FORUM OF REGULATORS

POLICIES ON RENEWABLES: REPORT

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FORUM OF REGULATORS
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EXECUTIVE SUMMARY

Non-conventional energy sources are environment friendly and green and should therefore be promoted. The Electricity Act, 2003, the National Electricity Policy and the Tariff Policy also echo this sentiment. The responsibility of promoting co-generation and non-conventional energy sources has been entrusted to the Appropriate Commission in section 61 and in particular to the State Commissions under section 86(1)(e) of the Act.

Various State Commissions have specified the renewable purchase obligation (RPO) for their distribution companies as required under section 86(1)(e) of the Act. They have also determined the tariffs of renewable sources generation based on different technologies. However, the specified RPO varies from 1% to 10% across the country. At the same time there is wide divergence in the tariffs of different technologies set by different Regulatory Commissions.

The Forum of Regulators (FOR) felt there was a need for evolving a common approach to the promotion of renewable sources of energy in the country as a whole. The Forum, therefore, constituted a Working Group consisting of chairpersons of some State Commissions and external experts including a representative from the Ministry of New and Renewable Energy (MNRE), Government of India as a special invitee, to examine the issues in detail and make recommendations. The Group deliberated on various issues and submitted its report which was considered by the Forum in its meeting in Chennai on January 1, 2009.

The report, as approved by the Forum, examines the potential of renewable sources of energy in different States. It also puts in place the initiatives taken by State Electricity Regulatory Commissions (SERCs) in determining the RPO, tariff for different renewable sources of energy. The report recommends that each State Commission should specify a minimum RPO of 5% in line with the National Action Plan for Climate Change. It, however, recognises that it may be difficult for a State with insufficient potential for renewable sources to meet the RPO set in this manner. The report, therefore, reiterates the need for a facilitative framework for connectivity and inter-State exchange of power. The report emphasises the need for evolving a renewable energy certificate (REC) mechanism which could go a long way in enabling such states to meet their obligations while encouraging developers to set up generation facilities based on renewable sources in the most optimal locations. The report recommends preferential tariff for renewable sources at least during their loan tenure, subsequent to which they should be encouraged to compete amongst themselves. The report urges the Ministry of Power, Government of India to frame guidelines and standard bid documents for competitive bidding for renewables under section 63 of the Act. The report takes note of the Government support for promotion of renewable sources of energy (GBI) and articulates that GBI is preferable to capital subsidy. GBI should be declared upfront to enable the Regulatory Commission to factor it in the tariff determination process.

TABLE OF CONTENTS

1 Introduction

1.1 Constitution of the Working Group

1.1.1 The Forum of Regulators (FOR) was constituted by Notification dated February 16, 2005 in pursuance of the provision under section 166(2) of the Electricity Act, 2003 (EA, 2003). The FOR comprises the Chairperson of the Central Electricity Regulatory Commission (CERC), and Chairpersons of the SERCs. The Chairperson of the CERC is also the Chairperson of the FOR.

1.1.2 In order to meet the objectives of smooth and coordinated development of the power system in the country and to evaluate and address policy issues on renewables, the FOR decided to constitute a Working Group on "Policies on Renewables" during its meeting on June 13, 2008.

1.1.3 The scope of work of the Working Group was, inter-alia, to consider the relevant provisions of the National Electricity Policy, Tariff Policy and the discussion paper circulated by the CERC and SERCs with comments, and to give its recommendations on the following matters:

a. Guidelines for specifying the minimum percentage of power procurement from renewable sources;

b. Share of different renewable sources in such percentage;

c. Methodology for pricing the non-firm power from renewable sources;

d. The way forward on competitive procurement of energy from renewable sources;

e. Generation-based incentive for different technologies;

f. Facilitative framework for connectivity to the grid for renewable source-based power plants;

g. Facilitative framework for inter-State exchange of renewable energy (RE);

h. Feasibility of introducing RECs;

i. Sharing of Clean Development Mechanism (CDM) benefits; and

j. any other relevant issue.

1.1.4 The Chairperson of FOR was authorised to nominate various SERCs on the Working Group; accordingly, the Working Group on “Policies on Renewables” was constituted as follows:

a. Chairperson, CERC	...	Chairperson
b. Chairperson, CSERC	…	Member
c. Chairperson, J&KSERC	…	Member
d. Chairperson, JSERC	…	Member
e. Chairperson, HERC	…	Member
f. Chairperson, MPERC	…	Member
g. Chairperson, MERC	…	Member
h. Chairperson, RERC	…	Member
i. Chairperson, TNERC	…	Member
j. Chairperson, UERC	…	Member
k. Chairperson, WBERC	…	Member
l. Secretary, CERC	…	Member
m. Deputy Chief (RA), CERC	…	Coordinator

1.1.5 The Secretariat of the FOR acted as the Secretariat of the Working Group. MERC offered to support the FOR Secretariat for this Working Group through its representative Regulatory Experts.

1.2 Deliberations of the Working Group

1.2.1 The first meeting of the Working Group was convened at Lonavala on July 20, 2008 which Smt. Gauri Singh, Joint Secretary, MNRE attended as a special invitee with the following participants:

a. Dr. Pramod Deo, Chairperson, CERC

b. Shri Bhaskar Chatterjee, HERC

c. Shri J.L. Barkakati, AERC

d. Dr. J.L.Bose, MPERC

e. Shri A. Velayutham, MERC

f. Shri V.J. Talwar, UERC

g. Shri K.L. Vyas , RERC

h. Shri Rajupandi , TNERC

i. Shri Alok Kumar, CERC

j. Shri S. K. Chatterjee, CERC

1.2.2 To facilitate a focussed discussion on the issues related to “Policies on Renewables”, the Regulatory Experts of MERC, which acted as the Secretariat of this Working Group, were requested to make a presentation on the issues.

1.2.3 A Draft Report summarising the deliberations of the Working Group and issues finalised during the first meeting was circulated for further consideration. The Discussion Summary was classified under the following three categories:

a. Issues and action plan finalised during the meeting

b. Issues to be finalised in the next meeting

c. Issues to be considered after detailed study

1.2.4 The second meeting of the Working Group was convened at Bhubaneshwar on November 14, 2008 to finalise the recommendations and to deliberate further on the outstanding issues. Smt. Gauri Singh, Joint Secretary, MNRE was a special invitee to the Working Group’s discussions along with the following attendees:

a. Dr. Pramod Deo, Chairperson, CERC

b. Shri S.K. Misra, CSERC

c. Shri K.B. Pillai, J&KSERC

d. Shri Mukhtiar Singh, JSERC

e. Shri Bhaskar Chatterjee, HERC

f. Shri B.K. Das, OERC

g. Dr. P.K. Mishra, GERC

h. Dr. J.L. Bose, MPERC

i. Shri A. Velayutham, MERC

j. Shri V.J. Talwar, UERC

k. Shri K.L. Vyas , RERC
l. Shri Prasad Ranjan Ray, WBERC
m. Shri R. Rajupandi , TNERC
n. Shri Alok Kumar, CERC
o. Shri S. K. Chatterjee, CERC
p. Shri Kulamani Biswal, CERC

1.2.5 The Working Group has finalised its recommendations in respect of each issue, identified under the terms of reference, and these have been organised under the following chapters:

a. Chapter-2: Guidelines for specifying percentage for RE procurement
b. Chapter-3: Share of different RE sources within overall RPO percentage
c. Chapter-4: Methodology for pricing of non-firm power from RE
d. Chapter-5: Way forward on competitive procurement of RE
e. Chapter-6: Generation-based incentive for different RE sources
f. Chapter-7: Facilitative framework for grid connectivity of RE sources
g. Chapter-8: Facilitative framework for inter-State exchange of RE
h. Chapter-9: Feasibility of introducing RE certificate mechanism
i. Chapter-10: Sharing of CDM benefits

2 Guidelines for specifying percentage for RE procurement

2.1 Statutory framework

2.1.1 Section 86(1)(e) of EA 2003 mandates the SERC to:

> *"Promote Co-generation and generation from Renewable sources of energy by providing suitable measures for connectivity to Grid and sale of electricity to any person, and also specify, for purchase of electricity from such sources, a percentage of total consumption of electricity in the area of distribution licensee."*

2.1.2 Para 6.4 of the Tariff Policy stipulates:

> *"Pursuant to provisions of S 86(1) (e) of EA 2003, Appropriate Commission shall fix minimum percentage for purchase of power from RE sources taking into account availability of such sources in the region and its impact on retail tariffs."*

2.2 Key issues addressed

2.2.1 In view of these statutory provisions, the following issues were raised during the deliberations of the Working Group:

Issue-1: Percentage specification

- Whether percentage for RE procurement should be applied on 'energy input' or 'energy sales' by licensees?
- Whether percentage specification should address minimum procurement or maximum procurement or both?
- What should be the period for percentage specification? Whether it should be co-terminus with MYT Control Period?

Issue-2: Eligibility for application percentage

- Should the obligation for RE procurement in percentage terms be applied to captive consumers and open access users apart from distribution licensees?

Issue-3: Key considerations for percentage specification

- How should resource availability in the region be considered while specifying the percentage? How should the issue of national perspective vs state-specific availability be addressed?
- How should impact on retail tariff be considered? Whether impact should be computed in terms of average power purchase cost or marginal power purchase cost?

2.3 Summary of deliberations

2.3.1 Various States have issued Renewable Purchase Obligation (RPO) orders or regulations specifying the percentage for mandatory RE procurement obligation. A summary of the RPO regulatory framework across the States is presented in Annexure 1. It is evident that RPO percentage has been specified for different control periods. Further, different approaches have been adopted while specifying the RE procurement obligation in terms of RE source-specific targets or licensee-specific target percentage etc. A uniform approach will have to be adopted across the States while deciding on the RPS percentage. It is prudent to apply percentage on the gross energy input (gross energy procurement) by the distribution licensee instead of energy sales as consumption by licensee amounts to energy procurement by the licensee. Licensees procure energy on ex-bus basis and are required to bear energy losses. Similarly, RE procurement also takes place on ex-bus basis and, usually, RE generation at embedded network level (sub-transmission or distribution) at remote areas facilitates reduction in losses. Hence, RPO percentage should be applicable on energy input.

2.3.2 The Tariff Policy stipulates that the 'minimum' percentage of procurement from renewables should be specified, with the intention that at least the percentage RPS specified by SERCs is procured. However, some State utilities are reluctant to contract for RE immediately after RE procurement crosses or is likely to cross the stipulated percentage obligation. This amounts to treating 'minimum' percentage as 'ceiling/maximum' for RE procurement, despite RE being available. One option, which has been adopted by RERC, is to specify a minimum percentage (approximately 2%) for consumption purposes and to also specify a maximum percentage (approximately 5%) for contracting purposes in a particular year. This ensures that contracting and procurement of RE would continue even though RE procurement may have exceeded the stipulated ‘minimum’ percentage for a particular year.

2.3.3 The RPO regulations are forward looking and require advance action by licensees to fulfil their mandatory obligations stipulated under RPO regulations. In order to operationalise RPO obligations, it needs to be ensured that the Control Period for RPS percentage specification coincides with the MYT Control Period.

2.3.4 The RE procurement obligation could be extended to captive and open access consumers as well, since section 86(1)(e) of EA 2003 mandates such application of percentage on consumption within the area of distribution licensee, irrespective of the source of supply to meet such consumption. However, a mechanism for financial settlement has to be devised to enforce the RPO for captive consumers and open access consumers, as it would be difficult for them to manage this small requirement.

2.3.5 A national perspective for harnessing of Renewable Energy is desirable, which will enable States such as Delhi with little or no RE sources (but with high consumption) to meet their RE procurement obligations from States with predominant RE sources, such as Tamil Nadu, Gujarat, Maharashtra, etc.

2.4 Future course of action

2.4.1 In view of these comments and suggestions, the Working Group recommended as follows:

Recommendations

2.4.2 The RPO should be maintained at the minimum level of 5% by 2010 as suggested in the National Action Plan on Climate Change. The RE procurement obligation should also be specified in terms of purchase of energy and not in terms of installed RE capacity. Besides, the RPO should increase progressively as envisaged in the National Electricity Policy. The increase could be 1% every year till it reaches 10%. Thereafter, the increase could be moderated taking into account the availability of RE sources.

2.4.3 The RPO should be related to energy input in the system of distribution licensee, after adjustment of transmission losses, and not the energy billed (sales).

2.4.4 The RPO prescribed should specify a minimum procurement level. A higher percentage may be specified by the SERC for the purpose of contracting the capacity from RE sources taking into account the gestation period of RE technologies and projected growth in consumption. The RERC has specified the minimum and maximum RPO in this manner. In this context, the RPO may be specified bearing in mind the impact on power purchase cost of the utility and the available potential in the State, till such time as the REC mechanism is in place.

2.4.5 While fixing the RPO, the impact on average power purchase cost should be assessed.

2.4.6 The RPO should coincide with the MYT Control Period when MYT is introduced, or else the RPO should be specified for a period of three to five years. It is desirable that the future trajectory of RPO is announced for a longer period in order to provide relief to investors.

2.4.7 Monitoring of compliance with RPO should be undertaken with reference to the MYT Control Period and a reasonable carry over may be permitted vis-à-vis yearly targets.

2.4.8 There was a view that RPO should also be applicable for captive consumers and open access consumers in view of the provision of section 86(1)(e). This section provides for specification of percentage applicable on the 'consumption' within the area of distribution licensee. If RPO is levied only on distribution licensees and if eligible open access consumers are exempted, this may not be fair to non-eligible open access consumers of the distribution licensees due to the cost of RE procurement being borne by non-eligible open access consumers alone. The SERCs in Maharashtra, Rajasthan and Andhra Pradesh have applied the obligation to RE on open access and captive consumers to the extent of their outsourcing.

2.4.9 However, there may be implementation difficulties, as in imposing RPO on open access or captive consumers, since purchase of small quantities of RE would be practically impossible by these consumers. Therefore, this aspect needs to be further studied. Legal issues also need to be examined in depth.

3 Share of different RE sources within overall RPO percentage

3.1 Need for RE resource- specific percentage

The generation of RE is location specific. Its potential varies both across States and the regions within each State. Balanced growth of all types of RE sources is desirable. Environmental benefits and costs between RE sources vary significantly. If the intention is to promote any promising technology (solar PV/solar thermal), technology-specific RPS targets may have to be specified. A proper and scientific assessment of RE potential and demand may be necessary before setting resource-specific targets. A summary of State-wise RE potential and installed capacity in respect of various types of RE sources such as wind energy, biomass power, small hydel power etc. is presented in Annexure 2.

3.2 Key issues addressed

3.2.1 The following issues were raised during the deliberations of the Working Group:

Issue-1: Balanced growth of all RE sources

- Should a single RPO percentage be specified for all RE sources, or does RE source/RE technology-specific percentage need to be specified?
- How can the Regulator ensure balanced growth of all types of RE sources in case RE source-specific percentage is not specified?

Issue-2: Enforcement mechanism

- What should be the compliance monitoring mechanism for RPS obligations? Should it be monitored on an annual basis or on a cumulative basis over the Control Period?
- What are the different approaches for enforcement of the RPS framework? Should the enforcement be RE technology-specific or on an overall basis?

3.3 Summary of deliberations

3.3.1 The Group deliberated on whether mandatory renewable procurement obligations should be referred to as RPO or RPS. For the sake of uniformity, the Group agreed to refer to these obligations as RPO.

3.3.2 During the initial years, an overall percentage for RE sources should be specified and technology-specific percentage could be specified subsequently.

3.3.3 In order to promote different RE sources and technologies, a part of RPO may be reserved for such RE resources in a nascent stage of development. In case technology-specific RPO is specified and there is limited availability of a particular RE source in a year, such shortfall in RE procurement may be allowed to be met through another type of RE source.

3.3.4 An enforcement mechanism needs to be introduced. RPO regulations without an appropriate enforcement mechanism will not be effective as, for example, in the following cases:

- MERC has introduced an enforcement charge for shortfall in compliance with RPS obligations at the rate of Rs 5.00/kWh during FY 2007-08, at Rs 6.00/kWh for FY 2008-09, and at Rs 7.00/kWh for FY 2009-10. It was further clarified that this enforcement charge, if levied, shall not be allowed as 'pass through' expense while approving the annual revenue requirement (ARR) of the licensee.
- RERC has ruled that any shortfall in meeting RE obligation shall be subject to payment of RE surcharge by the distribution licensee, open access consumer or captive power plant. The payment of RE surcharge shall be made to the State Transmission Utility (STU). The surcharge collected by the STU will be credited to a fund to be utilised for creation of transmission system infrastructure of RE power plants. The RERC has determined RE surcharge as Rs 3.59 /kWh for FY 2007-08.

3.3.5 Examples of enforcement mechanism in Maharashtra and Rajasthan may be explored by other States. Alternatively, achievement of RPO could be made mandatory under the distribution licence conditions.

3.3.6 Monitoring of compliance of RE obligation through the ARR/Tariff approval process is essential.

3.4 Future course of action

3.4.1 After considering these comments and suggestions, the Working Group made various recommendations.

Recommendations

3.4.2 The overall RPO percentage may be specified, rather than technology-specific percentages, and investors may decide on the basis of techno-economic analysis. A part of RPO should be reserved for RE resources in the region, such as solar PV and solar thermal, which are in the nascent stage of exploitation, as also the fact that the technology involved has risks from the viewpoint of the investor.

3.4.3 Compliance with RPO, subject to availability of energy from renewable sources (not restricted to the state), may be enforced by invoking sections 142&149 of EA 2003 against the responsible officer of the utility. The penalty under sections 142 and 149 of EA 2003 should be levied in addition to imposition of financial liability in terms of Rs/unit of shortfall and this amount should not be allowed to pass in ARR. Such a mechanism has been put in place by MERC. In addition, including RPO as a part of distribution licence conditions and duties of the licensee may also be explored. Having established fulfilment of RE obligation as part of the licence condition, non-fulfilment of RPO obligation would be treated as violation of licence conditions and would attract suitable actions as provided under the Act.

3.4.4 In order to promote RE sources, use of only non-fossil fuel based co-generation and generation should ordinarily qualify for fulfilment of RPOs. Thus purchase of energy from co-generation based entirely on fossil fuel may not qualify for fulfilment of RPOs. However, when a mix of fossil and non-fossil fuels is used for generation purposes, the use of non-fossil fuels should exceed at least 180 days operation during the year, and the use of fossil fuels should be limited as per MNRE guidelines. The SERCs may also set up a monitoring mechanism for use of fossil fuels. The MERC has institutionalised a monitoring and verification mechanism through **Maharashtra Energy Development Agency (MEDA).**

3.5.5 The eligibility of fossil fuel-based co-generation for the purpose of fulfilment of obligations under section 86(1)(e) needs to be further studied as the definition of co-generation given in EA 2003 is much wider than that being followed by MNRE.

4 Methodology for pricing of non-firm power from RE

4.1 Statutory framework

4.1.1 Para 6.4 of the Tariff Policy stipulates:

> *"It will take some time before non-conventional technologies can compete with conventional sources in terms of cost of electricity. Therefore, procurement by distribution licensees shall be done at 'Preferential Tariff' determined by Appropriate Commission."*
>
> *"Central Commission should lay down guidelines for pricing of non-firm power, especially from non-conventional sources, to be followed in cases where such procurement is not through competitive bidding."*

4.2 Tariff determination for RE

The SERCs have generally followed a 'cost-plus' approach for fixation of tariff for power generation from RE sources. A normative approach could be evolved by FOR to ensure uniformity in approach.

4.3 Key issues addressed

4.3.1 The following issues were raised during the deliberations of the Working Group:

Issue-1: Definition of non-firm power

- The term 'non-firm' has not been defined under EA 2003 or the Tariff Policy.
- Are all types of RE sources non-firm?
- Is a distinction between RE firm power and RE non-firm power desirable?

Issue-2: RE tariff determination

- What is 'preferential' tariff?
- What should be the basis for determination of 'preferential' tariff?
- Should frequency linked Unscheduled Interchange (**UI**) mechanism be considered for pricing of non-firm RE?

4.4 Summary of deliberations

4.4.1 The term 'non-firm' has not been defined in EA 2003 or the Tariff Policy. It is also not a standard industry term. As a result, interpretation of 'non-firm' assumes significance. One reasonable interpretation of the term, 'non-firm' is that power which cannot be scheduled, such as wind energy generation. However, the term 'infirm' rather than 'non-firm' is common industry terminology for such power. Another reasonable interpretation is that where injection (and subsequent procurement) of power occurs without any contract. This interpretation essentially refers to commercial issues rather than the technical nature of generation. This second interpretation is more plausible here as the later part of clause 6.4 (3) of the Tariff Policy deals with commercial issues related to the mode of power procurement, that is competitive bidding.

4.4.2 Even if the first interpretation of 'non-firm' is accepted, it is possible to schedule generation from most RE technologies such as biomass, bagasse etc. These technologies can supply power on 'firm' basis. Barring wind and small hydel, it is currently possible to schedule generation from all other technologies. Further, wind generation is also scheduled in many European countries where it forms a dominant part of the grid.

4.4.3 However, since precise scheduling is not possible, wind, solar and small hydro may be categorised as 'non-firm' power sources.

4.4.4 The cost-plus regime for tariff determination of RE should continue. For the purpose of determination of 'preferential tariff' for RE, preference over conventional generation in terms of higher Return on Equity **(RoE)** may be considered.

4.5 Future course of action

4.5.1 After considering these comments and suggestions, the Working Group recommended as follows:

Recommendations

4.5.2 On the issue of scheduling, 'non-firm' power such as wind, MNRE was of the opinion that precise forecasting is not yet possible in India. It was agreed that wind, solar and small hydro may be categorised as 'non-firm' power sources for which actual generation may be deemed as scheduled generation, since precise scheduling is not possible with the technology available currently in the country. These RE sources need to be treated as 'non-firm' sources until forecasting techniques for these RE technologies mature. Energy from 'non-firm' sources of power should be paid for on the basis of cost-plus tariff, using the site-specific capacity utilisation factor.

4.5.3 In case CERC determines the tariffs for RE-based generating stations under sections 79(1) (a) and 79(1) (b), the concessions given by the State Government should be factored in. For 'non-firm' power, CERC may specify the project independent norms such as capital cost, financing cost, etc. Such capital cost benchmarks should be revised annually taking into account the relevant escalation indices. The site-specific aspects should be specified by the SERC. Appropriate benchmarks could be developed for capital cost along with necessary escalation indices for major input costs such as steel, cement, etc.

4.5.4 Cost-plus tariff based on reasonable norms should be permitted for RE. However, to give preferential treatment to RE purchase, SERC may allow a higher rate of return on equity keeping in view the risks involved in deployment of a specific technology. Such higher RoE should be periodically revised for future projects, keeping in view the status of commercialisation of the concerned technology.

4.5.5 Non-fossil fuel-based co-generation would also thus receive preferential tariff. Fossil fuel-based co-generation could be separately promoted on the grounds of energy efficiency.

5 Competitive procurement of RE: Way forward

5.1 Statutory framework

5.1.1 Para 6.4 of the Tariff Policy stipulate:

"Procurement of power from non-conventional sources for future shall be done, as far as possible, through competitive bidding under Section 63 within suppliers of same type of RE."

5.1.2 Section 63 of EA 2003 stipulates:

"Notwithstanding anything contained in Section 62, the Appropriate Commission shall adopt the tariff if such tariff has been determined through transparent process of bidding in accordance with the Guidelines issued by Central Government."

5.2 International experience of competitive RE procurement

5.2.1 International experience in procurement of RE based on competitive bidding has not yielded favourable results. For example, in the UK, during successive rounds of Non-Fossil Fuel Obligation (NFFO) bidding, the number of projects awarded through competitive bidding increased from 75 (152 MW in NFFO-1) to 261 (1,177 MW in NFFO-5). However, the number of projects actually commissioned reduced from 61 (144 MW in NFFO-1) to 17 (24 MW in NFFO-5) with a success rate of RE capacity addition reducing from 93% to 2% out of projects awarded.

TABLE 1 Status of NFFO1–5

	Projects contracted			Projects generating		No progress projects		
	Date	Number	MW DNC	Number	MW DNC	Number	MW DNC	%
NFFO1	1990	75	152.12	61	144.53	14	7.58	93
NFFO2	1991	122	472.23	82	173.73	40	298.49	37
NFFO3	1994	141	626.91	75	254.47	38	234.4	40.6
NFFO4	1997	195	842.72	56	132.62	90	494.66	15.74
NFFO5	1998	261	1177	17	24.31	159	960.43	2.07
TOTAL		794	3270.98	291	729.66	341	1995.3	

Source: England & Wales NFFO – History and Lessons by Catherine Mitchell.

**DNC:– Declared Net Capacity*

5.3 Key issues addressed

5.3.1 The following issues were raised during the deliberations of the Working Group:

Issue-1: Competitive RE procurement

– Is competitive procurement of RE desirable and feasible?
– Should 'preferential RE tariff' act as 'ceiling tariff'?
– Should 'competitive RE procurement' and 'preferential tariff' determination co-exist?

Issue-2: Procedural aspects of competitive RE procurement

– Is notification of Competitive Bidding Guidelines (CBG) by the Central Government a pre-requisite for introduction of competitive RE procurement?
– In the absence of notified CBG, should SERCs approve the competitive bidding process and documents for competitive RE procurement?
– What are 'appropriate timelines' and 'appropriate mechanisms' for introduction of competitive RE procurement?

5.4 Summary of deliberations

5.4.1 The CBG notified by the Central Government essentially refers to procurement of conventional power through competitive bidding. The feasibility of applying this to RE based procurement needs to be explored. The Standard Bidding Documents (SBD) notified by the Central Government do not refer to 'renewable energy' or 'non-conventional energy' throughout the document though there is reference to fossil fuels such as coal/lignite, liquid fuels, etc. However, the CBG provide for single part tariff- based procurement as well as load centre based or source-specific procurement, which needs to be explored further in the case of RE-based competitive procurement.

5.4.2 In the absence of notification of SBD for RE sources, the licensee will have to submit the entire bidding documentation for competitive procurement to the Commission for its approval before initiation of a competitive procurement process.

5.4.3 Further, competitive bidding may be introduced on a pilot basis for demonstration projects. To promote RE generation, tariff support may need to be continued at least for the period covering loan repayment obligations.

5.5 Future course of action

5.5.1 After considering the above comments and suggestions, the Working Group recommended as follows:

Recommendations

5.5.2 The process of competitive bidding for renewable sources is yet to evolve fully. International experience in the UK has shown that though successive rounds of competitive bidding resulted in lowering the tariffs, actual capacity addition was much lower. Since capacity addition and additional generation is the country's objective, competitive bidding may not yield the desired results at this stage and hence need not be insisted upon at this stage for renewable sources of power which can not be scheduled. However, competitive bidding should be undertaken to ascertain the capital costs in such cases. Therefore, preferential tariff based on the cost-plus approach may be allowed for non-firm RE-based projects for the period until debt service obligations are covered.

5.5.3 Preferential tariff should be determined and the power purchase agreement (PPA) established for a period of at least 10-12 years, depending on technology, covering debt service obligations. During this period, the hydrological risk in case of small hydro should be borne by the procurers.

5.5.4 The practice of delivering **PPA** after commissioning of the project needs to be revisited. The PPA should be delivered upfront so that the developers do not face uncertainty.

5.5.5 Such RE projects who have availed cost plus tariff during debt repayment period should be allowed to compete among themselves for sale beyond this minimum support period. The developers should not be forced to supply energy at very nominal rates.

5.5.6 Appropriate Guidelines and Standard Bidding Documents for undertaking competitive bidding under Section 63 of the Act needs to be framed by Ministry of Power in consultation with Ministry of New and Renewable Energy for (a) bidding amongst schedulable RE sources like bagasse based generation and (b) bidding amongst the unschedulable generation based projects which have availed preferential tariff during debt repayment period.

6 Generation-based incentive for different RE sources

6.1 MNRE's generation-based incentive schemes

a. The MNRE has introduced a generation-based incentive scheme for grid connected solar PV and solar thermal projects up to Rs 12/kWh and Rs 10/kWh, respectively, subject to: (i) tariff determination by SERCs; (ii) limitation to projects to be commissioned before March 31, 2010; (iii) total capacity addition up to 50 MW; and (iv) capacity addition up to 10 MW for each State.

b. Recently, an incentive of Rs 0.50/kWh has been introduced for wind power plants for **Wind Energy Generation** capacity addition up to 49 MW, which do not avail of accelerated depreciation benefit. The incentive is provided in addition to tariff determined by SERCs.

6.2 Key issues addressed

6.2.1 In view of this, the following issues were raised during the deliberations of the Working Group:

Issue-1: Generation-based incentive (GBI)

- How should GBI for RE be promoted?
- How should GBI be computed and specified for each type of RE source/technology?

Issue-2: Generation-based incentive and RE tariff determination

- Should the GBI mechanism be factored into 'preferential tariff' determination? If so, to what extent?
- How would the GBI mechanism operate in a 'competitive environment'?

6.3 Summary of deliberations

6.3.1 The MNRE wished to know whether it was necessary to give GBI to promote RE generation. It was unambiguously clarified that GBI would be necessary if renewable sources such as solar power are to be promoted at the scale envisaged in the national policies; otherwise the burden on consumer tariff would be unbearable.

6.3.2 Incentives linked to 'generation' are preferable to incentive linked to 'capacity addition', as they encourages actual RE generation.

6.3.3 The MNRE is expected to announce such incentives for various RE technologies upfront. This will enable SERCs to factor in such incentives while determining tariff.

6.4 Future course of action

6.4.1 After considering the above comments and suggestions, the Working Group recommended as follows:

Recommendations

6.4.2 GBIs are preferable to capital subsidies for promotion of RE technologies.

6.4.3 GBI would be necessary if renewable sources such as solar power are to be promoted at the scale envisaged in the national policies, otherwise the burden on consumer tariff would be unbearable.

6.4.4 GBI should be announced upfront, for being factored into the tariff to be set by ERCs. The GBI should be fixed with the objective of making the costs of energy from different renewable sources comparable. However, any GBI announced by the government as an incentive over and above the tariff, such as for wind projects in lieu of accelerated depreciation, need not be factored into the tariff by SERCs.

7 Facilitative framework for grid connectivity of RE sources

7.1 Statutory framework

Section 86(1)(e) of EA 2003 mandates the SERC to:

"*promote Co-generation and generation from Renewable sources of energy by providing suitable measures for connectivity to the Grid and sale of electricity to any person, and also specify, for purchase of electricity from such sources, a percentage of total consumption of electricity in the area of distribution licensee*."

7.2 Aspects of grid connectivity of RE-based generation

- Transmission system planning and connectivity standards for RE
- Role and responsibility of STU/distribution licensees
- Responsibility for development of evacuation infrastructure

7.3 Key issues addressed

7.3.1 In view of this, the following issues were raised during the deliberations of the Working Group:

Issue-1: Grid connectivity related issues

- What are the key technical and commercial issues for grid connectivity of RE?
- Should grid connectivity and grid planning standards for RE be different from those applicable to conventional power plants? If this is so, should it be different for all RE or ought to depend on RE technology?

Issue-2: Addressing requirements of grid connectivity

- What are the possible mechanisms and solutions to remove the hurdles or bottlenecks in harnessing and operationalising grid connected RE?
- Should the responsibility for development of evacuation facility for grid connected RE be entrusted to STU alone?

7.4 Summary of deliberations

7.4.1 With advancement in technology for harnessing RE sources, the market for larger capacity RE units has emerged and the concept of wind farm or biomass project schemes, etc. has found favour with investors and developers. The primary responsibility to evacuate RE generation rests with the distribution licensees, as such sources are mainly connected at distribution voltages. In fact, increased RE generation at the distribution level will relieve the stress on the transmission network to an extent. However, some of these RE projects such as those based on wind energy are located in remote hilly or coastal regions, necessitating the creation of adequate evacuation infrastructure to exploit the available potential. Barring one or two, such as the STUs, **Maharashtra State Electricity Transmission Company Ltd. (MSETCL)** and Rajasthan Vidhyut Prasaran Nigam (**RVPN**)), none of the others have included evacuation infrastructure for RE as / part of their overall transmission plan.

7.4.2 The resource constrained STUs are averse to investing in transmission assets and evacuation infrastructure dedicated to RE sources such as wind, due to its inherent lower capacity utilisation. The developers and investors would be keen to invest in creation of such infrastructure provided there is regulatory clarity and certainty as regards recovery of costs pertaining to such investments. Creation of a market model may be necessary to address infrastructure requirements of RE sources. However, when planning transmission capacity, STUs should first become conversant with such evacuation infrastructure requirements.

7.4.3 As part of the regulatory process, MERC has received an application from a wind energy developer highlighting two technical aspects that influence grid connectivity and evacuation arrangement of wind energy sources. These are: (a) Line Loading, which allows line loading more than Surge Impendence Loading (SIL) for short lines; and (b) Redundancy Criteria, which allows relaxation of (N-1) redundancy criteria in respect of wind evacuation projects. The Commission recognised the need to establish specific norms for grid connectivity for RE sources within its mandate to address such concerns under section 86(1) (e) of EA 2003. However, as both these aspects needs to be covered under grid standards and standards for construction of transmission lines, which are to be governed by CEA Regulations under sections 34 and 73(b) of EA 2003, the Commission has directed STUs to address these in co-ordination and consultation with CEA.

7.4.4 Development of evacuation infrastructure and provision of measures for connectivity to the grid for RE sources is the responsibility of the transmission utility. The MERC has emphasised this through its order while considering the issue of responsibility of development of transmission network and grid connectivity for RE sources.

7.4.5 Grid connectivity to RE generation should be provided by transmission licensees through their capex plan. Transmission system plans, which are prepared by STUs should cover evacuation and transmission infrastructure requirements for RE sources.

7.5 Future course of action

7.5.1 After considering the above comments and suggestions, the Working Group recommended as follows:

Recommendations

7.5.2 Technical standards for providing grid connectivity for RE-based power stations should be developed expeditiously. The FOR recommends that the CEA should undertake development of such standards through its Grid Connectivity Regulations. Connectivity standards for solar PV and solar thermal power projects, for both grid connected and rooftop systems, should also be formulated.

7.5.3 Grid connectivity should be optimally provided by transmission licensees and distribution licensees for RE sources, through their capex plans submitted to the appropriate commissions for approval. The recovery of costs of transmission and evacuation infrastructure for RE sources should be addressed through the regulatory process of approval of ARR of transmission or distribution licensee. The transmission charges should be computed in a rational manner, ensuring that initial projects in an area are not burdened by the total cost of network expansion. It is further recommended that the concessional transmission charges could be levied on RE being sold within the State keeping in view the spirit of the EA for promoting RE.

7.5.4 A separate co-ordination mechanism should be established for RE in SLDCs and STUs to ensure smoother operations and grid integration of RE sources, while also including the creation and maintenance of databases regarding future RE projects.

8 Facilitative framework for inter-State exchange of RE

8.1 Background

8.1.1 Imperatives for inter-State exchange of RE:

In view of the energy crisis and prevalent supply shortages, a national perspective for RE development is essential. States like Delhi, which do not have any RE potential, will not be able to procure RE unless inter-State exchange of RE is enabled. Instances have come before the CERC where RE generators have been subjected to procedural hurdles, leading to denial of access for inter-State exchange of RE. Some SERCs have mandated the utilities to meet RPS obligations by procuring RE 'within the State'. However, a shortfall in the State can be met through RE available in another State, provided inter-State exchange of RE is validated for meeting RPS obligations.

8.2 Key issues addressed

8.2.1 The following issues were raised during the deliberations of the Working Group:

Issue-1: Ascertaining need for inter-State exchange of RE

- Is inter-State exchange of RE desirable? Should it be promoted?
- What are the regulatory hurdles in effecting inter-State exchange of RE?

Issue-2: Operationalising inter-State exchange of RE

- What are the operational hurdles in implementing inter-State exchange of RE?
- What should be the role of CERC and SERCs in promoting inter-State exchange of RE?

8.3 Summary of deliberations

8.3.1 In many States, only a small part of total RE potential has been harnessed so far. Some of the States, which have huge RE potential, have been hesitant to increase the share of RE in their energy portfolio, and some of State utilities insist on providing measures for inter-State transaction of RE.

8.3.2 At present, the development of RE is guided by the principles laid down by the State Commissions. The jurisdiction of the SERCs is limited to their respective

States. Besides, no institutional mechanism is currently available whereby the regulators of two States could co-operate for optimal utilisation of resources within the region. As a result, no State has permitted purchase of RE from outside the State. However, in order to enable inter-State exchange of RE power, the working group has recommended that RE generated in one State should be recognised for the purpose of compliance of RE obligation in the other State. The SERCs may need to amend their respective RPS regulations to recognise such inter-State RE-based transactions for compliance with RPO obligations.

8.3.3 Inter-State exchange of RE is desirable from the national perspective.

8.3.4 RE should be classified as firm and non-firm power for facilitating inter-State exchange, as it may be possible to schedule firm power through open access.

8.3.5 Innovative mechanisms, such as RECs need to be evolved without disturbing existing arrangements for energy accounting or differential treatment for RE transactions.

8.4 Future course of action

8.4.1 After considering the above comments and suggestions, the Working Group recommended as follows:

Recommendations

8.4.2 For RE sources such as biomass power, the option stated below may be considered for inter-State exchange of RE power under the existing Regional Energy Accounting framework. To begin with, the following conditions shall be applicable for inter-State exchange of scheduled RE power such as biomass power:

- Minimum capacity of 1 MW of RE power.
- Scheduling of inter-State RE power to be permitted at 6 time-blocks (1.5 hours) in advance instead of day-ahead basis.
- Actual injection for any time-block shall not be lower or higher than 50% of gross scheduled capacity for which open access is sought. Actual deviation should be watched and reported if gaming is suspected.

Such transactions could also be easily facilitated through power exchanges where a bid can be as small as one MW.

9 Feasibility of introducing RE certificate mechanism

9.1 Background

9.1.1 Renewable Energy Certificate (REC) Mechanism:

The REC as a tool for promotion of RE sources has been used in some countries. Several implementation issues including legal feasibility needs to be addressed. These include:

- Pricing and denomination of RECs
- Authority responsible for pricing of RECs
- Tradability of RECs across States
- National registry for RECs

The MNRE has recently initiated action to evolve methodologies for adoption of REC mechanism in India.

9.2 Key issues addressed

9.2.1 The following issues were raised during the deliberations of the Working Group:

Issue-1: Ascertaining the feasibility of REC mechanism

- What are the merits and de-merits of the REC mechanism?
- Is the REC mechanism legally tenable under the framework of EA 2003?
- What is the appropriate time for introduction of the REC mechanism?

Issue-2: Operationalising the REC mechanism

- What is the institutional framework required for introduction of the REC mechanism?
- What is the regulatory framework required for introduction of the REC mechanism?

9.3 Summary of deliberations

9.3.1 Co-operation amongst States and recognition by SERCs would be essential.

9.3.2 The MNRE should undertake a study to devise the framework for introducing the REC mechanism.

9.3.3 The operationalisation of this provision under the existing legal framework of EA

2003, and co-operation amongst various States to implement RECs, needs to be explored.

9.4 Future course of action

9.4.1 After considering the above comments and suggestions, the Working Group recommended as follows:

Recommendations

9.4.2 A suitable mechanism like REC is necessary to promote RE sources on the scale envisaged in the National Action Plan on Climate Change. The MNRE has commissioned a study for examining the feasibility and developing a model for operationalising RECs. The study should also examine the GBI as a basis for evaluation of RECs. The legal sanctity of REC vis-à-vis the EA 2003 needs to be examined.

10 Sharing Clean Development Mechanism (CDM) benefits

10.1 Statutory framework

Para 5.3(i) of the Tariff Policy stipulates:

> *"Tariff fixation of all electricity projects that result in lower Green House Gas (GHG) emissions than the relevant base line should take into account the benefits obtained from Clean Development Mechanism (CDM) into consideration, in a manner as to provide adequate incentive to the project developers."*

10.2 Other considerations for sharing CDM benefits

- CDM benefits accrue to the project after commercial operation and after approval and registration of the proposal as a CDM project.
- The process of registration and approval is cumbersome and the extent of CDM benefits cannot be ascertained to begin with.
- RE developers have to incur various costs for registration, monitoring and verification.
- Sharing of CDM benefits should be commensurate with the associated risks and efforts.

10.3 Key issues addressed

10.3.1 The following issues were raised during the deliberations of the Working Group:

Issue-1: Basis for sharing CDM benefits

- How should the sharing of CDM benefits be considered for tariff determination?
- Should the CDM benefits be computed on a 'gross basis' or a 'net basis' after accounting for costs of availing of CDM benefits?
- What should be the sharing ratio? Ought it to be 50:50, 75:25 or any other ?

Issue-2: Other considerations for sharing CDM benefits

- Should the sharing of CDM benefits be uniform or vary across RE technologies?
- Should the mechanism for sharing CDM benefits be uniform across States or State-specific?

10.4 Summary of deliberations

10.4.1 Several factors influence the process of availing of CDM benefits for a particular project. Significant effort is also involved on the part of RE developers in registration of the project and subsequent monitoring and verification, apart from the global market scenario for CDM with several competing projects. Some of the SERCs such as in Karnataka, Gujarat and Rajasthan have ruled in favour of the sharing of CDM benefits by the RE developer with the concerned beneficiary. The ratio of sharing of CDM benefits has varied from 75:25 to 50:50. However, the manner of computation of CDM benefits and modalities of sharing them has not been clarified. A sample of CDM benefits concerning of the NHPC project and its associated cost is illustrated in **Annexure 3**. It is suggested that CDM benefits should be shared between developers and consumers on a gross basis.

10.5 Future course of action

10.5.1 After considering the above comments and suggestions, the Working Group recommended as follows:

Recommendations

10.5.2 The CDM benefits should be shared on a gross basis, starting from 100% to developers in the first year after commissioning, and thereafter reducing by 10% every year till the sharing becomes equal (50:50) between the developers and the consumers, in the sixth year. Thereafter, the sharing of CDM benefits should remain equal till the time that benefits accrue.

11 Summary of recommendations

This section summarises the recommendations of the Working Group.

11.1 Guidelines for specifying percentage for RE procurement

11.1.1 The RPO should be maintained at least at the level of 5% by year 2010 as suggested in the National Action Plan on Climate Change; Additionally, the RE procurement obligation should be specified in terms of purchase of energy and not in terms of installed RE capacity. The RPO should also increase progressively as envisaged in the National Electricity Policy. The increase could be 1% every year till it reaches 10%. Thereafter, the increase could be moderated taking into account availability of RE sources.

11.1.2 The RPO should be calibrated with regard to the energy input in the system of distribution licensee, after adjustment of transmission losses and not energy billed (sales).

11.1.3 The RPO prescribed should specify the minimum procurement level. A higher percentage may be specified by the SERC for the purpose of contracting the capacity from RE sources, taking into account the gestation period of RE technologies and projected growth in consumption. The RPO may be specified bearing in mind the impact on power purchase cost of the utility and the available potential in the State, till such time as the REC mechanism is in place.

11.1.4 The RPO should coincide with the MYT Control Period when MYT is introduced or, till then the RPO should be specified for a period of three to five years. It is also desirable that the future trajectory of the RPO is announced for a longer period in order to provide relief to investors.

11.1.5 Monitoring of compliance with RPO should be undertaken with reference to the Control Period of MYT. A reasonable carry over may be permitted vis-à-vis yearly targets.

11.2 Share of different RE sources in percentage

11.2.1 Overall RPO percentage may be specified rather than technology-specific percentages, and investors may decide on the basis of techno-economic analysis. A part of RPO should be reserved for such RE resources in the region, such as solar PV and solar thermal, which are in the nascent stage of exploitation and the technology involved has risks from the viewpoint of the investor.

11.2.2 Compliance with RPO, subject to availability of energy from RE, not restricted to the state, may be enforced by invoking sections 142 and 149 of EA 2003 against the responsible officer of the utility. The penalty under sections 142 and 149 of EA 2003 should be levied in addition to imposition of financial liability in terms of Rs/unit of shortfall and this amount should not be allowed to pass in ARR. In addition, inclusion of RPOs as a part of distribution licence conditions and duties of the licensee may also be explored. With fulfilment of RE obligations becoming part of the licence condition, non-fulfilment of RPO obligations would be treated as violation of licence conditions and attract the provisions of the Act.

11.2.3 In order to promote RE sources, use of only non-fossil fuel-based co-generation and generation should ordinarily qualify for fulfilment of RPOs. Thus, purchase of energy from co-generation based entirely on fossil fuel may not qualify for fulfilment of RPOs. However, when a mix of fossil fuels and non-fossil fuels is used for generation, the use of non-fossil fuels should exceed at least 180 days of operation during the year, and usage of fossil fuels should be limited as required under MNRE guidelines. The SERCs may also set up a monitoring mechanism for use of fossil fuels.

11.2.4 The eligibility of fossil fuel-based co-generation to fulfill obligations under section 86(1)(e) needs to be further studied as the definition of co-generation in EA 2003 is much wider than that being followed by MNRE.

11.3 Methodology for pricing of non-firm power from RE

11.3.1 Wind, solar and small hydro may be categorised as non-firm power sources for which actual generation may be deemed as scheduled generation, since precise scheduling is not possible with the technology currently available in the country. These RE sources need to be treated as non-firm sources until forecasting techniques for these RE technologies mature. The energy from non-firm sources of power should be paid for on the basis of cost-plus tariff and the site-specific capacity utilisation factor.

11.3.2 In case CERC determines the tariffs for RE-based generating stations under sections 79(1)(a) and 79(1)(b), the concessions given by the State government should be factored in. For non-firm power, CERC may specify the project's independent norms such as capital cost, financing cost, etc. Such capital cost benchmarks should be revised annually, taking escalation indices into account. Site-specific factors should be clarified by the SERC. Appropriate benchmarks could be developed for both capital with and escalation indices for major input costs such as steel, cement, etc.

11.3.3 Cost-plus tariff based on reasonable norms should be permitted for RE. However, in order to give preferential treatment to RE purchase, SERC may allow a higher rate of return on equity keeping in view the risks involved in deployment of a specific technology. Such higher ROE should be periodically revised for future projects keeping in view the status of commercialisation of the concerned technology.

11.3.4 Non-fossil fuel based co-generation would also, thus, get preferential tariff. Fossil fuel-based co-generation could be separately promoted on the grounds of energy efficiency.

11.4 Way forward in competitive procurement of RE

11.4.1 Competitive bidding should be undertaken to ascertain capital costs in typical cases. Preferential tariff based on the cost-plus approach may be allowed for non-firm RE-based projects for the period until debt service obligations are covered.

11.4.2 Preferential tariff should be determined and power purchase agreements established for a period of at least 10-12 years, depending on technology, covering debt service obligations. During this period, the hydrological risk in case of small hydro should be borne by the procurers.

11.4.3 The practice of delivering PPA after commissioning of the project needs to be reconsidered. The PPA should be delivered upfront so that developers do not face uncertainty.

11.4.4 Such RE projects who have availed cost plus tariff during debt repayment period should be allowed to compete among themselves for sale beyond this minimum support period. The developers should not be forced to supply energy at very nominal rates.

11.4.5 Appropriate Guidelines and Standard Bidding Documents for undertaking competitive bidding under Section 63 of the Act needs to be framed by Ministry of Power in consultation with Ministry of New and Renewable Energy for (a) bidding amongst schedulable RE sources like bagasse based generation and (b) bidding amongst the unschedulable generation based projects which have availed preferential tariff during debt repayment period.

11.5 Generation-based incentive for different RE sources

11.5.1 GBIs are preferable to capital subsidies for promotion of RE technologies.

11.5.2 GBIs would be necessary if renewable sources such as solar power are to be promoted at the scale envisaged in the National Policies, otherwise the burden on consumer tariff would be unbearable.

11.5.3 GBIs should be announced upfront, which could be factored in the tariff to be set by ERCs. The GBI should be fixed with the objective of making the costs of energy from different renewable sources comparable. However, any GBI announced by the government as an incentive over and above the tariff, such as GBI for wind projects in lieu of accelerated depreciation, need not be factored into the tariff by SERCs.

11.6 Facilitative framework for grid connectivity of RE sources

11.6.1 Appropriate technical standards for providing grid connectivity for RE-based power stations should be developed expeditiously. The CEA should develop such standards through its Grid Connectivity Regulations. Connectivity standards for solar PV and solar thermal power projects, for both grid connected and rooftop systems, should also be formulated.

11.6.2 Grid connectivity should be provided by transmission licensees and distribution licensees for RE sources in an optimum manner, through their capex plans submitted to the appropriate Commissions for approval. The recovery of costs of transmission and evacuation infrastructure for RE sources should be addressed through the regulatory process of approval of ARR of transmission or distribution licensee. The transmission charges should be computed in a rational manner, ensuring that initial projects in an area are not burdened by the total cost of network expansion. Concessional transmission charges could be levied on RE being sold within the State, keeping in view the spirit of the Electricity Act for promoting RE.

11.6.3 A separate co-ordination mechanism should be established for RE in SLDCs and STUs to ensure smoother operations and grid integration of RE sources, also including the creation and maintenance of databases regarding future RE projects.

11.7 Facilitative framework for inter-State exchange of RE

11.7.1 To begin with, the following conditions shall be applicable for inter-State exchange of schedulable RE power such as biomass power: (i) Minimum capacity of 1 MW of RE power; (ii) Scheduling of inter-State RE power to be permitted at six time-blocks (1.5 hours) in advance instead of day-ahead basis; (iii) Actual injection for any time-block shall not be lower or higher than 50% of gross scheduled capacity for which open access is sought; and (iv) Actual deviation should be watched and reported if gaming is suspected.

Such transactions could also be facilitated through power exchanges where the bid can be as small as one MW.

11.8 Feasibility of introducing RE certificate mechanism

11.8.1 A suitable mechanism like REC is necessary to promote RE sources on the scale envisaged in the National Action Plan on Climate Change. The MNRE has commissioned a study to examine the feasibility of developing a model to operationalise RECs. The study should also examine the GBI as a basis for evaluation of RECs. The legal sanctity of REC vis-à-vis EA 2003 needs to be examined.

11.9 Sharing of CDM benefits

11.9.1 CDM benefits should be shared on a gross basis starting from 100% to developers in the first year after commissioning and, thereafter, reducing by 10% every year till the sharing becomes equal (50:50) between the developers and the consumers, in the sixth year. Thereafter, the sharing of CDM benefits should remain equal till the time that benefits accrue.

Annexure-1: Summary of RPS Regulatory framework in India

Summary of RPS Regulatory Framework in India										
S.No.	States	References for RPS Order(s)/ Regulation(s)	Minimum percentage for RE procurement across States							
			RE Source / Eligible Entities	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12
1	Andhra Pradesh	Order September 27, 2005 extended up to July 31, 2008.		5%	5%	5%	5%			
2	Chhattisgarh	Regulation dt. July14, 2008	Biomass				5%	5%	5%	
			Small hydel				3%	3%	3%	
			others				2%	2%	2%	
3	Delhi	(Order dt. Feb 23, 2008)	NDPL			1%	1%	1%	1%	
		(Order dt. Feb 23, 2008)	BYPL			1%	1%	1%	1%	
		(Order dt. Feb 23, 2008)	BRPL			1%	1%	1%	1%	
		(Order dt. March 7, 2008)	NDMC			1%	1%	1%	1%	
4	Gujarat	Notification dt. Oct 29, 2005			1%	1%	2%			
5	Haryana	(Order dated May 15, 2007)				3%	5%	10%	10%	10%
6	Karnataka	Amendment of regulation 2004 (notification dt. January 23, 2008)	BESCOM, MESCOM & CESC		10%	10%	10%			
			GESCOM, HESCOM & Hukeri		7%	7%	7%			
7	Kerala	Regulation June 24, 2006	SHP-2% Wind-2% Others-1%		5%	5%	5%			
8	Madhya Pradesh	Draft Regulation of June 2008	Wind				5%	6%	6%	6%
			Biomass				2%	2%	2%	2%
			Cogeneration and others				3%	2%	2%	2%
9	Maharashtra	RPS Order August 16, 2006			3%	4%	5%	6%		
10	Punjab	Order dated December 13,2007				1%	1%	2%	3%	4%
11	Rajasthan	Proposed Order- 31.03.06	wind		2.00%	4.00%	5.00%	6.00%	6.75%	7.50%
		Final RPS order 29.09.06,	biomass		0.50%	0.88%	1.25%	1.45%	1.75%	2.00%
		RPS order dt.7.03.07			2.50%	4.88%	6.25%	7.45%	8.50%	9.50%
12	Tamil Nadu	Order dt. May 15,2006			10%	10%	10%			
13	U.P	Regulation dt. March 23, 2006			7.5%	7.5%	7.5%	7.5%	7.5%	
14	Uttarakhand	UERC (Tariff and Other Terms for Supply of Electricity from Non-conventional and Renewable Energy Sources) Regulations, 2008				5%	5%	8%	9%	10%
15	West Bengal	Notification dated March 25, 2008	WBSEB				4.8%	6.8%	8.3%	10.0%
			CESC				4%	6%	8%	10%
			DPL				2.5%	4.0%	7.0%	10.0%
			DPSC				2%	4%	7%	10%

Source: SERC RPS Orders/Regulations

Annexure-2: State-wise RE Potential and Installed RE Capacity

Wind Energy : State-wise Potential and Installed capacity

States	Gross Potential (MW)	Installed Capacity* (MW)
Andhra Pradesh	8275	122.5
Gujarat	9675	874.8
Karnataka	6620	917.2
Kerala	875	2
Madhya Pradesh	5500	70.3
Maharashtra	3650	1646.3
Orissa	1700	
Rajasthan	5400	495.7
Tamilnadu	3050	3711.6
West Bengal	450	
Others		4.3
TOTAL	**45195**	**7844.7**

Source : MNRE Annual Report 2007-08 (as on 31-Dec-07)*

Biomass Power : State-wise Potential and Installed capacity

States	Potential (MW)	Installed Capacity* (MW)
Andhra Pradesh	648	334
Chhattisgarh	221	131
Gujarat	1131	1
Harayana	1304	6
Karnataka	950	262
Kerala	1018	
Madhya Pradesh	1240	1
Maharashtra	1781	96
Punjab	3145	28
Rajasthan	1000	23
Tamilnadu	967	228
Uttar Pradesh	2300	144
West Bengal	370	
Others	173	
TOTAL	**16248**	**1254**

Source : MNRE Annual Report 2007-08 (as on 30-Sep-07)*

Small Hydel Power

Sr. No	Name of state	Identified number of sites	Potential (MW)	Installed capacity (MW)	Under Implementation (MW)
1	Himachal Pradesh	457	2019	142	64
2	Karnataka	468	1940	417	104
3	Uttarakhand	354	1478	76	61
4	Jammu & Kashmir	208	1294	5	6
5	Arunachal Pradesh	452	1243	45	42
6	Maharashtra	221	485	209	14
7	Chhattisgarh	132	483	18	1
8	Kerala	207	456	98	40
9	Tamil Nadu	155	373	90	13
10	Madhya Pradesh	85	336	51	40
11	Punjab	204	270	-	-
12	Uttar Pradesh	211	267	25	-
13	Andhra Pradesh	377	251	179	18
14	Orissa	206	218	7	61
15	Sikkim	70	214	39	13
16	West Bengal	141	214	98	79
17	Meghalaya	90	197	31	2
18	Gujarat	287	186	7	-
19	Jharkhand	89	170	4	35
20	Bihar	74	149	50	8
21	Nagaland	84	149	21	12
22	Mizoram	53	136	17	16
23	Assam	40	120	2	15
24	Manipur	99	92	5	3
25	Haryana	23	37	63	6
26	Tripura	10	31	16	-
27	Rajasthan	55	28	24	-
28	Goa	4	5	-	-
29	A&N Island	5	1	5	-
Total		**4861**	**12842**	**1976**	**650**

(Source: MNRE dated Sep, 2007)

Annexure-3: Sample Case of CDM benefits for illustration

NHPC(Case-CDM)

S.No.	Name of the H. E. Project	Installed Capacity	Net Generation in GWhr	Schedule of Commissioning	Estimated CERs in tCO2						Share in percentage	Validation Cost in Lakhs	Registration Cost in Lakhs	Verification Cost in Lakhs	Total CDM cost to be paid by consultant in INR lakh upto 2012	Annual Revenue in INR Lakh	Total Revenue up to 2012 in Lakh	Net Revenue upto 2012 in INR Lakh
					Annually CERs	Contracted CER Annually for payment	Total period upto 2012	CER up to 31st Dec 2012	Total payment to Consultant as success fee + 2 lakh fixed fee	Up to a Period of 7 years								
1	Nimoo Bazgo Project	45 MW	236.94	Aug,2010	180074	215000	2 yr 5 month	435180	413	1260518	10.5	10	14.496	10	83.49	1357.76	3281.26	2867.9
2	Chutak Project	44 MW	210.38	Feb,2011	159889	190000	1 yr 11 month	306454	318	1119223	11.5	10	12.801	10	78.4	1205.56	2310.66	1992.89