Explanatory Memorandum

For

Draft Terms and Conditions for determination of Tariff

For

Renewable Energy Sources

May 2009

CENTRAL ELECTRICITY REGULATORY COMMISSION

NEW DELHI

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ABBREVIATIONS

Act	Electricity Act 2003 (EA 2003)
ACF	Auxiliary Consumption Factor
CAGR	Compounded Annual Growth Rate
CEA	Central Electricity Authority
CERC	Central Electricity Regulatory Commission
COG	Cost of Generation
COD	Commercial Operation Date
CPI	Consumer Price Index
CPPs	Captive Power Plants
CTU	Central Transmission Utility
CUF	Capacity Utilisation Factor
DISCOM	Distribution Companies
EPA	Energy Purchase Agreement
FIs	Financial Institutions
GoI	Government of India
GCV	Gross Calorific Value
GFA	Gross Fixed Asset
IREDA	Indian Renewable Energy Development Agency
IWC	Interest on Working Capital
kCal	kilo Calories
kg	kilo gram
kV/kVA	kilo Volt / kilo Volt-Ampere
kWh	kilo Watt Hour
MNRE	Ministry of New and Renewable Energy
MkCal	Million kilo Calories
MSW	Municipal Solid Waste
MW	Mega Watt
MU	Million Units
NEP	National Electricity Policy
TP	Tariff Policy
OA	Open Access
O&M	Operation and Maintenance
PLF	Plant Load Factor
RE	Renewable Energy
RLDC	Regional Load Despatch Centre
ROE	Return on Equity

RPO	Renewable Purchase Obligation
Rs	Rupees
Rs/kWh	Rupees per kilo Watt hour
Rs/MkCal	Rupees per Million kilo Calories
R&M	Repair and Maintenance
SERC	State Electricity Regulatory Commission
SHR	Station Heat Rate
SLDC	State Load Despatch Centre
STU	State Transmission Utility
TSU	Transmission System User
UNFCCC	United Nation's Framework Convention for Climate Change
UI	Unscheduled Interchange
WPI	Wholesale Price Index

1 BACKGROUND

India has been bestowed with huge renewable energy potential and it is distributed non-uniformly across the States. Wind, biomass, solar and small hydro constitutes significant potential for their commercial development. Till the enactment of Electricity Act, 2003, the renewable energy development was mainly governed by the policies framed by Central and State Governments. Enactment of Electricity Act, 2003 (herein after referred as the Act) has brought out radical changes to legal and regulatory framework applicable to renewable sector in the country as it has specific provisions for matter related to promotion of renewable energy technologies.

1.1 Legal and Policy Framework for Renewable Energy

The Act provides for policy formulation by the Government of India and mandates State Electricity Regulatory Commissions to take steps to promote renewable sources of energy within their area of jurisdiction. Section 3 of the Act, clearly mandates that formulation of National Electricity Policy, National Tariff Policy and Plan thereof for development of power systems shall be based on optimal utilization of all resources including renewable sources of energy.

The Act has also mandated the Central Electricity Regulatory Commission (herein after referred as the Commission) to deal with aspects involving inter-State generating stations and generating stations set up by the Central Government owned Companies. The Section 79 of the Act empowers the Commission to regulate the tariff for generating stations owned and controlled by the Central Government and also to regulate the tariff of generating companies other than those owned and controlled by the Central Government, if such generating stations enter into or otherwise have a composite scheme for generation and sale of electricity to more than one state. Therefore, in accordance with the provisions of the Act, the renewable energy power plants set up by the Central Government owned companies and other inter-state generating stations also needs to be regulated by the Central Commission.

Further, Para 6.4 (3) of National Tariff Policy's empowers the Central Electricity Regulatory Commission to determine the guidelines for pricing of non-firm power. Para 6.4 provides 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".*

Section 61 (h) of the Act requires the appropriate Commission to specify the terms and conditions for the determination of tariff. The relevant clause is reproduced below:

> ***Section 61 (Tariff regulations):***
> *The Appropriate Commission shall, subject to the provisions of this Act, specify the terms and conditions for the determination of tariff, and in doing so, shall be guided by the following, namely:-*
> *……………*
> *(h) the promotion of co-generation and generation of electricity from renewable sources of energy;*

In terms of clause (s) of sub-section (2) of section 178 of the Act, the Commission has been vested with the powers to make regulations, by notification, on the terms and conditions of tariff under section 61.

In accordance with the Tariff Policy provisions, the Commission issued a discussion paper on "Promotion of Cogeneration and Generation of Electricity from Renewable Sources of Energy" on May 16, 2008 under which various modes of inter-state sale of renewable energy had been discussed. Based on comments, objections and suggestions received from various stakeholders, it was felt that the Tariff Guidelines should also cover various other critical aspects related to renewable energy sources from long term perspective of harnessing of available renewable energy potential.

With the objective to evolve the norms that could be applicable for the determination of tariff for generation of electricity from 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, the Commission has engaged the services of ABPS Infrastructure Advisory Pvt Ltd (ABPS Infra) to develop and recommend appropriate tariff structure, benchmark norms for capital cost along with the indexation formulae to take care of the market variations of the project parameters for various renewable sources of energy.

1.2 Approach for development of Tariff norms

In order to analyse various aspects for determination of tariff for renewable sources of energy, it was essential to undertake comprehensive review of legal and regulatory framework as applicable for tariff determination for renewable sources of energy across various States. Several SERCs have issued feed-in tariff orders for variety of renewable energy technologies across States. It is also important to understand the regulatory process and approaches adopted by various SERCs to appreciate the rationale and reasoning behind

RE tariff Orders across States, which has played key role in the development of renewable energy technologies during the last 6 years since enactment of EA 2003.

ABPS Infra has carried out extensive study in order to develop benchmark tariff norms for various renewable energy technologies and to develop suitable indexation mechanism. The key considerations while determining the tariff norms were,

(a) Detailed review of the tariff orders and 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 discussion paper issued by the various Electricity Regulatory Commissions in the subject matter.

ABPS Infra made a detailed presentation, covering various aspects of renewable energy (RE) tariff determination, before the Commission on February 26, 2009. Further rounds of detailed deliberations were held with the Commission's staff from time to time and detailed presentation before Commission, on April 16, 2009. Based on the discussions with the Commission's staff and further analysis of data, ABPS Infra has prepared the draft Regulations and Explanatory Memorandum.

The tariff norms have been categorised 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 7 sections as under:

- General Principles
- Financial Principles
- Technology specific Principles: ***Wind Energy***
- Technology specific Principles: ***Biomass Power***
- Technology specific Principles: ***Non-fossil fuel based Cogeneration***
- Technology specific Principles: ***Small Hydro Power***

General Principles

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.

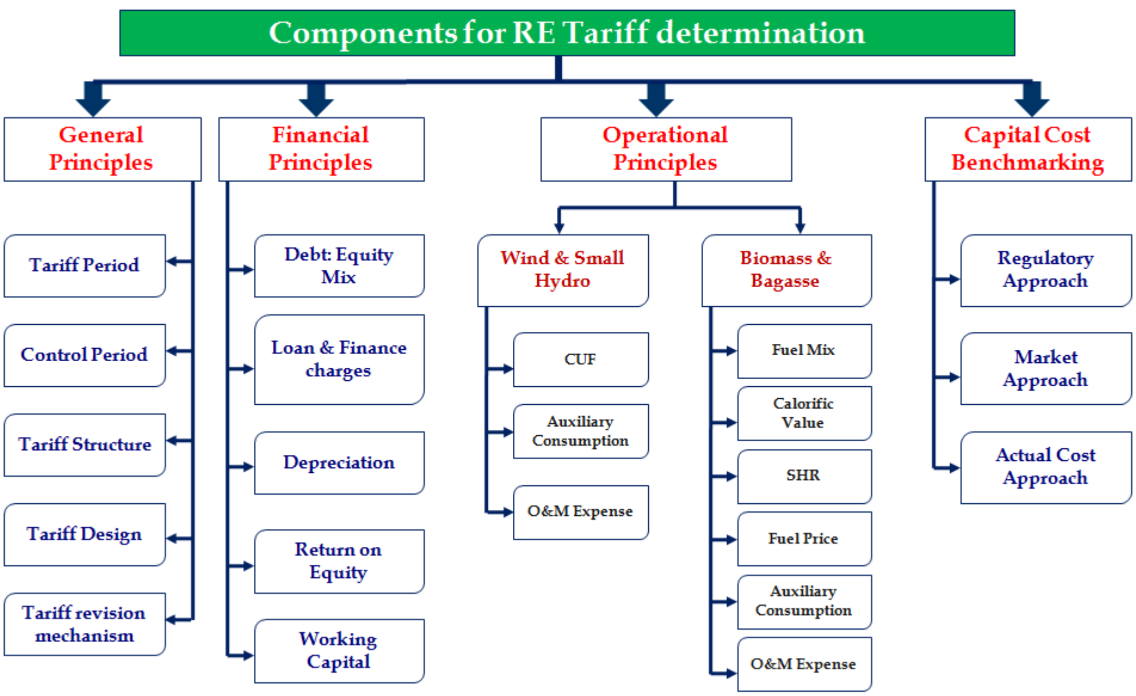
Financial Principles

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 in length.

Technology Specific Parameters

Under this section, technology specific parameters such as Capital Cost norm, capital cost indexation mechanism, Capacity Utilisation Factor, Auxiliary Consumption, O&M Expenses, Fuel mix, Calorific Value, Station Heat rate, fuel price etc. for individual renewable energy sources have been discussed, separately.

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.



2 SCOPE OF RE TARIFF REGULATIONS

2.1 Applicability of Regulations

As per Section 79 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 is to be determined by the Commission under Section 62 of the Act read with Section 79 thereof. Further, in cases of wind, small hydro projects, biomass power and non-fossil fuel based cogeneration these regulations shall apply subject to the fulfilment of eligibility criteria as specified under the Regulations.

2.2 Eligibility Criteria

The preferential tariff determined under these Regulations should be applicable in respect of RE technologies meeting specific Eligibility Criteria. Eligibility Criteria for each RE technology has been proposed as under:

(a) **Wind power projects**

The variability of wind at a particular site is most important parameter influencing the energy generation from wind turbine generator (WTG), which can either be measured in terms of wind velocity or in terms of wind power density. Annual Mean wind power density is better parameter as it takes into account the variability of wind velocity per unit area over a period of time. With the decrease in wind power density, the energy generation from WTG decreases and at annual mean wind power density below 200 Watt/m2, it may not be economical to harness such site for wind energy generation. Therefore it is proposed that wind energy projects must be located at the sites having minimum annual Mean Wind Power Density of 200 Watt/m^2. It has been proposed that the proposed Tariff Regulations shall be applicable for wind power projects located at the wind sites having minimum annual mean Wind Power Density (WPD) of 200 Watt/m^2 using new wind turbine generators.

(b) **Small hydro projects –**

In India, hydro power project upto plant capacity of 25 MW at single location has been classified as small hydro power project. Ministry of New and Renewable Energy (MNRE) has conducted preliminary studies at various locations and thereafter identified the sites which can be used for energy generation. Therefore, it has been proposed that small hydro project should be located at the sites approved by Ministry of New and Renewable Energy (MNRE) using new plant and machinery. Accordingly, eligibility criteria for the purpose of Tariff Regulations shall be SHP projects located at the sites approved by MNRE 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 projects**

Energy generation using biomass can be undertaken through various technologies like direct combustion based on rankine cycle, biomass gasification, thermo-chemical conversion or bio-chemical conversion or combination thereof. The most common among all technologies is rankine cycle based direct combustion of biomass. The capital cost and performance parameters for each technology shall vary significantly from other. The biomass power projects based on rankine cycle are well established in India. Therefore, at this stage, it is proposed that norms under Tariff Regulations shall be applicable for biomass power project based on rankine cycle technology alone.

Other eligibility criteria for biomass projects is that such power projects should be designed to use and should use locally available biomass as main fuel source. It has been observed that biomass projects use significant amount of fossil fuels like coal etc which is not entitled for 'preferential' tariff as applicable for renewable energy sources. However, it is noted that supply of biomass depends on agriculture pattern in that region therefore there may not be sufficient availability of biomass during some months of the year. Further, for flame stability, some amount of fossil fuel needs to be mixed with biomass during combustion process. MNRE through a notification has specified 15% limit for use of fossil fuel for the biomass projects. Therefore, it has been proposed that use of fossil fuel shall be restricted only to 15% of total fuel consumption on annual basis.

Accordingly, eligibility criteria for biomass power projects has been proposed as such biomass power projects 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**

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 output be greater than 45% of the facility's energy consumption, during season."

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. has been discussed.

3.1 Control Period or Review Period

The Control Period refers to the period for which the norms outlined under these Regulations shall remain valid. Tariff determination for all renewable energy projects commissioned during the Control Period (or Review Period) shall be governed by the conditions and norms outlined under these Regulations. The clarity on applicable Control Period (or Review Period) is desirable as the approach on Control period varies considerably across various States. The Control Period of 5 years has been specified by Haryana, Madhya Pradesh, and 3 years by Gujarat, and 2 years by Tamil Nadu. The Control Period as specified by different SERCs for RE technologies has been shown in the following table:

Table: 2.1 Control Period specified by SERCs for RE Technologies

State	Wind	Small Hydro	Biomass	Bagasse	Solar	MSW
Andhra Pradesh	5	5	5	5	10	5
Gujarat	3					
Maharashtra	5	5	5	5		5
Rajasthan	2	n.a.	2	n.a.	10	
Himanchal Pradesh		5				
Kerala	3	3				
Karnataka	5	5	5	5	10	5
Tamil Nadu	2					

Specifying a short duration Control Period of 2 years or long duration Control Period of 5 years has its own advantage and disadvantage. A short duration Control Period leads to frequent revision of tariff however, regulatory concerns can be easily addressed due to close regulatory monitoring. On the other hand, while long duration Control Period offers long term certainty of regulatory principles, it may lead to situation when the underlying tariff parameters may not hold valid through the long duration of the Control Period. Other aspect that needs to be taken into account is gestation period of different RE technologies covered under the Regulations. **After considering above aspects, Control Period of 3 years has been proposed.**

3.2 Tariff Period

'Tariff Period' refers to the period for which 'preferential tariff' to be determined as per the proposed tariff regulations shall be applicable. In case of RE technologies, the SERCs have adopted varying approach for tariff period, ranging from period of 5 years to as high as 20 years period, equivalent to useful life of the project. The Tariff Period as specified by different SERCs for RE technologies has been shown in the following table:

Table: Tariff Period specified by SERCs for RE Technologies

State	Wind	Small Hydro	Biomass	Bagasse	Solar PV	MSW
Andhra Pradesh	5	10	10	10	10	10
Gujarat	20					
Maharashtra	13	20	13	13		20
Rajasthan	20	n.a.	20	n.a.	10	
Himanchal Pradesh		40			5	
Kerala	20	25			10	
Karnataka	10	10	10	10	10	10
Tamil Nadu	20				3	

A longer duration of the tariff period will provide the developer the much needed regulatory certainty for cost recovery. However, in case of renewable energy project, it needs to be ensured that regulatory certainty exist for the period, at least covering the debt service obligation period of 10 to 12 years duration.

Further, it is important that preferential tariff should be applicable only for debt service period and the same need not be continued for useful life of the project. The Utilities and RE developers may be encouraged to explore opportunities for sale/purchase beyond period of debt service. Therefore, as per the provisions of Tariff Policy, the power procurement from renewable sources of energy once debt service obligations are covered, should be undertaken through competitive basis.

<u>In view of above, Tariff Period of 13 years has been proposed after considering the normative debt repayment period of 12 years. One year addition to normative debt repayment period has been proposed to take care of contingencies and to address other eventualities of variation in cashflow, if any.</u>

3.3 Tariff Structure

The tariff structure for conventional projects essentially comprises two parts – viz. fixed part and variable part. In case of renewable energy projects, the SERCs have specified single part tariff for the technologies with no fuel cost component and two part tariff for RE technologies having fuel cost component. The tariff structure adopted by SERCs for different RE technologies has been shown in the following table:

Table: Tariff Structure specified by SERCs for RE Technologies

State	Wind	Small Hydro	Biomass	Bagasse	Solar PV	MSW
Andhra Pradesh	Single	Single	Two Part	Two Part	Single	Two Part
Gujarat	Single					
Maharashtra	Single	Single	Two Part	Single		
Rajasthan	Single		Two Part	Two Part	Single	
Himanchal Pradesh	Single	Single				
Kerala	Single	Single			Single	
Karnataka	Single	Single	Single	Single	Single	
Tamil Nadu	Single		Single	Single	Single	

Under the 'preferential tariff' regime based on cost plus approach, it needs to be ensured that tariff structure and revenue thereof represents underlying costs and performance of the RE projects. In case of RE projects, due to its non-firm nature of generation and dependence on natural factors, the linkage to actual generation is preferred rather than machine/plant availability factors. Hence, it is suggested to specify RE tariff on 'Single Part' basis for all RE technologies.

Further, in case of biomass power and bagasse cogeneration projects where fuel cost component is involved and actual generation is linked to fuel consumption, variable component needs to be specified separately. Accordingly, in case of biomass and bagasse cogeneration project cases, instead of referring to 'Single Part Tariff' alone, it should be referred as 'Single Part Tariff with two components'

<u>In view of above, Singe part tariff with one component has been proposed for wind, small hydro and solar PV renewable energy technologies, having no fuel cost. Single part tariff with two components has been proposed for RE technologies having fuel cost such as biomass power and bagasse cogeneration.</u>

3.4 Tariff Design

Tariff design is one of the most important aspects in ensuring the cash-flow stream to the developers and at the same time, protecting the interest of utility and consumers by avoiding cost burden during initial stages. Tariff should be designed in such a way that the project developer is able to meet its all cash obligations.

The SERCs have adopted varying approach in tariff design; such as front loaded tariff, back loaded tariff, levellised tariff and tariff on average cost basis. The tariff design adopted by SERCs for different RE technologies has been shown in the following table:

Table: Tariff Design across the States for different RE Technologies

State	Wind	Small Hydro	Biomass	Bagasse	Solar PV	MSW
Andhra Pradesh	-	Front Ended	Back Ended	Back Ended	Back Ended	Front Ended
Gujarat	Levellised					
Maharashtra	Back Ended	Back Ended	Back Ended	Back Ended		
Rajasthan	Back Ended		Back Ended		Levelised	
Himanchal Pradesh		Levellised				
Kerala	Levellised	Levellised				
Karnataka	Average	Average	Back Ended	Back Ended	Levelised	
Tamil Nadu	Average					

The average cost approach for tariff determination fails to recognise time value of money hence, it is not recommended. The aspect of time value of money is well recognised under levellised tariff structure approach over the Tariff Period. The discount factor for the purpose of levellisation should be equivalent to cost of capital to be derived based on debt: equity ratio, approved interest rate regime and allowed equity returns over the useful life of the RE project.

Accordingly, Levellised tariff corresponding to useful life of the project has been proposed for the purpose of determination of Tariff. Such Tariff stream may be applicable over the Tariff Period of 13 years. Developers would be able to address its cash flow requirement over debt service period, while at the same time, it will not lead to significant burden on utility during initial period which otherwise may be the case with front loaded tariff.

3.5 Project Specific Tariff

The renewable energy technologies such as Solar PV, Solar thermal and MSW projects are still under nascent stage of development. Significant grid connected capacity is yet to be developed and hence information about actual project cost or performance parameters for the purpose of determination of norms is not available. Based on the information gathered about solar power projects under development at various States, it is evident that, there is significant variation in terms of technology, applications, costs and other performance parameters for Solar PV projects. The information furnished by Solar PV developers before the nodal agencies during the project registration indicates range of technology options such as (Thin film, polycrystalline, mono-crystalline, flat plate module, CSP) etc.

Even for Thin film applications, range of materials such as amorphous Silicon, Ga-As etc. has been proposed. Accordingly, range of capital cost (Rs 16 Cr per MW to Rs 25 Cr per MW) and range of capital utilisation factor (17% to 25%) have been proposed by various solar power project developers. It is envisaged that once the pilot projects as contemplated under GBI scheme are operational, relevant performance data and most suitable technology applications for Indian conditions would be readily available. Until then, it would not be appropriate to develop suitable sample representative case for development of Norms for solar power projects, as 1% variation in CUF alone for solar projects may lead to variation of approximately Rs 1 - 1.25 per unit in cost of generation.

Similarly, it is difficult to develop norms due to limited experience of municipal solid waste (MSW) based installations and plant performance in India. Around 4 large scale MSW power projects have been installed in India (Delhi, Hyderabad, Lucknow and Vijaywada) However, each MSW power project has unique features in terms of technology, quality of fuel and plant performance. Under the circumstances, it may not be appropriate to develop 'generic norm' for MSW project.

Therefore, it is proposed that till Solar and MSW technology achieves maturity level, at least during the first Control Period, the project specific tariff on case to case basis should be specified. The regulations may provide for adoption of such 'project specific tariff' determination approach in case of Solar PV and MSW power projects.

3.6 Tariff for other new Renewable Technologies

In the draft Regulations, the tariff norms for only four RE technologies such as wind, small hydro, biomass and non-fossil fuel based cogeneration has been proposed.

However, there are other renewable energy technologies which are under various stages of development. While developing generic norms for such new RE technologies is not preferred, the preferential tariff for such RE technologies can determined on case-to-case basis upon detailed scrutiny including availing expert inputs in the process. Therefore, the Regulatory framework must have enabling provisions for tariff determination for such technologies, as and when need arises. Therefore, it has been proposed in the draft Regulation that the tariff for all new renewable technologies, for which tariff norms has not been specified by the Commission, will be determined on case to case basis on the basis of petition filed by concerned generating company or licensee, as the case may be.

3.7 Scheduling of renewable energy

Generation from renewable energy sources such as wind energy, solar power, small hydro etc. is non-firm in nature and dependent on the several natural factors and phenomenon. Further, in order to maximise generation from such renewable energy based sources, the same needs to be despatched at all times as and when such RE sources are available and need not be subjected to conditions of merit order despatch as applicable under scheduling and despatch code. Accordingly, it has been proposed that such RE based generation shall be treated as 'MUST RUN' and shall not be subjected to any merit order despatch principles in order to maximise generation from such sources and in order to gainfully utilise RE generation assets already installed. However, with increasing penetration of such RE generating stations, it is equally important to address concerns of grid operations. In case, information about likely generation forecast is available then, it will facilitate grid operations. Internationally, such information about wind energy generation forecast is available through sophisticated software and rigours data analysis and simulation techniques.

Accordingly, under Draft Regulations, it has been proposed that all non-firm renewable energy generating companies such as wind energy, solar power and small hydro etc. shall furnish the tentative day-ahead generation forecast (MWh) in blocks of 1.5 hour duration (6 timeblocks) for the energy availability **on collective basis at inter-connection point** (i.e. Pooling Station) to the concerned Load Despatch Centre to facilitate better grid-co-ordination and management. Further, it has been clarified that above forecasts shall be used only for estimating the tentative energy availability in the system and deviation from such scheduled forecasts shall not be subjected to any UI mechanism outlined under CERC UI Regulations, 2009.

It is recognised that unlike non-firm RE generation sources such as wind energy/solar power and small hydro, the biomass power and non-fossil fuel based cogeneration represents 'firm' generating source, if fuel chain and fuel management plan is well established and the same is amenable to 'scheduling'. However, the critical aspect here to be addressed is 'visibility' to concerned load despatch centre and establishment of requisite communication and metering facilities to be able to subject such biomass power/co-generation facilities to 'scheduling and despatch' regime. Considering the efforts and complexities of subjecting a RE generating station to scheduling and despatch requirement and accounting of energy thereof, it is proposed that such 'scheduling and despatch' requirement may be extended to biomass power and non-fossil fuel based co-generation facilities with minimum installed capacity of 10 MW and above, to begin with.

Accordingly, under Draft Regulations, it has been proposed that the biomass power generating stations and non-fossil fuel based co-generation projects with installed capacity lower than 10 MW shall be treated similar to non-firm RE generating stations and shall provide 'forecasts' only for the purpose of facilitating grid operations. Such generating stations will not be subjected to UI mechanism.

However, the biomass power generating station and non-fossil fuel based co-generation projects with an installed capacity of 10 MW and above shall be subjected to scheduling and despatch code as specified under IEGC 2009 and Central Electricity Regulatory Commission (Unscheduled Interchange and related matters) Regulations, 2009 including amendments thereto.

3.8 Grid Connectivity and Evacuation Arrangement

Grid connectivity has posed as major challenge in harnessing the renewable energy as most of the renewable energy sources, particularly wind and small hydro sites are in remote areas wherein transmission and distribution network is sparse. As per the provisions of Electricity Act 2003, it is the responsibility of concerned licensee to provide grid connectivity to the generating stations. However, due to various reasons, there have been difficulties for developing the infrastructure for evacuation of energy generated from RE sources.

Further, Electricity Act 2003 under Section 86(1)(e) specifically empowers SERCs to take suitable measures for ensuring the grid connectivity to the renewable energy projects. SERCs through Orders and/or Regulations in this regards has developed the evacuation framework. However in most of the cases, responsibility of licensee and project developer in developing the evacuation infrastructure varies across the States. In most of the states, inter-connection point stretches up to nearest grid sub-station and associated cost for development of such evacuation infrastructure is required to be borne by the project developer.

Therefore, it is preferred that evacuation infrastructure from generator terminal up to grid inter-connection point shall be developed by the project developer and beyond inter-connection point the concerned licensee shall develop the network. The concerned licensee shall be responsible for providing grid connectivity to the renewable energy power plants from the inter-connection point, on payment of wheeling or transmission charges as the case may be, in accordance with the regulations of the Appropriate Commission.

For more clarity on this critical issue, the inter-connection point has been specifically defined for each type of RE generating stations. For a wind and solar PV projects, inter-connection point shall be line isolator on outgoing feeder on HV side of the pooling sub-station, whereas, for small hydro, biomass and bagasse cogeneration projects, inter-connection point shall be line isolator on outgoing feeder on HV side of generator transformer.

4 FINANCIAL PRINCIPLES

4.1 Capital Cost

Under regulatory regime of tariff determination based on cost plus approach, Capital Cost forms most critical element of regulated tariff. This assumes even more significance and daunting task in case of 'renewable energy projects' where norms based on 'sample representative case' are required to be developed taking into consideration the diversity of site/state specific parameters, wide variations in technology applications, range of unit sizes from multiple suppliers etc.

To begin with the task of capital cost benchmarking, various approaches were evaluated for development of benchmark capital cost in respect of different RE technologies and subsequently suitable indexation mechanism was devised to consider the year on year variation for the underlying capital cost parameters. Following approaches were considered to arrive at benchmark capital cost in respect of each RE technology:

- Regulatory Approach
- Market Based Approach
- Actual Project Cost Approach
- International Project Cost based Approach

4.1.1 Regulatory Approach

Capital cost benchmarking on the basis of comparison of existing capital cost norms as approved by various SERCs is most simple and easy to follow. However, the capital cost approved by the Commissions has limitations as the basis of approval of such capital cost has varied across States. In most of the cases, the capital cost norms were derived based on the claims made by manufacturers, developers and nodal agencies. No in-depth study was carried out before approving the capital cost. In very few cases, the project specific parameters like unit size, and technology has been taken into account while approving capital cost. Further, the scope/battery limit of capital cost has varied from State to State, for example, Gujarat and Rajasthan have included evacuation/grid connectivity cost as part of Capital Cost. Further, Tariff Orders have been issued over the period from 2003 to 2006 so that comparing capital costs without normalising for time dimension will not be appropriate.

However, we have considered RE capacity addition during each year across various States as important normalising factor. The information about RE capacity addition for each RE technology across States for the period 2003 to 2008 was collated from MNRE.

Accordingly, 'Pooled Capital Cost' (Rs Cr/MW) of RE capacity added during each year from 2003 to 2008 was derived under Regulatory Approach, which provided basis of trend analysis of capital cost to arrive at benchmark.

The capital cost benchmarking on this approach has its own merits and demerits. As this approach is based on actual renewable energy capacity addition in those respective States therefore, the capital cost as arrived through this method reflects capacity addition under regulated regime and hence can be considered as benchmark cost.

However, most of the State Electricity Regulatory Commissions 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.

Further, the renewable energy capacity addition across the States has largely been influenced by the year of issuance of Order. It is observed that the States have seen significant capacity addition in the period immediately after the Order issuance, and it dropped gradually over a period of time.

The other shortcomings of this approach is that in most of the cases the capital cost and other norms were approved based on the claims made by manufacturers, developers in their Detailed Project Reports submitted to respective Commissions and no in-depth study was carried out before approving the capital cost. In very few cases, the project specific parameters like unit size, and technology has been taken into account while approving capital cost.

4.1.2 Market based Approach

Under market based approach, a comparison of capital cost awarded through competitive tender process carried out by public and private entities have been carried out for installation of renewable energy projects, particularly, wind energy projects. The tender conditions have also been scrutinised to evaluate the scope of supply/services for the RE projects awarded through competitive basis over period from 2005 to 2008. The capital cost norm (Rs Cr/MW) for RE capacity awarded through competitive basis for various unit sizes, location of the project, manufacturer/supplier is collated and trend analysis is carried out.

Further, the market based approach has its limitations as the scope of supply and services as outlined under tender conditions has varied across various tender documents. Besides, under tender conditions the bidder was expected to provide services including identification of sites, availing various project clearances and also provide O&M services in some cases. Thus, for the purpose of capital cost benchmarking, above components need to be excluded, however, price break-up for these services is not separately available.

Market based approach provides information about capital cost of projects awarded through competitive route. Hence, it 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. Besides, information about projects/capital cost awarded through competitive route was available only in case of wind energy.

4.1.3 Actual Project Cost based Approach

Actual project cost approach is based on analysis of capital cost data for the projects commissioned during the past few years. The information furnished by project developers as a part of project appraisal requirements to various financial institutions/banks to avail loan or to UNFCCC for registering the project to avail CDM benefits. For the purpose of this analysis, we have considered only the commissioned RE projects. Therefore, the project cost data from IREDA and UNFCCC website was collected and analysed for capital cost benchmarking purpose. The following two sources have been used for collecting the actual project cost:

- Capital cost information for RE projects as provided by IREDA
- 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.

The capital cost data from IREDA and UNFCCC in respect of various RE technologies has been collected and analysed for the following number/capacity of RE projects:

Technology	**IREDA**		**UNFCCC**	
	No. of Projects	MW	No. of Projects	MW
Wind	92	742	42	827

Technology	IREDA		UNFCCC	
	No. of Projects	MW	No. of Projects	MW
Biomass	5	45	22	190
Bagasse cogeneration	8	184	14	155
Small Hydro	25	143	33	280

Various components of the capital cost such as plant and machinery cost, erection and commissioning expenses, land development and civil works and financing cost including interest during construction (IDC) cost has been analysed to the extent of available information. A trend analysis in terms of movement of Capital Cost (Rs Cr/MW) for the period from 2003 to 2008 has been carried out together with component-wise analysis.

4.1.4 International Project Cost Approach

In some countries like Germany, Denmark, and US etc, the renewable sources based energy generation constitutes significant part of total energy requirement. In those countries, several studies have been undertaken covering various aspects of renewable energy equipment procurement and installation cost, generation cost, impact of renewable energy in social and economic aspects etc. As per the research studies, the main plant equipment cost, has not varied significantly across the countries as raw material/equipment cost across the countries is influenced by the international market price.

Therefore, equipment cost across the different countries can be used as a basis for cost benchmarking purpose. However, the capital cost in each of the country 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.

4.2 Basis for Formulation of Capital Cost Benchmark

After considering the merits and demerits of different approaches, the actual project cost has been considered as a basis for capital cost benchmarking purpose.

As actual project cost information is collected from sources such as IREDA and UNFCC, it is assumed that the project cost information has already been scrutinised for accuracy and representation. Besides, it has been ensured that the number of projects and RE project capacity represents fairly large sample size (around 10%) of the cumulative RE capacity installed in the country in respect of each RE technology. Besides, the project database covers RE projects information across various States and no locational or state-specific bias is introduced under the sample under study. Following aspects have been considered while developing capital cost norms for each RE technology:

(a) Project battery limit has been clearly specified for each RE technology for which capital cost norm is developed.
(b) Capital cost information is separated out in terms of site specific parameters (such as land development, civil works, erection and commissioning) and site-independent parameters (mainly comprising plant and machinery).
(c) Soft cost component such as financing cost and interest during construction have also been identified as separate component as percentage of capital cost.
(d) Indices influencing Plant and Machinery across projects have been identified as material indices which constitute underlying cost parameters for plant and machinery.
(e) Indices considered are whole sale index for steel and whole sale index for electrical machinery. Appropriate weightage for each index has been considered.

Accordingly, capital cost for each RE technology has been specified as function of 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 IDC as outlined below.

CC(n) = P&M(n)* (1+F1+F2+F3)
F1 = Factor for Land and Civil Works (say, 0.08)
F2 = Factor for Erection and Commissioning (say, 0.07)
F3 = Factor for IDC and Financing Cost (say, 0.10)

Separate factors have been specified for each RE technology depending on its percentage component within overall capital cost as summarised below.

Technology	**Plant & Machinery**	**Land and Civil Work (F_1)**	**Erection and commissioning (F_2)**	**IDC and financing (F_3)**
Wind	80%	0.08	0.07	0.10
Biomass	75%	0.10	0.09	0.14
Bagasse cogeneration	80%	0.10	0.08	0.07
Small Hydro	70%	0.16	0.10	0.14

In order to define suitable weightage factor for the component, land and civil works, erection and commissioning and IDC and financing cost, the capital cost breakup as furnished by the developers and available in public domain have been analysed. The weightage factors have varied across RE technologies depending on influence of site specific components (e.g. land development, civil works, erection and commissioning etc.) within overall capital cost for particular RE technology.

The share of each of these components, including the plant and machinery cost, in the total capital cost for a number of projects has been identified. It has been observed that the share of these components in the total capital cost vary, as it depends on site specific and project specific conditions. However, analysis reveals that while other factors may depend on the site specific conditions, the plant and machinery cost should not vary significantly from one project to another. Hence, it was found appropriate to assign the weightages to the factors keeping the plant and machinery cost as base.

Taking into account the range in which the share of these components vary with respect to the capital cost appropriate weightages for each of the factors viz. land and civil works, erection and commissioning and IDC and financing cost, for respective renewable energy technology has been assigned.

Further, plant and machinery has been indexed with the Wholesale Price Index (WPI) to take care of variation in underlying cost components. The WPI of steel and electric machinery has been used for indexation purpose as these two elements constitute major part of plant and machinery cost.

The FY 2004-05 has been considered as base year for benchmarking purpose as most of the SERCs have specified the preferential tariff for RE projects on cost-plus basis since then. The capital cost for base year has been indexed to compute the benchmark capital cost for FY 2009-10 using following formulation. The WPI indices for steel and electrical machinery for the period 2004-05 to 2008-09 have been applied to arrive at Capital Cost for first year of control period (i.e. FY 2009-10).

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

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

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, (In default it is 0.6), for weightage to Steel Index

b = Constant to be determined by Commission from time to time, (In default it is 0.4), for weightage to Electrical Machinery Index

The Capital Cost derived based on proposed formulation have been compared against the 'Pooled Cost' under regulatory approach as well as actual capital cost database so compiled for various RE projects. The analysis for benchmark capital cost formulation for each RE technology has been elaborated separately under Technology specific section.

4.3 Evacuation Cost

The transmission cost, per unit, required for the evacuation of power from renewable energy based projects is higher as compared to conventional power projects, especially in case of Wind and Solar power projects due to lower capacity utilisation factors. It has been proposed that the evacuation infrastructure up to inter-connection point including the lines, switch gears, metering and protection management and other related equipments shall be developed by the RE generator at its own cost and as per the standards specified by the Authority. However, it shall be responsibility of the concerned licensee to build the evacuation infrastructure or strengthening of existing system beyond the interconnection point i.e. the interface point of renewable energy facility with the transmission system or distribution system as the case may be.

4.4 Debt Equity Ratio

With emergence of large RE projects under IPP mode assuming significance, the lenders concerns for DSCR requirements may need to be addressed for non-recourse RE projects, hence Debt : Equity ratio of 2:1 instead of 70:30 is preferred by lenders and investors in view of their higher risk perception about RE projects. Further, it is noted that at the depreciation rate of 5.28% in line with CERC Tariff Regulations, 2009 and depreciation spread over Tariff Period of 12-13 years, loan repayment at Debt: Equity of 2:1 (66.6:33.3) can be readily addressed.

However, it is noted that the Tariff Policy (TP) notified by the Government of India stipulates the debt equity ratio of 70:30 for financing all future projects. Clause 5.3 (b) of the TP is reproduced below:

"b) Equity Norms

For financing of future capital cost of projects, a Debt: Equity ratio of 70:30 should be adopted. Promoters would be free to have higher quantum of equity investments. The equity in excess of this norm should be treated as loans advanced at the weighted average rate of interest and for a weighted average tenor of the long term debt component of the project after ascertaining the reasonableness of the interest rates and taking into account the effect of debt restructuring done, if any. In case of equity below the normative level, the actual equity would be used for determination of Return on Equity in tariff computations."

Moreover, CERC Tariff Regulations, 2009 also provide for normative debt-equity ratio of 70:30 for Generating Company/licensee. Regulatory Commissions across different States for RE projects have been following the same principle laid down in the TP.

Further, for RE projects where equity employed is more than 30% (in case of project specific tariff determination), the amount of equity for the purpose for determining the tariff shall be limited to 30% only whereas in case the equity employed is less than 30%, the actual equity employed shall be considered.

Accordingly, it is suggested that the debt to equity ratio of 70:30 as per existing practice and in line with Tariff Regulations, 2009 should be followed in case of RE projects. The concerns about cashflow requirement for debt repayment purposes can be addressed through appropriate depreciation rate.

4.5 Loan and Finance Charges

4.5.1 Loan Tenure

Normative loan tenure of 12 years has been specified as long term loan is preferred to ensure adequate yearly cashflow for RE projects. As per existing industry practice, loans with tenure upto 10-12 years are available for RE projects.

4.5.2 Interest Rate

While the actual interest costs are allowed in case of conventional power projects, in case of RE projects with generic tariff determination approach, it is necessary to specify benchmark interest rate as actual interest cost determination for each RE project is not envisaged. The risk profile of Renewable energy projects is perceived to be higher as compared to conventional power projects. Thus, normative interest rate of 100 basis points above State Bank of India long term prime lending rate (SBI-LTPLR), as on 1st April of the relevant of the control period has been proposed.

The tariff determined based on normative interest rate assumptions shall normally not vary on account of variation in SBI PLR over the duration of the Tariff Period.

However, it has also been acknowledged that RE developer's interest due to significant variation in interest rate due to change in SBI PLR needs to be protected. In order to address such situation it is proposed that if the variation in SBI PLR is in excess of (+/-) 200 basis points than SBI PLR prevalent at the time of tariff determination, the Commission may initiate regulatory process for revision in Tariff either on suo-motu basis or on application filed by concerned generating company.

4.6 Depreciation

The word 'Depreciation' is interpreted differently by different stakeholders and professionals. From accounting point of view, in line with the Accounting Standard issued by the Institute of Chartered Accountants of India, 'Depreciation is a measure of the wearing out, consumption or other loss of value of a depreciable asset arising from use, efflux of time or obsolescence through technology and market changes'. It reflects annual consumption of a capital asset in use. From Investor's point of view, depreciation is a non-cash expense which reduces tax burden but generates internal cash for further investment. From engineering point of view, depreciation means decline in capability or loss of value in an asset over time of usage. From Economist's point of view, economic depreciation over a given period is the reduction in the remaining value of the future services. Under certain circumstances, such as unanticipated increase in the price of the services generated by an asset, its value may increase rather than decline. Depreciation is then negative. From regulatory perspective, there can be two view points on depreciation. One view is depreciation is the refund of capital subscribed, and the other view is depreciation is a constant charge against an asset to create a fund for its replacement.

As highlighted earlier, in case of renewable energy projects the risk perception of the investors/lenders is higher and the concerns about debt service coverage needs to be addressed if more and more renewable energy capacity is envisaged to be funded by way of non-recourse finance basis.

Considering the above facts, it is proposed that, for the purpose of refund of capital over the estimated useful life of the assets concerned, the loan repayment period of 12 years is made applicable to all normative loans and accordingly the rate of depreciation will have to be commensurate with the assumptions in terms of normative loan component (70%) and loan tenure (12 years). Therefore, it has been proposed to divide estimated useful life of the project into two parts for the purpose of tariff determination. The first part would be 12 years duration over which the loan capital can be serviced by the investors by way of depreciation at the rate of 6% per annum and thereafter it will be spread over the useful life of the project.

4.7 Return on Equity

The Tariff Policy (TP) notified by the Central Government in pursuance of the Section 3 of the EA 2003 has stipulated that Appropriate Commission may determine 'preferential tariffs' for procurement of power by distribution licensees from non-conventional energy sources. The Commission under recently notified Tariff Regulations, 2009 has specified return on equity of 15.5% on pre-tax basis for conventional power projects upon considering applicable income tax rate (MAT or Corporate Tax rate) as per Finance Act.

The renewable energy generation projects are expected to cause less environmental pollution and also help in conserving the fossil fuel. However, the renewable energy projects have ample risk and uncertainties associated with them. Hence, it is required to provide appropriate compensation to cover the risk associated with the renewable energy projects and incentive to encourage investment in renewable energy sector.

Accordingly, it is proposed that preferential returns at the rate of 16% may be allowed in case of renewable energy projects. Further, considering the fact that renewable energy projects shall be entitled to avail 80 IA benefits, MAT rate (11.22%) may be applicable for initial period of 10 years since commercial operation and Corporate Tax rate (33.66%) may be applicable for period beyond 10 years. Accordingly, pre-tax return on equity of 17% p.a. (16%/(1-11.22%)) for initial 10 years and at the rate of 23% p.a. (16%/(1-33.66%)) for period beyond 10 years may be considered. 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.

4.8 Interest on Working Capital

The Working Capital requirement in respect of wind energy projects and small hydro power may be computed as per conditions outlined below:

(a) Wind Energy / Small Hydro Power

(i) Operation & Maintenance expense for one month,

(ii) Receivables equivalent to 1½ (one and a half) months of energy charges for sale of electricity calculated on the normative CUF.

(iii) Maintenance spare @ 15% of operation and maintenance expenses.

Further, Interest on Working Capital shall be at interest rate equivalent to average State Bank of India short term PLR prevalent for the period 1st April 2008 to 31st March 2009.

(b) Biomass Power and Non-fossil fuel Co-generation

(i) Fuel costs for four months equivalent to normative PLF

(ii) Operation & Maintenance expense for one month,

(iii) Receivables equivalent to 1½ (one and a half) months of fixed and variable charges for sale of electricity calculated on the target PLF.

(iv) Maintenance spare @ 15% of operation and maintenance expenses.

Further, Interest on Working Capital shall be at interest rate equivalent to average State Bank of India short term PLR prevalent for the period 1st April 2008 to 31st March 2009.

4.9 Operation and Maintenance Expenses

O&M expense comprise employee expense, A&G expense and repairs and maintenance expense. While the RE project developers such as biomass power, small hydro project have their own establishments, wind energy project developers have adopted different model of outsourced O&M activity with WTG supplier or windfarm developer offering O&M services. Even in case of biomass projects the fuel procurement, storage and handling activities are outsourced to limited extent. The industry practice or regulatory approach, for O&M expense is to specify the same as percentage of the capital cost. However, it is preferred that O&M expenses are stipulated in absolute terms as Rs L per MW rather than as percentage of capital cost as capital cost is itself proposed to be determined based on benchmark norms and index parameters.

Accordingly, O&M expenses in terms of Rs L per MW was derived based on approved norm of O&M expense (% terms) by various SERCs alongwith approved capital cost for each RE technology, separately. O&M expenses norms (Rs L per MW) so derived were compared across various States upon normalisation with due escalation factors on account of varying timelines. Further, the above O&M expense norms (Rs L per MW) for biomass power and small hydro power has also been compared vis-à-vis O&M norms stipulated under Tariff Regulations, 2009 for thermal power and hydro power, respectively to verify abnormal variation, if any.

The escalation factor for the purpose of normalisation of operation and maintenance expenses for the years 2003-04 to 2007-08, has been carried out at the rate of 5.17% p.a. The average normalized operation and maintenance expenses at 2007-08 price level has been proposed to be escalated at the rate of 5.72% p.a. (as considered under Tariff Regulations, 2009) to arrive at the operation and maintenance expenses for year 2009-10 and over Tariff Period.

4.10 Subsidy and Incentive

For renewable energy projects, the Central and State Governments have provided certain benefits like capital subsidy, generation based incentive, etc. Recently, the Central Government has announced Generation Based Incentive (GBI) scheme for solar and wind projects. Generation based incentives are preferred over capital subsidies as it promotes renewable energy generation rather than mere capacity addition. Further, it is also acknowledged that GBI would be necessary, if renewable sources such as Solar Power are to be promoted at the scale envisaged under National policies, otherwise it would impose significant burden on consumer tariff.

Under the cost plus regulated regime, all the expenses on normative basis are considered for the purpose of tariff determination. Thus, developer’s concerns regarding tariff to reflect adequate cost coverage has been addressed. At the same time, it is also required that through incentive/subsidy mechanism, project developer do not earn significant profit in addition to the return assured by the Commission so that consumer’s interest can also be protected. Accordingly, it is proposed that the Commission shall take into consideration any incentive or subsidy offered by the Central/ State Government to the renewable energy power plants while determining the tariff under these Regulations.

5 TECHNOLOGY SPECIFIC NORMS: WIND ENERGY

5.1 Capital cost

In order to derive benchmark capital cost for wind energy projects following approaches have been considered viz. Regulatory Approach or Pooled Cost Approach, Actual Project Cost Approach, and market based approach. The analysis of various approaches and summary result has been detailed in following paragraphs.

5.1.1 Pooled Capital Cost under Regulatory Approach

Pursuant to enactment of Electricity Act 2003, several SERCs have issued the normative tariff for wind projects on the basis of cost-plus approach. During the last 6 years, almost all the States having predominant wind potential have issued Tariff Orders. In all those states, significant capacity addition has taken place during the last 6 years which indicates that tariff as specified by the Commission has generated adequate developer interest resulting into significant capacity addition which in turn means that normative capital cost assumed by the SERCs may be considered as representative capital cost for benchmark purposes. On this basis, the 'Pooled Capital cost' for 6 years has been computed on the basis of normative cost approved by various SERCs and corresponding year wise capacity addition taken place in each State. The pooled capital cost as computed has been shown in the following table:

Table 4.1 Pooled Capital Cost, Rs Cr/MW

Year	2004-05	2005-06	2006-07	2007-08	2008-09
Pooled Cost	4.06	4.09	4.51	4.57	4.58

As evident from the above table that pooled capital cost has increased over the period from FY 2005-06 to FY 2006-07, pursuant to issuance of tariff orders by the Tamil Nadu Electricity Regulatory Commission, Gujarat Electricity Regulatory Commission and Rajasthan Electricity Regulatory Commission in FY 2006-07 in which normative capital cost of Rs 5.0 Cr/ MW, Rs 4.65 Cr/MW and Rs 4.42 Cr/MW respectively was considered. However, in subsequent years, virtually there has been no change in the average capital cost as there was no major development by SERCs towards the normative wind tariff and the capital cost assumptions thereof.

5.1.2 Actual Project Cost Approach

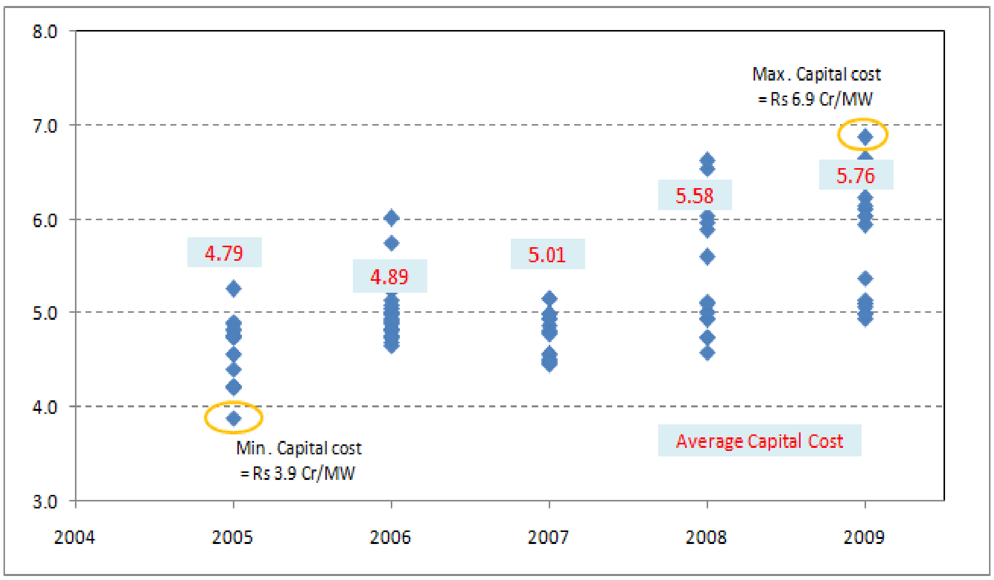
Under this approach, the capital cost data has been collected from two sources namely projects sanctioned by IREDA and projects registered with UNFCCC. The capital cost data for around 134 projects which translates into 1569 MW of capacity addition have been analysed under this approach. The sample size of 1569 MW can be considered as representative sample for analysing the variation in capital cost as it represents approximately 18% of total installed capacity of wind power in the country.

Table 4.2: Summary of Sample Size

Source	No. of Projects	MW
IREDA	92	742
UNFCCC	42	827
Total	**134**	**1569**

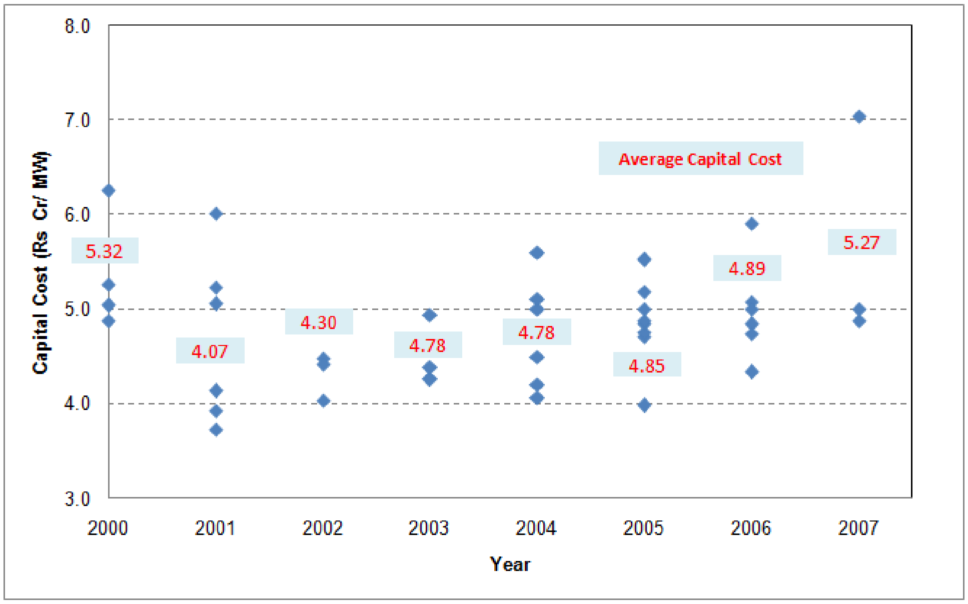
A trend analysis in terms of movement of Capital Cost (Rs Cr/MW) for the projects funded by IREDA for the period from the FY 2004-05 (referred as 2005) to FY 2008-09 (referred as 2009) has been carried out to understand the variation in capital cost during these years, as shown in the following graph:

Figure: Capital cost variation for IREDA funded projects



As it is evident from the above chart that, the per MW capital cost has increased over the period however, such increase was significant between the years FY 2007 and FY 2008, mainly due to steep rise in material/equipment cost. Similar capital cost analysis has been carried out for the projects registered with UNFCCC. Trend analysis for the UNFCCC registered projects have been carried out for the period of 2000 to 2007, as shown in the following graph:

Figure: Capital cost variation for UNFCCC registered projects



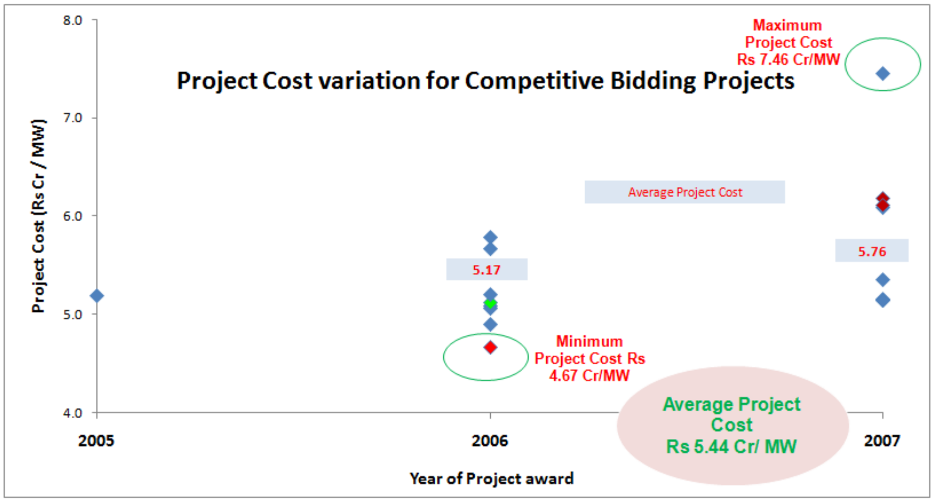
The capital cost variation for projects registered with UNFCCC also shows the increasing trend in the capital cost, similar to trend observed for IREDA projects. The comparison of capital cost variation in actual project cost approach with the pooled cost approach clearly indicates that the pooled regulated capital cost norm derived under regulatory approach is lower than the average capital cost norm derived under actual project database approach.

It may be argued that the capital cost disclosures for loan sanction or CDM project registration purposes could have element of over-estimation, however, it may be noted that the project cost information has already been scrutinised for accuracy and representation at the institutional level. Besides, it has been ensured that the number of projects and RE project capacity represents fairly large sample size (around 8%) of the cumulative Wind power capacity installed in the country. Besides, the project database covers RE projects information across various States and no locational or state-specific bias is introduced under the sample under study.

5.1.3 Market based approach

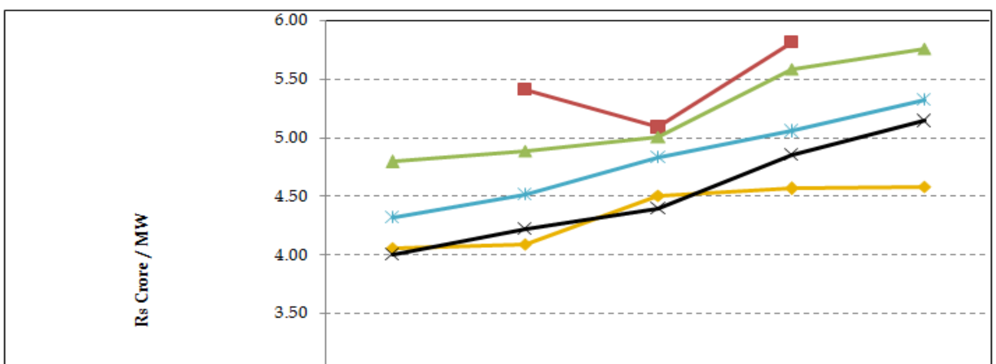
In case of wind energy projects, the various private and public entities have set up wind farms by inviting the tenders from various wind project developers. However, the total MW capacity awarded through tender process is very miniscule, 2-3% of total wind projects installed capacity. A comparison of capital costs of projects awarded through competitive bidding/ tendering process is shown in the following graph:

Figure: Capital cost variation in Market based approach



5.2 Capital cost formulation for wind energy

Based on analysis of the actual project cost component-wise information, appropriate weightage factors and capital cost formulation has been devised as elaborated under section 4.2. A comparison of Capital Cost derived based on proposed formulation against the 'Pooled Cost' under regulatory approach as well as Capital Cost under actual project database approach is presented under following chart.



	2004-05	2005-06	2006-07	2007-08	2008-09
Regulatory Approach	4.06	4.09	4.51	4.57	4.58
Market based approach		5.41	5.09	5.82	
IREDA based projects	4.79	4.89	5.01	5.58	5.76
Proposed capital cost working	4.00	4.22	4.40	4.85	5.14
Index based apporach	4.32	4.52	4.83	5.05	5.32

The Capital Cost for FY 2008-09 under various approaches has varied from Rs 4.58 Cr/MW under 'Pooled Cost' regulatory approach to Rs 5.76 Cr/MW under actual project cost approach whereas capital cost based on proposed formulation suggests norm of Rs 5.14 Cr/MW. Accordingly, the normative capital cost of **Rs 515 Lakh/MW** has been proposed for first year of the Control Period.

5.3 Capital Cost Indexation Mechanism for wind energy

The following indexation mechanism shall 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.

CC(n) = P&M(n)* (1+F1+F2+F3)

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 the 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, (In default it is 0.6), for weightage to Steel Index

b = Constant to be determined by Commission from time to time, (In default it is 0.4), for weightage to Electrical Machinery Index

F1 = Factor for Land and Civil Works (0.08)

F2 = Factor for Erection and Commissioning (0.07)

F3 = Factor for IDC and Financing Cost (0.10)

5.4 Capacity Utilisation Factor (CUF)

CUF represents important parameter that influences the economics of a wind project at a particular wind site. CUF depends on prevailing wind regime at particular site. Generally, coastal and hilly regions has better wind regime as compared to sites located in plain region and hence yield better CUF.

The diversity in CUF across States due to varying wind regimes prevalent in such States need to be factored in while specifying norm for CUF. Further, possibility was explored that norm specified by the respective SERCs in their tariff regulations may be adopted with certain improvement trajectory in view of advancement in technology. However, the CUF norm set by the SERCs doesn't take into account the site specific parameters as single CUF norms has been specified for projects to be installed at different sites in the State. Therefore, it was considered that instead of adopting norms specified by SERCs in respective States, study of Wind Zone mapping may be undertaken. In order to undertake such study, the data as maintained by the C-WET was taken into account.

The capacity utilisation factor depends on site specific parameters (Wind velocity, wind density and weibull shape parameter) as well as machine specific parameters (Hub height, rotor diameter, and power curve). Wind Power density which is function of wind velocity and air density represents better indicator for wind zoning as compared to wind velocity. Centre for Wind Energy Technology has carried out the detailed wind resource survey of around 200 potential wind sites located across the different States. The classification of these potential wind sites based on annual mean wind power density (watt/sq m) across various States is summarised below:

Wind Power Density (W/sq m)	Gujarat	AP	Karnataka	Rajashtan	Madhya Pradesh	Maharashtra	Tamil Nadu	Kerala	Total
< 200	0	0	2	0	0	0	0	1	**3**
200 - 225	9	5	4	1	3	11	2	2	**37**
225 - 250	11	7	2	2	0	5	4	4	**35**
250 - 275	2	6	4	2	2	5	4	0	**25**
275 - 300	5	5	3	1	1	8	3	2	**28**
300 - 400	8	7	5	1	1	2	14	4	**42**
> 400	3	2	6	0	0	0	14	4	**29**
TOTAL	**38**	**32**	**26**	**7**	**7**	**31**	**41**	**17**	**199**

Based on analysis of data prepared for various sites across States, it can be inferred that most of wind sites are within the range of annual mean wind power density of 200-300 W/m². Further, simulation has been carried for CUF for the range of different wind turbines for sites with varying annual mean wind power density. On this basis, following CUF norms have been proposed for different annual mean wind power density range.

Annual Mean Wind Power Density (W / m²)	CUF
200-250	20%
250-275	22%

Annual Mean Wind Power Density (W / m^2)	CUF
275-300	24%
300-400	27%
> 400	30%

Further, for the purpose of applicable tariff to particular wind energy project, it is proposed that the wind energy project developer shall arrange for its wind resource data and annual mean wind power density for the project site to be duly certified by Centre of Wind Energy Technology (C-WET) at least 3 months prior to project COD.

5.5 Operation and Maintenance Expense

Operation and maintenance practices for wind projects are different from that adopted for other renewable energy projects. Typically, the WTG equipment supplier and windfarm developer offer this service to the WTG project developer, thereby optimising costs of windfarm operation for particular project developer. The centralised monitoring of a wind farm results into less employee expense and A&G expense.

During the process of specifying the norms for operation and maintenance expenses, it was observed that none of the project developer/ industry association/investor has submitted detailed break up of actual operation and maintenance expense, for the commissioned wind projects, to the SERCs during the regulatory process of preferential tariff determination. There was wide variation in the claims made by different stakeholders towards the actual operation and maintenance expenses. Therefore, it was considered that operation and maintenance expense in percentage terms as specified by SERCs can be considered the basis for development of norm for operation and maintenance expense with due indexation mechanism.

The normative operation and maintenance expense and the escalation mechanism used by the SERCs were considered for working out the normalised operation and maintenance expense for the FY 2009-10. Accordingly, O&M expense norm of Rs 6.50 Lakh per MW for first year of Control Period (i.e. FY 2009-10) with escalation factor of 5.72% per annum has been proposed.

6 TECHNOLOGY SPECIFIC NORMS: SMALL HYDRO POWER

6.1 Capital Cost

Capital cost for small hydro projects varies significantly across the States, mainly due to variation in civil works and transportation etc. The approaches for benchmarking the capital cost for small hydro projects viz. regulatory approach or pooled cost approach, and actual project cost approach has been discussed in the following paragraphs.

6.1.1 Pooled Capital Cost or Regulatory Approach

Pursuant to enactment of Electricity Act 2003, several SERCs have issued the normative tariff for small hydro power projects on the basis of cost-plus approach. During the past 5 years, almost all the States having predominant small hydro potential have issued Tariff Orders. In all those states, significant capacity addition has taken place during the past 5 years which indicates that tariff as specified by the Commission has generated adequate developer interest resulting into significant capacity addition which in turn means that normative capital cost assumed by the SERCs may be considered as representative capital cost for benchmark purposes. On this basis, the 'Pooled Capital cost' for 5 years has been computed on the basis of normative cost approved by various SERCs and corresponding year wise capacity addition taken place in each State. The pooled capital cost as computed has been shown in the following table:

Table 6.1 Pooled Capital Cost, Rs Cr/MW

Year	2004-05	2005-06	2006-07	2007-08	2008-09
Pooled Cost	4.02	3.90	3.91	4.30	4.46

As evident from the above table, the pooled capital cost decreased in FY 2005-06 as compared to FY 2004-05, mainly due to the reason that Karnataka Electricity Regulatory Commission issued Order in January 18, 2005 in which it specified the capital cost of Rs 3.90 Cr/MW. However, in subsequent years, the pooled capital cost has increased with the issuance of tariff orders in other States like Maharashtra, Kerala, Uttarakhand and Himanchal Pradesh etc. The normative capital cost considered by Himanchal Pradesh Electricity Regulatory Commission (Rs 6.5 Cr/MW) and Uttarakhand Electricity Regulatory Commission (Rs 6.0 Cr/MW) is significantly higher than the capital cost considered by other Electricity Regulatory Commission (less than Rs 5.0 Cr/MW) mainly due to difficult terrain, high cost of civil works and erection and transportation cost in these two States.

6.1.2 Actual Project Cost Approach

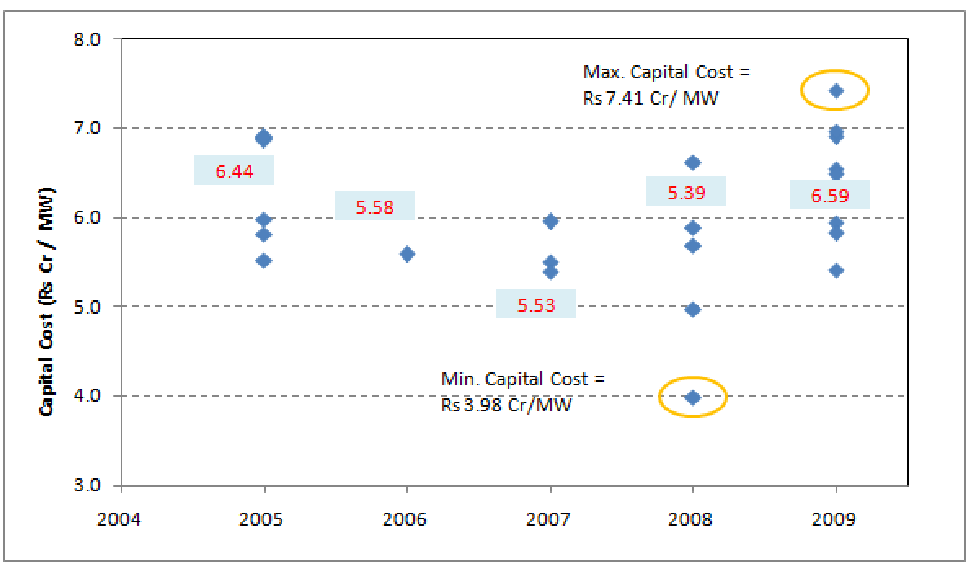
Under this approach, the capital cost data has been collected from two sources namely projects sanctioned by IREDA and projects registered with UNFCCC. The capital cost data for around 58 projects which translates to 423 MW have been analysed under this approach. The sample size of 423 MW can be considered as representative sample for analysing the variation in capital cost as it represents approximately 18% of small hydro installed capacity in the Country.

Table 6.2: Summary of sample size for SHP under Actual Project cost approach

Source	No. of Projects	MW
IREDA	25	143
UNFCCC	33	280
Total	**58**	**423**

To the extent of the information available, various components of the capital cost such as plant and machinery cost, erection and commissioning expenses, land development and civil works and financing cost including interest during construction (IDC) cost has been analysed. A trend analysis in terms of movement of capital cost (Rs Cr/MW) for the projects funded by IREDA for the period from the FY 2004-05 (referred as 2005) to FY 2008-09 (referred as 2009) has been carried out to understand the variation in capital cost over the period, as shown in the following graph:

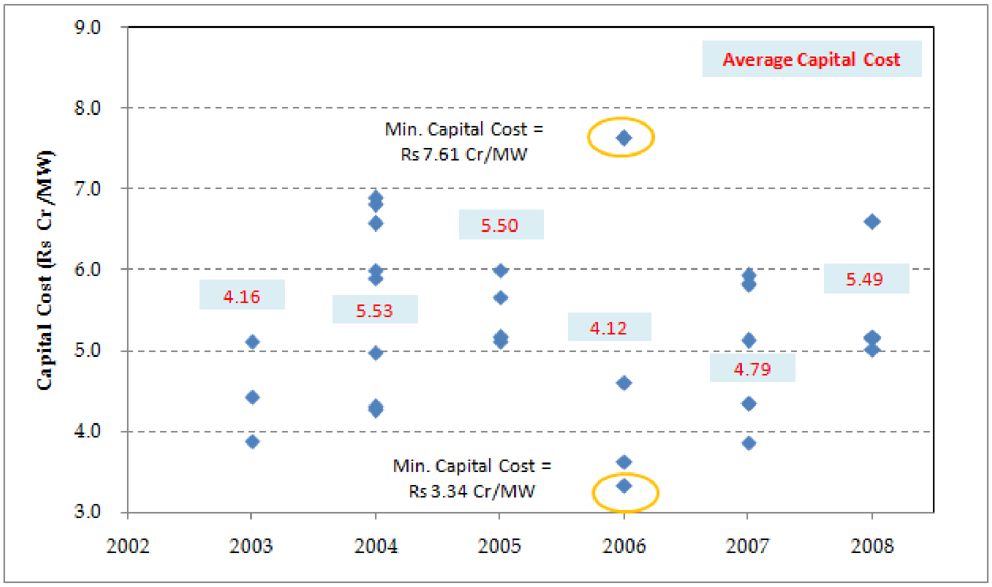
Figure: Capital cost variation for IREDA funded projects



As it is evident from above chart that the capital cost for IREDA funded small hydro projects has varied significantly across the years. Further, it is observed that the most of the small hydro projects funded by IREDA were located in Himanchal Pradesh and Uttarakhand, for which capital cost remains high due to difficult terrain.

In the second step, the capital cost analysis has been carried out for the projects registered with UNFCCC. The capital cost variation and the average per MW capital cost has been shown in the figure

Figure: Capital cost variation for UNFCCC registered projects

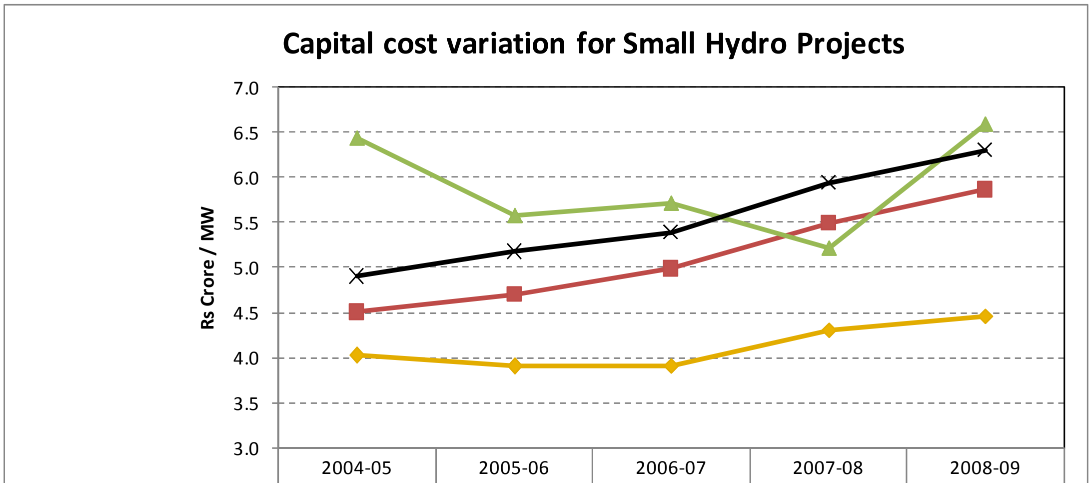


The average capital cost for the projects registered with the UNFCCC is significantly lower than the IREDA funded projects. In case of UNFCCC data, there are significant number of SHP projects commissioned in the southern and western region states for which per MW project installation cost is lower than the SHP projects in hilly terrains of Himachal Pradesh or Uttarakhand.

6.2 Capital cost formulation for small hydro

Based on analysis of the actual project cost component-wise information, appropriate weightage factors and capital cost formulation has been devised as elaborated under section 4.2. A comparison of Capital Cost derived based on proposed formulation against the 'Pooled Cost' under regulatory approach as well as Capital Cost under actual project database approach is presented under following chart.

Figure: Capital cost variation across the approaches



	2004-05	2005-06	2006-07	2007-08	2008-09
Regulatory Approach	4.02	3.90	3.91	4.30	4.46
Index based approach	4.50	4.70	4.99	5.49	5.86
IREDA based projects	6.44	5.58	5.72	5.22	6.59
Proposed formulation	4.90	5.17	5.39	5.94	6.30

The Capital Cost for FY 2008-09 under various approaches has varied from Rs 4.46 Cr/MW under 'Pooled Cost' regulatory approach to Rs 6.59 Cr/MW under actual project cost approach whereas capital cost based on proposed formulation suggests norm of Rs 6.30 Cr/MW.

Accordingly, the normative capital cost of **Rs 6.30 Cr / MW** for SHP projects in Himanchal Pradesh, Uttarakhand and North-Eastern States and normative capital cost of **Rs 5.00 Cr per MW** for other States for first year of the Control Period (2009-10) has been proposed.

6.3 Capital Cost Indexation Mechanism for small hydro

The following indexation mechanism shall be applicable in case of small hydro power projects for adjustments in capital cost over the Control Period with the changes in Wholesale Price Index for Steel and Electrical Machinery.

CC(n) = P&M(n)* (1+F1+F2+F3)

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 the 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, (In default it is 0.6), for weightage to Steel Index

b = Constant to be determined by Commission from time to time, (In default it is 0.4), for weightage to Electrical Machinery Index

F1 = Factor for Land and Civil Work (0.16)

F2 = Factor for Erection and Commissioning (0.10)

F3 = Factor for IDC and Financing Cost (0.14)

6.4 Capacity Utilisation Factor (CUF)

CUF represents important parameter that influences the economics of any small hydro project at a particular site. CUF for small hydro plants primarily depends on site specific conditions like water flow rate, availability during the year, head and irrigation schedule in case of canal based irrigation linked SHP projects. The water availability for northern region states like Himanchal Pradesh and Uttarakhand is better due to perennial water stream while for southern and western region sites, water availability remain high only during the monsoon period and remains low during other seasons. Due to variation in water availability, the average CUF for SHP projects in Himachal Pradesh, Uttarakhand and north-eastern states is higher as compared to the small hydro projects located in southern and western part of the Country. Therefore, the normative CUF approved by the SERCs can be considered as indicative of such difference in CUF in different State, which needs to be factored in while specifying the CUF norms for SHP projects across States. Considering all these factors, 45% CUF has been proposed for SHP projects in Himanchal Pradesh, Uttarakhand and north-eastern States, while 30% CUF has been proposed for sites in other States.

6.5 Auxiliary Consumption factor

Normative auxiliary consumption for SHP projects has been considered at 0.5%.

6.6 O&M Expense for small hydro

O&M expense for small hydro projects to some extent depend on the site specific conditions. Higher silt level in the water can cause the frequent break down in the machine parts which may result into high repair and maintenance expense. The employee expense and administrative & general expense for the small hydro projects are not so high due to central monitoring of the project.

Based on information available from IREDA and UNFCCC for SHP projects and also through information available about regulatory proceedings across various States, it is observed that the project developer/ industry association/investor have not submitted detailed break up of actual operation and maintenance expense, for the commissioned small hydro projects. There was been wide variation in the claims made by different stakeholders towards the actual operation and maintenance expenses. Therefore, it was considered that operation and maintenance expense as specified by SERCs as percentage of capital cost can be the basis for deriving norm for operation and maintenance expense in terms of Rs L per MW.

The normative operation and maintenance expense and the escalation mechanism used by the SERCs were considered for working out the normalised operation and maintenance expense for the FY 2009-10. Accordingly, O&M expense norm of Rs 12.00 Lakh per MW for first year of Control Period (i.e. FY 2009-10) with escalation factor of 5.72% per annum has been proposed.

6.7 Treatment of Water royalty charges

It is observed that different practices are adopted in various States for levy of royalty charges from the project developers for utilisation of water resource for generation of electricity. The amount of royalty charges varies across the States. Accordingly, it is proposed in the Draft Regulations that water royalty shall not be considered for the purpose of determination of tariff, however, the actual amount of water royalty charges as levied by the respective state government shall be allowed as pass-through component and shown separately in the energy bills to be sent to the beneficiaries.

7 TECHNOLOGY SPECIFIC NORMS: BIOMASS PROJECTS

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 and Indexation

In order to develop norm for benchmark capital cost for biomass power projects following approaches have been considered viz. Regulatory Approach or Pooled Cost Approach, Actual Project Cost Approach and Escalation of Capital Cost approved by respective SERC. The analysis of various approaches and summary of result has been detailed in following paragraphs,

7.2.1 Pooled Capital Cost Approach

In the 'Pooled Capital Cost Approach' the biomass power projects installed in the nine States viz, Andhra Pradesh, Haryana, Karnataka, Madhya Pradesh, Maharashtra, Punjab, Rajasthan, and Tamil Nadu have been taken into consideration. The pooled capital cost for each of the financial year has been determined by taking into account the capital cost as approved by the respective State Electricity Regulatory Commissions while determining the tariff and the capacity added during each of the financial year in each respective States. Under this approach the RE capacity addition during each year across various States has been considered as the normalising factor. The information about RE capacity addition across States has been collated from MNRE. The determination of Capital Cost, for various years, on the basis of this methodology is presented in the table below,

Table 7.1 Pooled Capital Cost, Rs Cr/MW

Year	2003-04	2004-05	2005-06	2006-07	2007-08	2008-09
Pooled Cost	4.00	4.00	4.00	4.11	4.00	4.19

Among the major shortcomings of this approach is in most of the cases the capital cost and other norms were approved based on the claims made by manufacturers, developers in their Detailed Project Reports submitted to respective Commissions and no in-depth study was carried out before approving the capital cost. In very few cases, the project specific parameters like unit size, and technology has been taken into account while approving capital cost.

7.2.2 *Actual Project Cost Approach*

In the 'Actual project cost approach' the following two sources have been used for collecting the actual project cost:,

- Capital cost information for RE projects as provided by IREDA
- 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.

The capital cost data for around 27 projects which translates into 235 MW have been analysed under this approach.

Table 7.2: Summary of Sample Size

Source	No of Projects	Capacity, MW
IREDA	5	45
UNFCCC	22	190
Total	**27**	**235**

To the extent of the information available, various components of the capital cost such as plant and machinery cost, erection and commissioning expenses, land development and civil works and financing cost including interest during construction (IDC) cost has been analysed. A trend analysis in terms of movement of Capital Cost (Rs Cr/MW) for the period from 2003 to 2008 has been carried out together with component-wise analysis.

The table below summarises the average capital cost for the projects during various years.

Table 7.3: Average Actual Capital Cost, RsCr/MW

Year	2003-04	2004-05	2005-06	2006-07	2007-08
UNFCCC	**4.58**	**3.27**	**4.71**	**4.12**	**4.18**
IREDA	**n.a.**	**2.93**	**3.84**	**4.24**	**n.a.**

The comparison of capital cost variation in actual project cost approach with the pooled cost approach clearly indicates that the pooled regulated capital cost norm derived under regulatory approach (Rs 4.00 Cr/MW for FY 2007-08) is lower than the average capital cost norm (Rs 4.18 Cr/MW for FY 2007-08) derived under actual project database approach.

It may be argued that the capital cost disclosures for loan sanction or CDM project registration purposes could have element of over-estimation, however, it may be noted that the project cost information has already been scrutinised for accuracy and representation at the institutional level. Besides, it has been ensured that the number of projects and RE project capacity represents fairly large sample size (around 14%) of the cumulative biomass power capacity installed in the country. Besides, the project database covers RE projects information across various States and no locational or state-specific bias is introduced under the sample under study.

7.2.3 *Escalation of Capital Cost Approved in the Tariff Orders*

Various State Electricity Regulatory Commissions have issued the Tariff Orders for biomass power projects over the past five years since 2004. It has been found that once the capital cost is approved, while specifying the tariff norms/orders, it has not been revised on account of the change in market conditions. In order to form a trend of capital cost during various years, under this approach, we have applied escalation factors on the approved capital cost of various SERCs at wholesale price index in order to normalise and compare regulated capital cost over the period.

Following table summarises the trend in regulated capital cost (Rs Cr/MW) adjusted for the escalation factor corresponding to wholesale price index (WPI).

Table 7.4: Escalation of Capital Cost with WPI, RsCr/MW

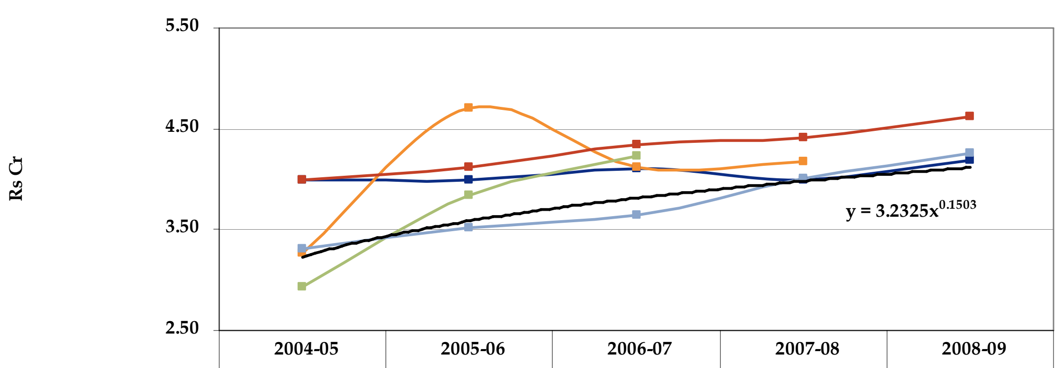
State	TO Issuance Year	Approved Capital Cost RsCr/MW	2004-05	2005-06	2006-07	2007-08	2008-09
Andhra Pradesh	End March'03	4.00	4.00	4.18	4.40	4.61	4.84
Haryana	2007-08	4.29				4.29	4.50
Karnataka	2004-05	4.00	4.00	4.18	4.40	4.61	4.84
Madhya Pradesh	2007-08	4.25				4.25	4.46
Maharashtra	2005-06	4.00		4.00	4.22	4.41	4.63
Punjab	2007-08	4.00				4.00	4.20
Rajasthan	2006-07	4.70			4.70	4.92	5.16
Tamil Nadu	2006-07	4.00			4.00	4.18	4.39
Average Capital Cost (RsCr/MW)			**4.00**	**4.12**	**4.34**	**4.41**	**4.63**

Under this approach the 'Pooled Capital Cost' under regulated approach adjusted for escalation factor has varied from Rs 4.00 Cr/MW during FY 2004-05 to Rs 4.63 Cr/MW during FY 2008-09.

7.3 Basis for Formulation of Capital Cost Benchmark

Based on analysis of the actual project cost component-wise information, appropriate weightage factors and capital cost formulation has been devised as elaborated under section 4.2. A comparison of Capital Cost derived based on proposed formulation against the 'Pooled Cost' under regulatory approach as well as Capital Cost under actual project database approach is presented under following chart.

Figure 7.1: Summary of the Capital Cost Variation following different approaches



	2004-05	2005-06	2006-07	2007-08	2008-09
Pooled Cost	4.00	4.00	4.11	4.00	4.19
UNFCCC	3.27	4.71	4.12	4.18	
IREDA	2.93	3.84	4.24		
Projection	3.32	3.52	3.64	4.01	4.26
Escalation of TO	4.00	4.12	4.34	4.41	4.63

The Capital Cost for FY 2008-09 under various approaches has varied from Rs 4.19 Cr/MW under 'Pooled Cost' to Rs 4.63 Cr/MW with escalation factors whereas capital cost based on proposed formulation suggests norm of Rs 4.26 Cr/MW. Accordingly, the normative capital cost of **Rs 450 Lakh/MW** has been proposed for first year of the Control Period.

7.4 Capital Cost Indexation Mechanism for Biomass Power

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The following indexation mechanism shall be applicable in case of biomass power projects for adjustments in capital cost over the Control Period with the changes in Wholesale Price Index for Steel and Electrical Machinery,

CC(n) = P&M(n)* (1+F1+F2+F3)

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 the 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,

(In default it is 0.7), for weightages to Steel Index

b = Constant to be determined by Commission from time to time,

(In default it is 0.3), for weightages to Electrical Machinery Index

F1 = Factor for Land and Civil Works (0.10)

F2 = Factor for Erection and Commissioning (0.09)

F3 = Factor for IDC and Financing Cost (0.14)

7.5 Plant Load Factor

The Plant load factor (PLF) is a critical performance parameter for any power plant installation. It is dependent on factors such as reliable and quality fuel supply, plant availability and unconstrained off-take. Considering the information available from IREDA/UNFCCC in respect of biomass power projects, it is noted that most of the Projects assume a capacity utilization at 60-70 % during the 1st year of operation, and 75 % to 80 % from the 2nd year onwards. The Projects consider plant operating days during a year to be around 300-330 days (i.e. availability factor of > 85%). This translates into an estimated PLF of 67% during the 1st year, and around 81% from the 2nd year of operation.

Accordingly, it is proposed that the threshold Plant Load Factor for determining fixed charge shall be:

During Stabilisation:	60%
During the first year after Stabilisation:	70%
From 2nd Year onwards:	80%

7.6 Auxiliary Energy Consumption

The auxiliary consumption factor is one of the key performance parameters for thermal power plants, and is dependent on the size of plant and plant configuration. The auxiliary consumption factor in respect of various Project cases under consideration varies from 9% to 12%, with most Projects indicating auxiliary consumption requirement to the extent of 10%.

As per CERC Tariff Regulations, 2009 has specified a auxiliary consumption norm of 8.5% (without cooling tower), albeit for 200 MW and 500 MW series power plant installations, which are not strictly comparable in this respect with small size biomass power installations such as those of 6-10 MW capacity. Accordingly, for the purpose of determining Tariff for the Representative Case, it is proposed to consider auxiliary consumption factor of 10% of gross energy generated.

7.7 Station Heat Rate

The station heat rate depends on factors such as plant capacity, plant design and its configuration, technology employed (boiler type and pressure levels), plant O&M practices, quality of fuel received etc.

Under rankine cycle based biomass power generation, there are essentially two types of boilers being used. Viz. travelling grate and fluidised bed. While fluidised boilers offer higher efficiency as compared to travelling grate, there are limitations in use of fluidised bed boilers due to fuel quality and fuel size requirements. On the other hand, travelling grate type boilers offer flexibility as it can handle variety of type/quality of fuel without significant modifications. Biomass project developers, as industry practice have deployed predominantly travelling grate type boilers for biomass based power generation. While design efficiency/design Station Heat Rate is of the order of 3400-3800 kCal/kWh, the operational efficiency is significantly lower (consequently operational station heat rate is higher) due to several factors such as deterioration in quality of fuel due to storage, O&M practices etc.

Considering various factors, it is proposed to consider SHR of 3650kCal/kWh for the purpose of tariff norms.

7.8 Gross Calorific Value

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 Gross Calorific Value of biomass fuel for individual States has been determined based on weighted average of the availability of the various types of biomass fuel sources alongwith their respective calorific value, as specified by the IISc, Bangalore. In this manner the weighted average gross calorific value of biomass fuel for 10 states, Andhra Pradesh, Chhattisgarh, Haryana, Karnataka, Maharashtra, Madhya Pradesh, Punjab, Rajasthan, Tamil Nadu and Uttar Pradesh, which comprises of above 70% (around 13,000 MW) of the power generation potential and around 75% (1,00,727 kT/year) of the total biomass surplus available in country for power generation using biomass fuel has been specified. However, for other States, a weighted average Calorific Value for all types of biomass fuel sources has been specified.

The methodology for specifying state-wise GCV has been summarised under following table,

Table 7.5: State-wise Biomass fuel availability and fuel mix

Type of Biomass	GCV (kCal/kg)	Maharashtra	UP	AP	Tamil Nadu	Karnataka	Rajasthan	Punjab	MP	Haryana
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**								

Accordingly, the Calorific Value of the biomass fuel used for the purpose of determination of tariff across various States shall be as follows:

Table 7.6: Pooled GCV of Biomass fuels across States

State	Calorific Value (kCal/kg)
Andhra Pradesh	3275
Haryana	3458

Maharashtra	3611
Madhya Pradesh	3612
Punjab	3368
Rajasthan	3689
Tamilnadu	3300
Uttar Pradesh	3371
Other States	3467

7.9 Fuel Price Related Assumption

The price of the biomass fuel depends on various components such as remuneration to farmers, cost related to collection and storage, transportation, loading and unloading cost, agents commission etc. The fuel procurement and transportation is handled by the highly unorganised sector and the prices are influenced by the local factors.

The price of the fuel can be determined either by formulating the trend of the fuel prices quoted by the various biomass project developers or it can be determined on the basis of 'equivalent heat value term' of domestic coal.

It has been observed that the prices quoted by the various agencies for similar kind of biomass fuel vary widely. Hence, in such a context, it will not be appropriate to rely on the prices quoted by the project developers and hence the first scenario i.e. the prices quoted by the various developers, was not considered while determining the fuel price.

Most of the biomass power projects use variety of biomass fuels with differing characteristics and calorific values, used in varying proportion. Hence it will be appropriate to determine the price of fuel in equivalent heat terms.

For this purpose the landed cost and calorific value of coal for 'E to F' grade, for coal based thermal power stations and as approved by the respective State Commission while determining the generation tariff has been taken into account.

The methodology has been explained with the help of the table below,

Table 7.7: Biomass fuel prices (derived) across States

State	Cost of Coal Rs/MT	CV of Coal kCal/kg	Eq. Heat Value Rs/kCal	Calorific Value of Biomass kCal/kg	Price of Biomass Rs/MT
	a	**b**	**c = a/b/1000**	**d**	**e = c*d*1000**
Andhra Pradesh	1,365.63	3,634.98	0.00037569	3,275	1,231
Haryana	2,320.99	3,936.72	0.00058957	3,458	2,039
Maharashtra	1,750.00	3,730.00	0.00046917	3,611	1,694
Madhya Pradesh	1,217.91	3,600.00	0.00033831	3,612	1,222
Punjab	2,417.62	4,139.18	0.00058408	3,368	1,967
Rajasthan	1,831.92	3,740.14	0.00048980	3,689	1,807
Tamil Nadu	1,762.16	3,391.38	0.00051960	3,300	1,715
Uttar Pradesh	1,478.03	3,490.05	0.00042350	3,371	1,428
Others	1,750.00	3,600.00	0.00048611	3,467	1,685

This approach of determining the price of biomass in equivalent heat terms of coal, where there is limited experience of biomass power generation, has been adopted in many States. It is to be noted that the potential power generation based on biomass and bagasse cogeneration is around 19500 MW however, around 1677 MW as on November, 2008, around 9% has only been installed.

The Electricity Regulatory Commissions' of Andhra Pradesh, Karnataka, Tamil Nadu, Madhya Pradesh, Maharashtra, Uttar Pradesh etc. have followed the equivalent heat value approach while determining the fuel price of biomass. Accordingly, it is proposed that Biomass Prices as outlined under following table may be applicable during first year of Control Period (i.e. FY 2009-10).

Table 7.8: Biomass fuel price assumption for FY2009-10 (Rs/MT) across States

State	Biomass Price (Rs/MT)
Andhra Pradesh	1231
Haryana	2039
Maharashtra	1694
Madhya Pradesh	1222
Punjab	1967
Rajasthan	1807
Tamilnadu	1715
Uttar Pradesh	1428

State	Biomass Price (Rs/MT)
Other States	1685

7.10 Fuel Price Escalation

Procurement of fuel depends on several factors depending on local conditions and every project developer need to establish its fuel management chain in order to ensure uninterrupted supply of quality fuel on a sustained long term basis. The landed price of the biomass fuel at the project site comprises primarily the cost towards raw fuel to supplier, labour charges for storage and handling and transportation cost.

Hence, in order to take care of variation in prices for such factors, a fuel price indexation formulae has been specified wherein the various components of base price of the biomass fuel has 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. However, a normative fuel price escalation factor of 5% per annum shall be applicable at the option of the producer.

In case of Biomass energy projects, the following indexing mechanism for adjustment of fuel prices for each year of operation will be applicable for determination of applicable Variable Charge Component of Tariff, in case developer wishes to opt for indexing mechanism:

$$P(n) = P(n-1) * \{a * (WPI(n)/WPI(n-1)) + b * (1+IRC)(n-1) + c * (Pd(n)/Pd(n-1))\}$$

Where

P (n) = Price per ton of biomass for the nth 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. In case of n=1, Pn-1 shall be equal to Po.

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.

Accordingly, the biomass prices and hence variable charge component shall be escalated as per indexation formulation or at 5% per annum at the option of the producer.

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

i.e. VCn = VC0 x (Pn / Po) or VCn = VCo x 1.05 ^(n-1) (optional)

where,

VC0 represents the Variable Charge based on Biomass Price Po for FY 2008-09 (i.e. beginning of Control Period) and shall be determined as under:

$$VC0 = \frac{\text{Station Heat Rate (SHR)}}{\text{Gross Calorific Value (GCV)}} \times \frac{1}{(1 - \text{Aux Consum. Factor})} \times \frac{P0}{1000}$$

7.11 Usage of Fossil Fuel in biomass projects

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

7.12 Monitoring Mechanism for use of fossil and non-fossil fuels

The availability of biomass fuel varies from one season to another and from one year to another. The plant load factor has been specified to be 80% from 2nd year onwards, when the plant will be in full operation. A higher threshold PLF for fixed cost recovery would ensure optimal utilisation of power plant assets and maximise electricity generation round the year while reducing per unit fixed cost of generation. Under these circumstances, and in order to ensure fixed cost recovery to the Project holders, it has been recognised that use of fossil fuels to a limited extent to supplement biomass, particularly considering its cyclical and seasonal nature, may be necessary. However, in order to have continuous and uninterrupted power generation MNRE has allowed use of fossil fuel to an extent of 15% of total energy consumption. In order to restrict the use of fossil fuel to 15%, necessary monitoring mechanism should be put in place.

Hence, following mechanism for monitoring the usage of fossil and non-fossil fuels have been specified under Draft Regulations:

(1) The Project developer shall furnish a monthly fuel usage statement and monthly fuel procurement statement duly certified by Chartered Accountant to the beneficiary (with a copy to appropriate agency appointed by the Commission for the purpose of monitoring the fossil and non-fossil fuel consumption) for each month, along with the monthly energy bill. The statement shall cover details such as

a) Quantity of fuel (in tonnes) for each fuel type (biomass fuels and fossil fuels) consumed and procured during the month for power generation purposes,
b) Cumulative quantity (in tonnes) of each fuel type consumed and procured till the end of that month during the financial year,
c) Actual (gross and net) energy generation (denominated in units) during the month,
d) Cumulative actual (gross and net) energy generation (denominated in units) until the end of that month during the financial year,
e) Opening fuel stock quantity (in tonnes),
f) Receipt of fuel quantity (in tonnes) at the power plant site and
g) Closing fuel stock quantity (in tonnes) for each fuel type (biomass fuels and fossil fuels) available at the power plant site.

(2) Non-compliance with the condition of fossil fuel usage by the project developer, during any financial year, shall result in withdrawal of applicability of 'preferential tariff' as per these Regulations for such biomass based power project.

7.13 Operation & Maintenance Expenses

The size of the biomass plants is small usually 5 to 10 MW as compared to the conventional power plants. However, the expenses towards plant manager, shift operators and other establishment and administrative expenses translate into higher proportion of capital cost as compared to the conventional power plants. Also, unlike bagasse cogeneration projects, biomass based power projects additional manpower and equipments are required in fuel procurement and fuel handling. And hence the O&M expenses required for biomass based projects are higher as compared with the cogeneration projects.

The Central Commission in its tariff regulations, 2009-14 have specified an O&M expense of Rs.18.20Lakhs/MW for unit size of 200/210/250 MW. Considering that the fact that biomass plants incur more administrative and labour cost, **an O&M expense of Rs.20.25lakhs/MW (4.5% of the Capital Cost) for FY2009-10 has been specified.**

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

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 output ***be greater than 45%*** *of the facility's energy consumption,* ***during season****."*

8.2 Capital Cost Benchmarking

In order to develop norm for benchmark capital cost for biomass power projects following approaches have been considered viz. Regulatory Approach or Pooled Cost Approach, Actual Project Cost Approach, and Escalation of Capital Cost approved by respective SERC. The analysis of various approaches and summary of result has been detailed in following paragraphs,

8.2.1 Pooled Capital Cost Approach

In the 'Pooled Capital Cost Approach' six States viz, Andhra Pradesh, Haryana, Karnataka, Maharashtra, Tamil Nadu and Uttar Pradesh have been taken into consideration. The pooled capital cost for each of the financial year has been determined by taking into account the capital cost as approved by the respective State Electricity Regulatory Commissions while determining the tariff and the capacity added during each of the financial year in each respective States. Under this approach the cogeneration capacity addition during each year across various States has been considered as the normalising factor. The movement of Capital Cost, for various years, on the basis of this methodology is presented in the table below,

Table 8.1: Pooled Capital Cost, Rs Cr/MW

Year	2003-04	2004-05	2005-06	2006-07	2007-08	2008-09
Pooled Cost	3.25	3.35	3.14	3.70	3.76	3.65

Among the major shortcomings of this approach is in most of the cases the capital cost and other norms were approved based on the claims made by manufacturers, developers in their Detailed Project Reports submitted to respective Commissions and no in-depth study was carried out before approving the capital cost. In very few cases, the project specific parameters like unit size, and technology has been taken into account while approving capital cost.

8.2.2 *Actual Project Cost Approach*

In the 'Actual project cost approach' the following two sources have been used for collecting the actual project cost:

- Capital cost information for RE projects as provided by IREDA
- 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.

The capital cost data for around 22 projects which translates into 339 MW have been analysed under this approach.

Table 8.2: Summary of Sample Size

Source	No of Projects	Capacity, MW
IREDA	8	184
UNFCCC	14	155
Total	**22**	**339**

To the extent of the information available, various components of the capital cost such as plant and machinery cost, erection and commissioning expenses, land development and civil works and financing cost including interest during construction (IDC) cost has been analysed. A trend analysis in terms of movement of Capital Cost (Rs Cr/MW) for the period from 2003 to 2008 has been carried out together with component-wise analysis. The table below summarises the average capital cost for the projects during various years.

Table 8.3: Average Capital Cost, RsCr/MW

Year	2003-04	2004-05	2005-06	2006-07	2007-08
UNFCCC	**n.a.**	**3.46**	**3.62**	**3.29**	**n.a.**
IREDA	**n.a.**	**3.00**	**2.75**	**3.63**	**4.25**

The comparison of capital cost variation in actual project cost approach with the pooled cost approach clearly indicates that the pooled regulated capital cost norm derived under regulatory approach (Rs 3.76 Cr/MW for FY 2007-08) is lower than the average capital cost norm (Rs 4.25 Cr/MW for FY 2007-08) derived under actual project database approach.

It may be argued that the capital cost disclosures for loan sanction or CDM project registration purposes could have element of over-estimation, however, it may be noted that the project cost information has already been scrutinised for accuracy and representation at the institutional level. Besides, it has been ensured that the number of projects and RE project capacity represents fairly large sample size of the cumulative bagasse based co-generation capacity installed in the country. Besides, the project database covers RE projects information across various States and no locational or state-specific bias is introduced under the sample under study.

8.2.3 Escalation of Capital Cost Approved in the Tariff Orders

Various State Electricity Regulatory Commissions have issued the Tariff Orders for bagasse based cogeneration projects over –the past six years since 2003. It has been found that once the capital cost is approved, while specifying the tariff norms/orders, it has not been revised on account of the change in market conditions. In order to form a trend of capital cost during various years, under this approach, we have applied escalation factors on the approved capital cost of various SERCs at the wholesale price index in order to normalise and compare regulated capital cost over the period.

Following table summarises the trend in regulated capital cost (Rs Cr/MW) adjusted for the escalation factor corresponding to wholesale price index (WPI).

Table 8.4: Escalation of Capital Cost with WPI, RsCr/MW

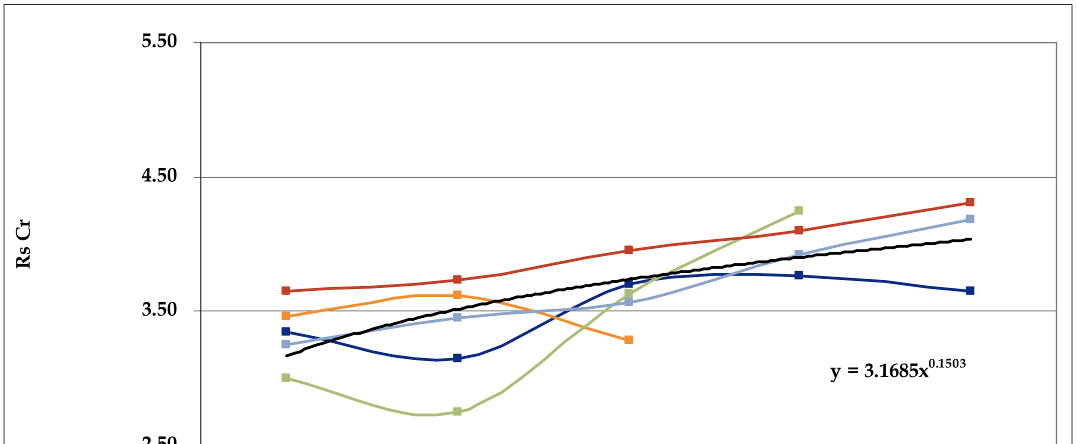
State	TO Issuance Year	Approved Capital Cost RsCr/MW	2003-04	2004-05	2005-06	2006-07	2007-08	2008-09
Andhra Pradesh	2003-04	3.25	3.25	3.46	3.61	3.81	3.99	4.18
Haryana	2007-08	3.95					3.95	4.15
Karnataka	2004-05	3.00		3.00	3.13	3.30	3.45	3.63
Maharashtra	2002-03	3.99	4.21	4.48	4.68	4.94	5.16	5.42
Tamil Nadu	2006-07	4.00				4.00	4.18	4.39
Uttar Pradesh	2005-06	3.50			3.50	3.69	3.86	4.05
Average Capital Cost (RsCr/MW)			**3.73**	**3.65**	**3.73**	**3.95**	**4.10**	**4.30**

Under this approach the 'Pooled Capital Cost' under regulated approach adjusted for escalation factor has varied from Rs 3.73 Cr/MW during FY 2003-04 to Rs 4.30 Cr/MW during FY 2008-09.

8.3 Basis for Formulation of Capital Cost Benchmark

Based on analysis of the actual project cost component-wise information, appropriate weightage factors and capital cost formulation has been devised as elaborated under section 4.2. A comparison of Capital Cost derived based on proposed formulation against the 'Pooled Cost' under regulatory approach as well as Capital Cost under actual project database approach is presented under following chart.

Figure 6.1: Summary of the Capital Cost Variation following different approaches



	2004-05	2005-06	2006-07	2007-08	2008-09
Pooled Cost	3.35	3.14	3.70	3.76	3.65
UNFCCC	3.46	3.62	3.29		
IREDA	3.00	2.75	3.63	4.25	
Projection	3.25	3.45	3.57	3.93	4.18
Escalation of TO	3.65	3.73	3.95	4.10	4.30

The Capital Cost for FY 2008-09 under various approaches has varied from Rs 3.65 Cr/MW under 'Pooled Cost' to Rs 4.30 Cr/MW with escalation factors whereas capital cost based on proposed formulation suggests norm of Rs 4.18 Cr/MW. Accordingly, the normative capital cost of **Rs 445 Lakh/MW** has been proposed for first year of the Control Period.

8.4 Capital Cost Indexation Mechanism for cogeneration projects

The following indexation mechanism shall be applicable in case of non-fossil fuel based cogeneration projects for adjustments in capital cost over the Control Period with the changes in Wholesale Price Index for Steel and Electrical Machinery,

CC(n) = P&M(n)* (1+F1+F2+F3)

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 the 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,
(In default it is 0.7), for weightages to Steel Index
b = Constant to be determined by Commission from time to time,
(In default it is 0.3), for weightages to Electrical Machinery Index
F1 = Factor for Land and Civil Works (0.10)
F2 = Factor for Erection and Commissioning (0.08)
F3 = Factor for IDC and Financing Cost (0.07)

8.5 Plant Load Factor

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

8.6 Auxiliary Consumption

The processing of fuel in cogeneration projects is lower as compared with the biomass based projects and hence comprises of lesser auxiliary system. Also, the auxiliary energy consumption is a function of plant efficiency and the energy conservation methods adopted by the developers. Hence, the auxiliary power consumption factor of 8.5% has been considered for the computation of tariff.

8.7 Station Heat Rate (Allocation of Fuel cost amongst Power and Steam)

The Station Heat Rate for non-fossil fuel based Cogeneration projects shall be 4000 kCal/kWh. The fuel cost during season shall be allocated between power and steam, on the basis of the ratio of heat content in the steam extracted for the process to the heat content of the total steam generated. Further, co-generation projects are assumed to be working on co-generation mode during crushing season for period of around 180 days and on rankine cycle mode during off-season for period of around 60 days.

Accordingly, for the purpose of determination of tariff the normative ratio of allocation of fuel cost between power and steam shall be 60:40

8.8 Gross Calorific Value

Based on the study of the comments received from the stakeholders on the discussion paper floated by the various State Electricity Regulatory Commission in the matter determining the tariff for the bagasse cogeneration projects, it has been found that the gross calorific value of the bagasse for different projects varies in the range of 2200kCal/kg to 2300kCal/kg on wet basis.

In order to determine the gross calorific value of bagasse a 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), has been referred. The book quotes that, while there are many formulae proposed to determine the gross and net calorific value of bagasse, the more reliable formulae include: Pritzelwitz van der Horst formula and Hessey formula. According to these formulae, the gross calorific value of the bagasse range between 2210kCal/kg to 2340kCal/kg depending on the percentage of the moisture content and the soluble solids in the bagasse. Further, it has quoted that, while net calorific value would represent more realistic measure of the heat content in the fuel, in practice the commercial arrangements for the bagasse procurement and the price thereof, are linked to gross calorific value of bagasse on 'wet basis'.

Accordingly, from the information collated for various projects, literature available on the gross calorific value of bagasse, as well as verification with agriculture research institutes the Gross calorific value of bagasse has been considered as 2250 kcal/kg on 'wet basis'.

For the use of biomass fuels other than biomass, calorific value as specified under Para 7.8 shall be applicable.

8.9 Fuel Price

Determination of the price of bagasse is performed on equivalent heat value of coal approach. Under this approach, the price and calorific value of coal used by the thermal generating stations within the state has been considered in order to determine the fuel price linked to heat content (in terms of Rs/kCal) at each station. The fuel price for each station in terms of Rs/MT equivalent to heat content of 2250kCal/kg is then derived, which is presented under following table.

Table 8.5: Bagasse price assumption for FY2009-10 (Rs/MT) across States

State	Bagasse Price (Rs/MT)
Andhra Pradesh	845
Haryana	1327
Maharashtra	1056
Madhya Pradesh	761
Punjab	1314
Tamilnadu	1169
Uttar Pradesh	953
Other States	1094

8.10 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 n^{th} 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 $P_{o.}$

a = Factor representing fuel handling cost

b = Factor representing fuel cost

c = Factor representing transportation cost

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

Pd_n = Weighted average price of HSD for nth year.

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

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

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

Where a, b & c will be specified by the Commission from time to time. 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:

i.e. VCn = VC0 x (Pn / Po) or VC0 = 1.05 ^(n-1) (optional)

where,

VC0 represents the Variable Charge based on bagasse Price Po for FY 2008-09 (i.e. beginning of Control Period) and shall be determined as under:

$$VC0 = 60\% \times \frac{\text{Station Heat Rate (SHR)}}{\text{Gross Calorific Value (GCV)}} \times \frac{1}{(1 - \text{Aux Consum. Factor})} \times \frac{P0}{1000}$$

8.11 Operation and Maintenance Expenses

In case of cogeneration, there are several common expenses between the sugar factory and cogeneration unit. However, it is difficult to segregate those expenses. Also, unlike biomass power projects, bagasse does not require any special fuel preparation and therefore such expenses are not incurred in bagasse cogeneration plants. It is also to be noted that the bagasse is readily available in the premises of the sugar factory only, and hence does not require additional manpower in fuel transportation and hence associated handling charges are negligible. Thus, the O&M expenses in the bagasse cogeneration plants are lower as compared with the biomass plants. **Hence, an O&M expense of Rs.13.35Lakhs/MW (3.5% of the Capital Cost) for FY2009-10 has been specified for the bagasse cogeneration projects.**

The O&M expenses shall be escalated at 5.72% per annum and shall be linked with the WPI.