 6.5 Crore considering 30% as the soft cost, which includes pre-development, financing cost and margin money for working capital.

TNERC has in consultative Paper (August-2011) on "Procurement of Power from Biogas and Biogasification based Power Plants" referred Indian Renewable Energy Development Agency (IREDA) reported capital cost of ₹ 5.82 Crore/ MW for Biogasification based Power Plants. TNERC proposed that it is prudent to adopt the capital cost furnished by IREDA. Further, it is mentioned that the capital cost furnished by IREDA is inclusive of power evacuation cost.

Considering the above, the Commission is of the view that there is further scope of reduction in the price quoted by the supplier and if one can source engines other than from biomass gasifier supplier there is a further scope of reduction in the engine cost also. Considering the same the Commission proposes to consider ₹ 5.50 Cr/MW for the FY 2012-13 without power evacuation cost.

11.3.4 CAPITAL SUBSIDY FROM MNRE

Capital subsidy from MNRE, which as per the prevailing norms for Biomass Gasifiers is ₹ 1.5 Cr. /MW or part thereof for grid connected power plants. For power plants for captive use the same is ₹ 1 Cr./MW.

Considering the above, the Commission has proposed to consider net project cost at @ ₹ 4.00 (₹ 5.50Cr. - ₹ 1.5 Cr.) Cr./MW for the FY 2012-13 for the determination of tariff.

11.4 SPECIFIC FUEL CONSUMPTION

In case of Biomass Gasifier based Power Plants the specific fuel consumption is a combination of Producer Gas yield from Biomass Gasifier Plant and thereafter the efficiency of the Gas Engine-Generator sets. For Biomass Gasifiers for prepared biomass (chipped/ dried woody biomass and/or briquetted agriculture residues) specific fuel consumption/Wood Consumption per Unit (kW-hr) with less than 20% moisture level, based on the specifications provided by the biomass gasifier manufacturer, is around 1.1 +/- 0.1 kg per unit.
The study carried out by IISc / CGPL on the performance of the Biomass Gasifier based Power Plants set up by BERI also reveals that with less than 20% moisture level specific fuel consumption is around 1.1 kg / kWh.

These values are also corroborated by the basic efficiency data of the gasifiers and gensets separately, coupled with the known calorific values of various biomass materials with given moisture content. Typical overall gasifier efficiencies in cold and clean gas mode as required for engines are given as 73 to 75% with biomass of woody nature (waste wood, cotton stalks, mustard stalks, maize cobs etc.). Indicative efficiencies of producer gas engines are around 30-31%. The overall efficiencies therefore workout to 22-23% and the heat rate therefore works out to 3820 Kcal / kWh. Woody biomass with 20% moisture content generally has a calorific value of around 3500 Kcal / kg and SFC therefore works out to close to 1.1 kg / kWh for woody biomass but gasificatin is very specific and need biomass at 20% or below moisture contents.

Technical Specification for 1 x WBG-850

Gasifier Model	WBG-850
Gasifier Type	Down Draft
Fuel Specifications	
Size (mm)	*Minimum:* Diameter (∅) – 10 mm; Length (L) – 10 mm
	Maximum: ∅ – 75 mm; L – 75 mm
Moisture Content (%)	< 20% (Wet Basis)
Gasifier Output	
Rated Gas Flow (Nm3/hr)	1,912.5
Average Gas Calorific Value (Kcal/Nm^3)	> 1,100
Rated Thermal Output (Kcal/hr)	2,103,750
Maximum Biomass Consumption (Kg/hr)	Maximum 765
Gasification Temp. (°C)	1050 - 1100
Indicative Gasification Efficiency (%)	
Hot Gas Mode (No Scrubbing)	> 85%
Cold Gas Mode (With Scrubbing)	> 75%
Temperature of Gas at Gasifier Outlet (°C)	300 to 500°C
Biomass Feeding	
Mode	Skip Charger/ Manual
Frequency	Every 12-15 minutes
Ash Removal	Continuous, through proprietary control and water seal/ Dry Ash Char Removal System
Gas Cooling *(For Scrubbed and Ultra Clean Gas Modes)*	Venturi Scrubber / Promiser with water re-circulation
Gas Cleaning *(For Ultra Clean Gas Mode)*	Through proprietary & patented fine filters
Start-Up	Through Scrubber Pump / Blower
Typical Gas Composition	CO - 19±3% H_2 -18±2% CO_2 - 8±3% CH_4 -Up to 3% N_2 - 50%

JSERC in its Terms and Conditions for Tariff Determination for Biomass and nonfossil fuel based co-generation projects) Regulations, 2010 specified Station Heat rate at 3800 kCal/kWh and calorific value at 3500 kCal/kg which works out to close to 1.1 kg/kWh.

Considering the above, the Commission proposes that the specific fuel consumption for biomass gasifier at 1.10 kg/KWh.

11.5 AUXILIARY POWER CONSUMPTION

The RE Regulations-2009 for Biomass Power Plants based on the Rankine Cycle were based on the assumption of 10% Auxiliary Power Consumption. The auxiliary consumption includes electricity consumption in upstream (biomass processing) and downstream (residues treatment) units.

According to a DPR submitted to the MNRE of 500 kW of Biomass gasifier the Auxiliary Power Consumption is 12%. MNRE referred the request of Grameen Abhirudhi Mandli to CERC seeking amendment in the CERC RE tariff Regulations-2009 by specifying Biomass gasifier technology specific parameters, wherein, normative Auxiliary Power Consumption wassuggested at 12%.

TNERC in its consultative paper on “Procurement of Power from Biogas and Biogasification based Power Plants” dated 25.08.2011 referred IREDA letter dated 25-03-2011 suggesting 10% Auxiliary Power Consumption for Biomass Gasifier based power project and accordingly proposed Auxiliary Power Consumption at 10%.

JSERC in its Terms and Conditions for Tariff Determination for Biomass and nonfossil fuel based co-generation projects) Regulations, 2010 specified Auxiliary Power Consumption for Biomass Gasifier based power project at 10%.

Considering the same, the Commission proposes to consider norm of Auxiliary Power Consumption at 10%.

11.6 PLANT LOAD FACTOR (PLF)

Normative values of PLF of Biomass gasification based power projects adopted by GERC in its Order No. 2 of 2007 wherein 80% PLF considered for biomass gasifier based power project.

TNERC in its consultative paper on “Procurement of Power from Biogas and Biogasification based Power Plants” dated 25.08.2011 referred IREDA letter dated 25-03-2011 suggesting 80% PLF for Biomass Gasifier based power project.

MNRE referred the request of Grameen Abhirudhi Mandli to CERC seeking amendment in the CERC RE Tariff Regulations-2009 by specifying Biomass gasifier technology specific parameters, wherein, normative Plant Load factor at 75%.

Considering the above, the Commission proposes 80% PLF for Biomass Gasifier based power plants.

11.7 O&M EXPENSES

The norm for O&M expenses for Biomass Power Plants based on the Rankine Cycle, according to CERC RE Tariff Regulations-2009, is fixed at ₹ 20.25 lakhs/MW as O&M expenses for FY 2009-10 with annual escalation of 5.72% for the remaining years of the control period. Accordingly, for FY 2011-12 and FY 2011-12 O&M cost determined at ₹ 21.41 Lakhs/MW and ₹ 22.63 lakhs/MW respectively.

The O&M cost for Biomass Gasifier plant will be higher than that for Biomass Power Plant based on the Rankine cycle, as man power costs do not reduce proportionately with unit rating. In addition, higher expenditure towards feed-stock preparation incures extra cost on processing of agri-residues to obtain quality as required as feedstock for Biomass Gasification Plant. The overall O&M costs need to be considered in three parts:

i. Maintenance of gasifier
ii. Maintenance of engine genset, electricals etc.
iii. Manpower cost for regular operation and maintenance

Operation & Maintenance costs for any power plant generally include expenses related to manpower cost, maintenance cost, consumables (cost of spares), insurance and disposal.

TNERC Consultative paper on determination tariff for the biomass gasifier based power plant referred suggestion received from IREDA vide letter dated 25.3.2011 wherein O & M cost suggested at 3% of the capital cost for O&M and 0.5% for insurance. Based on the same TNERC has proposed a norm for operations & maintenance cost at 3% of the total project cost with 5% escalation cost and 0.5% for insurance

JSERC in its Terms and Conditions for Tariff Determination for Biomass and nonfossil fuel based co-generation projects) Regulations, 2010 specified normative Operation & maintenance Cost at 4.5% of the Capital cost with 5.72% escalation as considered for biomass combustion based power project.

Based on the DPR submitted by the project developers to MNRE for a 500 kW biomass based power generation wherein O&M cost is considered as 6% of the total project cost. The detailed break-up is reproduces as under:

In ₹ Lakh

Description	Ist year	IInd year	IIIrd year
Cost of lube oil	2.89	3.04	3.19
Manpower cost	4.80	5.04	5.29
Repairs & maintenance	5.20	5.46	5.73
Total O&M cost	12.89	13.54	14.21
Total Project Cost	250		
O&M cost as percentage of total project cost	5.15%	5.42%	5.68%
O&M cost / MW	25.76	27.08	28.42

However, above referred costs were for year 2009 for a captive system wherein no managerial and other support manpower was considered.

MNRE vide letter dated 7.12.2010 submitted a request Gramin Abhirudhi Mandli, Banglore to CERC for determining generic tariff for the biomass gasifier based power plant wherein Operation and Maintenance cost was suggested as under:

Description	Annual Amount (₹ Lakh)
Maintenance Costs	50.00
Man power Cost (for 18 person)	12.00
Total	62.00

Considering above, ₹ 35 Lakh /MW is proposed to be considered as a norm for Operation and maintenance cost for the FY2013 and same would be escalated at the rate of 5.72% every year during the next control period.

11.8 BIOMASS FUEL PRICE

The Commission proposes that the biomass fuel price suggested for the biomass based power plant with rankine cycle technology would be applicable for the biomass gasification based power plant.

12. TECHNOLOGY SPECIFIC NORMS: BIOGAS PLANTS

12.1 ELIGIBILITY CRITERIA

Norms for Biogas power project would be applicable for grid connected system that uses 100% Biogas fired engine, coupled with Biogas technology for co-digesting agriculture residues, manure and other bio waste as may be approved by MNRE.

12.2 BIOGAS PLANTS TECHNOLOGY

12.2.1 BIOMASS FEEDSTOCK

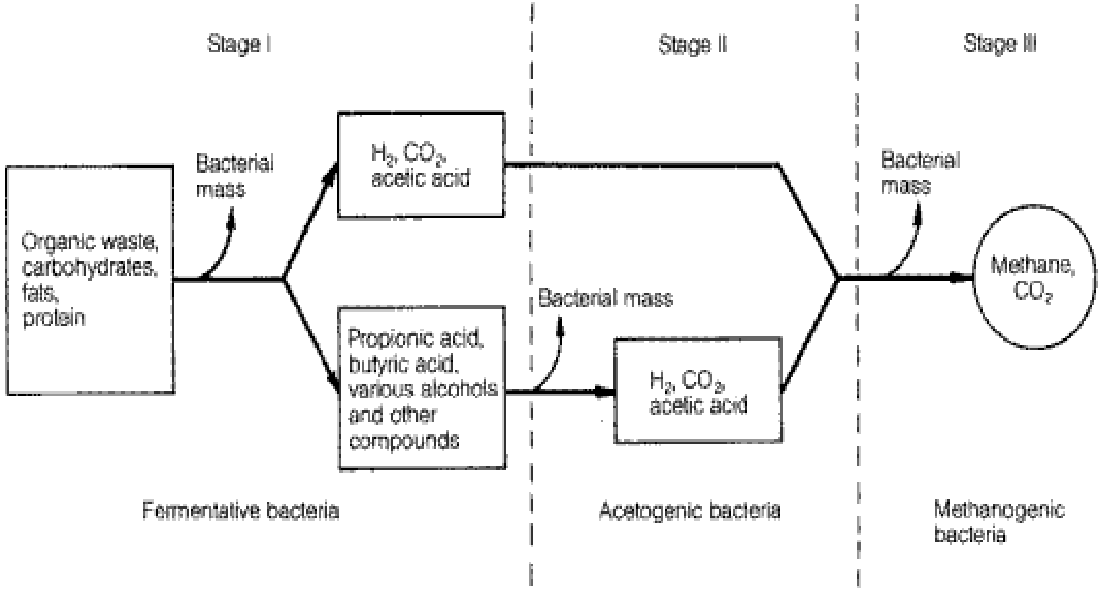
Biomass fuels available for Biomethanation include crop residues (with higher cellulosic content), cow/poultry manure, food and agro industry solid and liquid waste and segregated organic urban waste.

The chemical composition of biomass varies for different substrates but basically consists of high, but variable moisture content and relatively high digestable organic dry solids (or volatile solids).

12.2.2 BIO-METHANATION PROCESS

Bio-methanation is a process in which biogas, along with bio compost is produced by activity of anaerobic bacteria on organic matter prevalent in biomass/ waste. Anaerobic bacteria occur naturally in organic environments where oxygen is limited.

Converting organic matter to methane gas by anaerobic digestion is achieved by a three stage process.



i. The first sage involves hydrolysis of organic compounds.

ii. The second stage is acid formation, which is effected by a group of anaerobic bacteria – referred to as the acid formers.

iii. The third stage involves a group of bacteria – known as the methane formers – that breaks down the organic acids and produces methane as a by-product of the degradation of the organic acids.

The anaerobic digestion process produces biogas, whose constituents are producing power and heat. The biogas produced by anaerobic digestion, which is roughly about 52-60 %

methane, with CO_2 comprising most of the remainder. Hydrogen Sulphide, which is present in small amounts, gets converted into sulphate and then the sulphate is reduced to form elementary sulphur by sulphate – reducing bacteria.

The digester effluent contains the non digestible organic matter (humus) and inorganic matter (essentially major & micro nutrients which can be used for soil fertility management.

12.2.3 BIO-METHANATION REACTION

Bio-methanation process can be described through a generalized reaction as under: - Anaerobes Organic Matter + Combined Oxygen $\longrightarrow$ New Cells + Energy for Cells + CH_4 + CO_2 +Other End Products

The specific reaction of the Bio-methanation is as under: -

$C_6H_{12}O_6 + 2H_2O \longrightarrow 2CH_3COOH + 4H_2 + 2CO_2$

$CH_3COOH \longrightarrow CH_4 + CO_2$

$CO_2 + 4H_2 \longrightarrow CH_4 + 2H_2O$

12.2.4 BIOGAS PLANT DESIGN

The Biogas Plant design depends upon type of substrates that are used for biogas production and also the temperature range at which the anaerobic digestion processes are controlled. The pre-proven designs are:

(i) Upflow Anaerobic Sludge Blanket (UASB)

Upflow anaerobic sludge blanket (UASB) reactor is one of the anaerobic reactors for both high and low temperature. UASB reactor, in the past, has been the most widely used system for anaerobic treatment of distillery spent wash/food industry effluents and sewage. The digesters have extremely high volumetric efficiency and the nature of substrates eliminates the need of feedstock preparation, substrate mixing, stirring within digesters, recycling etc.

Consequently these have the advantage of lower capital cost as well as O&M cost. However, UASB reactor cannot be used for codigestion of crop/agriculture residues, manure, food industry waste etc., which have significantly higher dry solids content.

(ii) Continuous flow, fully mixed Digesters:

These find application in substrates with high dry solids content. The efficiency being improved through technological interventions in feedstock preparation, ability to co-digest substrates, substrates mixing, controlled dosing of substrates, proportionate stirring within digesters and process control to optimize production of CH4 and minimizing production of NH_3 & H_2S. In the past decade there has been significant evolution in plant technology and design resulting in high biogas yield and PLF in excess of 90%. A key physical factor for successful anaerobic digestion is the temperature and the proven plant designs are with following temperature ranges.

(iii) Mesophilic Temperature:

The mesophilic temperature range (35-38^{o}C) is the optimal temperature for a large number of methane forming microorganisms for production of Biogas. Mesophilic bacteria can tolerate temperature fluctuations of +/−3 °C without significant reductions in methane production. The HRT of this temperature range is 30-40 days. In the mesophilic temperature range, the dewatering properties are high and requires low amount of energy for heating the digester. The thermal destruction of bacteria is also very low in the mesophilic temperature. Hence the microorganisms are stable in this temperature and produce more biogas

(iv) Thermophilic Temperature:

In thermophilic anaerobic digestion, the temperature (55-60^{O}C) has to be maintained inside the digester which requires lot of energy. The thermophilic bacteria are more sensitive to temperature fluctuations and require longer time to adapt to a new temperature. The growth rate of methanogenic bacteria is higher at thermophilic process making the process faster and more efficient. Therefore, a well-functioning thermophilic digester can be loaded to a higher degree or operated at a lower hydraulic retention time (HRT) than at mesophilic conditions. But the thermophilic process temperature results in a larger degree of imbalance and a higher risk for ammonia inhibition.

12.3 CAPITAL COST

The capital cost of the Biogas based power plant based on the Otto cycle includes cost of two process units i.e. Gas Production Facility and Gas Fired Power Plant

12.3.1 CAPITAL COST NORMS AS APPROVED BY VARIOUS SERCS

HERC vide its order dated 5th July, 2011 determined a project specific tariff for Biogas Power Project wherein project cost was approved at ₹ 10.9 Crore/MW (₹ 4.36 Crore for a 400 kW) for a cow dung based Biogas Power Plant which included the digester effluent treatment systems and power evacuation system.

TNERC came out with a consultative paper – August 2011, in which they have quoted norms as suggested by :

i. MNRE : ₹ 12 Crore/MW for 1 MW Biogas Power Plant and ₹ 11 Crore/MW for 2 MW Biogas Power Plant,

ii. IREDA: ₹ 7.87 Crore/ MW (Distillary spent wash based biogas power plant),

iii. TEDA : ₹ 8 Crore/MW for Sago based and ₹ 10 Crore/MW for Poultry litter based Biogas Power Plant,

iv. Petiton filed by M/s Pallava Water and Power Ltd. Before TNERC: ₹ 10 Crore/MW

12.3.2 INTERNATIONAL EXPERIENCE

In Europe and in Germany in particular Biogas Plants have significant presence. Germany has over 5500 Industrial Biogas Plants, which operate with PLF's upwards of 80% and over 90% in case of plants built by the technology leaders. The European plants are based on co-digestion of substrates like manure, food industry waste, agriculture produce/waste and hence are akin to the Biogas Plants proposed in India. The equipment cost in Europe varies from Euro 3 million to 4 million/MW based on plants size and nature of substrates.

Biogas Plants built in Asia are largely mono substrates based on manure or distillery spent wash/industrial effluents or sewerage. These have a much simpler plant design without requirements of feedstock preparation, substrate mixing, stirring in digesters, recycling, etc. and hence are not a relevant benchmark for the Biogas Power Plants proposed as tail end of the grid power generation.

12.3.3 ACTUAL PROJECT COST COLLECTED FROM VARIOUS SOURCES

According to the DPR submitted to MNRE, through HAREDA, in 2011 by Shree Krishna Captive Energy Pvt. Ltd., the project cost for a 400 kW Biogas Power Plant was ₹ 5.58 Crore, or Rs 13.95 Crore/MW. Since this plant had 80% (by weight) cow manure the digester volume is relatively higher and project cost is relatively higher.

Capital Cost information collected from MNRE for 2 MW Biogas Power Plant, with cow dung and Agri Residues (maize Stalks, Paddy, Straw, Cane Trash) as key feedstock is ₹ 2000 Lacs as detailed under:

Sr. No	Description	₹in Lakh
	Biogas Plant	
1.	Land, Building and other infrastructure (Biomass Storage & Transfer facilities)	110
2.	Biomass Storage, Feeding, Mixing & Transfer Facilities (Slurry tank + Agitators + Shredder Pump)	295
3.	Digester (Tank) & Digester Accessories (Agitators + Plat form + Recirculation Tank)	412.5
4.	Digester Cover with gas holder, Supporting systems, etc.	125
5.	Digestate Storage tank (Tank + Agitators + Cover)	50
6.	Automation & Process Controls (PLC + Field devices + Gas control + Gas Flare)	95
7.	Mechanical BOP and Piping System (Pumps + Piping +Valves + Compressors + Ventilation)	265
8.	Electrical BOP, Cabling System (MCC + cabling+ Earthing)	50
9.	Heat Recovery System (for Digester heating)	11.5
10.	Technical Building	41

11.	Power Evacuation System (PCC + Transformer + DP Structure + Load Break Switch +11 kV Transmission Line)	105
12.	Gas Engine Coupled with Alternator & Accessories	440
Total Cost of Project including I&C Charges for 2 MW Biogas Power Plant		2000

Note: a) Above cost break down includes technology, engineering, procurement, transportation, insurance, erection & commissioning, project/construction management.

b) Above cost exclude Digestate Treatment System which is included in stabilized compost production cost

MNRE vide its letter dated 30th September suggested capital cost for bio-methanation based projects at ₹ 8-12 Crore/MW

MNRE earlier referred to the Commission, vide letter dated 7.12.2010, a request letter of Gramin Abhirudhi Mandli, Banglore wherein project cost suggested at ₹ 10 Crore/ MW

Considering above, the Commission proposes the capital cost of ₹ 10 Crore/MW for 1 MW Biogas Power Plant, which is the representative rating of Biogas plants that are likely to be built in rural areas with cow manure as a key feedstock. Considering the above, the commission proposes to consider ₹ 10 Crore/MW for the FY 2012-13

12.3.4 CAPITAL SUBSIDY FROM MNRE

Capital subsidy from MNRE, as per their circular F.No.10/1/2011-U&I dated 2nd May 2011 is ₹ 3 Crore/MW (limited to ₹ 6 Crore/project) for Biogas Plants with feedstock mix of cattle dung, vegetable market & slaughter house waste along with agriculture wastes/residues. Financial support is provided after successful commissioning of projects.

MNRE vide its circular F.No.2/1/2008-UICA dated 26th April 2010 stipulated capital subsidy of ₹ 1.5 Crore per MW (subject to ceiling of ₹ 5 Crore/project) for Biogas Plants with feedstock of industrial waste (which includes poultry manure).

Considering that most of the projects would be small capacity projects of 1 MW or so, under the proposed tail end of the grid programme would be having feedstock of agriculture residues, cow manure and other bio waste the commission has proposed to consider net project cost of ₹ 7 Crore/MW for the FY 2012-13 for determination of tariff.

12.3.5 SPECIFIC FUEL CONSUMPTION

In case of Biogas Power Plants the specific fuel consumption is a function of Biogas yield from Biogas Plant and thereafter efficiency of the Gas Engine- Generator sets.

TNERC consultative paper on "procurement of Power from Bio Gas and Biogasification based Power Plants" dated 25.07.2011 regarding specific consumption of fuel, Haryana ERC has specified 4.21 kg/kWh for poultry litter based biogas power plants and based on the Petition filed by the M/s Pallava Water and Power (p) Limited, TNERC has considered a specific consumption of 3 kg/kWh in this discussion paper.

The efficiency of new generation gas engines reveals a range of 35% to 45% depending upon the capacity. Therefore, assuming an electrical efficiency of 40% for bio gas based power plants is reasonable after accounting for efficiency variations linked to site conditions and this translates in to the station heat rate of 2150 kCal/kWh. (860/0.4=2150)

Regarding calorific value of the biogas, in the discussion paper of TNERC mentioned that the MNRE has reported a calorific value of 4500 to 5000 kCal/m3.

According to the MNRE website, the gas obtained from cow dung based biogas plants through anaerobic digestion contains a mixture of methane (55 – 65%), carbon dioxide (35-40%) and traces of other gases. The calorific value of biogas is around 5000 kcal/m3. Though the calorific value of biogas is less than that of natural gas (calorific value of CNG - 8600 kcal/m3), biogas can be offered as an excellent fuel for many energy applications. http://www.mnre.gov.in/annualreport/2004-2005_English/ch4_pg1.htm

Biogas produced from substrates mix of cow manure and agricultural residues would typically have 55% methane. The net calorific value of methane is 8750 Kcal/Nm3. Hence Biogas with 55% methane would have calorific value of 4812 Kcal/ Nm3.

The yield of biogas from a particular feedstock will vary according to:

i. Dry matter content, food wastes in particular will vary greatly
ii. The energy left in the feedstock, if it has undergone prolonged storage it may already have begun to break down
iii. Length of time in the digester
iv. The type of AD plant and the conditions in the digester
v. The purity of the feedstock

http://www.biogas-info.co.uk

The Biogas yield of different substrates varies but the MNRE has suggested typical yields for representative substrates are given in table below:

Substrates	% Dry Solids	Biogas yield cum/MT
Agriculture Residues (Paddy straw, maize stalks, cane trash)	55	255
Cow Manure	18	45

On a Pan India basis, the manure would be typically cow manure and substrate mix would be 60 % agriculture residues and 40% cow manure. This would result in average Biogas yield of 167 cubic meter/MT with typical feedstock mix (Agri. Residues (12400 MT) + Cow Dung (9000 MT) = 21400 MT and total biogas yield = 3567000 m3). Considering calorific value of biogas at 4812 kCal/m3 the specific fuel consumption works out to 2.86 kg/kWh.

Considering above, the commission proposes to consider specific fuel consumption of 3 Kg of substrate mix per kWh generated.

12.3.6 FEEDSTOCK COST

TNERC consultative paper on "procurement of Power from Bio Gas and Biogasification based Power Plants" dated 25.07.2011 has proposed Fuel cost at ₹ 1020/MT with 5% escalation. Cost of by-product proposed at ₹ 2500/MT as recommended by IREDA with 5% escalation.

In recent years it has been noticed that Biomass Cost tends to follow trends of coal as there are alternative applications for combustion. Recognising this, CERC in its RE Tariff Regulations-2009 provided for price escalation formula with 60% of biomass cost linked to that of coal, 20% linked to that of diesel (related to biomass transportation) and 20% linked to wholesale price index (related to labour in biomass collection/transportation).

The rice husk, wood, bagasse, cotton stalks and other agricultural residues tend to have costs around ₹ 2500/MT with calorific value of 3500 Kcal/kg,.

By applying above yardstick the price for agricultural residues with higher cellulosic content (maize stalk, paddy straw, cane trash), having 45% moisture and calorific value of 2000 Kcal/kg, would be around ₹ 1400/MT.

Cow manure prices vary based on current applications. However, the landed cost including collection/ loading/ transportation/ unloading, is observed to be between ₹ 500 to 650/MT for partially dried cow manure with 70% moisture.

Consequently, for Biogas Plant having feedstock mix of 40% cow manure and 60% agricultural residues, the average cost would range between ₹ 1040 to ₹ 1100/MT.

MNRE vide letter dated 7.12.2010 submitted a request from Gramin Abhirudhi Mandli, Banglore to CERC for determining generic tariff for the biogas based power plant wherein fuel cost considered 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

Biogas Plant digester effluent needs to be treated, prior to discharge, to comply with Pollution Control Board norms. The treatment process involves usage of expensive flocculants along with labour and other consumables. However, the separated solids would then have value as organic manure. As the quantity of such separated solids is high it cannot be sold for only specialized applications such as horticulture but would go back to the agricultural fields from where the agricultural residues are collected. It is not possible to monetize such organic manure at high rates in view of the availability of heavily subsidized chemical fertilisers.

Consequently, MNRE, in recent hearings of TNERC for fixation of Biogas tariff, has advised taking the by-product cost recovery at around 10% of the feedstock cost.

Considering the above, the Commission proposes to consider average feedstock mix cost, net of by-product cost recovery, as ₹ 990/MT for FY 2012-13

12.3.7 AUXILIARY POWER CONSUMPTION

The RE Tariff Regulations-2009 for Biomass Power Plants based on the Rankine Cycle were based on the assumption of 10% Auxiliary Power Consumption.

TNERC Consultative paper on determination tariff for the biogas gas based power plant referred suggestion from various stakeholders as under:

- MNRE (Letter dated 19.7.2010) : 10-12%
- TEDA Letter Dated 20-04-2010: 14.60 % for Sago based and 155 for Poultry litter based plant;
- HERC (Order dated 21-09-2010): 12.74%;
- Petition filed by M/s. Pallava Water and Power (P) Ltd. : 13%;
- IREDA (letter dated 25.3.2011): 10%

Based on the above, TNERC has proposed normative Auxiliary Consumption at 12% considering special nature involved in biogas based plant such as effluent treatment system etc.

HERC in its order dated 5.7.2011 approved Auxiliary Consumption at 10% for biogas based power plant. While specifying the said norm the HERC has recorded that in the absence of any norms for biogas power projects and keeping in view the associated processes including fertilizer unit, waste heat recovery system, reject water treatment system etc. which has several spin off benefits and norm for biomass based projects, has considered auxiliary power consumption for biogas power projects as 10%.

MNRE vide letter dated 7.12.2010 submitted a request from Gramin Abhirudhi Mandli, Banglore to CERC for determining generic tariff for the biogas based power plant wherein auxiliary power consumption for biogas power projects is proposed as 13%.

In case of Biogas Power Plants the auxiliary power consumption would include electricity consumption in upstream (feedstock preparation and substrate mix) and downstream (digester effluent treatment) units. Accordingly to a DPR submitted to MNRE for 2 MW Biogas Power Plant the auxiliary power consumption is 13% as detailed below:

S No	ITEM	Qty (No)	UNIT LOAD (KW)	TOTAL LOAD (KW)	OPERATING LOAD (KW) FACTOR(0.9)	OPERATING TIME (Min. Per Cycle)	OPERATING TIME (Min. Per Day)	Auxiliary Power Consumption (KWhr/ Day)
Biogas Plant								
1	Agitators for slurry tanks	4	13	52	46.8	5	120	93.6
2	Slurry transfer pump	2	15	30	27	5	120	54
3	Rupture Rollers	8	3	24	21.6	8	192	69.12
4	Screw conveyors & Walking Floor for silage	6	14.5	87	78.3	8	192	250.56
5	Screw conveyor for DOC	2	7.5	15	13.5	4	96	21.6
6	Shredder for Biomass feed pump	2	9.2	18.4	16.56	10	240	66.24

7	Biomass feed pump to digester	2	15	30	27	10	240	108
8	Agitator for Mixing Tank	2	22	44	39.6	20	480	316.8
9	Agitators for Digester	10	25	250	225	10	240	900
10	Instrument Air Compressor	2	2.5	5	4.5	100	100	7.5
11	Desulphurization compressor	2	3	6	6	Continuous	1440	144
12	Lighting load	-	-	10	9	720	720	108
13	Recirculation Transfer Pump	4	5.5	22	19.8	4	96	31.68
14	Agitators for Residual Storage Tank	4	10	40	36	13	312	187.2
15	Ventilation System	2	14	28	25.2	Continuous	1440	604.8
16	Heating pump for Digester	4	5	20	18	Continuous	1440	432
	Sub Total			681.4	613.86			3395.1
Power generation per day (kWh)								43200
% age of Biogas Plant Auxiliary Consumption								7.9%
17	Engine Auxiliary	2	16.42	32.84	29.556	Continuous	1440	709.34
% age of Engine Auxiliary Consumption								1.6%
18	Digestate Treatment	2	35	70	63	Continuous	1440	1512
% age of Digestate Treatment Auxiliary Consumption								3.5%
							Total % of Auxiliary Consumption	13%

Considering above, the Commission proposes to consider auxiliary power consumption at 12% for determination of tariff.

12.3.8 PLANT LOAD FACTOR (PLF)

Normative values of PLF of Biogas based power projects adopted by HERC in its Order dated 21.09.2010 wherein 65% PLF considered for first year of operation and 80% PLF considered for the subsequent years.

TNERC recently came out with a Consultative Paper on "Procurement of Power from Biogas and Biogasification based Power Plants" – August 2011 wherein IREDA letter dated 25-03-2011and MNRE letter dated 19.07.2010 have been referred suggesting 80% PLF for biogas based power project.

HERC in its order dated 5.7.2011 approved Plant Load Factor at 85% for biogas based power plant.

MNRE vide letter dated 7.12.2010 submitted a request from Gramin Abhirudhi Mandli, Banglore to CERC for determining generic tariff for the biogas based power plant wherein Plant Load Factor was proposed at 90%.

Considering the above and keeping in mind of smaller size of the projects, the Commission proposes 90% PLF for Biogas based power plants.

12.3.9 O&M EXPENSES

The norm for O&M expenses for Biomass Power Plants based on the Rankine Cycle, according to CERC RE Tariff Regulations-2009, is fixed at ₹ 20.25 lakhs/MW as O&M expenses for FY 2009-10 with annual escalation of 5.72% for the remaining years of the control period. Accordingly, for FY 2011-12 and FY 2011-12 O&M cost was determined at ₹ 21.41 Lakhs/MW and ₹ 22.63 lakhs/MW respectively.

HERC in its order dated 5.7.2011 allowed ₹ 8.1 Lakh as O&M expenses for 400 kW biogas based power plant considering the norm as specified by the CERC for 2009-10 for biomass based power plant with rankine cycle technology. Biogas Power Plants comprises Biogas Production unit and Power unit, the overall O&M costs needs to be considered in two parts. First part relates to regular maintenance of Biogas Plant, Engine gen set, etc. and the other part relates to manpower for regular operations and maintenance.

TNERC Consultative paper on determination tariff for the biogas gas based power plant referred suggestion from various stakeholders as under:

- TEDA Letter Dated 20-04-2010: 10% of Project Cost for Sago based, 5% of Project Cost for Poultry litter;
- HERC (Order dated 21-09-2010): 6% of the Project Cost;
- Petition filed by M/s. Pallava Water and Power (P) Ltd. : 5.25% of Project Cost with 5.72% escalation;
- IREDA (letter dated 25.3.2011): 3% of the capital cost (₹ 7.87 Crore) for O&M and 0.5% for insurance.

Based on the above, TNERC has proposed norm for operations & maintenance cost at 3% of the total project cost with 5% escalation cost and 0.5% for insurance

The O&M cost for Biogas Plant would be higher than that for Biomass Power Plant based on the Rankine cycle, as man power costs do not reduce proportionately with unit rating. In addition, higher expenditure towards feedstock preparation and substrate mixing as well as extra costs for digester effluent treatment as per Pollution Control Board norms have to be incurred.

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 ₹ Lacs

Year	1	2	3	4	5	6	7	8	9	10	Avg 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

The working for operations & maintenance costs, per MW, assuming optimization in engine O&M costs are as follows:

Description	Annual Amount ₹ in Lakh	Remarks
Biogas Plant & Digester Effluent Treatment Maintenance	18.15	₹ 0.46 /M^3
Engine Maintenance including Lube Oil	29.40	
Manpower Cost		Cost/Persons ₹ in Lakh
1 Engineer	3.00	3.00
4 Technicians	4.80	1.20
1 Chemist	1.20	1.20
1 Accountant	1.20	1.20
10 Labours	6.00	0.60
3 Security Persons	2.25	0.75
Grand Total	**66.00**	

MNRE vide letter dated 7.12.2010 submitted a request from Gramin Abhirudhi Mandli, Banglore to CERC for determining generic tariff for the biogas based power plant wherein data provided pertaining to the Operation and Maintenance Costs are as under:

Particulars	Annual Amount ₹ in Lakh	
	2 MW	1 MW
Manpower Cost	24.00	12.00
Maintenance Cost	81.00	40.50
Annual O & M Charges	105.00	52.50
Capital Cost	2000	1000
% O & M cost on Capital Cost	5.25%	5.25%

Considering the above, the Commission proposes norm for operations & maintenance cost at 3% of the total project cost which works out to ₹ 30 Lakhs/MW for the FY 2012-13 and the same will be escalated at the rate of 5.72% every year during the next control period.

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