INTEGRATING VARIABLE RENEWABLE ENERGY WITH THE GRID: LESSONS FROM THE SOUTHERN REGION

Prepared by

MERCADOS ENERGY MARKETS INDIA PVT. LTD. (AF-MERCADOS EMI)

November 2012

An initiative supported by

SHAKTI SUSTAINABLE ENERGY FOUNDATION

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ABBREVIATIONS

ACF	Auto Correlation Function
CCGT	Combined Cycle Gas Turbine
CEA	Central Electricity Authority
CIL	Coal India Limited
CUF	Capacity Utilization Factor
CWET	Centre for Wind Energy and Technology
DA	Day Ahead
EPS	Electric Power Survey
FiT	Feed in Tariff
GBI	Generation Based Incentive
GoI	Government of India
GWEC	Global Wind Energy Council
IEGC	Indian Electricity Grid Code
ISO	Independent System Operator
LBNL	Lawrence Berkeley National Laboratory
LoA	Letter of Agreement
MNES	Ministry of Non Conventional Energy Sources
MNRE	Ministry of New and Renewable Energy
NAPCC	National Action Plan on Climate Change
NLDC	National Load Despatch Centre
OCGT	Open Cycle Gas Turbine
RE	Renewable Energy
REC	Renewable Energy Certificate
RET	Renewable Energy Technology
RLDC	Regional Load Despatch Centre
RPO	Renewable Purchase Obligation
RPO	Renewable Purchase Obligation
SCCL	Singareni Collieries Company Ltd
SLDC	State Load Dispatch Centre

SR	Southern Region
SSEF	Shakti Sustainable Energy Foundation
TN	Tamil Nadu
UI	Unscheduled Interchange
VRE	Variable Renewable Energy
WISE	World Institute of Sustainable Energy
WTG	Wind Turbine Generator

EXECUTIVE SUMMARY

1. IMPERATIVES FOR GRID INTEGRATION OF GENERATION FROM VRE SOURCES OF ELECTRICITY

Grid integration of Generation from Variable Renewable Energy (VRE) sources of electricity has long term and short term connotations. From the long term perspective, augmentation of transmission capacity enables generation from conventional sources to better manage the variability in generation from VRE sources and ensures adequacy of reactive power sources in the network. From a short term - system operation perspective, better forecasting of generation from VRE sources allows better provision of ancillary support for maintaining grid frequency within an acceptable range at all instances; to maintain grid stability. This enables efficient scheduling and dispatch of generation from VRE sources. Finally interval metering coupled with transparent mechanisms for scheduling and dispatch allow economical and efficient balancing and settlement of energy accounts and accounts for the “green” aspect of VRE generation

These aspects, when adequately taken care of, not only allow better grid integration but also better market integration of generation from VRE sources. The present analysis focuses on the issues pertaining to system operation and market integration of generation from VRE sources.

On the basis of the analysis conducted it is apparent that large scale introduction of VRE into the Indian grid is indeed possible. The technical potential indicated in various studies is far larger than official MNRE estimates. Developer interest is strong. The demand for energy continues to grow, even as conventional fuel constraints seem to aggravate over time. The potential for integration of VRE on a large scale is apparent.

Indian power system design, at a high level, is also conducive for large scale VRE integration. Indian grid has many significant advantages including:

a. A large synchronously integrated system for most parts of the country (NEW Grid), with installed capacity of more than 150 GW

b. A smaller, but still significantly large Southern Region (SR) grid with installed generation capacity in excess of 50 GW

c. Likelihood of integration of the two grids in the foreseeable future (2014) which will create a giant frequency integrated grid;

d. Development of nine high capacity transmission corridors which will allow supply from wind/solar fed regions to be replaced by generation of hydro/coal/gas based generation in times of low generation from VRE sources;

e. A robust, tiered transmission system that features a National Grid that is increasingly growing strong with addition of large inter-regional capacities as 765 KV AC, 400 KV AC and 500 KV HVDC systems. Underlying this is a very strong regional grid system as an intermediate layer. At the lowest levels the transmission grid features 400 KV, 220 KV, 132 KV and (some) 110KV/66KV transmission systems at the state level. These systems are increasingly becoming more robust

f. The diversity of generation resources across the country is a significant advantage, with a reasonable mix of coal, hydro and gas assets.

All of the above would be significant advantages as India takes a strong low carbon growth path with renewable energy as the centrepiece of this growth. However, the translation of these advantages in favour of renewable energy is not automatic. Several issues (some of which will inevitably prove difficult to resolve) would need to be overcome. Beyond the issues that are discussed subsequently, impetus can be provided to the integration of renewable through following changes in the market design:

All long-term electricity scenarios show a large increase in installed VRE capacities in India in the coming decades. Inadequate levels of accuracy in wind generation forecasting result in day-ahead forecasts which have the potential to induce increasing uncertainty into the Indian electricity system. It will therefore be essential to make use of two factors: the improving wind forecasts within the hours between the day-ahead market and real-time dispatch, and the full flexibility that the generation, transmission, and demand side of the power system can offer to limit cost increases to deal with this uncertainty and to ensure full system security.

The power market design therefore has to satisfy five criteria:

(a) Facilitate system-wide intra-day adjustments to respond to improving wind forecasts:

- to ensure that the least cost generation capacity provides power and ancillary services.

(b) Allow for the joint provision and adjustment of energy and balancing services:

- to reduce the amount of capacity needed to provide balancing services and to operate on part load.

(c) Manage the joint provision of power across multiple hours:

- a broader set of actors can contribute energy and balancing services in day-ahead and intraday markets if they can coordinate sales across adjacent hours (thus more accurately reflecting technical constraints of power stations like ramp-up rates or start-up costs).

(d) Capture benefits from national integration of the power system:

- the transmission network is the most flexible component of the power system, but requires fully integrated intra-day and balancing markets to replace more costly generation assets and enhance system security. Also, with the physical integration of grids, the commercial, institutional and regulatory processes need to match up.
- RLDCs need to have a “visibility” over variable sources of generation connected at 110/132 kV or lower voltage levels for the purposes of balancing and control. Institutionally, Renewable Energy Control Centre needs to be developed (may be as a part of the RLDC/NLDC) to manage “operation” of variable sources of generation. This would be critical – as discussed in the report for management of both – reactive and active sources of balancing. The need for integration of variable sources of generation into the grid from the perspectives of inter-alia economic operation, energy security, and lower carbon emissions etc. provides opportunities to complement the bottom-up approach pursued so far by the states with huge potential for renewable generation with top-down requirements. One cornerstone is the centralized structure of the nature of Renewable Energy Control Centre. As many market participants have disincentives to fully support a bottom-up transition to an integrated power market design, the provisions from such a centralized mechanism might become essential in the Indian pursuit of a harmonized and effective power market design;
- The analysis in the report points to a considerable reduction in balancing costs from 40% (in 2014) to maximum of 75% (in 2022) if SR were considered as a one system for provision of balancing resources for variable sources of generation. This of course needs to backed up with institutional changes proposed in the report.

(e) Integrate the demand side into intraday and balancing markets:

- Creating incentives and systems –essentially Demand Response (DR) Programs - that allow the demand side to fully contribute to the available flexibility.
- Such DR customers are an important part of the Ancillary Services Mechanism/Market
- DR resources have the flexibility to match up most closely with the ramp rates of variable sources of generation like wind and solar

2. PRE-REQUISITES: CHANGES REQUIRED IN COMMERCIAL, REGULATORY AND INSTITUTIONAL MECHANISMS

Five elements of market design described above need to be supported through improvement in the following seven processes and infrastructure requirements discussed through the report and summarised below:

Issue # 1: **Forecasting and Planning Processes.** Forecasting serves two purposes – (1) allows wind generators to take operational decisions which are aligned to market prices of energy, (2) allows the system operator to better plan ancillary services required to balance generation from VRE sources. The VRE generators are often compensated based on feed-in-tariff rates and hence there is little inducement for the generators to gain from better prices in the market. The second requirement is however critical for better grid integration. The host states, as exemplified in states like Tamil Nadu and Rajasthan, often have to bear the brunt of high UI charges/ Load shedding / operation of high cost pumped storage based generators to manage variability of wind – especially when poor quality forecasts are used. While the report proposes a detailed mechanism (with infrastructure requirement) for improving forecasts from each wind farm, it also proposes that either scheduling and dispatch of VRE be made mandatory and they be held commercially responsible for deviations from their schedules or each VRE generator install equipment which facilitate collection, recording and transmission of data which is required for forecasting by the system operator. This implies that such VRE generators allow full visibility of their generators to the system operator at all times.

Issue # 2: **Planning for and charging for Integration of VRE sources.** The primary question that governs planning for grid integration of VRE generators in the Indian context is: **Why should states who have met their RPO, invest in balancing resources, transmission and reactive power support equipment for the wind generators whose primary objective is to help other states meet their RPO?**

The high costs of VRE integration have dissuaded states from encouraging investment in VRE generation despite these states having high potential. In order for the REC market to be a success it is pertinent that a comprehensive framework for planning of capacities required for grid integration of wind based generators be developed. **Clearly, since the REC mechanism operates in a national market, planning for grid integration of VRE generators which serves such a national market needs to be also done at a national level.**

Transmission planning in India is done through coordination between CEA, CTU, STUs, RPCs. **Planning for systems required for integration of wind based generation or other intermittent sources could also be done centrally in a similar manner. All such investments – since these are primarily being done to allow all the states in India to meet their RPO, could be approved by the Central Electricity Regulatory Commission.**

How would the costs of integration be shared?

There are two types of costs that would need to be shared:

- The fixed costs – against capital expenditure identified above
- Variable costs – which would again be of two types
    - Costs of balancing - cycling of coal / gas or operation of pumped hydro plants / OCGT / Diesel based power plants

- The cost of losses – wind generators draw inductive power from the grid – which results not only in lower voltages but also higher system losses in the state networks

The capital costs are proposed to be approved by the Central Electricity Regulatory Commission (CERC) and since most of these are transmission related costs – the same could be made a part of the Point of Connection (PoC) mechanism. Similarly, sharing of transmission losses could be as per the PoC mechanism.

Sharing the costs of cycling

The development of Ancillary Services mechanism – which is proposed to be implemented by POSOCO will serve to estimate/determine (based on market signals) the costs of cycling of coal/gas/pumped hydro plants. Ancillary services markets usually take the price offers from various generation resources and demand response resources and these offers set the spot prices in electricity markets. The following mechanism is proposed for charging of cycling costs:

(a) In case of generators selling power under FiT to any purchaser (whether home state or other state) – the costs of cycling would be borne by the purchaser.

(b) In the case of generators selling power under APPC to the home state, the cost of cycling could be borne by the home state and the wind generator is the ratio of APPC and the average REC price realized during the month. For example if the cost of cycling due to a wind generator is Rs 100 during a month. The APPC of the state is Rs 2.75 / kWh and the average REC price during the month is Rs 2.00 / kWh. Then Rs 100*2.75/(2.75+2.00) would be borne by the state and Rs 100*2.00/(2.75+2.00) would be borne by the wind generator.

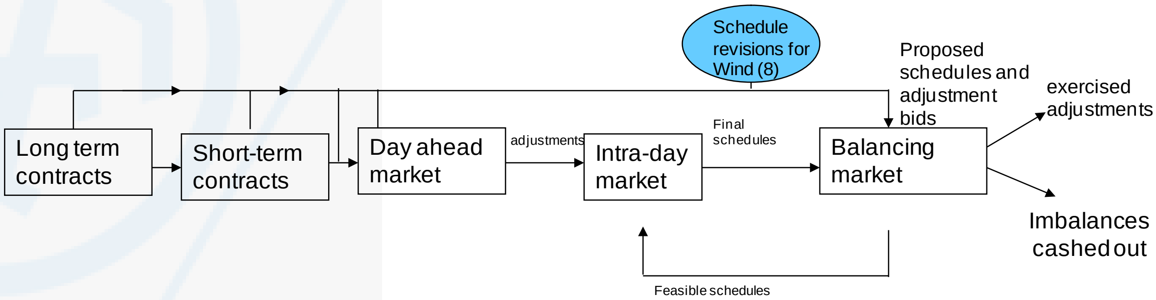
(c) In the case of generators selling electricity on the power exchange, the costs of cycling shall be borne by such generators.

Till such time as, ancillary services market mechanisms are implemented, CERC may determine the cycling costs in Rs / kWh for various types of generation resources. As a policy, while coal / gas based power plants can have retrofits which allow economic cyclical operations, renovation and modernization, or repowering of older power plants can mandatorily require such flexibilities in power plants. Methodologies to compute cycling costs and international examples where retrofits have been used to make base load power plants more flexible, in line with the requirements of the changing electricity markets are summarized in the report.

Issue # 3: **Scheduling and Dispatch of VRE Generation.** VRE generation becomes easier to forecast the closer the predictions are to real-time market operations, and correspondingly, more difficult to predict farther in advance. Therefore, submitting wind generation schedules closer to real-time market operations will allow for more accurate predictions of wind generation, although some trade-offs are involved. That said, having a shorter period of time before the start of real time market operations may contribute to a need for more reserves such as load following or perhaps higher costs from the increased starting and stopping of conventional units, as those shorter periods of time will not allow sufficient time to change unit commitment decisions for conventional generating units.

Notwithstanding the above limitations of allowance of "close to real time scheduling", IEGC already permits eight schedule revisions in a day at three-hour notice and this offers an opportunity for wind generators to correct themselves, as is shown schematically below.

Figure 1: Scheduling Mechanism



However, from the system operation perspective, the system operator needs to a-priori plan for capacity to meet sudden loss of generation or needs to plan back down of running generators in case electricity from intermittent sources is to be accommodated. Such planning for "unit commitment" is possible a day in advance. Close to real time management of such exigencies requires a well functioning ancillary services mechanism/market and a demand response program. Criticality of day-ahead security constrained unit commitment requires that the scheduled wind generators be held responsible for grid security like other generators.

Currently, states like Tamil Nadu where, in terms of capacity, wind penetration is approximately 46%, sudden ingress or withdrawal of wind causes considerable difficulties in grid operation. During periods of sudden wind generation ingress, if the grid frequency increases and correspondingly the UI rate falls below the FIT rate, it becomes uneconomical for the state to accept wind electricity. Further, if wind generation suddenly decreases and frequency falls – the utility either has to shed load (which is normal course of action) or the state overdraws at high UI rates. In such cases if the RPO obligations of the state have already been met, there is no incentive for Tamil Nadu to encourage more wind based generation – despite having a large potential. Such a situation demands development of a mechanism with following characteristics:

(a) The VRE generators must be responsible for their schedules albeit with some relaxation – because the intermittent nature of wind needs to be considered

(b) The host state should not be singularly responsible for bearing the entire costs of grid integration of wind based generation, i.e., costs due to imbalance, costs of balancing capacity requirements – since most such generation falls within the control area of the SLDC despite serving the RPO needs of other states, costs due to load shedding, demand response, wind generation forecasting, etc.

(c) Generators, with spinning reserves, connected in other control areas should have an incentive to help declining grid frequency especially when it happens concomitantly with a sudden decline in wind based electricity generation. Maintaining frequency within tight bands would help the scheduled VRE generators by reducing excessive charges on them.

(d) The conditions under which wind based generation is required to back down must be extremely transparent and grid contingencies should be "visible" not only to the utility but also the system operator and be readily verifiable.

Scheduling of wind based generation could be managed as follows:

1. Day-ahead Scheduling (DAS)

   Scheduled Wind resources shall provide day-ahead schedules. Wind resources participating in the day-ahead scheduling process are treated no differently than any other resource in the day-ahead scheduling system.

2. Intra Day Scheduling (IDS):

   Wind resources are permitted eight schedule revisions in a day with at three hour notice. The IDS will be optimized for the most reliable dispatch and may select a resource to reduce its output. If operation of the wind resource infringes security and reliability at its forecasted output level, the system will create a basepoint that reflects the resource's ability to be limited, taking into account its stated response rate. The wind resource must limit its output to the level (or below) specified in the basepoint within the next five minutes (if there is a direct communication between the SLDC/RLDC with the VRE Generator) or within fifteen minutes (if the communication to generators is via the transmission owner at the pooling station).

The system will use the wind resource's last intraday schedule - its last known energy output, and its forecasted energy output to help determine the wind resource's schedule. Absent any constraints, the instructions sent to wind resources will reflect the ability of the system to take all the energy the wind resource can produce if it is does not infringe security and reliability of system operation. However, if the wind resource is selected to limit its output, instructions sent to the wind resource will reflect those limitations.

Instructions are sent electronically from SLDC/RLDC via basepoints to the transmission owners (pooling station operators), in case there is no direct communication with the generators. Transmission owners will communicate these instructions to the projects.

Ancillary Services Market/Mechanism is a pre-requisite for effective balancing the variability due to VRE generation. Ancillary Services markets/mechanisms allow for spinning reserves to be available, allow charging for ramp-up/ramp-down services provided by thermal generators and also allow for demand side participation for managing variability of generation.

Issue # 4: **Imbalance Settlement Mechanism – Balancing and Settlement.** Despite scheduling based on acceptable forecasts, it is inevitable that there would be a deviation between schedule and actual generation/drawal. This deviation is termed as "imbalance". All power systems / markets have an imbalance settlement mechanism. India has an imbalance settlement mechanism wherein the charges for "imbalance" energy are regulated and linked to grid frequency. These are referred to as Unscheduled Interchange (UI) rates. The report illustrates that when FiT rates are higher than UI rates, the system operators ask the wind generators to back down, especially in high wind months. Similarly, even during periods when wind generation suddenly falls concurrently with a dip in grid frequency, the neighbouring states (like Andhra Pradesh) would have no incentive to ramp up their hydro/gas based generation because this would reduce their drawal from the inter-state grid and they would be inadequately rewarded for helping the grid – as per the current provisions of the UI mechanism.

The process of imbalance settlement is proposed as follows:

1. VRE Generators who abide by the full forecasting guidelines and allow visualization of their farms by the system operators are not penalized for deviation. This is also the case in California ISO, Ontario IESO etc. The aim of such criteria is to incentivize farms to adopt good forecasting methodologies. Further, from the security perspective, this allows the system operator to forecast based on farm site conditions and plan balancing resources.

2. The imbalance settlement (UI Accounting) shall be done on a weekly basis, as is the current practice, for other generation resources.

3. If the deviation, with respect to the schedule, on an aggregate weekly basis is within -10%[1], the applicable UI charges shall be borne by the Regulatory Renewable Fund (RRF).

[1] The rationale for 10% is that tighter the norm – more will be the incentive for the wind farms to adopt forecasting methodologies and allow full visualization of their farms by the system operator. Further, tighter

a. Current allowable deviation (which does not invite penalty or other commercial implications) is ±30% from the schedule at the level of each time block. However, here allowable deviation of -10% is applicable to those wind generators who do not allow full visualization of their wind farm by the system operators. These generators would be required to schedule and be commercially responsible for deviation and hence imbalance charges.

b. With larger control areas with effect from March 2014, when SR is proposed to be synchronized with the NEW grid, and with the proposed development of Ancillary Services Market – where the frequency support services are explicitly procured from the market – it is expected that frequency would vary in a very narrow band – thereby reducing the burden of imbalance on VRE generators.

4. If the deviation, with respect to the schedule, on an aggregate weekly basis is within +10%, the applicable UI charges shall be credited to the RRF.

5. The extent to which under-generation, with respect to the schedule, exceeds 10%, the UI charges shall be borne by the generators who opt for abide by the forecasting code proposed. The rate applicable to the UI energy in excess of 10% shall be the average UI charge for the generator. For example, if the total UI charges for the generator are Rs 100, and the UI energy (under-generation) is 50 units, then the applicable average UI rate for the generator is Rs 2 / unit (100/50). If the 10% for the generator corresponds to 40 units, there is excess under-generation of 10 units (50-40). Therefore, the generator will have to bear the burden of Rs 20 (2 multiplied by 10).

6. Similarly, if the over-generation accepted into the grid exceeds 10% of the scheduled energy over a week, the generator would be paid at the average rate UI rate multiplied by the UI (over-generation) energy that exceeds 10%.

7. The above mechanism may leave the RRF account in a net deficit or a surplus. The RRF is proposed to be funded by the DISCOMs (under the REC requirement) in the inverse proportion of the RPO targets and in direct proportion of the RECs purchased from the national markets for Renewable Energy Certificates (RECs).

a. The rationale behind "inverse proportion of RPO targets" is to load the RRF burden on those states which have lower RPO targets. Further, the states which meet their shortfall of RPO from the REC market would normally not have adequate in-state VRE sources and therefore do not bear the costs of grid integration of VREs. Therefore, "direct proportion to RECs purchased" allows such states to share the burden of those who have considerable in-state VER generation.

b. As compared to the current mechanism, wherein, the deficit in RRF is funded by various DISCOMs in proportion of their contribution to peak, the proposed mechanism is better aligned to the purpose of the RRF – to create sustainable markets for generators based on renewable sources. Whereas, a state which has a high contribution to national peak, may also have sufficient renewable based generation in the state, a state with low RPO target (in % terms) needs to be incentivized to increase its RPO. An ideal situation would be where all the states have same RPO (in percentage terms) – thereby reducing disparity in power purchase costs on account of having to purchase costlier renewable based generation.

c. Current mechanism or any mechanism that charges RRF shortfalls on the basis of contribution to peak demand or energy consumption may end up burdening those states which might have adequate in-state VRE generation. For example, Maharashtra – which has adequate in-state VRE would have to bear the burden of RRF shortfall

norms have helped develop "Aggregators" who forecast and schedule on behalf of wind farms. This observation draws upon experience in Spain.

because the state has the highest contribution to national peak and is also one of the largest in terms of electrical energy consumption.

The mechanism proposed above will have an impact on renewable energy accounting and the REC market. This is discussed in the following section.

Issue # 5: **Imbalance Settlement in "Green" accounts.** When a VRE generator under-generates (with respect to its schedule), but is compensated at its scheduled energy (under the ABT mechanism) by the counterparty to the power sale contract – an imbalance occurs between the renewable energy purchased by the buyer (who still pays for the contracted amount) and the renewable energy actually generated.

Further, when a wind-generator over-generates (with respect to its schedule), but is compensated at its scheduled energy by the counterparty to the contract – an imbalance occurs between the renewable energy purchased by the buyer and the renewable energy actually generated and absorbed in the system.

The following mechanism is proposed to settle the imbalance in the renewable energy market:

1. When a generator under-generates (and the terms of its contract require that the RECs or RE rights will be held by the buyer of energy), it is required to purchase corresponding RECs from the market and transfer the same to the counter-party to the energy contract – who has paid to the generator for the scheduled energy at the contract rate.

    a. In case generator has an energy only contract with the buyer, the RECs will be issued to the generator as per its actual generation.

2. When a VRE generator over-generates (and the terms of its contract require that the RECs or RE rights will be held by the buyer of energy), it gets corresponding RECs after due certification of such generation from the SLDC/RLDC. The VRE Generator may either neutralize such RECs with RECs that it is required to purchase because of under-generation or sell the same in the REC market – whatever is perceived to be in the best commercial interest of the generator.

3. The balance between the renewable energy generated and the corresponding RECs may be achieved over a year.

Issue # 6: In several high wind areas transmission system is weak and inadequate: In the states analysed by us, Tamil Nadu has a particular constraint in this regard. Most of the connectivity is at 110 KV and below. The grid is ill-equipped to handle such flows (and especially so because of poor SO visibility of network/generation). Connectivity in future has to be predominantly at higher voltage levels (with possible exceptions for small sized projects), with complete system operator visibility. A commercial mechanism for sharing of transmission costs is required;

Issue # 7: System Operations Organisations need redesign: Our interactions have revealed that the current processes in SO organisations are not at all geared for large scale VRE penetration. In most cases there is no forecasting of VRE generation. Even in states like Gujarat that have performed well on power systems planning and operation, the systems are primitive at present. At the state level the SO organisations need to be equipped adequately. Further, in line with the need for larger balancing areas discussed in this report, there is a need to introduce greater co-operation between SOs for VRE, and integration of SO operations for VRE corresponding to the definition of balancing areas. The SO processes for VRE also need to be revisited. Managing VRE on the lines of conventional generation would expose the system to severe risks, and systems and processes need to be appropriately designed to avoid these changes.

The above present a large and complex agenda. Handling each issue in a piecemeal basis is unlikely to resolve them. As a consequence, large scale VRE introduction and integration is also unlikely unless the issues are addressed comprehensively. Based on the analysis conducted we present below the potential agenda for large scale VRE integration.

Table 1: Potential agenda and Roadmap for large scale VRE integration

Implementation Plan Aspect	2012-13	2013-14	2014-15
SO Technical and Commercial Infrastructure and Processes			
Forecasting of VRE			
SO visibility of all major VRE			
Scheduling of VRE			
Settlement (UI) modifications			
Infrastructure Creation and Related Commercial Processes			
Transmission Need Identification			
Transmission pricing framework for VRE			
Identification of Balancing Needs			
Commercial/Incentive Framework for Balancing			
SO Organisation Design			
Redesign of SO Organisation for RE (incl control area definition)			
Implementation of new SO organisation			

Implementing the above agenda would present its challenges, but would be eminently possible if the policy and regulatory framework strongly reinforces the needs and benefits of the same to all stakeholders including generators, transmission companies, system operators, and particularly the utilities. The benefits would need to be quantified with reasonable precision. To that effect we recommend specific and detailed studies on:

a. Balancing power requirements, specific resource identification and corresponding costs, based on system simulation studies. This should be done for specific system conditions, transmission networks, for various years and under various levels of VRE penetration. The studies should specifically identify the pricing, commercial and contractual mechanisms for balancing power;

b. Integrated transmission planning in view of the VRE penetration for least cost system expansion for various levels of renewables. Studies should identify the specific augmentation requirements considering the various development and commercial scenarios for various system conditions over a period of time. The studies should also investigate how the transmission augmentation is to be designed, financed and priced, including the potential expansion of the Point of Connection transmission pricing mechanism for VRE resources;

c. Investigations into SO organization and evaluation of SO integration for renewables at a regional and national level. Our analysis reveals that there is no apparent legal impediment in such integration, but would require strident policy action. Our initial analysis, reproduced here, indicates very significant benefits of integration on a regional level, coupled with better forecasting.

Table 2: Penetration levels, Balancing Capacity and associated costs (refer details in Chapter III)

	Maximum Volatility of VRE generation (High wind season)									
	Tamil Nadu					Southern Region				
	% Penetration	Balancing Capacity (MW)	Balancing cost (Rs/Kwh)			% Penetration	Balancing Capacity (MW)	Balancing cost (Rs/Kwh)		
			Case 1	Case 2	Case 3			Case 1	Case 2	Case 3
2012	34%	624	0.68	0.44	0.21	18%	334	0.30	0.20	0.11
2014	39%	835	0.72	0.48	0.23	22%	798	0.43	0.27	0.12
2016	45%	1,126	0.78	0.53	0.28	27%	1,112	0.44	0.28	0.13
2022	55%	2,533	1.20	0.89	0.58	35%	2,465	0.51	0.32	0.14

d. In any event the SO organizations need to be strengthened with maximum visibility of the system, forecasting capabilities, scheduling processes, system management skill enhancement etc. This would require investments that would need to be accompanied with policy and regulatory efforts. Studies should quantify the investment requirements;

e. We expect ancillary markets to play a very critical role in supporting the expansion of VRE resources. The NLDC has already filed a petition with the CERC for introduction of ancillary services markets. The studies should establish how the ancillary services products are to be defined and priced, and also define the design aspects of the market;

f. As has been commented upon, the UI mechanism needs significant change as a settlement mechanism to be appropriate for VRE. In view of the fluctuating nature of VRE, a moot question arises on whether a frequency linked settlement mechanism is at all appropriate for VRE resources (or for the system as a whole, especially in view of the relative stabilization of frequency). This is a matter worthy of specific investigation.

In conclusion, the potential of renewable energy does not appear to place constraints for development. The constraints are more related to infrastructure and commercial aspects. Even as the commodity supplied is electricity, the characteristics of VRE generation are very distinct from conventional generation. Incrementally VRE is anticipated to contribute to a very large share of India's energy production. Especially in view of the absence of alternatives, it is likely to replace conventional power as a centrepiece of Indian power sector development. However this shift in paradigm will have to be accompanied by fundamental changes in how the sector is commercially and operationally organised. Even as we have indicated a 3 year path for introducing these changes, they will require concerted policy and regulatory action, supported by detailed factual analysis to ensure robustness in the policy and regulatory measures undertaken.

3. ROADMAP FOR VRE GRID INTEGRATION

The Roadmap to full implementation of the above recommendations can be categorized into two parts:

1. Regulatory interventions
2. Infrastructure enhancement in pursuance of the regulations.

It is perceived that while the Infrastructure enhancements would follow the provisions in the Regulations, the draft of the regulations themselves would require a consultative process wherein – Ministry of Power, Ministry of New and Renewable Energy, CERC, ERCs (through FOR), Wind Developers and System Operators – both at the Central and the State level are development partners. The critical elements in the initiation of VRE integration are:

- Development of a Scheduling and Dispatch Mechanism
- Forecasting Mechanism – wherein the inputs to the forecasts are also visible to the system operator to accomplish security forecasts
- Commercial Mechanisms – pertaining to settlement – which is essentially a refurbished RRF mechanism
- To be able to physically manage variability of wind, after obtaining a reasonable forecast – institutional ability to do balancing through AS markets/mechanism is required. Here a decision on who would monitor and control balancing would need to be taken – a central body under the aegis of NLDC has been proposed in this report.
- Finally with the AS mechanisms/markets, UI mechanism would need to be phased out.

Table 3: Roadmap for VRE Grid Integration

S. No.	Action	Responsibility	Time-Frame
1	Development of Ancillary Services Market / Mechanism	CERC/POSOCO/SERCs/SLDC	CERC – 3 to 6 Months
2.	Forecasting and Planning Guidelines	POSOCO/SLDCs	This is a very basic requirement – 3-4 months.
3.	Scheduling and Dispatch Codes for VER	CERC/SERCs	Needs to be revised – 5 months
4.	Balancing and Settlement Mechanism	CERC/SERCs	Balancing and Settlement will happen in accordance with the design of the Ancillary Services Market. Further RRF mechanism needs to be instituted in the interim – 4 to 6 Months
5.	Revision of UI Mechanism	CERC	Frequency band must be tightened. Plan for replacement of UI mechanism by AS mechanism be

S. No.	Action	Responsibility	Time-Frame
			initiated as soon as India is ready for AS markets/Mechanism
6.	Installation of IT Infrastructure, required metering in conformance with the Forecasting, Scheduling and Dispatch mechanisms	ERCs / Individual Generators	The date for such installation can be specified in the Codes – as notified by the Regulatory Commissions. Should happen over next 1-2 years.

Beyond the above, it has been shown in the report that larger control areas allow better management of the variability of VRE resources of electricity generation. This is physically possible only when we have a strong national grid. NEW grid and SR are expected to be integrated by March 2014. Further, most components of the nine high power transmission corridors being developed in the ISTS are expected to commence commercial operation by 2018. These “physical” developments at the inter-state level need to be however backed up by policy and regulatory action backed by robust commercial mechanisms – as indicated in the above roadmap and also by “physical” augmentation of the networks at the level of intra-state transmission system.

I INTRODUCTION

1.1 BACKGROUND

India's substantial and sustained economic growth is placing enormous demand on its energy resources. Within the various forms of energy, electricity demand has been growing at the fastest rate. The demand for electricity is expected to grow by about 8-9% to keep the pace of economic development in line with Government of India targets. There is a significant amount of pent up demand that has to be met. Conventional energy resources have been unable to keep pace with the rising demand, resulting in large scale and sustained outages and also stranded generation capacity in the absence of adequate fuel resources.

Renewable energy in India has grown at a fast pace in the past few years, led by Wind, but also having substantial contributions from Biomass, Small Hydro and, more recently, solar energy. Wind energy deployment is now more than a decade old in Tamil Nadu and other states in South India. Particularly when compared to the other Indian states, Tamil Nadu has considerable experience in operating a power system with Variable Renewable Energy (VRE) resources. The first commercial wind farm was commissioned in 1990. While the wind capacity has grown considerably in Tamil Nadu, on an all India level development remains relatively modest, with close to 190 wind farms currently in operation in India. The installed capacity of wind in Tamil Nadu is around 6971 MW in Tamil Nadu, compared with a total generating capacity in India of 17644 MW. Wind energy currently contributes 44% of Tamil Nadu's generating capacity. The generation from this capacity is however concentrated in a part of the year.

It is anticipated that significant accelerated growth in the deployment of VRE, and in particular wind and solar energy will occur in the short to medium-term as evidenced by escalating targets and the amount of activity in the market in on-shore and off-shore wind energy. Both wind and solar face challenges to a varying extent by way of variability of the generation resource, leading to difficulties in load and grid management. Often these resources are located in remote areas. This, coupled with low capacity utilisation factors, renders power evacuation expensive.

The following table identifies some of the barriers that affect the large scale deployment of the key RETs in India identified in past literature analysis:

Table 1.1: Barriers to large scale RE deployment

Parameter	Wind	Solar	SHP	Biomass
Transmission Constraints	XXX	X	X	-
Supply Concentration	X	X	X	-
Infirm Nature	XXX	X	X	-
Seasonal	X	-	X	-
Access to site	X	-	X	-
Logistics	X	-	-	-
Clearances	X	-	-	-
Resource quality & reliability	X	X	X	XXX
Cost of Power delivered	-	XX	-	X
Accessible resource potential	-	-	-	X

Note – "XXX" denotes a very significant barrier, "X" indicates lesser barriers. Depending on the developments on technology and policy, these barriers evolve over time.

In view of the developments in the Indian energy and electricity markets and the increasing amount of decentralised generation, including the growing importance of VRE capacity, it is important to analyse the technical, economic and regulatory issues that relate to the expected increased penetration of VRE based electricity systems.

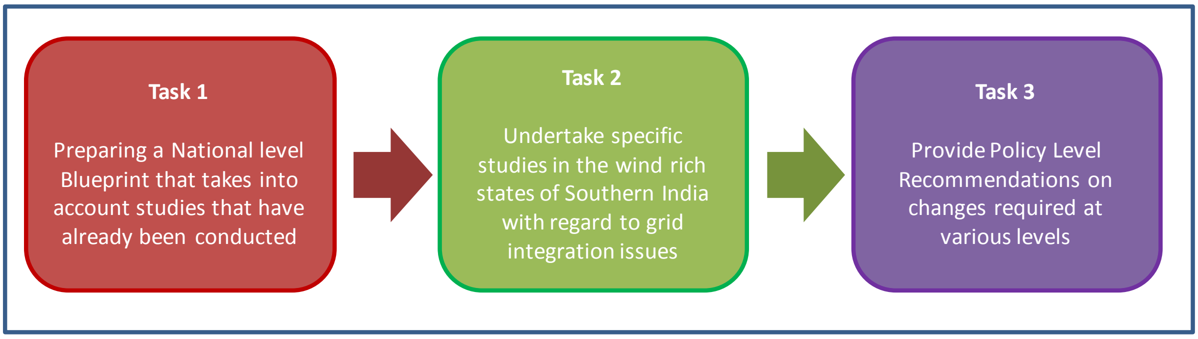
One part of this debate centres on the perception that because VRE resources are intermittent, this is a fundamental barrier to its future growth, and the operation of electricity systems. It is sometimes expressed that VRE resources are inherently unreliable because they are variable. However, it is important to note that the end product that VRE delivers is exactly the same as other power sources (gas, coal, hydro or nuclear), i.e. electricity, and that is the arena of relevance. Hence, the specific problems and solutions need to be investigated and a blueprint for development drawn up.

This report includes a comprehensive review of the relevant literature, analysis, and data available that allows an informed assessment of the issue. It contains a detailed investigation of the technical, economic and regulatory issues concerning an increasing proportion of wind energy in the electricity grids, with attention paid to the aspects of variability. This report is intended as a guide to key aspects of grid integration of VRE resources for electricity generation and seeks to assist in the political debate, policy formulation, research and investment decisions.

1.2 SCOPE OF OUR STUDY AND REPORT STRUCTURE

The overall scope of our study is illustrated in Figure 1 below.

Figure 1.1: Scope of Work



The main report hereafter is organised as follow:

- Chapter II provides a summary analysis of past studies on renewable energy and projects a potential picture of the scale and issues on large scale VRE integration in the country
- Chapter III discusses the problems of grid integration of VRE based generation in the context of South India, and articulates the predictability and management issues.
- Chapter IV discusses the potential solution areas and the outcomes of stakeholder consultations in this regard
- Chapter V specifically discusses the issues on forecasting and planning of VRE
- Chapter VI outlines the potential solutions on scheduling, dispatch and grid management
- Chapter VII concludes and articulates views on the way forward

II ANALYSIS OF PAST STUDIES FOR EVOLVING A NATIONAL LEVEL BLUEPRINT

2.1 ANALYSIS OF PAST STUDIES

Our first task was to undertake an overall assessment of the overall development scale and potential based on the various studies undertaken in the past. The methodology for activities to be undertaken in Task 1 is depicted below:

Figure 2.1: Proposed Approach for Task 1

The following studies were analysed to identify the relevant conclusions from the study:

1. **Assessment of achievable potential of New and Renewable Energy resources in different states during 12th plan period, determination of RPO trajectory and its impact on tariff (CRISIL, 2011-12);**
2. **Unleashing potential of Renewables (Energy Sector Assistance Management Programme, World Bank, 2011)**
3. **Assessment of Various Renewable Energy Resources Potential in Different States, Determination of RPO Trajectory and its Impact on Tariff (CRISIL, 2010);**
4. **Indian Wind Energy Outlook (GWEC, 2011)**
5. **Reassessing the Wind Potential in India (Lawrence Berkley National Laboratory, 2011)**
6. **Strategic Plan For New And Renewable Energy Sector For The Period 2011-17, MNRE, 2011**

In addition number of presentations by TERI, C-STEP, LBNL, WISE and other expert agencies were perused. In addition the study team has also evaluated detailed presentations by PGCIL consequent to their report for the MNRE and CERC titled “Green Energy Corridors – Transmission Plan for Envisaged Renewable Capacity” in 2012. Also, the project team studied international experiences which provide valuable insights to issues of VRE development and management.

The aspects identified and analyzed are:

1. **Resource Potential**: How much potential exists in the various states with high renewable energy potential?
2. **Development**: What is the project development pipeline?

3. **Renewable energy contribution anticipated to energy mix**: Assessment of different level of VRE penetration and accordingly requirements of the peak non-VRE capacity with their existing generation mix.
4. **Generation patterns from VRE**: Assessment of the wind power pattern at a turbine, wind farm level and state level.
5. **Balancing of VRE**: How is balancing conducted or proposed to be conducted? How much balancing power is required? From what kind of capacity?
6. **Transmission management**: What are the challenges and how are they being addressed? What are the consequences if these challenges are not adequately addressed?
7. **Forecasting of generation**: What are wind resource and generation forecasting techniques adopted by the VRE operators and system operators. What is the level of preparedness to adopt the wind resource scheduling with reference to the new grid code requirements.
8. **Market integration**: How do developers, regulators and system operators propose to integrate VRE on a large scale into the competitive power markets (including the UI mechanism)?
9. **Commercial framework and incentivisation mechanism**: How are the commercial arrangements for VRE and the incentive framework to be aligned to the demands of large scale VRE development?
10. **Demand side management**: How can techniques like demand response be integrated with supply side interventions on VRE.

The analysis revealed a considerable body of work around the potential for development of renewable energy. As commented upon subsequently in this chapter, the studies have revealed that resource potential of VRE does not appear to be a constraint. A significant amount of work has also been conducted on commercial arrangements and on incentive mechanisms for promoting renewables. However, at this stage there is very little detail available in published Indian literature on more technical aspects like generation forecasting imperatives, balancing power, network development and management, demand side integration and related aspects.

The findings of the analysis of various reports cited are provided in Annexure 1.

As mentioned, MNRE and CERC have commissioned a large study by PGCIL on transmission infrastructure requirements for large scale integration of renewable energy in the country. The draft report of the study has been discussed by PGCIL at different fora. The report brings out the issues of variability in wind and the network and control infrastructure required for managing variability. Our report evaluates a number of attendant issues related to balancing power provision, system management infrastructure and procedures, technical requirements for large scale integration, etc. While the extant studies have studied VRE integration from the perspective of the transmission capacity augmentation, there is not any detailed study that clearly brings out the problems of grid integration of VRE from system operation point of view with all the attendant commercial mechanisms that are a pre-requisite for the same. Our study aims to address these important needs.

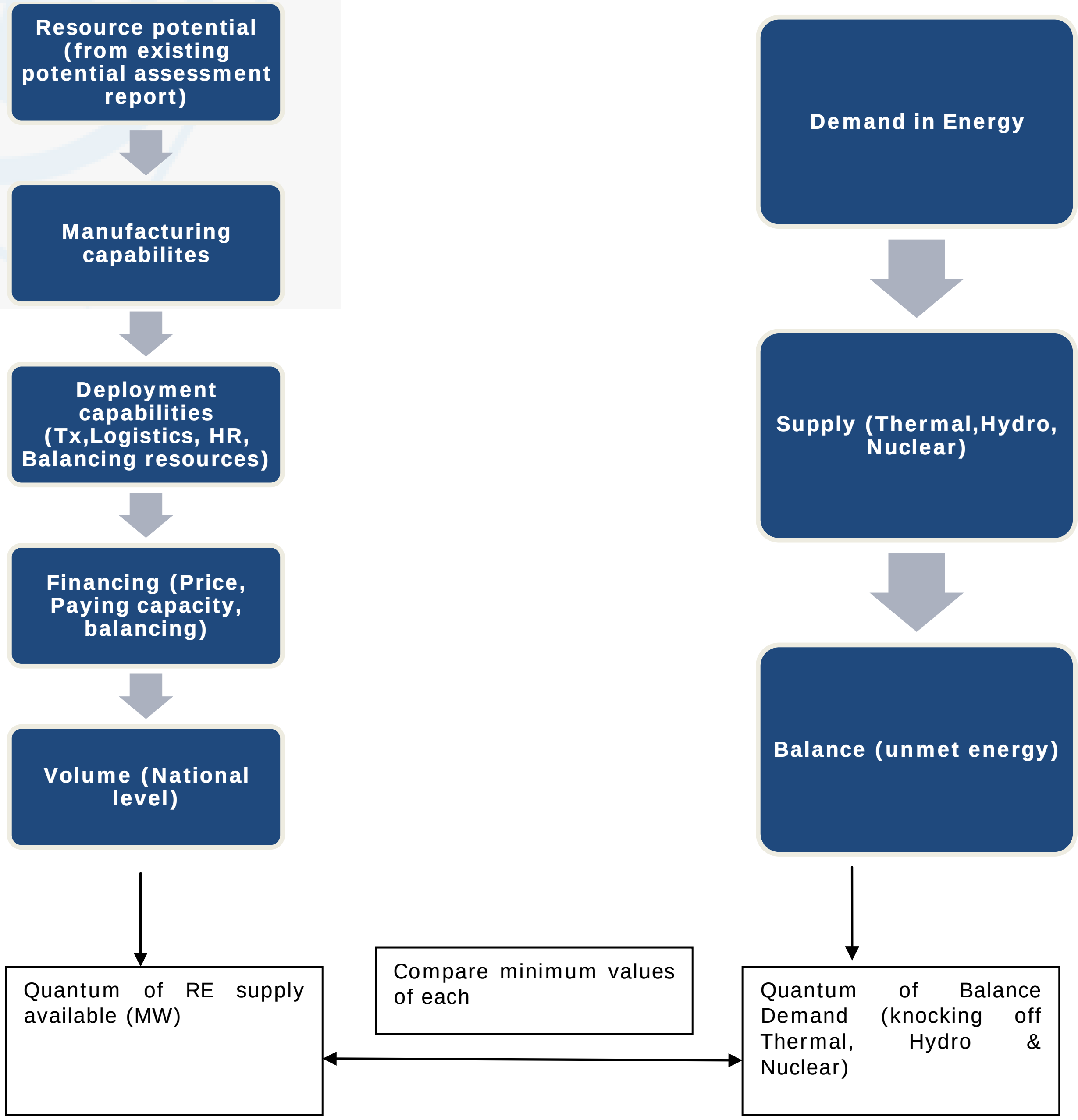
2.2 EVOLVING A NATIONAL LEVEL BLUEPRINT FOR VRE

Even as studies analysed indicate significant VRE potential and also investor interest, the constraints to VRE are significant. These include supply side constraints relating to land acquisition, clearances, access infrastructure, manufacturing capabilities, logistics, and also commercial constraints that limit the realisable potential. The issues related to availability of balancing energy, the commercial arrangements for settlement, etc also serve as limiting factors. On the demand side the potential constraints are largely related to the need for electricity and the ability to pay for the renewable energy generation.

For evolving a national level blueprint we have analysed the development of VRE from both the supply and demand sides to establish both the need and the ability to set up VRE capacity.

Essentially, the minimum of the two sets the cap on the potential that can be actually realised. This is schematically presented below.

Figure 2.2: Supply Vs Demand



Even as the above serves as a useful analysis framework for assessing the level of renewables that is required and achievable, in practice the relationship between conventional energy and renewable energy is more inter-linked. Renewable energy serves to address the issues faced on development, environment and fuel resources encountered in conventional energy, while conventional energy can in turn help the system manage the variability issues in renewable energy. The two thus have a symbiotic relationship and not necessarily conflicting positions in power system development and operations. This report analyses this relationship and explores on how one category of resource can assist effective and optimum utilisation of the other.

2.2.1 Supply Side Analysis

Analysis of some of the key supply side aspects reveals the following:

Resource Potential

A comparison of potential at the national level indicated through various studies for wind (as the principal VRE) is shown below:

Table 2.1: Wind Potential

Study / Source	Potential Indicated
MNRE (CWET) – National	102 GW
LBNL – National	2006 - 3121GW (Technical at 80 to 120m hub heights)
TERI – Gujarat	304GW (non-crop land) and 858GW (only crop land)
WISE – Tamil Nadu	69GW (80m) 113GW (100m) 169GW (120m)

Most recent studies indicate a large potential available for development. Hence this is not anticipated to be a constraint.

Manufacturing Capability

Indian wind development industry development has been traditionally led by manufacturers. Basing on a favourable policy environment from the erstwhile MNES (now MNRE) the development of renewable energy technologies (particularly wind, but also small hydro and biomass) gained momentum from the late 1990s. The core model of development of wind in India has been provision of a complete suite of solutions by the equipment provider, starting from site acquisition and development to post commissioning and O&M services. This has suited the investors in such projects since their primary interest traditionally was to avail accelerated depreciation benefits. However, this situation is now changing with the emergence of large IPPs such as CLP, Green Infra, Tata power, etc and with large conventional power utilities stepping into this area.

The wind turbine generator (WTG) technology has evolved very rapidly. State-of-the art technologies are now available in the country for the manufacture of wind turbines. All the major global players in this field have their presence in the country. The unit size of machines has gone up from 55-100kW in the 1980s to 2MW. Wind turbines are being manufactured by 17 manufacturers (Source: CWET) in the country. The technology is moving towards better aerodynamic design; use of lighter and larger blades; higher towers; direct drive; and variable speed gearless operation using advanced power electronics. There is continuous development happening on technology for local conditions as increasingly the developers are demanding the same. Hence manufacturing per-se is not anticipated to be a serious constraint.

Over the past few years the solar PV industry has also gained momentum. Buoyed by favourable policy environment ushered by the JNNSM and favourable policies in states like Gujarat, the solar PV industry is developing rapidly. This development brings enormous prospects for domestic industry for manufacturing, assembly, construction and management. The latter is important since solar PV, as an emergent VRE will require attention to manage the technical challenges arising from variability and generation characteristics including harmonics. Manufacturing will also have to pursue cost reduction and quality management actively to meet the standards of performance and also compete with imports. The industry has to gear up to these technological challenges, which are not insurmountable.

Development Constraints: Land Acquisition, Clearances, Access Logistics, Transmission, Human Resources, etc.

The development constraints at this time appear to be more significant than aspects related to potential or manufacturing. The issues are more severe for wind as compared to solar. There are significant issues related to land acquisition, consents and clearances (particularly where forest clearances are involved), access logistics, etc. Even as India has an apparently large wind potential, the quality of wind varies considerably across the country and across areas in various states. The relatively superior sites (e.g., in Karnataka) are in forest areas. Apart from clearances, access to these sites for large capacity trailers and cranes is difficult. This places considerable limitations on the scale of development in such areas. Remote areas also have relatively poor grid access, limiting development. These aspects have been analysed in several reports, and have not been specifically addressed as a part of our work (which principally focuses on grid integration issues). We have however consulted various entities involved in project development, and the interactions reveal that the issues can be addressed progressively if there is a steady development pipeline. In other terms, the constraints can slow down the growth trajectory, but does not present an intractable challenge.

Financing and Credit related issues

The renewable energy sector has been witnessing considerable financing interest, and lenders and investors (developers, private equity) have been favourably considering the sector. The principal issues contended are those of creditworthiness of utility offtakers.

In this context it is important to take note of is the framework for sale of VRE, which affects project revenues and cash flows. At the moment the following are in vogue:

(i) Home state sale under Feed In Tariffs (FIT)

(ii) Open Access and Captive Sale (typically in the home state)

(iii) Combination of power sale revenues and Renewable Energy Certificates (REC).

The REC mechanism is new, but is fast gaining popularity. However it also faces some important challenges that need to be understood. It needs to be noted that the three methods indicated above largely retain the energy produced in the host state. However newer approaches are emerging that could cause the power generated to flow out of the host state as well. Typical examples include:

(i) Sale through competitive power markets, including power exchanges

(ii) Sale under PPAs to other states where physically the energy is also delivered to the procuring state

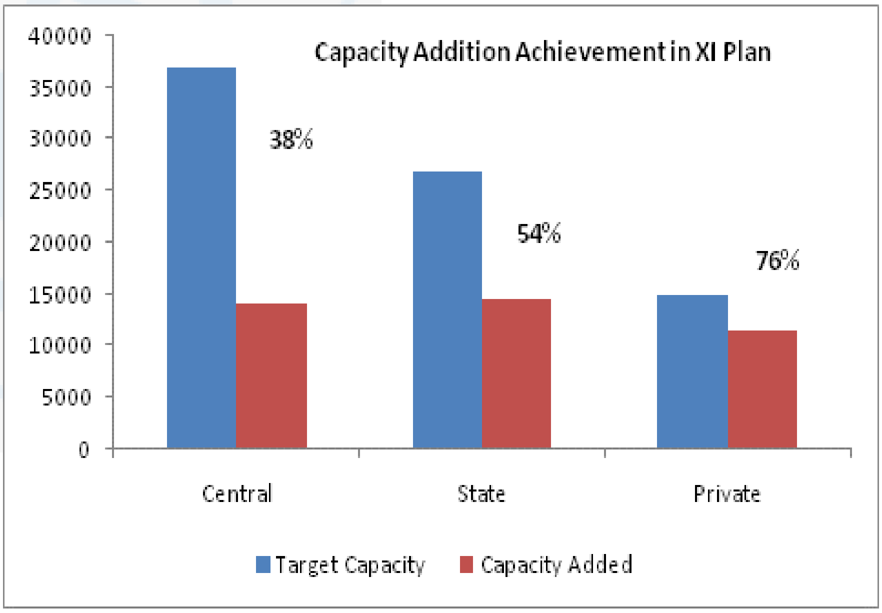
The nature of support interventions that would be required would widely vary based on the mode of sale adopted. If the power is to be primarily absorbed in the host state, then a strong network and balancing arrangements would need to be created in the host state. However, if inter-state power flows are involved, then the nature of infrastructure created would have to be substantially different.

In summary, the supply side issues are primarily linked to the certainty of the offtake pipeline, commercial arrangements and creditworthiness of offtakers. These are aspects to be addressed principally through policy and regulation.

2.2.2 Demand Analysis for VRE

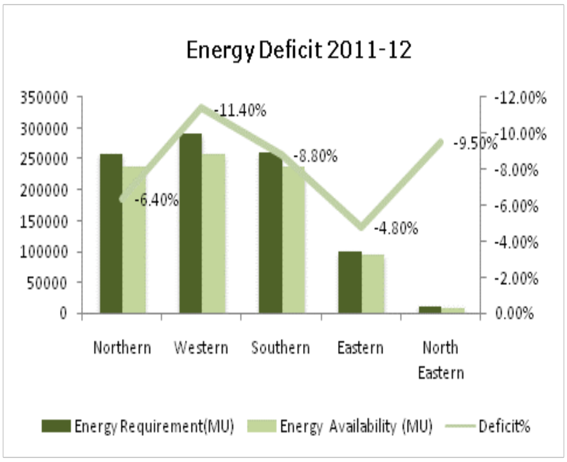
Analysis of demand side dynamics presents an interesting and instructive picture. During the XI Plan period (2007-12) India witnessed the following capacity addition for conventional power.

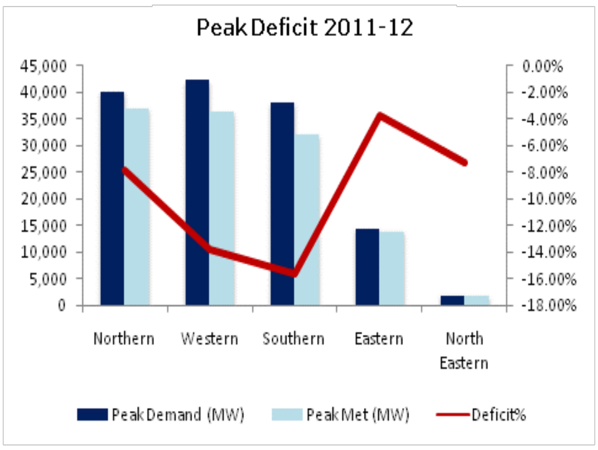
Graph 2.1: Capacity Addition achievement in XI Plan



Even with the shortfalls, the capacity addition statistics are the best among all recent plan periods. In spite of this the gap between demand and supply continued to feature strongly, as is apparent from the charts below.

Graph 2.2: Energy Deficit and Peak Deficit in 2011-12





Future demand projections (as per the 18th Electric Power Survey published by the Central Electricity Authority) shows a consistent growth in power demand during the XII plan

Table 2.2: Demand Growth Projections from 2012 to 2017 as per 18th EPS (Billion Units)

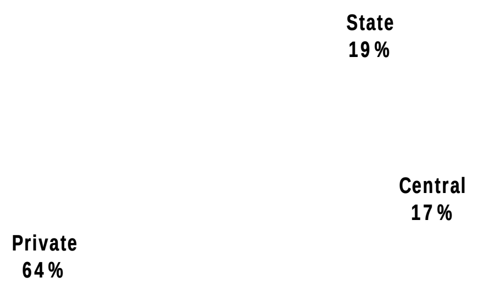
Region	2011-12	2016-17	CAGR (%)	Overall Growth (%)
Northern Region	276	415	8.5%	50.2%
Western Region	272	390	7.5%	43.5%
Southern Region	253	364	7.5%	43.9%
Eastern Region	106	163	9.0%	53.9%
North Eastern Region	11	16	7.7%	44.7%
All India	918	1349	8.0%	46.9%

Source: 18th Electric Power Survey, Central Electricity Authority

In order to meet the above projected energy demand, the Govt. of India has announced a conventional power capacity addition target of 75,785 MW in the XII plan, of which 62,695 MW[2] is coal based capacity. Figure 4 indicates the break-up of the capacity addition expected by various sector.

The 62,695 MW of coal based capacity envisaged for the XII plan will require an additional 344 MT of coal besides the existing requirement from the existing generating stations (~512 MT), taking the total coal requirement to a level of 855 MT by the end of XII plan.

Figure 2.3: Capacity contribution by various sectors to XII plan capacity addition



This is impossible to achieve. Our research indicates that production of domestic coal has been insufficient even for existing plants, and incrementally cannot cater to more than 5-6 GW per year. Even with blending (which is constrained by technical factors), a large part of the capacity is likely to be stranded, even if built. In all, about 17 GW of coal based capacity constructed or under construction face the prospect of being stranded. In addition about 10 GW of gas based capacity also faces stranding. New capacity on coal (other than those in the construction pipeline) is unlikely to materialize on the desired scale.

A similar situation prevails in hydro where the capacity addition levels are far lower than the 16 GW originally planned for the XI Plan. For the XII Plan the target is only of the order of 9 GW.

The gap between requirements and likely achievements (or availability after fuel constraints being reflected) sets the stage for other available options.

VRE has the ability to fill a significant part of the anticipated shortfall. We thus anticipate that the constraints for VRE will be more related to the supply side issues rather than demand side aspects.

2.2.3 Desired Scale for VRE

Even as an overall scale of development is difficult to speculate upon (in view of the various uncertainties and issues in the development chain) we believe that the potential to add renewable energy capacity in the context of Indian power demand is very large. It is also unlikely that the current difficulties in conventional power would be overcome, since the indications are that extraction of mineral resources will become increasingly difficult and demanding. For developing a blueprint we have made the following assumptions on levels of annual capacity addition through VRE:

Table 2.3: Annual VRE Capacity Addition proposed for Blueprint Development (MW)

	2012-13	2016-17	2021-22	2031-32
Business As Usual (based on XII Plan working Group till 2017)	3000	7000	10000	12000
Positive Growth	5000	8000	12000	16000
Aggressive Development Scenario	5000	10000	15000	20000

[2] The 62,695 MW coal based capacity for the XII plan considered in this report is based on figures recently announced by the Government of India. This excludes several other plants which are already at advanced stage of planning and are likely to be commissioned within the XII plan period.

Even at 20 GW annual capacity addition in 2031-32, the annual production at 24% CUF would be only of the order of 40 BU. Incrementally, this would not serve more than 18% of the energy needs of the country at that time. Thus, in view of the express requirements of the country, this scale of development of renewable energy represents an essential need and not a luxury.

However, incorporating and integrating renewable energy into the grid in the country on this scale is certain to present severe challenges for generators, distribution utilities and system operators. To identify the challenges and define a way forward, we have assessed the impact of the penetration levels in the Southern Grid (and particularly in Tamil Nadu) where the penetration levels are currently the highest. We have also compared the situation in Tamil Nadu with that in Gujarat, another high potential state. Also, for obtaining practical perspectives and representative results, our team has obtained field level information on wind generation for one calendar year at a location with high wind density, and also consulted extensively with utilities and system operators. The following sections present the analysis.

III PROBLEM OF GRID INTEGRATION OF VRE BASED GENERATION IN SOUTH INDIA: VARIABILITY OR PREDICTABILITY?

States in Southern India have varying levels of penetration of VRE, as is apparent from the table below:

Table 3.1: Penetration levels of VRE

State	Installed /Contracted Capacity as of March 2012	Peak Demand in 2011-12 (MW)	VRE Capacity (Wind & Solar) as of March 2012	Percentage VRE of Installed/ Contracted Capacity (%)	Percentage VRE of Peak Demand (%)
Tamil Nadu	17,601	12,421	7,338	42%	59%
Karnataka	13,394	10,347	3,183	24%	31%
Andhra Pradesh	16,094	13,917	885	5%	6%
Kerala	3,827	3,505	162	4%	5%
Puducherry	279	335	0	0%	0%

Source: CEA, AF-Mercados EMI Analysis

The current penetration on the ground is in contrast to the potential identified in the various states, which appears to be substantial in the three largest states – Andhra Pradesh, Tamil Nadu and Karnataka. Our study benefited from various studies undertaken by other agencies. Several of these studies were undertaken with the sponsorship and support of SSEF.

All the studies use significant assumptions, variance in which would change the potential estimated. However, irrespective of the assumptions, the technical potential is apparently large. **Thus, the focus has to shift from assessment of the potential (which must continue to be established with greater precision as required for various purposes) to the realisation of the potential.**

The team consulted with experts on the means to achieve a higher degree of penetration of variable renewable energy in the southern states. These consultations have not revealed any specific researched target on the scale that can be achieved in the medium and long term. Hence the study focused on the underlying constraints that affect the deployment of VRE in situations where the technical potential is not a significant constraint. International studies conducted in this regard identify the following as the main issues in deployment of VRE:

i. Intermittency of VRE and its corresponding impact on prices;
ii. Availability and cost of balancing power;
iii. Transmission availability and cost of transmission expansion;
iv. Timing of generation and correlation of VRE with the demand (essentially the net demand in the system);
v. Impact on plant load factors of other resources in the system (and hence the average costs of such resources);
vi. Step changes in generation and corresponding impact on grid management;
vii. Risks on account of the above and its corresponding impact on the investment climate for VRE.

The team also interacted with local transmission network managers and the SLDC to identify the issues encountered and the grid management practices. The interactions revealed that apart from the technical challenges posed by VRE, there are also very significant commercial/regulatory challenges that disincentivise the host utility in expanding the share of VRE. These challenges, unless addressed, will not permit higher proportion of VRE absorption into the grid.

Electricity production and consumption is variable. Electricity supply and demand are inherently variable, and are influenced by a large number of planned and unplanned factors. Demand in the power system is influenced by weather conditions and special events – most of which are predictable with considerable accuracy but a part of which is not always predictable.

On the supply side, power stations, equipment and transmission lines break down on an irregular basis, or are affected by extremes of weather such as drought, which particularly impacts hydro energy. Further when cross-country systems become more integrated, power demand from a neighbouring regions (within India) and country can put a strain on supply. Changes in Unscheduled Interchange (UI) electricity prices immediately impact not only the power withdrawal and hence supply decision of distribution utilities but also generation decision of generators, who often compare the variable cost of their operation with the UI charge for under-generation.

The entire electricity system is variable, both on the supply and demand side, and both can be predicted. The issue, therefore, is not one of variability or intermittency of a particular technology per se, but how to predict variability and what tools to utilise in order to control the process of constantly matching production to demand.

The system operators need to balance out planned and unplanned changes in supply and demand in order to maintain systems security. This is traditionally done through reserves. In supply strapped power systems, such as India, this is managed through load shedding or mechanisms such as frequency linked tariffs, where the generators / load serving entities are incentivized to observe grid frequency and take generation / withdrawal decisions which are in the best interest of grid security. Variability in electricity supply is as old as variability in demand; it has been a feature of electricity systems since its inception. **At modest penetration levels, the variability of VRE is always dwarfed by the normal variations.** Therefore wind cannot be analysed in isolation from the other parts of the electricity system, and all systems differ.

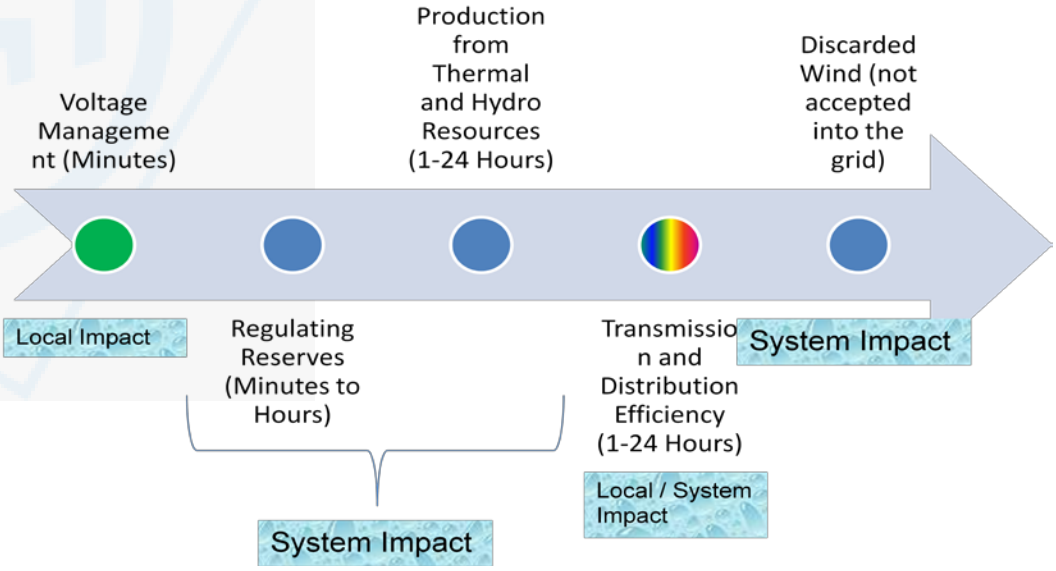
The size and the inherent flexibility of the power system are crucial aspects determining the systems' capability of accommodating a high amount of wind power. The role of a variable power source like wind energy needs to be considered as one aspect of a variable, dynamic electricity system. **Even though demand and supply from other sources of generation in a power system is also variable, it is predictable with a level of error which is manageable by system operators – the system operators and technologies have adapted to such errors in prediction over time. The same however is not true of wind and solar.** The day-ahead forecasts of VRE generation still have errors which impose considerable difficulties on the system operators.

The questions pertaining to grid integration of VRE generators arise not because of resource variability but because it is predictable with considerably reduced accuracy, as compared to demand or other sources of generation. It is important to explore how utilities, regulators and policymakers in India could address VRE reliability and integration, enabling more states to meet renewable energy production targets.

The impacts of VRE on the power system can be categorised in short-term and long-term effects. The short-term effects are caused by balancing the system at the operational time scale (minutes to hours). The long term effects are related to the contribution VRE can make to the adequacy of the system, which is its capability to meet peak load situations with high reliability.

In the short term, the decisions of the System Operator are enumerated in the graphic below:

Figure 3.1: Short Term Decisions of System Operator



The following sections delve briefly into each of the operational hurdles faced by the system operator in managing the transmission systems with the intent of analyzing:

(1) The costs of grid integration of VRE based generation and their sharing;

(2) The relative priorities of system operators at state and regional levels in mitigating the challenges posed by relatively less predictability of wind based generation;

(3) Barriers imposed by market design and wholesale commercial mechanisms

(4) Institutional changes required for facilitating VRE integration;

Figure 3.1 highlights the short term problems of system operation in terms of local impacts and system impacts essentially for the following reasons:

(1) In India, the State Load Dispatch Centres (SLDCs) are required to manage "local" issues – essentially in the context of wind where the generation resources are connected in the state network. These challenges are sometimes not "felt" by the regional system operator;

(2) SLDCs and RLDCs have different responsibilities;

(3) The SLDCs have "visibility" over power system components within their control area. Management of "system-wide" issues can sometimes be achieved by better coordination between state and regional load dispatch centres. In certain instances, institutional solutions offer least cost alternatives as opposed to a system of incentives and penalties which might alter behaviours of economic agents further exacerbating difficulties in grid integration of variable energy resources.

3.1 VOLTAGE MANAGEMENT

Voltage management is a local issue. In Tamil Nadu and most Indian states, wind generators / farms are connected either in the distribution network (below 66 kV) or in the network of STU at 110/132kV. In Tamil Nadu, the impact of low voltages due to heavy reactive power drawal) by wind generators in Kayathar, Udumalpet, Tirunvelli, Vagarai, Tennampatty, Thappagundu, Rasapaliyam, Anaikadavu and Kanarpatty areas is reported to be felt as far as Chennai – implying that reactive power flows over long transmission lines and hence causing huge system losses.

The output from a VRE generation facility will vary with resource variations (wind speed and insolation for wind and solar respectively). If these variations are large and rapid there will be corresponding changes in the magnitudes and directions of power flows from the project itself, and from the generators providing regulating and operating reserve services elsewhere on the system. Unless these are countered very quickly, the voltages on the system also will vary, and, if the variations are large enough, limits may be infringed.

Voltages on the transmission system are controlled through a combination of generator excitation systems, transformer tap-changers, static reactive devices and, increasingly, Flexible Alternating Current Transmission System devices (FACTS) globally though not in India. FACTS devices combine modern power electronics and control techniques with elements such as capacitors, inductors and transformers. In the Indian context the most important FACTS device are Static Var Compensators (SVC) / STATCOM – implementation of which at the state level has few instances**. Variations due to VRE are likely to be too rapid for transformer tap-changers, and too large for the generator excitation systems of many generators. Operators may have to rely to an increasing extent on FACTS devices. These devices are well proven, but expensive.**

Conventional generation largely uses synchronous generators, which are able to continuously operate during (‘ride-through’) severe voltage transients produced by transmission system faults. This capacity needs to be enforced for wind generators seeking grid connectivity, through changes in the state grid codes and the standards of grid connectivity developed by Central Electricity Authority. If a large amount of wind generation is tripped by a fault on the system, the negative effects of that fault could be greatly magnified.

Most of the wind generator systems currently used in India are induction generators. Squirrel Cage Induction Generators (fixed speed) are known to absorb heavy reactive power during start-up and also during normal operation. Wind generators, during normal operation, may start-up many times. The situation gets exacerbated during events of fault, when these machines consume large amounts of reactive power from the system. This may make recovery from the fault much harder. Solar projects can present similar voltage management problems due to the nature of output from the solar farm consequent to rapid insolation changes.

3.1.1. Need of mechanisms for determination and sharing of costs of voltage and Reactive Power Management

In case of wind Generators need to have a Voltage (or fault) ride through facility. Most of the modern wind turbines generators have this facility. Through regulations and changes in the grid code and connectivity conditions, these need to be enforced for older wind generators/farms also. IEEE Application Guide for IEEE Std 1547™, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems provides details of the technical standards for grid integration of variable energy resources – the same could be adapted for India.

All old smaller WTGs are under active policy consideration for re-powering. Repowering and new installations could take guidance from the grid interconnection standards which could have a focus on WTGs with variable speed and full scale frequency converter, with facilities for Low Voltage Ride Through (LVRT), reactive power and voltage control[3]. The cost of repowering of old WTGs in Tamil Nadu / India is expected to be in the range of Rs. 6.5-7 crore per MW. **The costs of management of voltage at the WTG end would therefore be internalized in the costs of repowering of old WTGs.**

[3] Such wind turbine systems allow various types of generators: synchronous generators with wound rotors, permanent magnet generators and squirrel cage induction generators. In such wind turbines the stator is connected to the grid via a full-power electronic converter. The rotor has excitation windings or permanent magnets. Being completely decoupled from the grid, it can provide an even more wide range of operating speeds than even variable drive systems with Doubly Fed Induction Generators, and has a broader range of reactive power and voltage control capacities.

Further, as regards the costs of SVCs/STATCOMs and procurement of reactive power from synchronous generators, reactive power pricing mechanism at the state level will need to be developed. Since states like Tamil Nadu – where there is abundance of wind based generation potential - would be generating to help other states meet their RPO standards – the costs of procurement of reactive power would have to be accounted for through any of the mechanisms proposed as under:

(a) The cost of reactive power for voltage support from static or FACT devices could be treated as fixed cost and charged to all the users of the grid including Wind Generators based on deviation of voltage at each bus from its nominal value; or

(b) As discussed under the section on alternative institutional mechanisms – such support services – could be procured through an Ancillary Services Mechanism by the State Load Dispatch Centre and charged according to causation in accordance with the user pays principle; or

(c) An alternative institutional mechanism – where all ancillary services, including reactive power for voltage support are procured centrally by an central agency designated to have an "operational control" over renewable sources of electricity generation.

Novel methods for pricing and procurement of reactive power for voltage control have been suggested[4]. These can be adapted to the Indian context, through further research in this area.

In case of solar power projects similar control mechanisms need to be instituted for voltage management. At the plant level this can be managed through better inverter design. However, a system heavy in solar requires adequate rotating machines to maintain system integrity. At an appropriate stage, when the problems require attention on account of the scale of solar project deployment, ancillary services would play an important role in network management.

3.1.2. Need for Changes in Institutional Mechanisms: a system operator for "Green Power"

The State Load Dispatch Centre (SLDC) is responsible for secure and reliable operation of the power system at the state level. The body, in all states, is currently under the control of the Transmission Licensee in the state. Capital investment planning – which includes planning for reactive power support is usually guided by the requirements of the state with due regulatory approval. The regulatory justification of capital investments pertaining to installation of reactive power equipment to support the Renewable Portfolio Obligations (RPO) of other states, after the host state has met its RPO would be difficult if the burden of the same were to be passed on to the state consumers.

Therefore, it is pertinent that either a commercial mechanism for sharing of such costs or an institutional mechanism be developed. If the costs are first incurred by the state utility and then passed on through a sharing mechanism on to other regional and national entities, it would involve:

[4] I. El-Samahy, K. Bhattacharya, C. Canizares, M. Anjos, and J. Pan, "A procurement market model for reactive power services considering system security," *IEEE Trans. Power Syst.*, vol. 23, no. 1, pp. 137–149, Feb. 2008.

S. Ahmed and G. Strbac, "A method for simulation and analysis of reactive power market," *IEEE Trans. Power Syst.*, vol. 15, no. 3, pp. 1047–1052, Aug. 2000.

J. B. Gil, T. G. S. Roman, J. J. A. Rios, and P. S. Martin, "Reactive power pricing: a conceptual framework for remuneration and charging procedures," *IEEE Trans. Power Syst.*, vol. 15, no. 2, pp. 483–489, May 2000.

K. Bhattacharya and J. Zhong, "Reactive power as an ancillary service," *IEEE Trans. Power Syst.*, vol. 16, no. 2, pp. 294–300, May 2001.

J. Zhong and K. Bhattacharya, "Toward a competitive market for reactive power," *IEEE Trans. Power Syst.*, vol. 17, no. 4, pp. 1206–1215, Nov. 2002.

J. Zhong, E. Nobile, A. Bose, and K. Bhattacharya, "Localized reactive power markets using the concept of voltage control areas," *IEEE Trans. Power Syst.*, vol. 19, no. 3, pp. 1555–1561, Aug. 2004.

P. Chitkara, J. Zhong, and K. Bhattacharya, "Oligopolistic Competition of Gencos in Reactive Power Ancillary Service Provisions," *IEEE Trans. Power Syst.*, vol. 24, no. 3, pp. 1256–1265, August 2009.

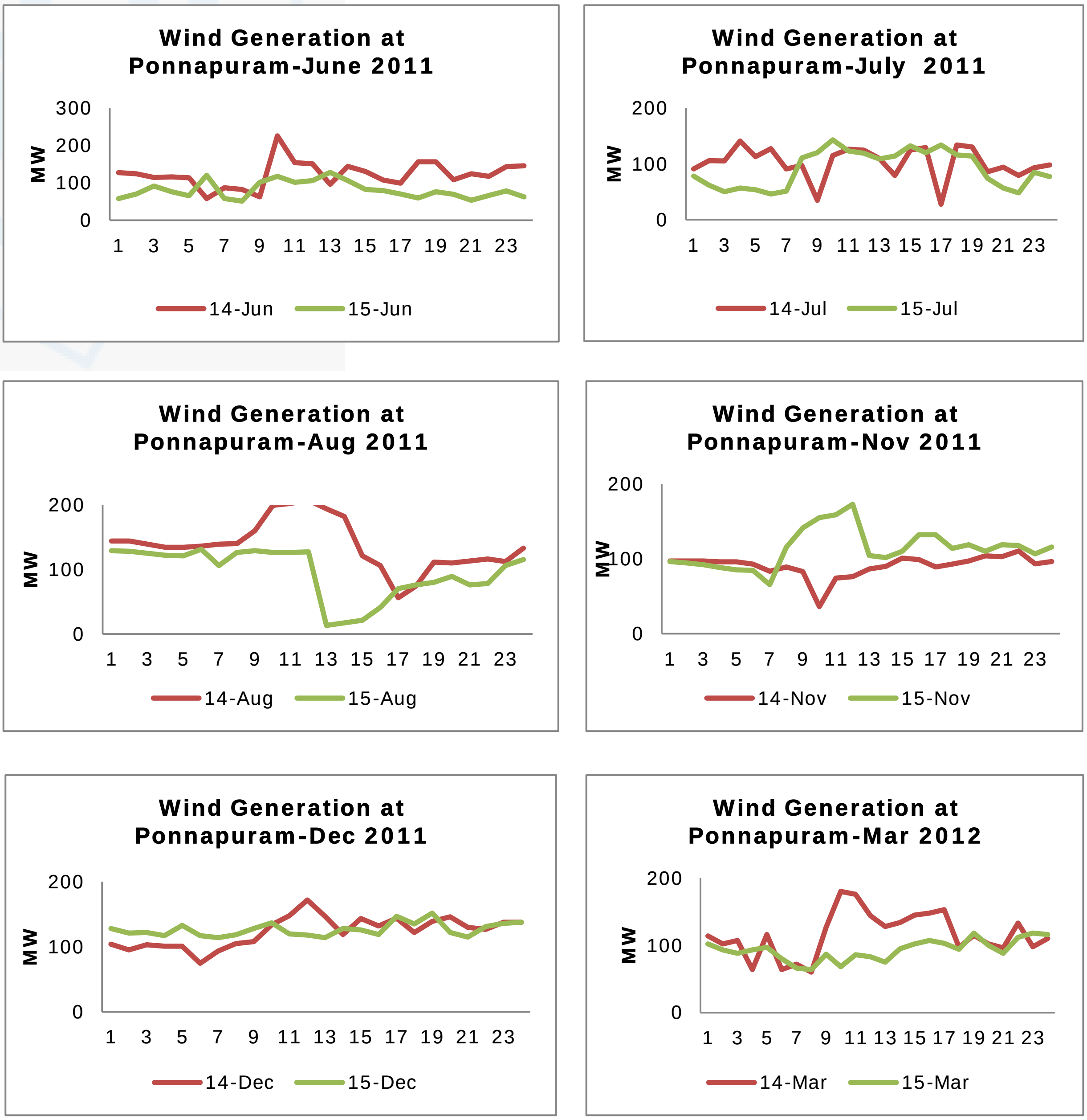
- Declaration of such assets as inter-state assets;
- Approval of such assets by a regional or a national body. RPCs may not be the appropriate body here because such assets are expected to benefit (satisfy the RPO and REC requirements) at the national level – for which the procedures are not yet well defined;
- Development of appropriate sharing mechanisms (by CERC).

Alternatively, if a Central Agency is designated to manage “system operation” pertaining to variable energy sources, such an institution could initially be set-up under the aegis of NLDC. This would not require any change in the Electricity Act 2003. Such sub-stations, where large farms seek connectivity could be brought under the “control area” definition of the RLDCs. Either PGCIL – the key ISTS licensee, or other ISTS licensees through the process of competitive bidding - could be directed to provide reactive power using inter-alia FACT devices. Charging for such services could be continued to be done as per the existing mechanism of charging for ISTS assets. In case the reactive power support is sought to be received from other rotating synchronous generators – SLDCs with a better “visibility” over the “local” network could provide such a support more reliably. The generators will have to be, however, compensated if they are required to generate reactive power by reducing real power output.

3.2 REGULATING RESERVES OR FREQUENCY SUPPORT ANCILLARY SERVICES

Real time balancing of demand and supply to keep the power system “stable” and hence “secure” is one of the primary responsibilities of the system operator. While uncertainty in demand always poses a challenge for system operation, system operators world-wide rely on spinning reserves or other real power support services which trigger into operation within seconds of receiving command from the system operator. Support of such services however needs to be procured in advance. When demand cycles through the day, the system operators have a reasonable estimation of supply requirements and keep such generators ready for operation during the day. However, as discussed, more than variability – predictability of wind with manageable accuracy is a greater challenge than predicting and managing uncertainty in demand or supply from conventional resources. As an example, in the case of Tamil Nadu, the data from various months indicates the variability in wind generation at a feeder level at Ponnapuram sub-station.

Graph 3.1: Wind Generation at Ponnapuram



For a system operator, extent of “predictability” is of great importance for reliable and secure system operation – where it is able to predict and thereby procure adequate balancing capacities. The purpose of depicting daily wind generation, in the above graphs, was that average monthly wind generation is not relevant for a system operator – these serve the requirements of system planners who plan capacity in medium to long term. It is seen from above graphs that:

- A comparison of the two days in June indicates that the balancing requirements at Ponnapuram, are completely different, especially at 1 AM, 5 AM, and 9 AM
- A similar comparison for all the other months indicates the difference in balancing requirements on two consecutive days. The ramping of wind is completely different on the two days.
- It is often argued that demand also varies similarly – but the fact is that it is much more predictable than wind and hence more manageable from system operation perspective.

- Also, as wind penetration increases, the problems for system operators increase. In Gujarat, system operation is currently easier as compared to Tamil Nadu because of lower levels of penetration in Gujarat.

Table 3.2: Wind Penetration in States

S.No.	State	Total Installed Capacity (MW)	Installed Wind Capacity (MW)	Wind Penetration (%)
1.	Tamil Nadu	17602	6917	39%
2.	Maharashtra	26142	2711	10%
3.	Karnataka	13394	2000	15%
4.	Rajasthan	10161	2100	21%
5.	Gujarat	21972	2894	13%
6.	Andhra Pradesh	16095	198	1%

The impact of poor predictability of wind on power system operations and consequently on state utility finances is also reported in Rajasthan. The following was reported in the 79th meeting of the Operations Coordination Committee (OCC) of the Northern Region Power Committee:

Representative of Jaipur Vidyut Vitran Nigam Limited (JVVNL) stated that the installed capacity of wind generation in Rajasthan is 2200 MW and wind generation on any day may go beyond 1700 MW and dip to 30-40 MW and sometimes even Nil on the same day in the total State load in the range of 4800-5200 MW. This huge variation in availability of wind energy makes it very difficult to assess the day ahead demand of the state. Further, Rajasthan Discoms. are keenly maintaining the grid discipline as per CERC guidelines. It is important to quote a situation here where Rajasthan Discoms draw power from the grid as per schedule in a particular block and having wind generation support of 1400-1500 MW at that time. Suddenly, the wind generation dips to 100 MW and under this condition it becomes very difficult to immediately shed 1400 MW load to keep the drawl within schedule. The Rajasthan Discoms face such situations very often.

He added that since twin grid disturbances in July, NRLDC/SLDC are not allowing over drawl even at frequencies above 49.7Hz. Although, while assessing the demand day ahead, data of wind forecast is also taken into consideration but these data are not accurate to the extent that it may help in exact demand assessment. Moreover, 30% variation is allowed in the day ahead schedule of wind generation as per CERC draft regulation for the wind energy. Therefore, over drawl from the grid to the tune of 300 to 400 MW may be allowed to Rajasthan to accommodate variation in wind generation.

Further, if, Rajasthan Discoms purchases short term power from exchange and unexpectedly wind generation increases resulting in the system under drawl, in that case heavy financial loss is inflicted on financially crippled discoms due to short term power purchase. If, the demand is assessed anticipating the wind generation and wind generation abruptly goes down then in that case Rajasthan Discoms have no option but to resort to heavy load shedding to maintain grid discipline. This un-scheduled load shedding adversely affects the quality of supply and consumer satisfaction.

Keeping in view the specific situation faced by Rajasthan Discoms arising out of availability of heavy but uncertain wind generation as mentioned above, he requested for relaxation in over drawl by Rajasthan at frequencies above 49.7 Hz. Further, some guideline may be issued by NRLDC regarding quantum of over drawl between 49.7 Hz & 50 Hz and beyond 50 Hz.

Representative of NRLDC stated that the solution to the problem lies in better foresting of wind generation by the generation. SE (O), NRPC suggested approaching State Regulator for provision of stringent Regulations on forecasting by wind generators. He also suggested implementation of automatic load shedding scheme in Rajasthan. Representative of JVVNL *intimated that they were receiving generation forecasts from wind generators in Jaisalmer and Barmer where there is concentration of wind generation but this has not helped. However, he requested for relaxation in over drawl and also for mentioning of prevailing of frequency by NRLDC while issuing "A" "B" or "C" messages to SLDCs for load control.*

After discussions, it was concluded that since limits on over drawl etc. are mandated by CERC regulations, the matter is outside the scope of OCC.

The above examples of Tamil Nadu and Rajasthan illustrate that:

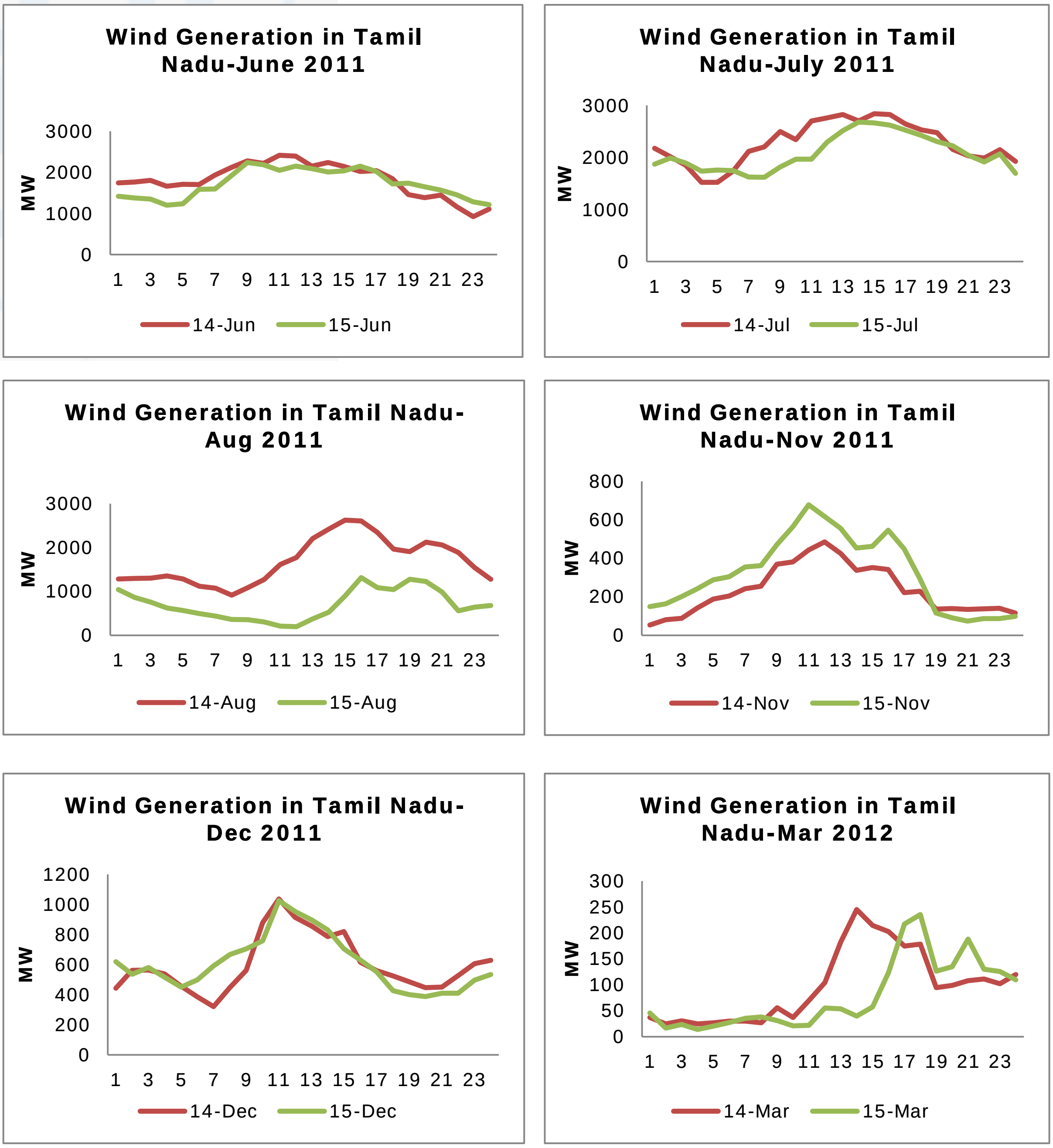
- The Day Ahead forecasts based on historical information may not be useful for system planning by the system operator and hence there is a need to develop faster electricity markets wherein gate closure for VRE based electricity generation is allowed close to real time;
- The importance of forecasting for not only "operational" needs of the system but also economic operation of the power system.

3.2.1 Larger control area help manage variability better

The forecasts typically used for VRE are based on metrological models and also are persistence forecasts**. It is clear from the above graphs that forecasting wind based on previous day generation levels is not useful for system operator in reserving capacities on a day-ahead basis.** If the transmission capacities are adequate, it may be possible for the system operator to "replace" loss of VRE generation at a location with thermal or hydro electricity from another location. Assessment of adequacy of transmission for VRE integration is a subject matter of a parallel study being conducted by Power Grid Corporation of India Limited. It is known that transmission networks not only at the inter-state level but also at the intra-state level will have to be strengthened for wind integration. However, the key question for investment at intra-state level is – Why should Tamil Nadu (or any host state) invest in transmission strengthening if not adequately compensated?

However, we assume adequacy of transmission for the purposes of balancing for this study. With adequacy of transmission, real power balancing is not a local issue and is in fact a system-wide issue. At the state level, VRE generation evens out considerably – as is evident from the following graphics at the SLDC level – the intra-day and even inter-day volatility much less in the following graphs as compared to Graph-3.1.

Graph 3.2: Wind Generation in Tamil Nadu



3.2.2 Identification of various costs of Grid Integration of VRE based Electricity Generation

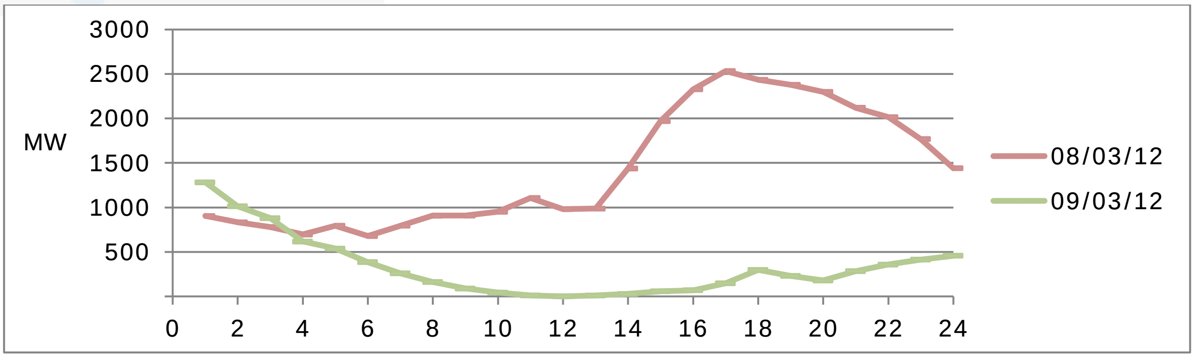
At the SLDC level, sudden reduction in wind generation can be balanced by ramping up existing thermal and hydro resources – if available as spinning reserves (secondary reserves) or by procuring power in the short term markets. Similarly, thermal / hydro generators have to be ramped down when there is sudden ingress of wind based generation. Typically in a state like Tamil Nadu, where thermal resources are designed to serve constant base loads, the SLDC is left with rather limited options to balance load and generation, such as:

(a) Ramping of tertiary reserves such as Pumped Hydro Power Plants, e.g. Kadamparai in Tamil Nadu
(b) Load Shedding
(c) Heavy UI Drawals

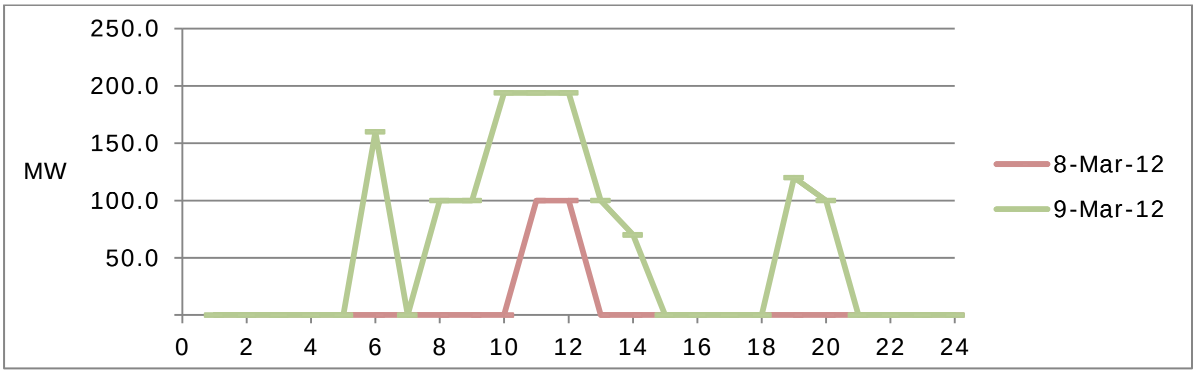
The above behavioural phenomenon in case of Tamil Nadu is depicted in the following Graphics – one for lean wind month of March and the other heavy wind month of August, for two consecutive days. Illustration of two consecutive days is also illustrative of the difficulties in resource planning that system operator at the state level faces owing to lack of good wind generation forecasts:

The states also resort to heavy UI drawls, but as illustrated in the case of Rajasthan, since imbalance Unscheduled drawls have huge costs, UI drawls may not always be correlated with lack of wind generation. The two examples illustrated in the graphics below show that UI drawls on the day of low wind during August were much more pronounced than they were on the low wind day in March.

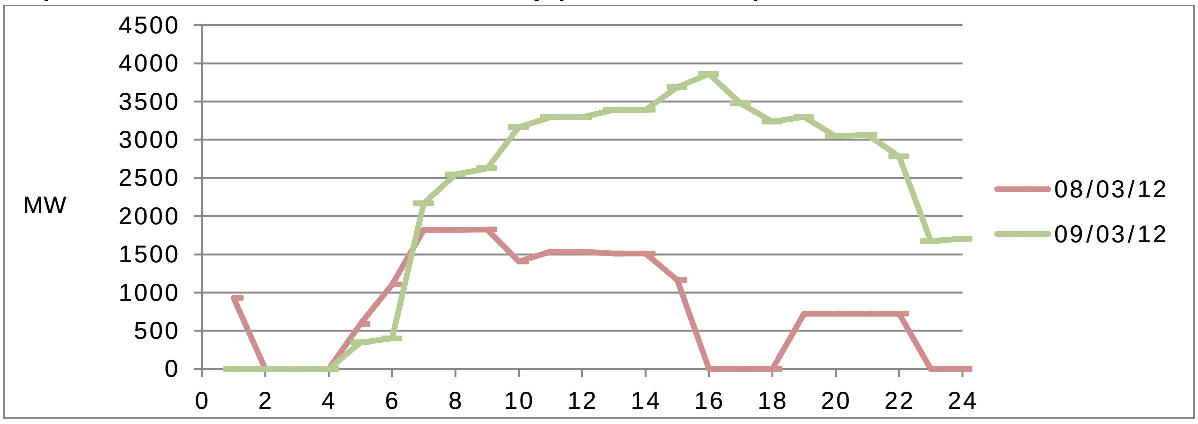
Graph 3.3: Wind Generation at TN SLDC Level on two consecutive days (08/03/2012, 09/03/2012)



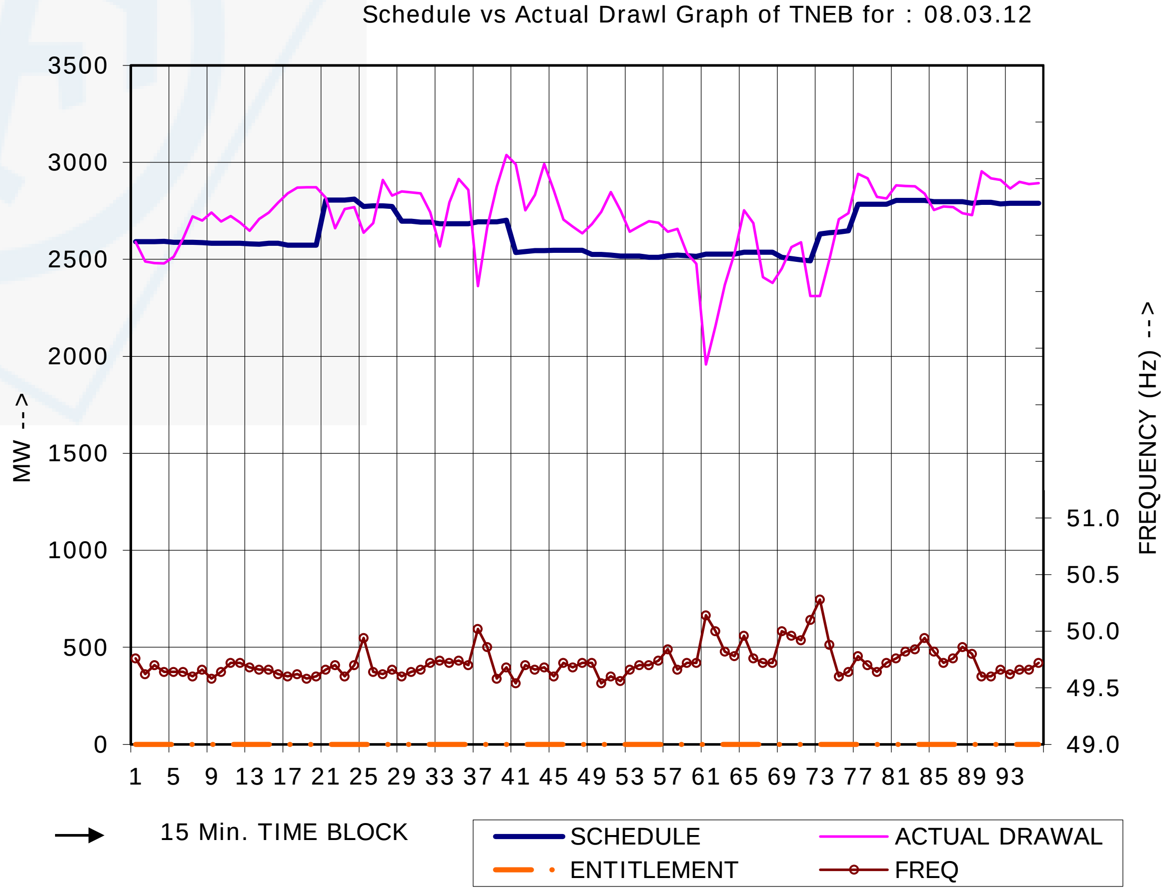
Graph 3.4: Kadamparai generates more on low wind day (09 March 2012)



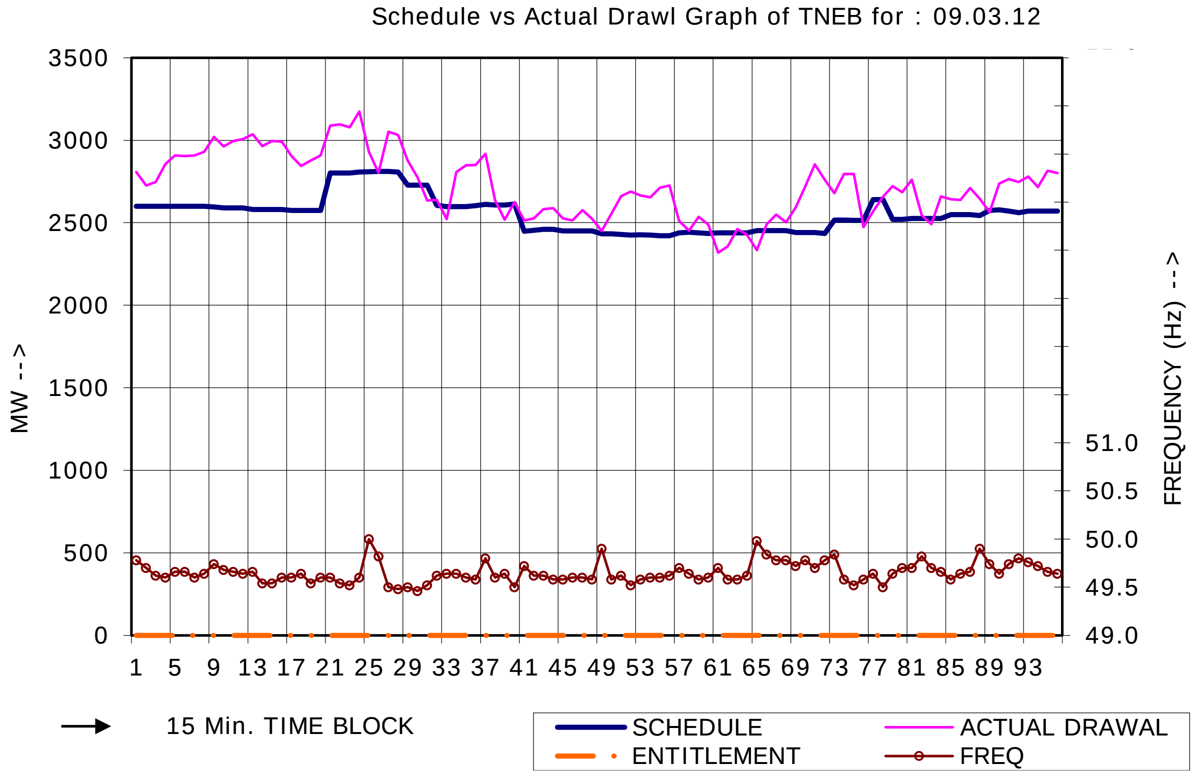
Graph 3.5: More load is shed on low wind day (09 March, 2012)



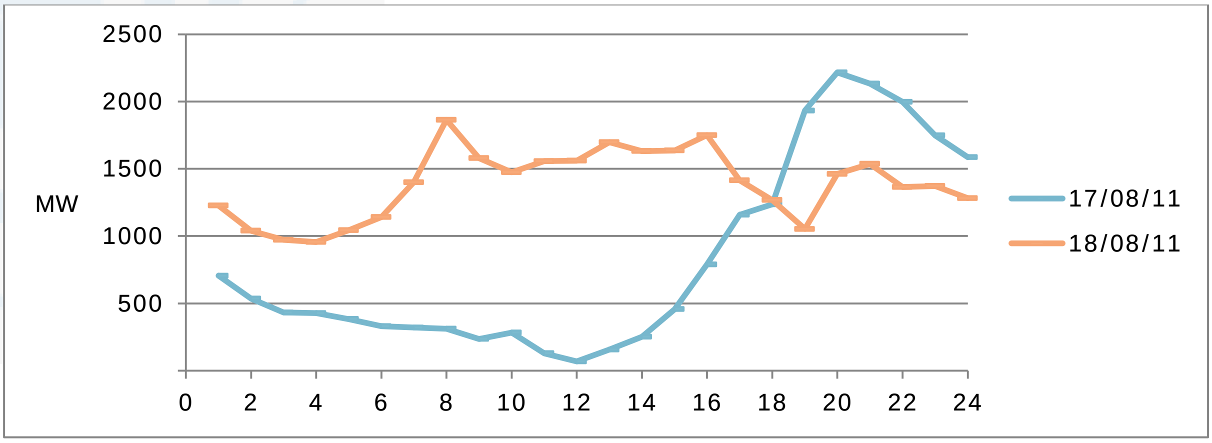
Graph 3.6: Difference between actual and schedule drawal is less on 08/03/2012



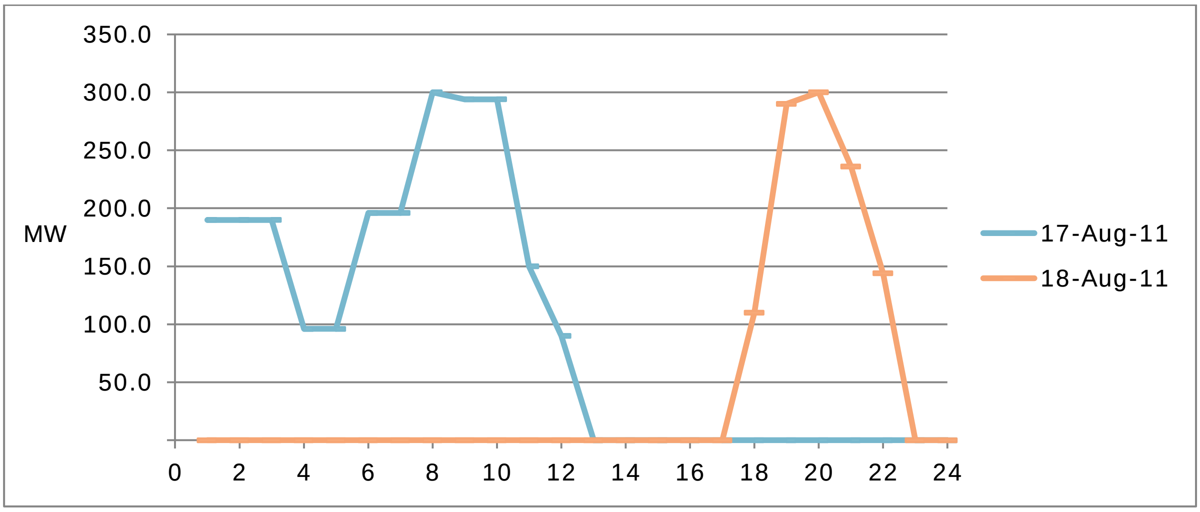
Graph 3.7: Difference between Actual and Schedule drawal is relatively greater on 09/03/2012



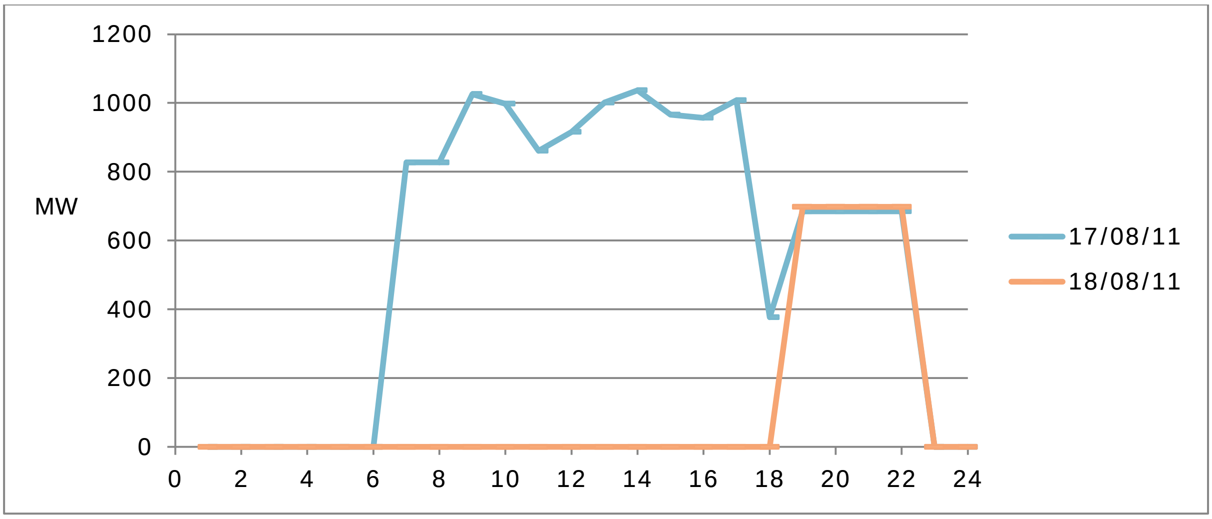
Graph 3.8: Wind Generation at TN SLDC Level on two consecutive days (17/08/2011, 18/08/2012)



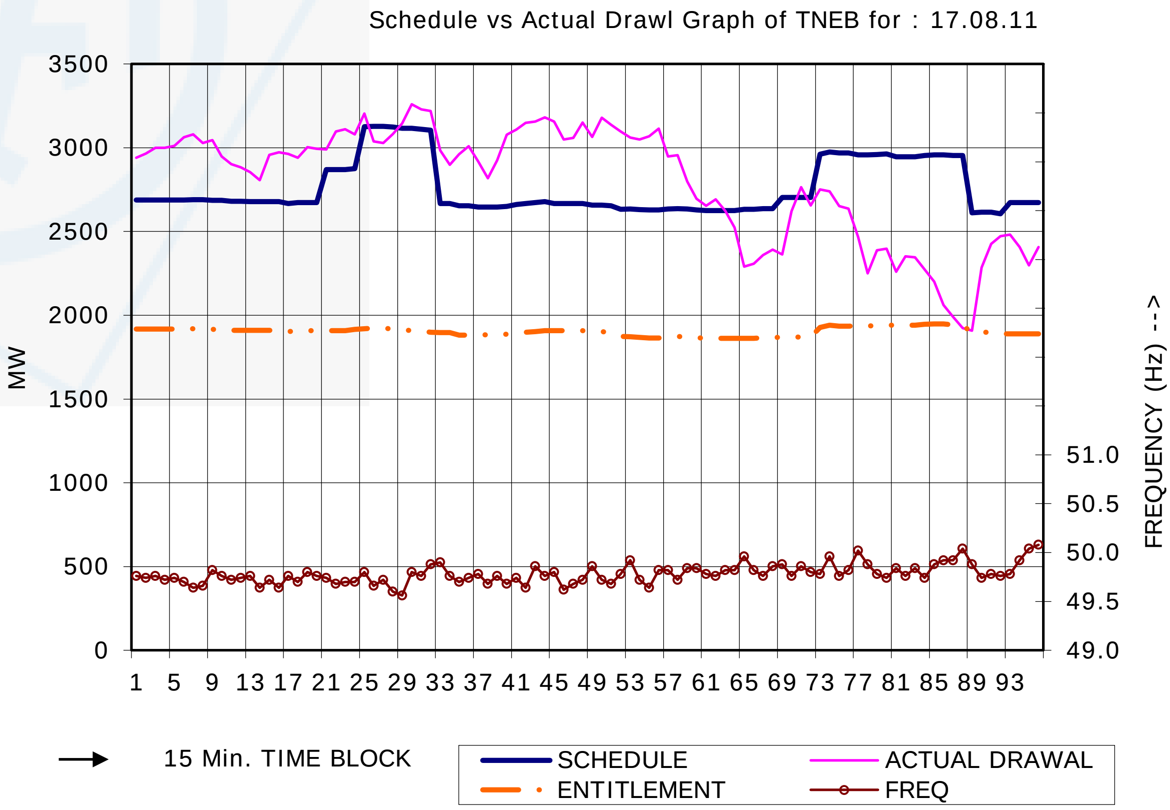
Graph 3.9: Kadamparai Generates more during 1-13 hours, reduces generation post 13 hrs. Generation picks up on 18/08/2011 when wind generation is lower than it was on 17/08/2012



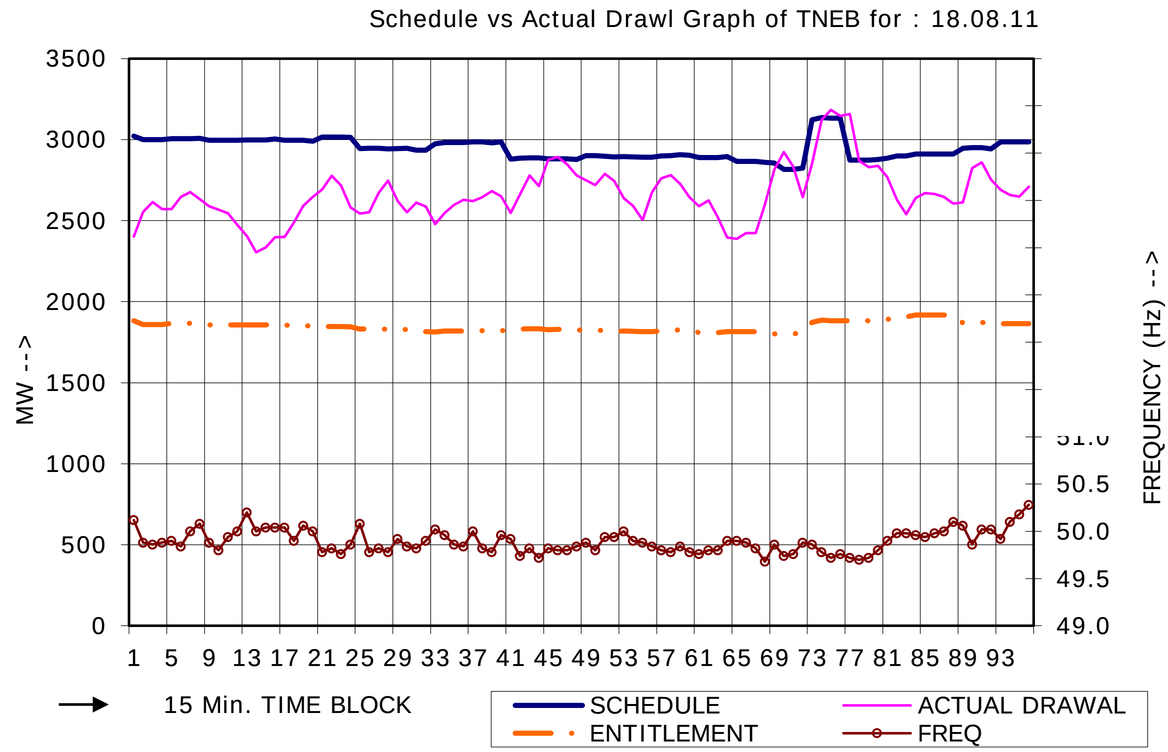
Graph 3.10: Lower wind generation on 17/08/2011 is made up through load shedding



Graph 3.11: Actual Drawal exceeded Scheduled Drawal considerably on 17/08/2011



Graph 3.12: Good Wind Generation on 18/08/2011 led to close to normative grid frequency and considerablylower actual drawal as compared to scheduled drawal



A comparison of actual v/s schedule drawal on 17 August and 18 August indicates that, probably, guided by the actual drawal on 17 August, TN SLDC scheduled a higher drawal on 18 August.

However, because of high wind generation on 18 August, TN ended up drawing much less than its schedule. This has a commercial implication – TN had to pay for the scheduled energy but for the under-drawal (under the current UI mechanism), got reimbursed at a much lower rate of the extent of under-drawal.

The above graphs indicate

- The nature of operational means – operation of tertiary reserves (such as Kadamparai Pumped Hydro Power Plant), load shedding and UI drawls - that are required to be used for integration of variable sources of generation – such as Wind / Solar. Cost of procurement of power from tertiary reserves / or from short term markets (as seen in the case of Rajasthan discussed above), loss of quality of supply due to load shedding or high costs of UI drawls which also compromise grid security has to be borne by the consumers in the host state. The brief description of similar problems has been discussed in the context of Rajasthan earlier in this section. The cost of balancing in all the cases above is clearly borne by the host state – Tamil Nadu – in the present example.
- That sudden ingress or withdrawal of wind based generation from the grid causes tertiary resources with quick ramp rates. In the above examples, it can be seen that generation from pumped hydro is one such source and the other important source is the UI mechanism – sudden loss of wind can be made up by increasing withdrawal from the grid. However, as discussed in this paper UI mechanism sometimes provides perverse incentives for grid integration of VRE based generation. This mechanism needs to be replaced by a more formal Ancillary Services Mechanism/Market.

Beyond the above costs, the cycling of thermal generators may also impose huge costs on the state generators, especially when VRE penetration increases– which ultimately is borne by the state consumers. Here, again, the costs are of two broad types – (1) the variable costs of cycling – where certain generators may require resorting to oil-firing if the generation is reduced below their minimum level to allow VRE, and (2) increase in life-cycle costs due to increased wear and tear[5]. While these costs may be low at low levels of wind penetration, this increases at higher levels of penetration. The costs of integration due to cycling of thermal generators have been analyzed very briefly for various levels of penetration below. When system operator plans unit commitment on a day-ahead basis– mismatch between load and generation cannot be allowed at this planning stage. Prediction errors in wind generation forecasts are to be expected and the system needs to be prepared for the worst. As seen in the Graph-1, the system operator will need to plan for the worst conditions – some of which may not have occurred but are expected. This is more so, when forecasting capabilities at the farm level and SLDC levels are not adequate. Therefore, in the analysis of the cycling requirements we have considered the worst case scenario of maximum volatility with respect to VRE generation.

Global experience has shown that larger control areas present better opportunities for balancing the loss / gain of generation due to wind. For example, while there may be a lack of flexible gas based / storage hydro generation in Tamil Nadu, the same may be spinning / available in Andhra Pradesh. However, with a limited view of their control area, TNSLDC may not be able to utilize that generation resource in a neighbouring state despite there being a robust transmission network. The costs of balancing can be considerably reduced when balancing is considered over entire SR grid than over Tamil Nadu network alone.

This is illustrated below for high wind month of June for the years 2012, 2014, 2016, and 2022 for Tamil Nadu and SR (including TN, Andhra Pradesh and Karnataka). Penetration level has been defined at the instant when maximum wind capacity is available as a percentage of demand (in MW) in the corresponding system.

[5] Refer to section on Forecasting and Planning, where sharing of such costs have been discussed. Annexure 2, Annexure 3 and Annexure 4 discuss the cycling costs in greater details.

The balancing costs have been computed by considering three distinct types of markets two of which are currently operational in India:

1) Day-ahead markets that clear the day before power is provided (currently operational);
2) Intraday markets that allow for adjustments after the closure of the day-ahead market until gate-closure (currently operational, but has very low volumes), typically about three hours before real time; and
3) Ancillary services markets that are used by the system operator to resolve remaining imbalances (currently not operational, and in proposal stage).

Procurement of balancing energy/capacity in each of the above markets presents three cases – each of which has different policy implications. Ramp rates of various balancing technologies are provided in Annexure 5.

Assumptions in Computation of Balancing Costs and their Rationale

Balancing services are currently not provided by system operator in India. The grid connected entities (State Distribution Utilities, Generators) are required to remain committed to their schedules or pay Unscheduled Interchange (UI) charges for deviation from their schedules. The UI mechanism is therefore a commercial mechanism for balancing.

Balancing, in more developed power systems with very low/zero wind/solar generators, is only necessary for events of small probabilities (power station failures) or for small volumes (as in the case of load prediction errors); the amount of reserve capacity contracted is thus large compared to the small share of actual electricity requested. Balancing services were provided nationally, or in the case of Germany, within the region of the Transmission System Operator. In recent years, globally, renewable energy and newly installed wind power have prompted additional demand for reserve and response operations. This demand arose predominantly due to the inadequate levels of accuracy in day-ahead forecasts for renewable feed-ins. These characteristics of balancing markets cause us to make the following assumption in our determination of balancing costs:

Assumption 1: Currently there is a considerable shortage both in Tamil Nadu and Southern Region Grid. Graph 3.5, above indicates load shedding between 3000-4000 MW in March. This entire shortfall cannot be considered as procured in “Balancing Market”. Therefore, we determine the capacity that Tamil Nadu and other states in SR need to procure through mechanisms other than “balancing mechanisms/markets”. **Therefore the “balancing capacity” and “balancing energy” requirements are computed with respect to Coal Based Capacity + CCGT Capacity + Nuclear Capacity + Hydro (Storage) Capacity + Capacity procured through mechanisms/markets other than balancing mechanisms/markets.**

Many generation assets can only adjust their output close to real-time, if they are already operating (nuclear, lignite, coal, and certain gas power plants). Only the plants that are operating can provide negative balancing reserve, while these plants have to operate in part-load to be able to provide positive balancing power. Moreover, a power plant is only willing to decrease its energy sales to provide reserve capacities for balancing markets if the expected price it gets for actually providing those reserves is able to compensate for the foregone margin (price minus marginal cost) in the energy market. Adjustable capacity is therefore highly dependent on the commitment of conventional generation units as part of energy sales in day-ahead and longer-term markets and the ability to adapt this day-ahead commitment to the changes in the market within the last 24h before physical dispatch.

Assumption 2: When Tamil Nadu SLDC is required to manage wind, with “visibility” only on generation resources within its control area, it can require such generators to provide negative balancing power or reduce level of generation when wind generation suddenly increases. Since such generators were initially designed to serve base load and have limited flexibility, low ramping down rates have been considered – as a conservative assumption. For Tamil Nadu, as a whole, it is assumed that no more than 20% of the maximum operating capacity can be reduced in an hour. Further, a thermal generator may operate below 60% of the maximum capacity, only if the system is left with no alternative. In such instances hydro generators reduce their generation first. Similar operational assumptions have been made when SR is considered as a whole.

Assumption 3: All thermal generators in Tamil Nadu which are owned by TANGEDCO are assumed to be not charging any amount for ramping down or ramping up – unless they are required to ramp below 60% of their maximum capacity. Actually the model allows the system operator to minimize costs of operation and select whether it is more economical for a generator to continue to generate and inject excess power into the grid or reduce its generation below 60% at a higher per unit cost. Further, as recognized in this document elsewhere that cycling of generators imposes costs on the generators – these have not been considered in this analysis.

Assumption 4: The Transmission Network has been considered as presenting no constraints. As discussed elsewhere in this document – transmission capacity addition and its costs are estimated in a study being conducted by Power Grid Corporation of India Limited.

The three cases considered are:

Case 1: 100% of the capacity, required to provide positive balancing energy, is procured through capacities committed to provide balancing energy. These capacities remain available for a "call" for generation from the system operator. Such capacities are normally procured through the Ancillary Services Markets;

Case 2: 50% of the capacity required to provide positive balancing energy is procured through Ancillary Services Market and 50% from the intra-day / day ahead energy market;

Case 3: 100% of the positive balancing energy is procured through the energy market – intraday and day ahead.

The following table provides the balancing costs in the three cases:

Table 3.3: Penetration levels, Balancing Capacity and associated costs

	Maximum Volatility of VRE generation (High wind season)									
	Tamil Nadu					Southern Region				
	% Penetration	Balancing Capacity (MW)	Balancing cost (Rs/Kwh)			% Penetration	Balancing Capacity (MW)	Balancing cost (Rs/Kwh)		
			Case 1	Case 2	Case 3			Case 1	Case 2	Case 3
2012	34%	624	0.68	0.44	0.21	18%	334	0.30	0.20	0.11
2014	39%	835	0.72	0.48	0.23	22%	798	0.43	0.27	0.12
2016	45%	1,126	0.78	0.53	0.28	27%	1,112	0.44	0.28	0.13
2022	55%	2,533	1.20	0.89	0.58	35%	2,465	0.51	0.32	0.14

Following inferences can be drawn from the above table:

1. With increase in penetration
    - The balancing costs increase
    - The balancing Capacity Requirement increases
2. With larger control area (when SR is considered as a single area within which balancing resources are available)
    - The balancing costs decline
    - The balancing capacities also decrease

The above analysis though indicative, is instructive for policy purposes. Detailed analysis – using unit commitment models with transmission network need to be developed to more accurately determine balancing costs.

Policy implications of the above analysis are:

(a) Case 1 is the costliest option. Case 3 requires the ability of the generator and system operator to forecast wind generation with reasonable accuracy. Further, it has been observed that accuracy of wind generation forecast improves closer to real time. Therefore, if the generators / system operators are able to provide better wind generation forecasts close to real time – balancing energy could be procured in the intra-day market. **Faster electricity markets are therefore important for lowering costs of wind integration as much as the ability to better forecast.** The technology and costs of better forecast are discussed in chapter V of this document.

(b) Case 3 assumes 100% accuracy of wind forecasts and the ability of the utility to procure power in electricity markets. This is not practical. However, case 2 assumes procurement of 50% of electricity through balancing capacity which is "available" at "call" for the system operator / utility and balance from electricity day ahead or intraday markets. Such balancing capacities will have to be paid fixed charges for making themselves available throughout the year. Need for such capacities in case 2 would depend on forecast accuracy. **Clearly, an ideal market design would be one that allows joint operation of such energy and capacity markets.** Therefore, when information on the wind-output improves during the day, reserve capacity no longer required in the balancing market could be sold in the intraday electricity market. **Market design needs to allow generators to supply their energy committed in long/medium/short term contracts and provision of balancing services in a joint bid, so that they can contribute to an efficient system operation.**

Balancing of real power while technically feasible – has commercial and institutional connotations. More than the technical feasibility – the main impediments in wind integration are the problems with commercial mechanisms. We will discuss the institutional mechanism in this context subsequently as a solution to the problems posed by the commercial mechanisms.

3.3 COMMERCIAL IMPEDIMENTS TO REAL POWER BALANCING

Real power balancing is a problem for the system operator under two conditions – (a) when there is an excess wind generation; (b) when the wind generation reduces.

Wind power is generally procured in India through one of the three mechanisms:

(a) Feed in Tariff Route – where the procurer of power satisfies its Renewable Portfolio Obligation;

(b) At Average Power Purchase Price (APPC) – where the procurer receives the power, the generator gets Renewable Energy Certificates (RECs) which it is free to trade in the national market and thereby help other obligated entities to service their RPO; or

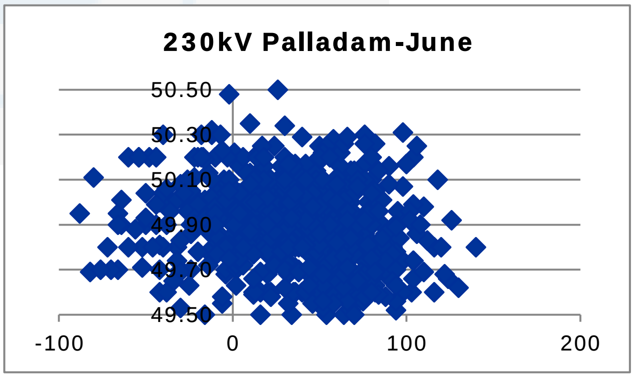
(c) Banking – Certain wind generators inject power into the state grid when wind blows, draw the same back over a year, and imbalances at the end of the year are commercially settled at regulated prices or at prices indexed to short term market prices.

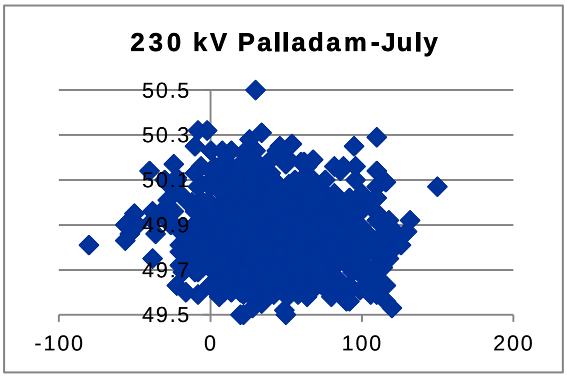
3.3.1 When Wind Generation Increases: Problem of "Discarded Wind"

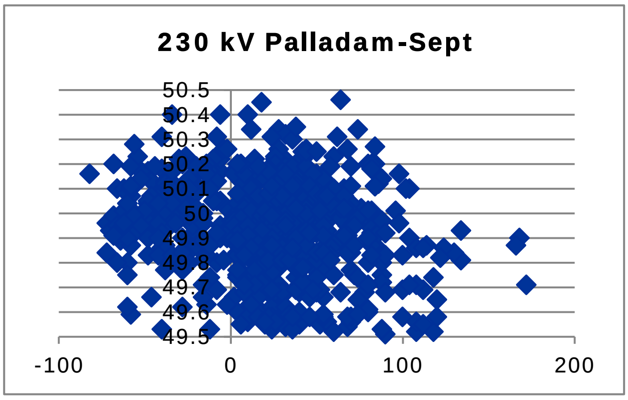
The "real time" energy prices in the ISTS network are determined through an imbalance mechanism where the energy prices are regulated and are linked to grid frequency. These are referred to as the Unscheduled Interchange (UI) prices. The host utility in which the wind generator is located has no incentive to continue to allow the wind generator to generate if the UI prices are below either the FiT rates or the regulated prices in case of the other two commercial mechanisms. Thus, there could be instances where the wind generator could be instructed to reduce generation even when the frequency is below 50 Hz., let alone instances when the frequency exceeds 50 Hz. Instances of such behaviour were captured through the analysis of the Palladam S/S data for high wind months.

As frequency increases and if at the same time wind generation also increases, the utility is faced with an operational decision which is modulated by financial considerations. When the frequency starts increasing but is still below 50.2 Hz and the UI rates are lower than FiT rates / contract rates, then SLDCs may be inclined to back down wind generators, since unscheduled drawal from the grid is commercially more advantageous. The feeders for which the following graphs are presented also have significant load. The negative values indicate that the wind generation was curtailed and there was a net load on the feeder. This is seen to be happening in most cases when frequency was greater than 49.5 Hz. – where the corresponding UI rate starts approaching the FiT rate.

Graph 3.13: Generation/Load vs Frequency at 230kV Palladam S/s







Legend:

- "+" X-axis: Generation exceeds load on the feeder
- "-" X-axis: Load Exceeds Generation
- Y-axis: Grid Frequency

Such behaviour could have been avoided through alteration in the UI mechanism or adopting an alternative institutional mechanism as proposed subsequently.

3.3.2 When Wind Generation Declines

When the wind generation declines and there is fall is grid frequency also, the system operator can, in the absence of balancing reserves in its control area, either continue to allow grid indiscipline and overdrawal at high UI rates or shed load – both costs to the consumers in the state.

The UI mechanism, with all its advantages, is also proving to be detrimental to co-operation between state utilities for balancing energy. During high frequency periods, the home state pays FiT for wind power, but states who overdraw pay very little UI charge. During low frequency periods, if wind power suddenly reduces, the burden of UI falls on the home state where wind is integrated – other states who may have balancing resources will not help since they are negatively impacted by under-drawal (which will happen under the UI framework if the other state with balancing resources generates more from its own sources and hence draws less from the ISTS grid). For example, when wind declines in Tamil Nadu and frequency is low and Andhra Pradesh is drawing as per schedule, it needs to be incentivized to ramp up its hydro / gas based power plants. Under the current UI mechanism, Andhra Pradesh may not be inclined to do so if increase of such in-state generation results in under drawal from the grid by more than 10% or 250 MW (whichever is less).

To overcome this Andhra Pradesh has to be incentivized to providing balancing reserves. Unless this is done if the home state has met its RPO, to integrate more wind, requires more balancing capacities – either fast ramping generation capacities or transmission. The home state has no incentive to create such capacities in the present set-up. This is perhaps best done by creating a proper ancillary services framework/market that incentivises the suppliers of such balancing energy instead of making it inherent in the system in a manner that creates such negative incentives.

3.4 INSTITUTIONAL SOLUTIONS

Ancillary Services (AS) Mechanism needs to be instituted now. This is an imperative for procurement of reactive power and for balancing real power in real time too. The Power System Operation Company (POSOCO) has submitted a paper on the issue which is under discussion at CERC. Further, while it is observed through the analysis in the above sections that balancing costs over larger control areas is less – it is important to deliberate if the current institutional mechanisms allow for the same. SLDCs, as discussed above, have the state as their control area and hence have a limited “visibility” of the system – so far as real power balancing is concerned. It is suggested that “system operation” of renewable based generators be taken up under the aegis of NLDC/RLDC – who have a larger “view” of the system and hence are better capable for providing balancing reserves.

Moreover, development of ancillary services market / mechanism is expected to be instituted under POSOCO. The AS markets/mechanisms could have the following features:

- The AS market/mechanism would provide the quick ramp-up / down reserves
- Such tertiary Generation Reserves could be procured either in advance or in an intra-day market (Hour Ahead markets, as in various US Markets),
- These reserves could be characterized as – 60 second reserves, 10 minute reserves etc depending on system requirements.
- Similarly, the system operator will need to make reactive sources of generation available.

The detailed market design and commercial mechanisms governing the operation of AS markets could be the subject of a consequent detailed study in the Indian context. This assumes importance because, unlike in the most US / Great Britain / Australian markets, Indian system operator cannot take title to power for resale as per the provisions of the Electricity Act 2003.

IV ADDRESSING UNPREDICTABILITY OF VRE: DIFFERING PERSPECTIVES

Issues pertaining to grid integration of VRE can be addressed by understanding, as discussed above, the issues that are faced by the system operator and the transmission network. In the present work, we have focussed on the issues pertaining to system operation. The above analysis highlights the importance of the need:

(a) To improve Predictability – Need for Forecasting
(b) For planning based on above
(c) For scheduling and dispatch based on forecasts
(d) for a proper balancing and settlement mechanism – which does not produce any incentives for any stakeholder to hinder development or integration of VRE

To validate the findings of the analysis above, the study team interacted extensively with the system operators in Tamil Nadu and Gujarat. The team also consulted NLDC on the issues related to large scale wind integration. The LDCs were requested to indicate their highest priority (1), second highest priority (2) and third highest priority (3) among the issues related to large scale VRE integration. The following table summarises some of the outcomes of the consultations.

Table 4.1: Summary of Stakeholder consultation

	NLDC	Tamil Nadu	Gujarat
Factor	Rank	Rank	Rank
Transmission Augmentation	3	3	3
Transmission standards of performance (particularly at STU level)	-	-	-
Designated Balancing Power	2	2	-
Larger balancing areas	?	2	3
Centralised forecasting	2	1	2
Project level forecasting and scheduling of VRE	2	1	1
Demand Response	3	-	-
Operator awareness of situation (rapid updates)	1	1	1
AS Markets	1	-	-
Standard and uniform Grid Codes/Connectivity Definition	-	-	-
Integration in operator decisions	?	-	3
More flexible power markets	2	-	-

As is apparent from the tabulation above, there is divergence of priorities between NLDC and the SLDCs. While NLDC's focus combines market design and operations aspects, the SLDC focus is more on the operations aspects. However, operator awareness was given the highest priority and transmission augmentation is given the least priority amongst all the three categories.

There are also significant differences between responses in Gujarat and Tamil Nadu respondents. The two states currently feature very different operating conditions as is summarised in the table below.

Table 4.2: Operating conditions in TN Vs Gujarat

Aspect	TN	Gujarat
Demand and Supply Balance(Peak, FY2012)	-14.9%	-1.75%
Demand and Supply Balance(Energy, FY2012)	-10.5%	-0.4%
Peak demand as % of system installed capacity	70%	50%
Renewables as % of total capacity	41.5%	16%
Hydro/Gas as % of total capacity	19%	23%
System Operator Visibility of Wind Generation Through SCADA	Very Low	Limited
System Operator Forecasting of Wind Generation	No forecasts	Use of General Weather Forecasts (BBC)
Primary Transmission Network level for wind integration	110 KV	220 KV
Degree of penetration in high wind periods	>40%	<20%

Gujarat has a power system with adequate system reserves as is shown in the table below.

Table 4.3: Installed capacity projection in Gujarat

	2012-13	2013-14	2014-15	2015-16	2016-17
Thermal	14,002	15,035	15,417	15,734	15,905
Gas	4,403	4,529	4,716	5,313	5,736
Diesel	17	17	17	17	17
Hydro	772	772	772	772	772
Renewable	5,999	8,499	10,999	13,499	15,999
Nuclear	559	559	559	559	559
Total	**25,752**	**29,412**	**32,479**	**35,894**	**38,987**

On account of sustained capacity addition, Gujarat is likely to have a reasonable surplus over the coming years.

Table 4.4: Future Power Scenario in Gujarat

	Peak Demand (MW)	Peak Met (MW)	Peak Def./ Surplus (MW)
2012-13	12930	13539	609
2013-14	14092	16608	2516
2014-15	15369	17561	2192

	Peak Demand (MW)	Peak Met (MW)	Peak Def./ Surplus (MW)
2015-16	16767	18733	1966
2016-17	18305	20057	1752

At the current levels of penetration (and with major system reserves) Gujarat does not have major technical concerns, but has some commercial concerns relating to:

- Cost of balancing power
- Transmission cost compensation

In contrast, at current levels of penetration Tamil Nadu has serious technical and commercial concerns. The large deficit in supply in Tamil Nadu results in wind contributing significantly in both peak demand and energy terms. In Gujarat in contrast, with the current levels of penetration, the contribution of wind is mostly in the form of energy. Gujarat also has substantial system reserves, which Tamil Nadu currently does not enjoy. The combination of high penetration and low reserves make wind a “necessary evil” from the perspective of Tamil Nadu – “necessary” because it helps Tamil Nadu considerably in times when hydro reservoirs are not full but wind is high, “evil” because of grid management issues pertaining to scheduling, dispatch and balancing of the power system.

Based on the above analysis – the way forward is therefore to develop clear principles for:

(a) Forecasting and Planning;

(b) Scheduling and Dispatch; and

(c) Balancing and Settlement

In the next sections, we, therefore develop the guiding principles for the above in the context of VRE generators.

V FORECASTING AND PLANNING

The variable nature of renewable energy resources, such as wind and solar power, poses challenges for an electric grid that has traditionally been powered by generating resources that are relatively stable and controllable. In contrast, the output of VRE projects is intermittent and dependent on uncertain factors such as weather.

The renewable challenge can be met with enhanced forecasting through improved visibility of output and changes in market design that recognize the unique attributes of wind, solar and other variable energy resources. To this end, following framework of regulatory and technical guidelines that are expected to facilitate the growth and integration of renewable energy while also protecting grid reliability is proposed.

It is a foregone conclusion through many studies and experience gained elsewhere that forecasting of the output of wind generation is important. Although already in use by some system operators, it can still be considered a research area – because the models have to be adapted to local conditions. Accurate forecasting will allow less conservative operating strategies to be adopted. It seems clear that the economic benefits of better forecasting will easily outweigh its cost.

A framework for forecasting and planning, proposed for implementation in India is based on the following principles:

1. The ability to develop an accurate real time production forecast for any particular generator strongly correlates to the availability of site specific and precise real time data.
2. The RLDC/SLDC must obtain accurate forecasts of Renewable Energy production to maintain reliable and efficient system operation.
3. Commercially responsive forecasting must be done at the level of sub-stations by Scheduling Coordinators or aggregators of renewable energy.
4. Centralized forecasting must be done by the system operator also.
5. For the forecasting services availed by the RLDC/SLDC, the charges would be payable by all the VRE generators.

Forecasts can never be precise – however this does not undermine the need for a robust forecasting methodology. From the perspective of the generator / trader, Forecasts – within a manageable range of accuracy – allows the players to optimize sales between various options – Week Ahead, Day Ahead or Spot sale and get the best value for the energy generated. From the perspective of the system operator, such forecasts allow planning and procurement of power from conventional sources to manage variability in generation from VRE sources. The critical difference between the two forecasts, however is that while the former is at the farm level (decentralized forecast), the latter is at the aggregate state level (centralized forecast). To summarize, therefore, the forecasts are made for two main reasons: (1) market scheduling, to encourage efficient competition in the wholesale market (key reason for the need for decentralized forecasting); and, (2) security scheduling, including to ensure that sufficient generation capacity will be available in real time to meet demand (key reason for the need for centralized forecasting).

As mentioned earlier, enhanced forecasting can be achieved only through better visibility. Therefore, first section below deals with the recommended process of data collection – accuracy of which is very critical to good forecasts.

5.1 IMPROVING VISIBILITY OF RESOURCE DATA AND OUTPUT: DATA COLLECTION AND PROCUREMENT

The need for centralized procurement of ancillary services for supporting VRE generation has been illustrated and emphasized in this report. RLDCs are best placed to coordinate such ancillary services in coordination with the SLDCs. Therefore, under the regulations in this regard from CERC, NLDC (and RLDCs), in consultation with SLDCs may formulate guidelines for improving visibility, data collection and procurement. These guidelines could then be notified by CERC/SERCs. The key characteristics of such guidelines (which are elaborated in the box below) could be:

- Physical Site Data
- Meteorological and Production Data
- Communication, Metering and IT infrastructure – with interoperability standards
- Frequency of transmission of data
- Data Security

These guidelines will facilitate collection and transmission of data which would permit both decentralized and centralized forecasting and ensure consistency between the two forecasts.

Along with the data to be procured from the farms, the generators also need to be able to view the system condition. The Regulators, through other support regulations, need to provide real time and time-synchronized information on various state estimators. The line loading on various lines must be able online to the generators to enable them to view the grid condition on a real time basis. This will help the generators better appreciate the back down instructions they receive from the system operators.

IMPROVING VISIBILITY OF WIND DATA AND OUTPUT

1. PHYSICAL SITE DATA

As part of Wind Generator's obligation to provide data relevant to forecasting Energy from the Wind Generator, each applicable wind generator or its Scheduling Coordinator / Aggregator must provide the RLDC/SLDC with accurate information regarding the physical site location of the Generator. The information must include

a. the location (latitude and longitude coordinates), and elevation of each wind turbine hub height and

b. the location (latitude and longitude coordinates), and elevation of meteorological collection devices.

2. METEOROLOGICAL AND PRODUCTION DATA

1. Each Wind Generator must install and maintain equipment required by the RLDC/SLDC to support accurate power generation forecasting and the communication of such forecasts, meteorological and other needed data to the RLDC/SLDC. Communication of such data to the RLDC/SLDC will remain via the Data Processing Gateway (DPG).
2. In accordance with this requirement, the Wind Generator would install
   a. a minimum of one (1) meteorological station measuring barometric pressure, temperature, wind speed and direction that is representative of the microclimate and winds at hub height on the prevailing upstream side of the wind farm.
   b. A second meteorological station is required to measure barometric pressure, temperature, wind speed and direction. The second meteorological station may be co-located on the primary meteorological station tower. The height of the second station should be approximately 30 meters below the average hub height. This requirement will not require any Wind Generator with an existing meteorological station tower(s) or final regulatory approvals to construct a meteorological station tower(s), to modify the location or configuration of such meteorological station(s).
   c. Further, in instances where placement of the meteorological Station tower(s) in

accordance with this requirement would cause a reduction in production or violation of a local, state, or central statute, regulation or ordinance, the RLDC/SLDC, in coordination with any applicable forecast service provider, will cooperate with the Wind Generator to identify an acceptable placement of the meteorological station tower.

3. RLDC/SLDC should issue directives as conditions for grid connectivity, such guidelines - which have as their objective - to ensure a dataset that adequately represents the variability in wind within the farm. It is recognized that individual Wind Generators may have circumstances that prohibit them from reasonably satisfying these requirement. In these cases, a cost-effective distribution of DTs that approximates this guideline and adequately measures the variability of the wind within the Wind Farm will be formulated by mutual agreement among the park owner, the RLDC/SLDC forecast service provider and the RLDC/SLDC. Wind Generators seeking a variance from this requirement should do so as part of development of their Interconnection Agreement and for those Wind Generators with an Interconnection Agreement, as part of entering into any further power sales / OA agreement.
4. It is understood that wind data collected at the nacelle will not represent the true wind value at a park, but instead will represent the apparent wind, which can be correlated to the co-located turbines. The need for this requirement is to
   a. ensure multiple data streams for anemometer information and
   b. ensure a more accurate representation of the data points to calculate wind energy production at the park.
5. Each meteorological station must have a backup power source that is independent of the primary power source for the station.
6. Production and meteorological data will be collected for a minimum of sixty (60) days before the Wind Generator can be certified to be scheduled for new Wind Generators. For the existing Wind Farms, production and meteorological data will be collected regularly and submitted to the SLDC/RLDC after the enforcement of these guidelines. This data must be collected in advance in order to train the forecast models responsible for producing the power production (MW) forecast for each site.
7. A centralised forecast by the SLDC/RLDC would need information about the power curve for each wind farm. This could take the form of historical meteorological information from an on-site mast, which can then be compared with historical output (and historical turbine availability) to form a power curve. The power curve is likely to be different for different wind directions, and may also require an adjustment for barometric pressure.
8. The SLDC/RLDC shall receive real time information about wind turbine availability. Intermittent generators must provide to the SLDC/RLDC, at least once every [X] seconds, the maximum output capacity of the wind farm (the number of connected generating units multiplied by the MW capability of each turbine).However, a high quality centralised forecast would need to obtain additional information about future intentions with respect to turbine availability. It would also require information about any intentions to spill wind (other than in response to a dispatch instruction).
9. At an appropriate time, as penetration increases, such principles can be suitably adopted for solar as well.

5.2 DECENTRALIZED AND CENTRALIZED FORECASTS

The system operator’s focus is on the need for a security forecast. In our view, adequate security forecasts with associated error and correlation estimates will not be able to be produced with sufficient certainty simply by aggregating every wind or solar farm’s market forecast. Consequently, the system operator will need to provide a separate, centralised security forecast. In practice, this centralised forecast is likely to be based on an ensemble forecasting approach that uses and adds value to the information in the decentralised market forecasts. The intent of considering both the centralised and the decentralised approach is to best combine the two to achieve the objectives of both market and security forecasting.

Broad principles governing decentralized and centralized forecasts are enumerated below:

1. Decentralised generation forecasting means that each farm is responsible for forecasting its own generation over the schedule period as an input into schedules submitted to the system operator.
2. Under a centralised regime, system operator (SLDC/RLC) is responsible for forecasting generation from each farm for market schedules.
3. RLDC/SLDC shall be appointed to govern the central forecast. An alternative would be for the Commission (or the Central Electricity Authority) to establish a separate service provider role.
    a. It is proposed that NLDC takes up the job because
        i. the system operator has important internal uses for a centralised forecast. The learning process, and the process of developing the centralised forecast would be enhanced by the close involvement of the system operator; and
        ii. the system operator is the organisation that has the most detailed knowledge of the needs of the industry as a whole in terms of scheduling information, and is the party responsible for preparing schedules.
4. Wind/solar farm generation forecasts, individually or collectively, are not available to other participants. Instead these forecasts will feed into "schedules". Rules may be required to set limits on the ownership rights of the central body; for example it might not be appropriate for the central body to sell the data to an entrepreneur who is considering the construction of a farm next door to the other farm. Requiring farms to provide meteorological data might also give rise to a question of whether a farm should be required to build a meteorological tower on site, where exactly on the site the met tower should be located, and whether small farms should be exempt from these requirements. This might give rise to some regulatory complexity, although the complexity would appear to be manageable.
5. Schedules provide information to participants about scheduled (projected) quantities, and about the scheduled price at each point on the grid.
6. Day ahead and intra-day forecasts will be submitted by either the scheduling coordinator(s)/aggregators responsible for delivering power at 33 kV and above sub-stations or by the generator itself. Further, any 10 MW of above generator may also submit its forecast to SLDC/RLDC directly[6].
7. Centralized forecasting allows for consistent and accurate forecasts. Standardized data would be submitted to a centralized forecaster for each renewable generator. The central forecaster can then compile this data and use it to create a forecast.
8. This will also be accomplished through decentralized forecasting and very specific market rules that would specify form, format and accuracy requirements for each individual forecast. This would require forecasts to be submitted for each generator (embedded and non-embedded).
9. There can be a number of stages in the forecasting process. Stages might include the running of one or more Numerical Wind Prediction (NWP) models, the post-processing of the results of the NWP model output to get meteorological forecasts at the relevant farm site, and the conversion of the meteorological forecasts into MW forecasts using information about turbine availability, intended wind spill and electrical losses etc. Forecasting regime shall use a centralised approach for some of these stages while other stages remain decentralised. For example, it would be possible for a central body to contract with a service provider for site specific meteorological forecasts, but for generators to be responsible for creating their own offers (in MWs) based on the information from the central meteorological forecast.
10. Instead of doing their own forecasts, in certain cases farms may submit decentralised forecasts that are informed by the centralised forecast. A centralised forecast is including a forecast for each farm, and each farm receives its own forecast. The farm can simply submit

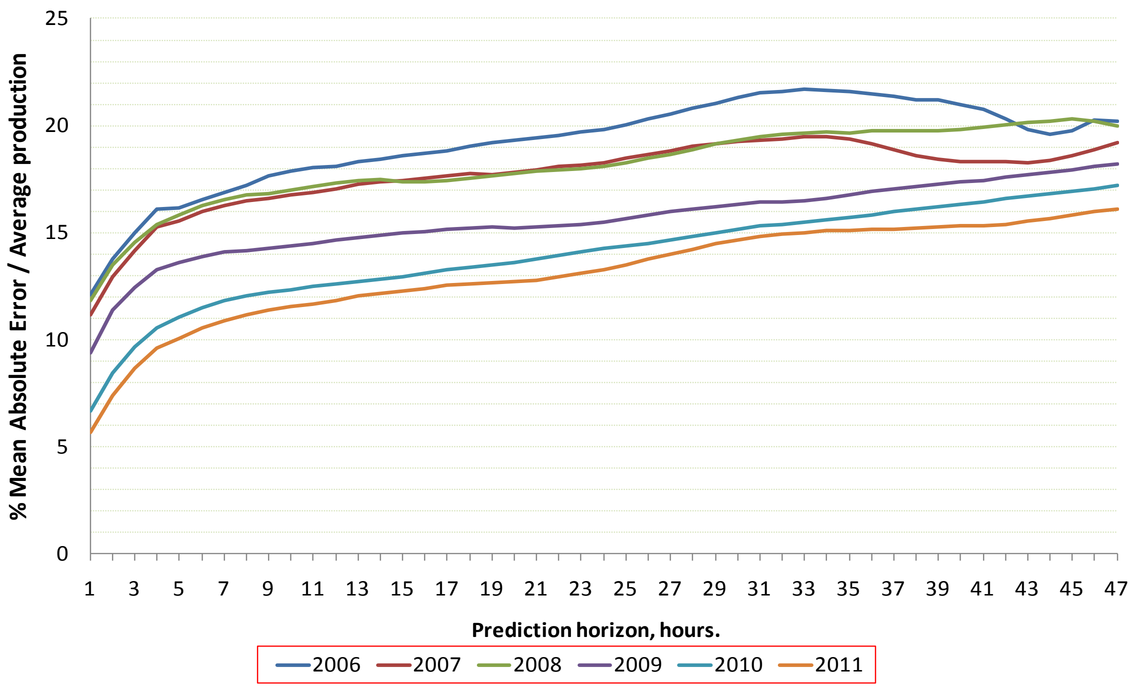
[6] The idea is that each generator should also take a direct commercial responsibility of its own forecasts. If owners of wind farms realize that individually they cannot get reasonably accurate forecasts, it may make sense to for them to take combine with other generators and approach forecast.

the centralised forecast number as its own forecast, or it can submit a revised forecast. There are usually direct monetary implications associated with the forecast, providing an incentive to the farm to improve the forecast if it can. The incentive arises from the lower UI burden (or a lower allocation of Frequency Support Ancillary Services Costs, when Ancillary Services Mechanisms are developed) (better forecasting would reduce the farm's share of those costs).

5.3 CHARGES FOR FORECASTING SERVICES

The decentralized forecasts are paid for individually by the generators and recovered from the beneficiaries of the "green power". For the centralized forecasts money is recovered through the RLDC/SLDC charge but levied only on the VRE generators. These charges need to be kept reasonable so as not to deter investments. Further, services of third parties can be utilised with suitable Service Level Agreements being put in place over time to ensure that the services are paid for adequately. This kind of an arrangement has emerged in the Spanish market where specialised forecasting and aggregating services have evolved to bring about better predictability. Over time this has brought down the forecasting errors as shown below, allowing the Spanish market to integrate very high levels of VRE.

Figure 5.1: Improvement in wing forecasting in the Spanish electricity markets



Alternatively, since decentralized and centralized forecasts play a pivotal role in grid integration of intermittent generation, mechanisms for centrally procuring both decentralized and centralized forecasts could be obtained. The charges for the same could be charged from all the users as SLDC/RLDC charges.

5.4 PLANNING FOR INVESTMENTS IN INTEGRATION OF VRE GENERATORS

Integration of VRE generation in the grid requires balancing reserves which:

- Should be able to replace wind generation when the latter reduces and
- Should have the ability to reduce generation at a rate which matches ingress of wind based generation.

This requires investment in transmission capacity, reactive power resources to support the flow of power over long lines and reactive power resources to support inductive power requirements of wind generators.

While transmission capacity is required to balance the variations in active power output of wind turbines, reactive power resources are required more “locally” to prevent excessive losses in the grid.

The primary question that governs planning for grid integration of VRE generators in the Indian context is: ***Why should states who have met their RPO, invest in balancing resources, transmission and reactive power support equipment for the wind generators whose primary objective is to help other states meet their RPO?***

The high costs of VRE integration have dissuaded states from encouraging investment in VRE generation despite these states having high potential. In order for the REC market to be a success it is pertinent that a comprehensive framework for planning of capacities required for grid integration of wind based generators be developed. Clearly, since the REC mechanism operates in a national market, planning for grid integration of VRE generators which serves such a national market needs to be also done at a national level.

Transmission planning in India is done through coordination between CEA, CTU, STUs, RPCs. Planning for systems required for integration of wind based generation or other intermittent sources could also be done centrally in a similar manner. All such investments – since these are primarily being done to allow all the states in India to meet their RPO could be approved by the Central Electricity Regulatory Commission.

5.4.1 How would the costs of integration be shared?

There are two types of costs that would need to be shared:

- The fixed costs – against capital expenditure identified above
- Variable costs – which would again be of two types
    - o Costs of balancing - cycling of coal / gas or operation of pumped hydro plants / OCGT / Diesel based power plants
    - o The cost of losses – wind generators draw inductive power from the grid – which results not only in lower voltages but also higher system losses in the state networks

5.4.2 Sharing of fixed charges and losses

The capital costs are proposed to be approved by the Central Electricity Regulatory Commission (CERC) and since most of these are transmission related costs – the same could be made a part of the Point of Connection (PoC) mechanism.

Similarly, sharing of transmission losses could be as per the PoC mechanism.

5.4.3 Sharing the costs of cycling

The development of Ancillary Services mechanism – which is proposed to be implemented by POSOCO will serve to estimate the costs of cycling of coal/gas/pumped hydro plants. Ancillary services markets usually take the price offers from various generation resources and demand response resources and these offers set the spot prices in electricity markets. The following mechanism is proposed for charging of cycling costs:

(a) In case of generators selling power under FiT to any purchaser (whether home state or other state) – the costs of cycling would be borne by the purchaser.

(b) In the case of generators selling power under APPC to the home state, the cost of cycling will be borne by the home state and the wind generator is the ratio of APPC and the average REC price realized during the month. For example if the cost of cycling due to a wind generator is Rs 100 during a month. The APPC of the state is Rs 2.75 / kWh and the average REC price during the month is Rs 2.00 / kWh. Then Rs 100*2.75/(2.75+2.00) would be borne by the state and Rs 100*2.00/(2.75+2.00) would be borne by the wind generator.

(c) In the case of generators selling electricity on the power exchange, the costs of cycling shall be borne by such generators.

Till such time as, ancillary services market mechanisms are implemented, CERC may determine the cycling costs in Rs / kWh for various types of generation resources. As a policy, while coal / gas based power plants can have retrofits which allow economic cyclical operations, renovation and modernization, or repowering of older power plants can mandatorily require such flexibilities in power plants. Methodologies to compute cycling costs[7] and international examples[8] where retrofits have been used to make base load power plants more flexible, in line with the requirements of the changing electricity markets are summarized in the annexure.

[7] Annexure 4

[8] Annexure 5

VI SCHEDULING, DISPATCH, BALANCING AND SETTLEMENT

6.1 REGISTRATION AND CLASSIFICATION OF INTERMITTENT GENERATORS FOR SCHEDULING

VRE generators in India are connected with the grid through one of the following modes:

- An individual feeder,
- Individual generator,
- Group of generators owned by a particular owner or
- Pooling station interface point with CTU/STU/DISCOM

Most of the projects commissioned after May 03, 2010 were connected on pooling station basis. For the purposes of these guidelines the following shall be considered for scheduling:

- Individual feeder connected to greater than 10 MW of generating capacity
- Group of generators owned by a particular owner with more than 10 MW generation
- Pooling station interface point with CTU/STU/DISCOM

In the case of wind, all energy in India is sold through either FiT mechanism, commercial arrangements such as banking or APPC + REC mechanism. All farms, irrespective of size, have metering facilities which are monitored regularly by the farm owners – based on which wind electricity is commercially settled. In all these arrangements, STU / DISCOM is a party in the commercial agreements, and the process of meter reading is “joint”. Further, it is possible to replace energy only meters with Special Energy Meters which are capable of time-differentiated measurements for time block wise active energy and voltage differentiated measurement of reactive energy. These meters must conform to the standards provided in Central Electricity Authority (Installation and operation of meters) Regulations, 2006.

Based on the above, there would be two types of generators – (1) which are self-scheduled[9] (and do not fall under any category defined above), and (2) scheduled, which would be scheduled by the SLDC/RLDC.

Therefore, the scheduled generator(s) would be the ones that satisfy the following:

> *The generating unit with output nameplate rating ≥ 10 MW, or the generating unit that is part of a group of generating units connected at a common connection point (a generating system) that has a combined output nameplate rating ≥ 10 MW, and the generating unit has an output that is intermittent.*

To participate in dispatch done by the Load Dispatch Centre (SLDC/RLDC) the Scheduled Generators would be required to:

- submit daily schedules for each time block to SLDC/RLDC for each scheduled generating unit / group of units at the pooling stations;
- allow the SLDC/RLDC to determine the dispatch instruction for each scheduled wind generating unit / group of units at the pooling station, based on dispatch of all other generators in the system; and

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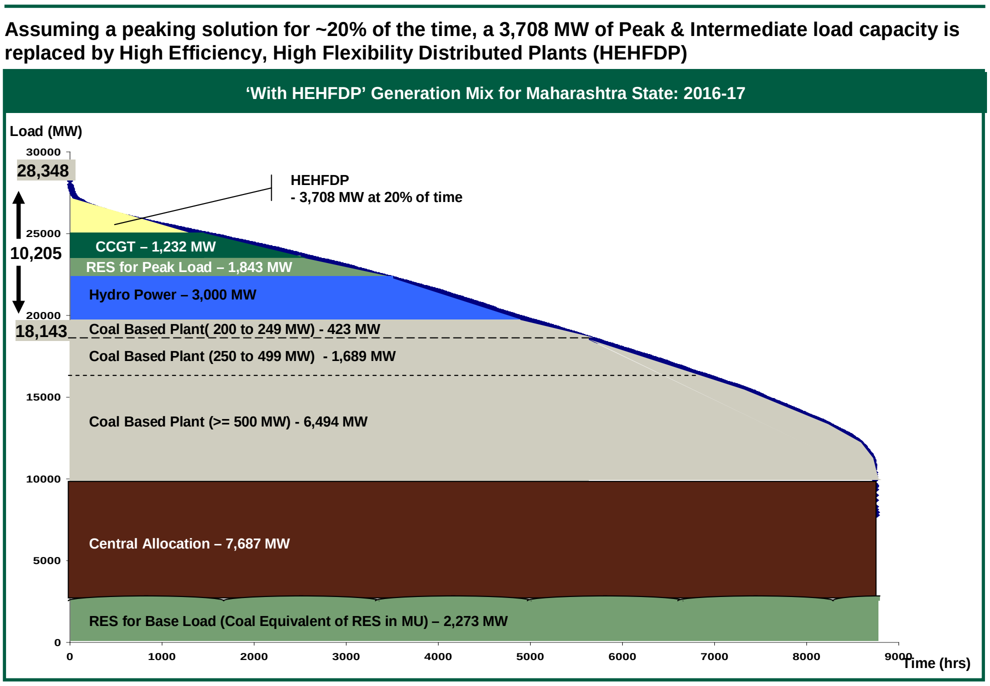
[9] There could be some generators which are less than 10 MW, and not connected to the grid through a pooling station .

- Receive electronic dispatch instructions from SLDC/RLDC and comply with these dispatch instructions as required

In the case of pooling stations, the responsibility of forecasting, deviation from the schedule and attendant imbalance settlement mechanism would have to rest on an aggregator. The selection of an aggregator could be either voluntary or based on criteria enumerated by the appropriate Regulatory Commission. However, given the requirement of the following proposed mechanism, there would be an incentive for the small farms to aggregate, formulate a mutually acceptable commercial agreement and appoint an aggregator[10].Such an aggregator / scheduling coordinator would act on behalf of generators to submit schedules to the system operator. The sharing of costs and benefits of deviation from the schedule could be shared between the aggregator and the farms based on mutually negotiated contracts – to which the ERCs or the system operator may not be a party. The aggregator / scheduling coordinator shall however have to interact with the system operator in accordance with the guidelines to be developed by the system operator and notified by the ERCs.
Given the nature of VRE, it is essential that it be treated as must run. This is the approach taken in all contemporary studies, including one for Maharashtra on Optimal Generation Mix.

Figure 6.1: Optimal Generation Mix for Maharashtra for 2016-17



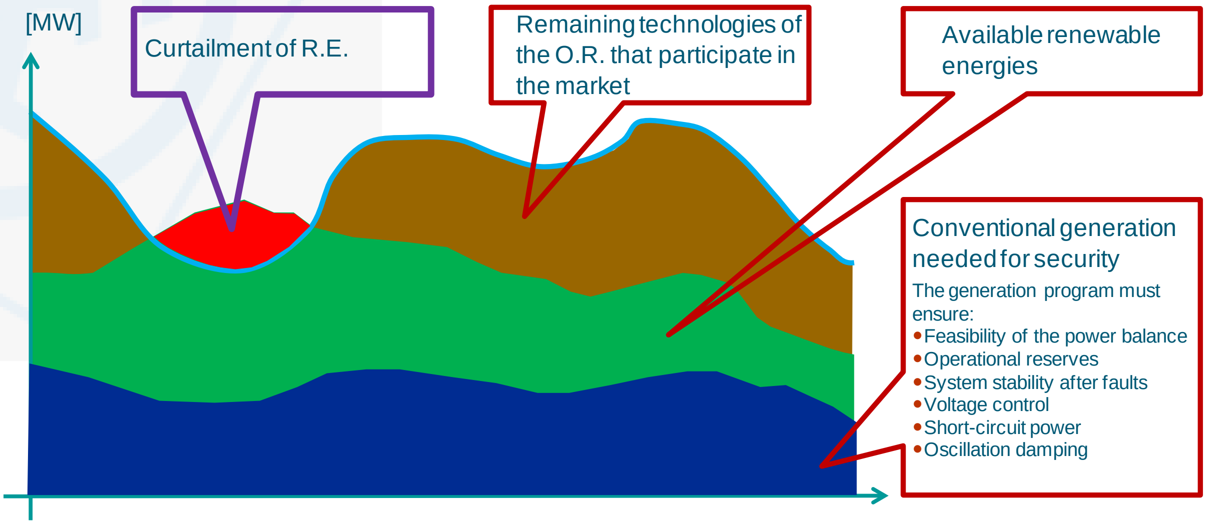
Note: Additional Spinning reserve Capacity of 1,814 MW comprises of 338 MW (250 – 499 MW coal plants) + 1476 MW (200 to 249 MW coal plants. The above graph and further calculations are based on 80% implementation rate for XII plan
Source: 17th Electric Power Survey of India, 2007 - CEA, UC Analysis

Source: Study on Optimal Power Generation Mix for India, Wartsila India, 2010. The study has been undertaken in the context of flexible peaking power solutions.

As shown in the above figure, typically VRE would be the last in the order of curtailment. It may be necessary to curtail VRE in certain cases. An illustration of such conditions is provided in the graphic below.

[10] A strict VRE of scheduling which penalizes all deviation from the schedule – as is the case in Spain – prompts the wind generators to sign a commercial agreement with an aggregator or a scheduling coordinator of their choice. There is a collective interest of small generators over a large geographic area but connected to the same pooling station to nominate an aggregator or a scheduling coordinator. The collective variation from the schedules of small farms over a relatively large area is expected to be small. Further with an aggregator the risk of deviation gets alleviated because of better forecasting methodology – the cost of which is shared by all the generators.

Figure 6.2: Dispatch of energy resources and curtailment of VRE



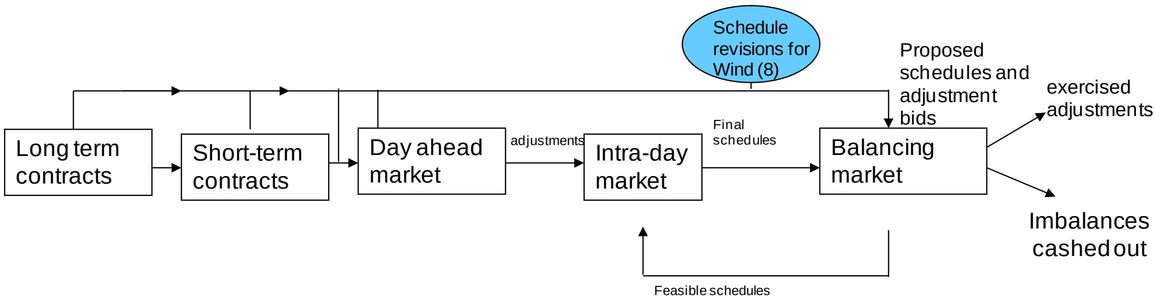
However conditions for curtailment must be clearly defined and be amenable to scrutiny to ensure that the rules laid out for system operation are strictly followed. As commented elsewhere in this report, this would eventually require institutional autonomy of the system operator.

6.2 SCHEDULING MECHANISM – DAY AHEAD AND INTRA DAY

VRE generation becomes easier to forecast the closer the predictions are to real-time market operations, and correspondingly, more difficult to predict farther in advance. Therefore, submitting wind generation schedules closer to real-time market operations will allow for more accurate predictions of wind generation, although some trade-offs are involved. That said, having a shorter period of time before the start of real time market operations may contribute to a need for more reserves such as load following or perhaps higher costs from the increased starting and stopping of conventional units, as those shorter periods of time will not allow sufficient time to change unit commitment decisions for conventional generating units.

Notwithstanding the above limitations of allowance of "close to real time scheduling", IEGC already permits eight schedule revisions in a day at three-hour notice and this offers an opportunity for wind generators to correct themselves, as is shown schematically below.

Figure 6.3: Scheduling Mechanism



However, from the system operation perspective, the system operator needs to a-priori plan for capacity to meet sudden loss of generation or needs to plan back down of running generators in case electricity from intermittent sources is to be accommodated. Such planning for "unit commitment" is possible a day in advance. Close to real time management of such exigencies requires a well functioning ancillary services mechanism/market or a demand response program. Criticality of day ahead security constrained unit commitment requires that the scheduled wind generators be held responsible for grid security like other generators.

Currently, states like Tamil Nadu where, in terms of capacity, wind penetration is approximately 46%, sudden ingress or withdrawal of wind causes considerable difficulties in grid operation. During periods of sudden wind generation ingress, if the grid frequency increases and correspondingly the UI rate falls below the FIT rate, it becomes uneconomical for the state to accept wind electricity. Further, if wind generation suddenly decreases and frequency falls – the utility either has to shed load (which is normal course of action) or the state overdraws at high UI rates. In such cases if the RPO obligations of the state have already been met, there is no incentive for Tamil Nadu to encourage more wind based generation – despite having a large potential. Such a situation demands development of a mechanism with following characteristics:

(a) The VRE generators must be responsible for their schedules albeit with some relaxation – because the intermittent nature of wind needs to be considered[11]

(b) The host state should not be singularly responsible for bearing the entire costs of grid integration of wind based generation, i.e., costs due to imbalance, costs of balancing capacity requirements – since most such generation falls within the control area of the SLDC despite serving the RPO needs of other states, costs due to load shedding, demand response, wind generation forecasting, etc.

(c) Generators, with spinning reserves, connected in other control areas should have an incentive to help declining grid frequency especially when it happens concomitantly with a sudden decline in wind based electricity generation. Maintaining frequency within tight bands would help the scheduled VRE generators by reducing excessive charges on them.

(d) The conditions under which wind based generation is required to back down must be extremely transparent and grid contingencies should be “visible” not only to the utility but also the system operator and be readily verifiable.

Scheduling of wind based generation could be managed as follows:

1. Day-ahead Scheduling (DAS)

   Scheduled Wind resources shall provide day-ahead schedules. Wind resources participating in the day-ahead scheduling process are treated no differently than any other resource in the day-ahead scheduling system.

2. Intra Day Scheduling (IDS):

   Wind resources are permitted eight schedule revisions in a day with at three hour notice. The IDS will be optimized for the most reliable dispatch and may select a resource to reduce its output. If operation of the wind resource infringes security and reliability at its forecasted output level, the system will create a basepoint that reflects the resource’s ability to be limited, taking into account its stated response rate. The wind resource must limit its output to the level (or below) specified in the basepoint within the next five minutes (if there is a direct communication between the SLDC/RLDC with the VRE Generator) or within fifteen minutes (if the communication to generators is via the transmission owner at the pooling station).

   The system will use the wind resource’s last intraday schedule - its last known energy output, and its forecasted energy output to help determine the wind resource’s schedule.

[11]. FERC order 888, issued in 1996 allowed transmission providers to apply a penalty if energy deliveries vary 1.5% or more (either higher or lower) from advance energy schedules (i.e., day ahead). The imbalance penalties were typically not based on the cost incurred by the system operator, but instead were punitive to prevent strategic behavior by generators. Under this regime, typical penalties were either set at a utility’s incremental cost of providing hourly energy plus an adder, or a pre-set price, such as 100 mills/kWh. Absent waivers or special provisions, the FERC Order 888 energy imbalance essentially forestalled wind development, as it was impossible for wind generators to deliver wind energy within the 1.5% band included in the Order 888 tariffs, and the penalty provisions typically exceed the commercial value of the wind energy. The condition had to be relaxed to further wind generation.

Absent any constraints, the instructions sent to wind resources will reflect the ability of the system to take all the energy the wind resource can produce if it is does not infringe security and reliability of system operation. However, if the wind resource is selected to limit its output, instructions sent to the wind resource will reflect those limitations.

Instructions are sent electronically from SLDC/RLDC via basepoints to the transmission owners (pooling station operators), in case there is no direct communication with the generators. Transmission owners will communicate these instructions to the projects.

As discussed in the Chapter-III, Ancillary Services Market/Mechanism is a pre-requisite for effective balancing the variability due to VRE generation. Ancillary Services markets/mechanisms allow for spinning reserves to be available, allow charging for ramp-up/ramp-down services provided by thermal generators and also allow for demand side participation for managing variability of generation.

6.3 ENERGY IMBALANCE SETTLEMENT MECHANISM

The process of imbalance settlement, in line with the above principles, is proposed as follows:

1. VRE Generators who abide by the full forecasting guidelines and allow visualization of their farms by the system operators are not penalized for deviation. This is also the case in California ISO, Ontario IESO etc. The aim of such criteria is to incentivize farms to adopt good forecasting methodologies. Further, from the security perspective, this allows the system operator to forecast based on farm site conditions and plan balancing resources.

2. The imbalance settlement (UI Accounting) shall be done on a weekly basis, as is the current practice, for other generation resources.

3. If the deviation, with respect to the schedule, on an aggregate weekly basis is within -10%[12], the applicable UI charges shall be borne by the Regulatory Renewable Fund (RRF).

    a. Current allowable deviation (which does not invite penalty or other commercial implications) is ±30% from the schedule at the level of each time block. However, here allowable deviation is ±10% on a aggregate weekly level. It is normally observed that over longer time periods, the deviations mutually cancel each other. Further, tighter norms could be adopted which would incentivize selection of renewable aggregators at the level of pooling stations.

    b. With larger control areas with effect from March 2014, when SR is proposed to be synchronized with the NEW grid, and with the proposed development of Ancillary Services Market – where the frequency support services are explicitly procured from the market – it is expected that frequency would vary in a very narrow band – thereby reducing the burden of imbalance on intermittent electricity generators.

4. If the deviation, with respect to the schedule, on an aggregate weekly basis is within +10%, the applicable UI charges shall be credited to the RRF.

5. The extent to which under-generation, with respect to the schedule, exceeds 10%, the UI charges shall be borne by the generator. The rate applicable to the UI energy in excess of 10% shall be the average UI charge for the generator. For example, if the total UI charges for the generator are Rs 100, and the UI energy (under-generation) is 50 units, then the applicable average UI rate for the generator is Rs 2 / unit (100/50). If the 10% for the generator corresponds to 40 units, there is excess under-generation of 10 units

[12] The rationale for 10% is that tighter the norm – more will be the incentive for the wind farms to adopt forecasting methodologies and allow full visualization of their farms by the system operator. Further, tighter norms have helped develop "Aggregators" who forecast and schedule on behalf of wind farms.

(50-40). Therefore, the generator will have to bear the burden of Rs 20 (2 multiplied by 10).

6. Similarly, if the over-generation accepted into the grid exceeds 10% of the scheduled energy over a week, the generator would be paid at the average rate UI rate multiplied by the UI (over-generation) energy that exceeds 10%.

7. The above mechanism may leave the RRF account in a net deficit or a surplus. The RRF is proposed to be funded by the DISCOMs (under the REC requirement) in the inverse proportion of the RPO targets and in direct proportion of the RECs purchased from the national markets for Renewable Energy Certificates (RECs).

   a. The rationale behind “inverse proportion of RPO targets” is to load the RRF burden on those states which have lower RPO targets. Further, the states which meet their shortfall of RPO from the REC market would normally not have adequate in-state VRE sources and therefore do not bear the costs of grid integration of VREs. Therefore, “direct proportion to RECs purchased” allows such states to share the burden of those who have considerable in-state VER generation.

   b. As compared to the current mechanism, wherein, the deficit in RRF is funded by various DISCOMs in proportion of their contribution to peak, the proposed mechanism is better aligned to the purpose of the RRF – to create sustainable markets for generators based on renewable sources. Whereas, a state which has a high contribution to national peak, may also have sufficient renewable based generation in the state, a state with low RPO target (in % terms) needs to be incentivized to increase its RPO. An ideal situation would be where all the states have same RPO (in percentage terms) – thereby reducing disparity in power purchase costs on account of having to purchase costlier renewable based generation.

   c. Current mechanism or any mechanism that charges RRF shortfalls on the basis of contribution to peak demand or energy consumption may end up burdening those states which might have adequate in-state VRE generation. For example, Maharashtra – which has adequate in-state VRE would have to bear the burden of RRF shortfall because the state has the highest contribution to national peak and is also one of the largest in terms of electrical energy consumption.

The mechanism proposed above will have an impact on renewable energy accounting and the REC market. This is discussed in the following section.

6.4 ENERGY ACCOUNTING MECHANISMS FOR IMBALANCE SETTLEMENT FOR “GREEN” ASPECTS: RPO, RECS AND RRF

When a VRE generator under-generates (with respect to its schedule), but is compensated at its scheduled energy (under the ABT mechanism) by the counterparty to the power sale contract – an imbalance occurs between the renewable energy purchased by the buyer (who still pays for the contracted amount) and the renewable energy actually generated.

Further, when a wind-generator over-generates (with respect to its schedule), but is compensated at its scheduled energy by the counterparty to the contract – an imbalance occurs between the renewable energy purchased by the buyer and the renewable energy actually generated and absorbed in the system.

The following mechanism is proposed to settle the imbalance in the renewable energy market:

1. When a generator under-generates (and the terms of its contract require that the RECs or RE rights will be held by the buyer of energy), it is required to purchase corresponding RECs from the market and transfer the same to the counter-party to the energy contract – who has paid to the generator for the scheduled energy at the contract rate.

a. In case generator has an energy only contract with the buyer, the RECs will be issued to the generator as per its actual generation.

2. When a VRE generator over-generates (and the terms of its contract require that the RECs or RE rights will be held by the buyer of energy), it gets corresponding RECs after due certification of such generation from the SLDC/RLDC. The VRE Generator may either neutralize such RECs with RECs that it is required to purchase because of under-generation or sell the same in the REC market – whatever is perceived to be in the best commercial interest of the generator.

3. The balance between the renewable energy generated and the corresponding RECs may be achieved over a year.

VII CONCLUSIONS AND WAY FORWARD

On the basis of the analysis conducted it is apparent that large scale introduction of VRE into the Indian grid is indeed possible. The technical potential indicated in various studies is far larger than official MNRE estimates. Developer interest is strong. The demand for energy continues to grow, even as conventional fuel constraints seem to aggravate over time. The potential for integration of VRE on a large scale is apparent.

Indian power system design, at a high level, is also conducive for large scale VRE integration. Indian grid has many significant advantages including:

a. A large frequency integrated system for most parts of the country (NEW Grid), with installed capacity of more than 150 GW

b. A smaller, but still significantly large Southern Region (SR) grid with installed generation capacity in excess of 50 GW

c. Likelihood of integration of the two grids in the foreseeable future (2014) which will create a giant frequency integrated grid;

d. A robust, tiered transmission system that features a National Grid that is increasingly growing strong with addition of large inter-regional capacities as 765 KV AC, 400 KV AC and 500 KV HVDC systems. Underlying this is a very strong regional grid system as an intermediate layer. At the lowest levels the transmission grid features 400 KV, 220 KV, 132 KV and (some) 110KV/66KV transmission systems at the state level. These systems are increasingly becoming more robust

e. The diversity of generation resources across the country is a significant advantage, with a reasonable mix of coal, hydro and gas assets.

All of the above would be significant advantages as India takes a strong low carbon growth path with renewable energy as the centrepiece of this growth. However, the translation of these advantages in favour of renewable energy is not automatic. Several issues (some of which will inevitably prove difficult to resolve) would need to be overcome. Beyond the issues that are discussed subsequently, impetus can be provided to the integration of renewable through following changes in the market design:

All long-term electricity scenarios show a large increase in installed VRE capacities in India in the coming decades. Inadequate levels of accuracy in wind generation forecasting result in day-ahead forecasts which have the potential to induce increasing uncertainty into the Indian electricity system. It will therefore be essential to make use of two factors: the improving wind forecasts within the hours between the day-ahead market and real-time dispatch, and the full flexibility that the generation, transmission, and demand side of the power system can offer to limit cost increases to deal with this uncertainty and to ensure full system security.

The power market design therefore has to satisfy five criteria:

(a) Facilitate system-wide intraday adjustments to respond to improving wind forecasts:

- to ensure that the least cost generation capacity provides power and ancillary services.

(b) Allow for the joint provision and adjustment of energy and balancing services:

- to reduce the amount of capacity needed to provide balancing services and to operate on part load.

(c) Manage the joint provision of power across multiple hours:

- a broader set of actors can contribute energy and balancing services in day-ahead and intraday markets if they can coordinate sales across adjacent hours (thus more accurately reflecting technical constraints of power stations like ramp-up rates or start-up costs).

(d) Capture benefits from national integration of the power system:

- the transmission network is the most flexible component of the power system, but requires fully integrated intraday and balancing markets to replace more costly generation assets and enhance system security. Also, with the physical integration of grids, the commercial, institutional and regulatory processes need to match up.

- RLDCs need to have a "visibility" over variable sources of generation connected at 110/132 kV or lower voltage levels for the purposes of balancing and control. Institutionally, Renewable Energy Control Centre needs to be developed (may be as a part of the RLDC/NLDC) to manage "operation" of variable sources of generation. This would be critical – as discussed in the report for management of both – reactive and active sources of balancing. The need for integration of variable sources of generation into the grid from the perspectives of inter-alia economic operation, energy security, and lower carbon emissions etc. provides opportunities to complement the bottom-up approach pursued so far by the states with huge potential for renewable generation with top-down requirements. One cornerstone is the centralized structure of the nature of Renewable Energy Control Centre. As many market participants have disincentives to fully support a bottom-up transition to an integrated power market design, the provisions from such a centralized mechanism might become essential in the Indian pursuit of a harmonized and effective power market design;
- The analysis in the report points to a considerable reduction in balancing costs from 40% (in 2014) to maximum of 75% (in 2022) if SR were considered as a one system for provision of balancing resources for variable sources of generation. This of course needs to backed up with institutional changes proposed in the report.

(e) Integrate the demand side into intraday and balancing markets:

- Creating incentives and systems –essentially Demand Response (DR) Programs - that allow the demand side to fully contribute to the available flexibility.
- Such DR customers are an important part of the Ancillary Services Mechanism/Market
- DR resources have the flexibility to match up most closely with the ramp rates of variable sources of generation like wind and solar

Five elements of market design described above need to be supported through improvement in the following seven processes and infrastructure requirements discussed through the report and summarised below:

Issue # 1: **Forecasting and Planning Processes.** Forecasting serves two purposes – (1) allows wind generators to take operational decisions which are aligned to market prices of energy, (2) allows the system operator to better plan ancillary services required to balance generation from VRE sources. The VRE generators are often compensated based on feed-in-tariff rates and hence there is little inducement for the generators to gain from better prices in the market. The second requirement is however critical for better grid integration. The host states, as exemplified in states like Tamil Nadu and Rajasthan, often have to bear the brunt of high UI charges/ Load shedding / operation of high cost pumped storage based generators to manage variability of wind – especially when poor quality forecasts are used. While the report proposes a detailed mechanism (with infrastructure requirement) for improving forecasts from each wind farm, it also proposes that either scheduling and dispatch of VRE be made mandatory and they be held commercially responsible for deviations from their schedules or each VRE generator install equipment which facilitate collection, recording and transmission of data which is required for forecasting by the system operator. This implies that such VRE generators allow full visibility of their generators to the system operator at all times.

Issue # 2: **Planning for and charging for Integration of VRE sources.** The primary question that governs planning for grid integration of VRE generators in the Indian context is: **Why should states who have met their RPO, invest in balancing resources, transmission and reactive power support equipment for the wind generators whose primary objective is to help other states meet their RPO?**

The high costs of VRE integration have dissuaded states from encouraging investment in VRE generation despite these states having high potential. In order for the REC market to be a success it is pertinent that a comprehensive framework for planning of capacities required for grid integration of wind based generators be developed. **Clearly, since the REC mechanism operates in a national market, planning for grid integration of VRE generators which serves such a national market needs to be also done at a national level.**

Transmission planning in India is done through coordination between CEA, CTU, STUs, RPCs. **Planning for systems required for integration of wind based generation or other intermittent sources could also be done centrally in a similar manner. All such investments – since these are primarily being done to allow all the states in India to meet their RPO could be approved by the Central Electricity Regulatory Commission.**

How would the costs of integration be shared?

There are two types of costs that would need to be shared:

- The fixed costs – against capital expenditure identified above
- Variable costs – which would again be of two types
    - Costs of balancing - cycling of coal / gas or operation of pumped hydro plants / OCGT / Diesel based power plants
    - The cost of losses – wind generators draw inductive power from the grid – which results not only in lower voltages but also higher system losses in the state networks

The capital costs are proposed to be approved by the Central Electricity Regulatory Commission (CERC) and since most of these are transmission related costs – the same could be made a part of the Point of Connection (PoC) mechanism. Similarly, sharing of transmission losses could be as per the PoC mechanism.

Sharing the costs of cycling

The development of Ancillary Services mechanism – which is proposed to be implemented by POSOCO will serve to estimate/determine (based on market signals) the costs of cycling of coal/gas/pumped hydro plants. Ancillary services markets usually take the price offers from various generation resources and demand response resources and these offers set the spot prices in electricity markets. The following mechanism is proposed for charging of cycling costs:

(a) In case of generators selling power under FiT to any purchaser (whether home state or other state) – the costs of cycling would be borne by the purchaser.

(b) In the case of generators selling power under APPC to the home state, the cost of cycling could be borne by the home state and the wind generator is the ratio of APPC and the average REC price realized during the month. For example if the cost of cycling due to a wind generator is Rs 100 during a month. The APPC of the state is Rs 2.75 / kWh and the average REC price during the month is Rs 2.00 / kWh. Then Rs 100*2.75/(2.75+2.00) would be borne by the state and Rs 100*2.00/(2.75+2.00) would be borne by the wind generator.

(c) In the case of generators selling electricity on the power exchange, the costs of cycling shall be borne by such generators.

Till such time as, ancillary services market mechanisms are implemented, CERC may determine the cycling costs in Rs / kWh for various types of generation resources. As a policy, while coal / gas based power plants can have retrofits which allow economic cyclical operations, renovation and modernization, or repowering of older power plants can mandatorily require such flexibilities in power plants. Methodologies to compute cycling costs and international examples where retrofits have been used to make base load power plants more flexible, in line with the requirements of the changing electricity markets are summarized in the report.

Issue # 3: **Scheduling and Dispatch of VRE Generation.** VRE generation becomes easier to forecast the closer the predictions are to real-time market operations, and correspondingly, more difficult to predict farther in advance. Therefore, submitting wind generation schedules closer to real-time market operations will allow for more accurate predictions of wind generation, although some trade-offs are involved. That said, having a shorter period of time before the start of real time market operations may contribute to a need for more reserves such as load following or perhaps higher costs from the increased starting and stopping of conventional units, as those shorter periods of time will not allow sufficient time to change unit commitment decisions for conventional generating units.

Notwithstanding the above limitations of allowance of “close to real time scheduling”, IEGC already permits eight schedule revisions in a day at three-hour notice and this offers an opportunity for wind generators to correct themselves.

However, from the system operation perspective, the system operator needs to plan a-priori for capacity to meet sudden loss of generation or needs to plan back down of running generators in case electricity from intermittent sources is to be accommodated. Such planning for “unit commitment” is possible a day in advance. Close to real time management of such exigencies requires a well functioning ancillary services mechanism/market and a demand response program. Criticality of day ahead security constrained unit commitment requires that the scheduled wind generators be held responsible for grid security like other generators.

Currently, states like Tamil Nadu where, in terms of capacity, wind penetration is approximately 46%, sudden ingress or withdrawal of wind causes considerable difficulties in grid operation. During periods of sudden wind generation ingress, if the grid frequency increases and correspondingly the UI rate falls below the FIT rate, it becomes uneconomical for the state to accept wind electricity. Further, if wind generation suddenly decreases and frequency falls – the utility either has to shed load (which is normal course of action) or the state overdraws at high UI rates. In such cases if the RPO obligations of the state have already been met, there is no incentive for Tamil Nadu to encourage more wind based generation – despite having a large potential. Such a situation demands development of a mechanism with following characteristics:

(a) The VRE generators must be responsible for their schedules albeit with some relaxation – because the intermittent nature of wind needs to be considered

(b) The host state should not be singularly responsible for bearing the entire costs of grid integration of wind based generation, i.e., costs due to imbalance, costs of balancing capacity requirements – since most such generation falls within the control area of the SLDC despite serving the RPO needs of other states, costs due to load shedding, demand response, wind generation forecasting, etc.

(c) Generators, with spinning reserves, connected in other control areas should have an incentive to help declining grid frequency especially when it happens concomitantly with a sudden decline in wind based electricity generation. Maintaining frequency within tight bands would help the scheduled VRE generators by reducing excessive charges on them.

(d) The conditions under which wind based generation is required to back down must be extremely transparent and grid contingencies should be “visible” not only to the utility but also the system operator and be readily verifiable.

Ancillary Services Market/Mechanism is a pre-requisite for effective balancing the variability due to VRE generation. Ancillary Services markets/mechanisms allow for spinning reserves to be available, allow charging for ramp-up/ramp-down services provided by thermal generators and also allow for demand side participation for managing variability of generation.

Issue # 4: **Imbalance Settlement Mechanism – Balancing and Settlement.** Despite scheduling based on acceptable forecasts, it is inevitable that there would be a deviation between schedule and actual generation/drawal. This deviation is termed as “imbalance”. All power systems / markets have an imbalance settlement mechanism. India has an imbalance settlement mechanism wherein the charges for “imbalance” energy are regulated and linked to grid frequency. These are referred to as Unscheduled Interchange (UI) rates. The report illustrates that when FiT rates are higher than UI rates, the system operators ask the wind generators to back down, especially in high wind months. Similarly, even during periods when wind generation suddenly falls concurrently with a dip in grid frequency, the neighbouring states (like Andhra Pradesh) would have no incentive to ramp up their hydro/gas based generation because this would reduce their drawal from the inter-state grid and they would be inadequately rewarded for helping the grid – as per the current provisions of the UI mechanism.

The process of imbalance settlement is proposed as follows:

1. VRE Generators who abide by the full forecasting guidelines and allow visualization of their farms by the system operators are not penalized for deviation. This is also the case in California ISO, Ontario IESO etc. The aim of such criteria is to incentivize farms to adopt good forecasting methodologies. Further, from the security perspective, this allows the system operator to forecast based on farm site conditions and plan balancing resources.

2. The imbalance settlement (UI Accounting) shall be done on a weekly basis, as is the current practice, for other generation resources.

3. If the deviation, with respect to the schedule, on an aggregate weekly basis is within -10%[13], the applicable UI charges shall be borne by the Regulatory Renewable Fund (RRF).

    a. Current allowable deviation (which does not invite penalty or other commercial implications) is ±30% from the schedule at the level of each time block. However, here allowable deviation of -10% is applicable to those wind generators who do not allow full visualization of their wind farm by the system operators. These generators would be required to schedule and be commercially responsible for deviation and hence imbalance charges.

    b. With larger control areas with effect from March 2014, when SR is proposed to be synchronized with the NEW grid, and with the proposed development of Ancillary Services Market – where the frequency support services are explicitly procured from the market – it is expected that frequency would vary in a very narrow band – thereby reducing the burden of imbalance on VRE generators.

4. If the deviation, with respect to the schedule, on an aggregate weekly basis is within +10%, the applicable UI charges shall be credited to the RRF.

5. The extent to which under-generation, with respect to the schedule, exceeds 10%, the UI charges shall be borne by the generators who opt for abide by the forecasting code proposed. The rate applicable to the UI energy in excess of 10% shall be the average UI charge for the generator. For example, if the total UI charges for the generator are Rs 100, and the UI energy (under-generation) is 50 units, then the applicable average UI rate for the generator is Rs 2 / unit (100/50). If the 10% for the generator corresponds to 40 units, there is excess under-generation of 10 units (50-40). Therefore, the generator will have to bear the burden of Rs 20 (2 multiplied by 10).

6. Similarly, if the over-generation accepted into the grid exceeds 10% of the scheduled energy over a week, the generator would be paid at the average rate UI rate multiplied by the UI (over-generation) energy that exceeds 10%.

7. The above mechanism may leave the RRF account in a net deficit or a surplus. The RRF is proposed to be funded by the DISCOMs (under the REC requirement) in the inverse proportion of the RPO targets and in direct proportion of the RECs purchased from the national markets for Renewable Energy Certificates (RECs).

[13] The rationale for 10% is that tighter the norm – more will be the incentive for the wind farms to adopt forecasting methodologies and allow full visualization of their farms by the system operator. Further, tighter norms have helped develop “Aggregators” who forecast and schedule on behalf of wind farms. This observation draws upon experience in Spain.

a. The rationale behind “inverse proportion of RPO targets” is to load the RRF burden on those states which have lower RPO targets. Further, the states which meet their shortfall of RPO from the REC market would normally not have adequate in-state VRE sources and therefore do not bear the costs of grid integration of VREs. Therefore, “direct proportion to RECs purchased” allows such states to share the burden of those who have considerable in-state VER generation.

b. As compared to the current mechanism, wherein, the deficit in RRF is funded by various DISCOMs in proportion of their contribution to peak, the proposed mechanism is better aligned to the purpose of the RRF – to create sustainable markets for generators based on renewable sources. Whereas, a state which has a high contribution to national peak, may also have sufficient renewable based generation in the state, a state with low RPO target (in % terms) needs to be incentivized to increase its RPO. An ideal situation would be where all the states have same RPO (in percentage terms) – thereby reducing disparity in power purchase costs on account of having to purchase costlier renewable based generation.

c. Current mechanism or any mechanism that charges RRF shortfalls on the basis of contribution to peak demand or energy consumption may end up burdening those states which might have adequate in-state VRE generation. For example, Maharashtra – which has adequate in-state VRE would have to bear the burden of RRF shortfall because the state has the highest contribution to national peak and is also one of the largest in terms of electrical energy consumption.

The mechanism proposed above will have an impact on renewable energy accounting and the REC market. This is discussed in the following section.

Issue # 5: **Imbalance Settlement in “Green” accounts.** When a VRE generator under-generates (with respect to its schedule), but is compensated at its scheduled energy (under the ABT mechanism) by the counterparty to the power sale contract – an imbalance occurs between the renewable energy purchased by the buyer (who still pays for the contracted amount) and the renewable energy actually generated.

Further, when a wind-generator over-generates (with respect to its schedule), but is compensated at its scheduled energy by the counterparty to the contract – an imbalance occurs between the renewable energy purchased by the buyer and the renewable energy actually generated and absorbed in the system.

The following mechanism is proposed to settle the imbalance in the renewable energy market:

1. When a generator under-generates (and the terms of its contract require that the RECs or RE rights will be held by the buyer of energy), it is required to purchase corresponding RECs from the market and transfer the same to the counter-party to the energy contract – who has paid to the generator for the scheduled energy at the contract rate.

    a. In case generator has an energy only contract with the buyer, the RECs will be issued to the generator as per its actual generation.

2. When a VRE generator over-generates (and the terms of its contract require that the RECs or RE rights will be held by the buyer of energy), it gets corresponding RECs after due certification of such generation from the SLDC/RLDC. The VRE Generator may either neutralize such RECs with RECs that it is required to purchase because of under-generation or sell the same in the REC market – whatever is perceived to be in the best commercial interest of the generator.

3. The balance between the renewable energy generated and the corresponding RECs may be achieved over a year.

Issue # 6: In several high wind areas transmission system is weak and inadequate: In the states analysed by us, Tamil Nadu has a particular constraint in this regard. Most of the connectivity is at 110 KV and below. The grid is ill-equipped to handle such flows (and especially so because of poor SO visibility of network/generation). Connectivity in future has to be predominantly at higher voltage levels (with possible exceptions for small sized projects), with complete system operator visibility. A commercial mechanism for sharing of transmission costs is required;

Issue # 7: System Operations Organisations need redesign: Our interactions have revealed that the current processes in SO organisations are not at all geared for large scale VRE penetration. In most cases there is no forecasting of VRE generation. Even in states like Gujarat that have performed well on power systems planning and operation, the systems are primitive at present. At the state level the SO organisations need to be equipped adequately. Further, in line with the need for larger balancing areas discussed in this report, there is a need to introduce greater co-operation between SOs for VRE, and integration of SO operations for VRE corresponding to the definition of balancing areas. The SO processes for VRE also need to be revisited. Managing VRE on the lines of conventional generation would expose the system to severe risks, and systems and processes need to be appropriately designed to avoid these changes.

The above present a large and complex agenda. Handling each issue in a piecemeal basis is unlikely to resolve them. As a consequence, large scale VRE introduction and integration is also unlikely unless the issues are addressed comprehensively. Based on the analysis conducted we present below the potential agenda for large scale VRE integration.

Table 7.1: Potential agenda and Roadmap for large scale VRE integration

Implementation Plan Aspect	2012-13	2013-14	2014-15
SO Technical and Commercial Infrastructure and Processes			
Forecasting of VRE			
SO visibility of all major VRE			
Scheduling of VRE			
Settlement (UI) modifications			
Infrastructure Creation and Related Commercial Processes			
Transmission Need Identification			
Transmission pricing framework for VRE			
Identification of Balancing Needs			
Commercial/Incentive Framework for Balancing			
SO Organisation Design			
Redesign of SO Organisation for RE (incl control area definition)			
Implementation of new SO organisation			

Implementing the above agenda would present its challenges, but would be eminently possible if the policy and regulatory framework strongly reinforces the needs and benefits of the same to all stakeholders including generators, transmission companies, system operators, and particularly the utilities. The benefits would need to be quantified with reasonable precision. To that effect we recommend specific and detailed studies on:

a. Balancing power requirements, specific resource identification and corresponding costs, based on system simulation studies. This should be done for specific system conditions, transmission networks, for various years and under various levels of VRE penetration. The studies should specifically identify the pricing, commercial and contractual mechanisms for balancing power;

b. Integrated transmission planning in view of the VRE penetration for least cost system expansion for various levels of renewables. Studies should identify the specific augmentation requirements considering the various development and commercial scenarios for various system conditions over a period of time. The studies should also investigate how the transmission augmentation is to be designed, financed and priced, including the potential expansion of the Point of Connection transmission pricing mechanism for VRE resources;

c. Investigations into SO organization and evaluation of SO integration for renewables at a regional and national level. Our analysis reveals that there is no apparent legal impediment in such integration, but would require strident policy action. Our initial analysis, reproduced here, indicates very significant benefits of integration on a regional level, coupled with better forecasting.

Table 7.2: Penetration levels, Balancing Capacity and associated costs (refer details in Chapter III)

	Maximum Volatility of VRE generation (High wind season)									
	Tamil Nadu					Southern Region				
	% Penetration	Balancing Capacity (MW)	Balancing cost (Rs/Kwh)			% Penetration	Balancing Capacity (MW)	Balancing cost (Rs/Kwh)		
			Case 1	Case 2	Case 3			Case 1	Case 2	Case 3
2012	34%	624	0.68	0.44	0.21	18%	334	0.30	0.20	0.11
2014	39%	835	0.72	0.48	0.23	22%	798	0.43	0.27	0.12
2016	45%	1,126	0.78	0.53	0.28	27%	1,112	0.44	0.28	0.13
2022	55%	2,533	1.20	0.89	0.58	35%	2,465	0.51	0.32	0.14

d. In any event the SO organizations need to be strengthened with maximum visibility of the system, forecasting capabilities, scheduling processes, system management skill enhancement etc. This would require investments that would need to be accompanied with policy and regulatory efforts. Studies should quantify the investment requirements;

e. We expect ancillary markets to play a very critical role in supporting the expansion of VRE resources. The NLDC has already filed a petition with the CERC for introduction of ancillary services markets. The studies should establish how the ancillary services products are to be defined and priced, and also define the design aspects of the market;

f. As has been commented upon, the UI mechanism needs significant change as a settlement mechanism to be appropriate for VRE. In view of the fluctuating nature of VRE, a moot question arises on whether a frequency linked settlement mechanism is at all appropriate for VRE resources (or for the system as a whole, especially in view of the relative stabilization of frequency). This is a matter worthy of specific investigation.

In conclusion, the potential of renewable energy does not appear to place constraints for development. The constraints are more related to infrastructure and commercial aspects. Even as the commodity supplied is electricity, the characteristics of VRE generation are very distinct from conventional generation. Incrementally VRE is anticipated to contribute to a very large share of India's energy production. Especially in view of the absence of alternatives, it is likely to replace conventional power as a centrepiece of Indian power sector development. However this shift in paradigm will have to be accompanied by fundamental changes in how the sector is commercially and operationally organised. Even as we have indicated a 3 year path for introducing these changes, they will require concerted policy and regulatory action, supported by detailed factual analysis to ensure robustness in the policy and regulatory measures undertaken.

ROADMAP FOR VRE GRID INTEGRATION

The Roadmap to full implementation of the above recommendations can be categorized into two parts:

1. Regulatory interventions
2. Infrastructure enhancement in pursuance of the regulations.

It is perceived that while the Infrastructure enhancements would follow the provisions in the Regulations, the draft of the regulations themselves would require a consultative process wherein – Ministry of Power, Ministry of New and Renewable Energy, CERC, ERCs (through FOR), Wind Developers and System Operators – both at the Central and the State level are development partners. The critical elements in the initiation of VRE integration are:

- Development of a Scheduling and Dispatch Mechanism
- Forecasting Mechanism – wherein the inputs to the forecasts are also visible to the system operator to accomplish security forecasts
- Commercial Mechanisms – pertaining to settlement – which is essentially a refurbished RRF mechanism
- To be able to physically manage variability of wind, after obtaining a reasonable forecast – institutional ability to do balancing through AS markets/mechanism is required. Here a decision on who would monitor and control balancing would need to be taken – a central body under the aegis of NLDC has been proposed in this report.
- Finally with the AS mechanisms/markets, UI mechanism would need to be phased out.

Table 7.3: Roadmap for VRE Grid Integration

S. No.	Action	Responsibility	Envisaged Time-Frame (Best case Scenario)
1	Development of Ancillary Services Market / Mechanism	CERC/POSOCO/SERCs/SLDC	CERC – 3 to 6 Months
2.	Forecasting and Planning Guidelines	POSOCO/SLDCs	This is a very basic requirement – 3-4 months.
3.	Scheduling and Dispatch Codes for VER	CERC/SERCs	Needs to be revised – 5 months
4.	Balancing and Settlement Mechanism	CERC/SERCs	Balancing and Settlement will happen in accordance with the design of the Ancillary Services Market. Further RRF mechanism needs to be instituted in the interim – 4 to 6 Months
5.	Revision of UI Mechanism	CERC	Frequency band must be tightened. Plan for replacement of UI mechanism by AS mechanism be initiated as soon as

S. No.	Action	Responsibility	Envisaged Time-Frame (Best case Scenario)
			India is ready for AS markets/Mechanism
6.	Installation of IT Infrastructure, required metering in conformance with the Forecasting, Scheduling and Dispatch mechanisms	ERCs / Individual Generators	The date for such installation can be specified in the Codes – as notified by the Regulatory Commissions. Should happen over next 1-2 years.

Beyond the above, it has been shown in the report that larger control areas allow better management of the variability of VRE resources of electricity generation. This is physically possible only when we have a strong national grid. NEW grid and SR are expected to be integrated by March 2014. Further, most components of the nine high power transmission corridors being developed in the ISTS are expected to commence commercial operation by 2018. These “physical” developments at the inter-state level need to be however backed up by policy and regulatory action backed by robust commercial mechanisms – as indicated in the above roadmap and also by “physical” augmentation of the networks at the level of intra-state transmission system.

VIII ANNEXURES

Annex I: Detailed review of available literature

1. **Report Summary**: CRISIL- FOR- Assessment of Achievable Potential of New and Renewable Energy in different states during 12th plan period, determination of RPO trajectory and its impact on tariff.

Factors	Key Issues/Challenges
Business/Commercial Model	1) Large number of solar projects were awarded through competitive bidding under National Solar Mission. Financing these projects is challenging as bankability of the projects allotted under competitive bidding scheme has not yet been established **Mitigation**: A single government or semi–government financing agency could act as the nodal agency for all applications to be processed (after detailed technical and commercial due diligence) and then other financing institutions could take up these projects for financing. 2) The implementation of small hydro projects is governed by the State policies and the State Governments allocated land site to private developers. The process of allotment of sites and selection of developer are often time consuming and is widely litigated. Also, small hydro has a longer gestation period of 5-6 years and there is a lot of uncertainty due to hydrological & geological risks
Land/Approvals/Clearance	1) Acquisition of land is very critical issue in Maharashtra which has resulted in long delays in commissioning of projects, cancellation of many projects and substantial increase in the cost of land. **Mitigation**: Clear land acquisition policy is required 2) States such as Karnataka have number of good windy sites but forest issues have resulted in developmental issues. The procedure for the change of land usage and other clearances is a time-consuming procedure. Getting Forest clearance (both stage 1 & stage 2) is a time consuming process and can take 1-1.5 years depending upon the progress of the project. **Mitigation**: Single window clearance policy and usage of land patches limited to turbine/tower width could encourage faster acquisition of land. 3) In case of Small Hydro power development land acquisition, forest clearance, irrigation clearance etc. takes long time also add to the increased gestation period
Transmission capabilities	1) The lack of adequate evacuation infrastructure and grid interconnections are one of the biggest barriers because of which potential wind sites in Rajasthan, Gujarat and coastal Tamil Nadu could remain less tapped. Once the SR grid is connected with the National grid, the evacuation of high wind energy would no longer be an issue. RoW issue is a matter of concern in the state of Maharashtra **Mitigation:** All state transmission utilities should prepare a comprehensive 5-year transmission plan with appropriate consideration

	of the renewable generation projects based on load flow studies and location of generation projects
Resource & potential Forecasting	1) Poor predictability of VRE hampers the grid management. **Mitigation**: Linking of Southern Grid with the National Grid, allowing open access & third party sale, improving forecasting tools and incentives for usage of IT enabled tools for carrying out the robust wind forecast are needed. 2) Revalidation of wind resource potential: MNRE's estimate of the wind energy potential of 49GW and needs updating. LBNL's study has estimated the potential to be between 400-800GW while a study carried out by Jami Hossain, Vinay Sinha and VVN Kishore gives a wind farm potential of 2,076GW. 3) India doesn't have its own solar potential assessment tools. **Mitigation:** Solar data collection centres should be set to facilitate correct data assessment. 4) A comprehensive estimation of small hydro potential in the country should be carried out. Key states where abundant and unused potential exist are the states of Arunachal Pradesh, Uttarakhand, Jammu & Kashmir and Himachal Pradesh.
Data Availability	1) A number of state nodal agencies are not able to establish and maintain a technical library, a data bank, or an information centre or collect and correlate information regarding renewable energy sources. **Mitigation**: There is also a strong need to integrate these data resources and present them to potential developers in a user-friendly way 2) Since success of a solar power project depended mainly on the correct assessment of the radiation data, there is requirement to set up a solar radiation data collection station to facilitate accelerated development of solar power projects
Cost	1) Renewable energy costs more than conventional energy on a stand-alone basis. Renewables are the only free hedging mechanism against price volatility of fossil fuels. The risk-adjusted cost of renewable energy is lower than that of fossil fuel–based fuels, and their use enhances the price certainty of the portfolio and increases energy security
Health of distribution utilities	1) Though the cost of supply is increasing steadily, the tariff revision is not being carried out as a necessity. Due to this, the DISCOMS are facing huge financial losses. **Mitigation**: An incentive structure to support additional burden on utilities for procuring renewable energy can be structured. Use of

	market-based competitive price discovery and least-cost REC trading across states can reduce the extent of subsidies.
Financing	A national partial risk guarantee facility, which could be managed by IREDA or private sector FIs, could share risks such as refinancing, construction financing, off -take by utilities, resource availability, and technology. IREDA needs to explore new instruments, such as green bonds, new equity, and synthesized products, with which to raise financing and enable risk sharing and mitigation in renewable energy projects.
Tariff Related issues	1) FiT rates for wind energy proposed by many states are very less and hence not attractive to investors. For e.g. AP has set FiT of Rs.3.50/kWh while the CERC proposes a tariff of Rs.4.63/kWh. Also the states do not revise tariff's as often as required. 2) In case of Small Hydro Projects the feed-in tariffs do not adequately compensate for the high resource and other operational risks investors are likely to face over the 35-year investment time horizon 3) Tariff calculation for biomass based generation doesn't take into consideration various issues like Wastage in storing the biomass stock, variation in cost of biomass fuel etc.,
Other issues	1) Only a few states (like Maharashtra and Rajasthan) have RPO shortfall clause in RPO regulation. This has resulted in many states not complying with their own RPO targets. Many states have not specified their targets beyond 2013 or 2014 which leads to uncertainty. **Mitigation**: Improved frequency (Monthly/Quarterly) for RPO Compliance monitoring, stricter enforcement for non-compliance is needed. Automatic pass through of RE and REC cost in retail tariffs could encourage compliance of RPO.

2. **Report Summary**: Unleashing the potential of Renewable Energy in India

Factors	Key Issues/Challenges
Business/Commercial Model	1) Although turn-key model has enabled rapid growth of the sector, it has discouraged competition in the areas of equipment and technology selection. As a result, the performance of commissioned projects has suffered and the cost of equipment has soared. **Mitigation**: Promoting competition in equipment sourcing might be an appropriate option for a sector which may help to bring down the equipment cost 2) In the Small Hydro sector, development has been relatively slow because of long delays in getting clearances and acquiring access to evacuation infrastructure, lack of clear policy for private sector

	participation in some states, and issues associated with land acquisition 3) The Biomass based generation sector suffers from lack of reliable resource assessment
Land / Approvals / Clearance	1) Land and resource acquisition issues are a major obstacle. SREDA/state nodal agencies, which have primary responsibility for resolving these issues, lack adequate resources and have limited importance within the state government hierarchy. **Mitigation**: There is a need to facilitate transparent, fair and timely acquisition of land.
Transmission capabilities	1) The limited availability of evacuation infrastructure and grid interconnections is one of the biggest obstacles. The lack of support infrastructure in the form of a strong indigenous supply chain remains a major barrier. **Mitigations**: ➢ Make renewable energy evacuation a high-transmission priority ➢ Invest in high-quality, integrated resource monitoring systems ➢ Dedicated funding should be allocated as part of existing programs, such as the government's RGGVY or new green funds
Data Availability	Lack of good-quality data on renewable resources also remains a problem, despite heavy investment by the MNRE in collecting data on renewable energy.
Other issues	Renewable energy parks can be created to implement comprehensive pilot models in a few states. Such parks could be created as joint national and state initiatives in pilot states. They can provide ready-to-bid project pipelines; prefeasibility studies, including resource assessment data; access to land; transmission infrastructure; and preferential open access policies. State and central funds could catalyse R&D and supply chain innovations in renewable energy parks. If proven successful, solutions tested in the parks could be replicated across India.
Cost	1) The cost-plus approach to tariff setting has led to incentives that hinder development of renewable energy resources in India. The combination of accelerated depreciation and a cost-plus mindset has failed to encourage cost competition in the wind sector **Mitigation**: Policies could be based on short- and long-term national targets and broken down into state-level RPOs that are mandatory and enforced. Technology-specific incentives could be supported by earmarked funding and increasingly allocated on a competitive basis. 2) Due to limited field experience and data, process standardization and quality benchmarks are not uniform across solar projects. This has prevented manufacturers from enjoying economies of larger scale production.
Health of distribution	1) Due to higher cost of power from RE, utilities are saddled with

utilities	losses. Also, no revision of consumer tariffs on a yearly basis but the increase of renewable energy feed-in tariffs are, leaving the utilities to make up the differential. 2) Given cross-subsidies from high-tension industrial and commercial customers to certain consumer categories (such as agriculture and low-volume households), industrial customers look for ways to purchase cheaper power through third-party sales or captive generation. This, in turn, forces utilities and regulators to constrain open access in order to ensure that the utilities retain their paying consumers and remain financially secure. As a result, utilities have limited incentives to go out of their way to encourage renewable energy development.
Financing	1) Tariff regulations lack an appropriate mechanism to minimize the risk of uncontrollable factors, such as wind variability and solar insulation level variation. This problem limits both - access to finance and introduces a bias toward investment in fossil fuel–based technologies, whose risks are more easily understood and mitigated. As a result, most projects are financed on the promoter balance sheet and not on a project finance basis. In many cases, project developers have to assume the refinancing risk, making it difficult for new entrants and small- to medium-size developers to raise finance.
Incentives	1) At the financial cost of coal-based generation, renewable capacity is not financially viable. Solar in particular is require subsidies in the short to medium term particularly if renewable purchase obligations are enhanced rapidly in line with the targets of the NAPCC. 2) Skewed financial incentives for facilitating investments in renewable energy.
Large scale deployment	1) India needs to streamline bureaucratic processes for clearances and approvals. **Mitigation**: State nodal agenciesneed to be strengthened. A comprehensive capacity-building program on emerging regulatory, legal, and financing issues to facilitate grid-connected renewable energy should be structured. Policy initiatives such as enforcement of state-level RPOs could provide an immediate boost to the sector. Initiatives that increase financial sector capability and awareness, strengthen state nodal agencies, and invest in high-quality resource information systems can also be implemented. 2) In the absence of unified national legislation, multiple laws and policies govern development, often creating delays and conflicts. **Mitigation:** A single agency or institution often becomes a bottleneck, creating problems for the entire project development cycle.
WTG Manufacturing	1) A strong domestic sector of WTG manufacturing can accelerate renewable energy development, as seen in the wind sector. All other major renewable energy sectors (solar, biomass, small hydropower)

	suffer from lack of strong indigenous supply chains. The solar sector needs strong local R&D and manufacturing to bring down costs over the long term **Mitigation:** The policy such as JNNSM intends to introduce incentives for facilitating local manufacturing and R&D.

3. **Report Summary:** CRISIL- Assessment of various Renewable Energy Resources Potential in different States, Determination of RPO trajectory and its impact on Tariff.

Factors	Key Issues/Challenges
VRE Concentration	1) Not all states are rich in Renewable energy sources. For instance, most of the wind potential is available in states like Tamil Nadu, Karnataka, Gujarat, Andhra Pradesh, Maharashtra, Rajasthan, Madhya Pradesh and Kerala. **Mitigation**: Integration of farms located in different pockets through transmission infrastructure will help in reducing the variability in generation of the wind resource which in turn will result in cost saving.
Land/Approvals/Clearance	Land availability and the time taken for clearance of land which comes under forest areas poses a problem to development of wind based generation.
Transmission capabilities	The biggest impediment as being perceived by the wind power developers is the inadequate power evacuation arrangement for RE based power.
Other issues	Lack of visibility for existence of AD scheme has become a concern for the investors in RE sector. Proposed amendments in the DTC and implementation of GST will impact the investor's portfolio in RE. **Mitigation**: A supplementary scheme to AD has to implement to continue investors interest in this sector.
WTG Manufacturing	Current and projected growth rates for wind power development in India are putting increasing strain on the WTG manufacturing sector, and the component supply chain needs to be improved. It would be beneficial for the small and medium enterprises [SMEs] to have access to concessional financing to bear the risks related to production capacity augmentation. **Mitigation**: Financing options for turbine manufacturing company should be available by the financing institutions like REC, PFC, IDBI etc.

4. **Report Summary:** Indian Wind Energy Outlook 2011

Factors	Key Issues/Challenges
Grid Management	1) For a conventional electricity network based on a radial power distribution model, high levels of wind power would pose some challenges related to the stability and efficiency of the interconnected systems. **Mitigation**: The IEGC 2010 sets up special provisions that require system operators to make efforts to evacuate all power generated from VRE like solar and wind with 70% accuracy in forecasting and scheduling.
VRE Concentration	The best wind sites in various states with high wind potential, and thus the large scale wind power generation are located in remote locations.
Land/Approvals/Clearance	1) When repowering of WTG is considered the new investors that are interested in entering this area would have land issues as the land owners may create complications for repowering. **Mitigation**: JVs or PPP projects can come up considering the interest of both the owners and investors for such projects. 2) In most of the states, availability of land for wind farms is a contentious issue. Conversion of land use status from agricultural to non-agricultural and forest clearance is a time consuming process. **Mitigation**: Single window clearance for land under forest area and quick decisions to be made. The govt. should acquire the land for project developer and then transfer the land to them on pro-rata basis.
Transmission capabilities	1) Inadequate grid infrastructure is a major problem. With more and more wind based generation coming up, the grid does not have sufficient spare capacity to be able to evacuate it. 2) In India, the local distribution network system is weak and often requires substantial augmentation and layout of parallel evacuation infrastructure. The issue is further complicated by stipulations related to cost sharing of this additional infrastructure, which represent an issue especially for state owned utilities that are cash strapped.
Resource& Potential Forecasting	With more and more variable sources likely to come online, managing variability will be a challenge. **Mitigation**: Accurate forecasting is critical to managing wind power's variability. To implement the IEGC guidelines, each new wind power developer has to make arrangements for a data acquisition system facility. This will help both the VRE project and grid operators to share data and pass on information in a short time span. Daily generation schedules and revised schedules can also be communicated to the grid operator through this arrangement.
Repowering	There is large concentration of old wind turbine with a lower rated

	capacity and are aged out which in turn increases the O&M costs and reduces revenues. Also the old turbines were installed at a hub- height of 30-40 metres with resulted in lower generation. Some factors that are posing a hurdle to repowering the old wind turbines are: Land ownership, Existing PPA's, High costs associated with Repowering, Disposal of old turbines, Lack of incentives. **Mitigation**: Repowering on WTG should be done with a higher capacity rated turbines and this in turn will also result in higher generation from the same piece of land with higher CUFs.
Variability	Variability of RE based power is a major deterrent to large scale RE deployment. **Mitigation**: There are two ways to solve the challenge. The first is to use a variety of renewable sources in combination. The second is to rely on energy storage. Additionally forecasting can help address the variability issue of renewables (wind and solar) when used for large-scale projects.
Other issues	Inadequate transportation facilities for sites located in the isolated areas like deserts and sea shore. **Mitigation**: Investments in transportation vehicles. Roads etc needs to be made for connecting the manufacturing hub to the sites.
Incentives	Introduction of Direct Tax Code (DTC) can cause slowdown in the wind power industry were investors have taken maximum advantage of the Accelerated Depreciation mechanism
Tariff Related Issues	1) Since both the CERC and SERC set tariff for wind power, there is a confusion due to the duality. Most of the time, tariff set by SERC's are not in line with that set by CERC
WTG Manufacturing	1) Due to rapidly increasing wind based generation, the WTG manufacturing industry is under stress to ramp up their manufacturing capacities. **Mitigation**: It would be beneficial for the small and medium enterprises [SMEs] to have access to concessional financing to bear the risks related to production capacity augmentation.
Other issues	1) There are a number of contradictions between existing policy guidelines and frameworks. For e.g. NAPCC stipulates that by 2020, India should be producing 15% of its energy from RE sources (other than large hydro). This provision comes in direct conflict with the IEP which visualizes only 5% renewable penetration by 2032

5. **Report Summary:** LBNL – Reassessing Wind Potential Estimates for India: Economic and Policy Implications

Factors	Key Issues/Challenges
VRE Concentration	1) More than 95%of the wind energy potential is concentrated in just five states in southern and western India – Tamil Nadu, Andhra Pradesh, Karnataka, Maharashtra, and Gujarat.
Resources & Potential Forecasting	1) There is ambiguity in the potential of wind energy in India because as per MNRE's potential estimates the potential harnessed in TN has already surpassed its estimated potential. MNRE has to reassess the potential. **Mitigation**: A latest version of potential of RE should be published and made available in the public domain which may help in investment decision. Research agencies like C-WET, LBNL, NREL should be engaged for this purpose.
Data Availability	The RE atlas for India has started proving incorrect as there are variations in the claimed potential and actual potential. It is outdated as in case of Wind it was formed considering 30-50 metre hub-heights which can, now with newer technologies, can reach upto 80 metres in India.
Large Scale Deployment	There is huge potential of RE lying in the deserts and seashore of India. But the grid infrastructure is still not adequate due to lack of proper planning. **Mitigation**: There is an immediate need for grid infrastructure planning with the vision of future RE deployment.
Other issues	There is no incentive or policy to encourage the repowering of WTG. **Mitigation**: There has to be an incentive scheme for the investors in form of subsidies or in form of policy to capture investor's interest in repowering the Wind technology. For this purpose, RRF can be used.

6. **Report Summary:** Ministry Of New and Renewable Energy – Transmission Infrastructure for Renewable Energy projects- Draft Sub- Group Report

Factors	Key Issues/ Challenges
Grid Management	1) Large amount of RE generation is expected in the coming years. The State alone cannot absorb, along with variability associated, the entire quantum of energy generated. **Mitigation**: The issue of variability can be addressed through pooling of geographically disperse intermittent sources so that average power at polling station does not have more fluctuation. Integrating different renewable sources like solar and wind, which produces peak energy during different times of the day will reduce supply fluctuation and leads to better utilisation of Transmission system

Transmission capabilities	Utilities under financial crisis find it difficult to absorb high cost RE. There is inadequate transmission infrastructure **Mitigation:** Adequate transmission infrastructure should be set up and gestation period must be brought down significantly. National Clean Energy Fund should be used to set up this facility.
Balancing Capacity	Due to intermittent nature of the RE based generation, adequate spinning reserves need to be installed which further increase the cost of renewable energy supply.
Other issues	1) Strong monitoring and evaluation frameworks for the various schemes and programs will be crucial for successful operation of the schemes. The deployment of wind farms, being widely distributed (often in inaccessible areas), the performance is extremely difficult to monitor. **Mitigation**: Most of MNRE's present programs incorporate monitoring and verification systems but these need to be strengthened. Modern technology needs to be used for greater and more efficient monitoring and verification which is possible through automatic data acquisition. 2) It is of vital importance that SNAs are adequately strengthened in terms of manpower and skill set. Also effective co-ordination with the other functional ministries -MoP, MoPNG, MoEF, etc. is needed **Mitigation**: There is need to encourage states to strengthen the administrative set-up and get local self-government institutions like Municipalities and Panchayats involved in planning and implementation process. The need to gear up the SNAs for playing a much more proactive role for promotion of renewable energy in their respective States

7. **Report Summary:** Strategic Plan for New and Renewable Sector for the period 2011-17

Factors	Key Issues/ Challenges
Business/ Commercial Model	1) RE technologies often do not have the economies of scale as individual projects. Hence the overheads of standalone projects tend to be high, often rendering such projects expensive. **Mitigation**: Channels that result in economies of scale and hence reduced unit costs can thus be extremely beneficial for deployment of such technologies. State Nodal Agencies and other elements of the delivery chain (including, for example, banking channels) needs to be strengthened. An overall capacity building and communication program will be developed to address this.Strong monitoring and evaluation frameworks for the various schemes is needed
Land/Approvals/Clearance	1) In many States the process for allotment of sites and statutory clearances, including land acquisition, forest clearance, irrigation clearance etc is extremely time consuming.

	Mitigation: The Ministry will ensure regular interaction with concerned State Departments, Regulatory Authorities and Agencies to periodically address issues relating to State policy & regulatory issues including appropriate enforcement of RPO regulations, statutory clearances, land acquisition, power evacuation & transmission, for sector specific renewable power projects.
Transmission capabilities	1) There are also inadequate power evacuation and transmission facility especially for Wind power projects, matching with the development of the sector in the State. **Mitigation**: The Ministry will ensure regular interaction with concerned State Departments, Regulatory Authorities and Agencies to periodically address issues. Ministry would like to assist states in setting up transmission systems required primarily for renewable energy projects. Similarly some assistance may be required for Solar Parks.
Resources & Potential Forecasting	1) For accelerated deployment of RE technologies, availability of detailed and credible information on the resources is imperative. There is need to continue to create/ update/ validate database on Renewable energy resources through a systematic approach in association with expert and specialized institutions.
Data Availability	1) Strengthening of database, documentation and recording system of all the important data and information is needed. **Mitigation**: In this regard it may be desirable to develop a centralised IT enabled database for easy access as well as security of data
Other issues	1) While the deployment and development activities of the Ministry have been gradually increasing, the availability of technically qualified manpower has been shrinking. **Mitigation:** Financial support for organizing trainings, deputation of professionals in trainings and study tours within the country and abroad, award of fellowships is needed. The Ministry is in the process of formulating sector wise HRD strategies in consultation with academic institutions and Industry. 2) Inadequate database management, documentation/ recording system are problem areas and needs to be strengthened.
Cost	Even as there has been substantial drop in technology costs in some of the key technologies, there is still a need for fiscal and subsidy support for them. **Mitigation**: For this, the alternate financial instruments that will be supported include: ➢ Risk Guarantee Fund that will address the technology risks, especially for solar ➢ Enabling availability of debt at a lower cost ➢ Enhancing the term lending period from 5 to 10 years particularly for technologies such as solar

	➢ Using NCEF effectively
Grid Code Protocols	Integration of wind will largely depend upon operating policies implemented in the control room. **Mitigation:** Key policies areas which require attention are: Policies regarding efficient procurement of more flexible resources, shorter gate closure time, frequent inter-hourly schedule, greater harmonization between national and regional markets in reserve sharing and transmission scheduling, congestion management, standard grid code, standard data requirement for wind plants etc.
Framework for planning forecasting, scheduling & dispatch	Power systems operate most efficiently when resources are economically and effectively scheduled to achieve the goal of balancing supply and demand. It is advantageous to manage wind variability if markets are able to make frequent changes in the schedules submitted to system operators. One of the ways to reduce forecasting and dispatch errors is to reduce gate closure time for better integration.

Annex II: Average distance between turbines to identify the designated turbine

The following algorithm outline the steps that need to be taken to define the average distance between turbines to identify the designated turbine (DT)

AVDST is defined as the average horizontal distance between a turbine and its nearest neighbour. Each turbine must be within a distance of 5 times AVGDIST of a designated turbine. The base of each turbine must also be within 75 m of elevation of the base of a designated turbine which also satisfies the first criterion.

ALGORITHM:

1. The distance between each turbine and every other turbine is calculated.
2. The distance between each turbine and its nearest neighbouring turbine is determined from the calculation in step 1.
3. A preliminary average distance between a turbine and its nearest neighbouring turbine is calculated.
4. If any turbine is more than 5 times the preliminary average distance between turbines and their nearest neighbour it is considered an outlying turbine. It will become a designated turbine. It is removed from consideration and the average distance between a turbine and it's nearest neighbour is re-calculated.
5. The number of turbines for which each turbine satisfies the location and elevation criteria is calculated.
6. The turbine which satisfies the location and elevation criteria for the most other turbines is tentatively selected as the first designated turbine.
7. If there is more than one turbine that satisfies the selection criteria for an equal number of other turbines, then the one which has the least average distance between itself and the other turbines for which it satisfies the criteria becomes a designated turbine.
8. If one turbine satisfies the selection criteria for more other turbines than any other turbine then it becomes a designated turbine.
9. All turbines for which the new designated turbine satisfies the selection criteria are removed from consideration.
10. If there are turbines left without an associated designated turbine repeat the process from step 5 considering ONLY those turbines without an associated designated turbine.

Annex III: Cycling Costs

Wind induced cycling costs are proposed to be computed for two plant cycling protocols (Curtail and Deep Cycle). Under both the above protocols, cycling costs are computed for different levels of installed nameplate wind capacity. The total wind induced cycling costs are the sum of the plant cycling component and the wind curtailment component. In the immediate instance for application in the Indian context, it is proposed that wind curtailment component may not be used. However, for the sake of completeness, both the cycling costs and curtailment costs determination is discussed below:

- Plant Cycling Component Calculation

This computation would require current resource expansion plans, unit operating characteristics, load forecasts and cost per cycle metrics to estimate wind induced cycling costs using a method that applies a cost per cycle to the forecast number of wind induced cycles to determine annual wind induced cycling costs. Plant cycling costs are the number of wind induced cycles multiplied by the cost per cycle where cycles are one of two types 1) shallow cycle or 2) deep cycle. The costs are calculated on an annual basis and divided by the associated MWh of annual wind generation resulting in a Rupee per Megawatt-hour metric for ease of discussion and ease of implementation.

- Types of Cycles

Cycling is generally defined as the operation of thermal electric generators at varying load levels, including turning units on/off, in response to system requirements. Some generators such as small gas-fired power plants (OCGT) and pumped hydro units are designed for cyclical operation to follow, or balance, variations in load. In contrast, the coal-fired fleet is normally designed for baseload, or full output, non-varying, operation.

Increasing amounts of wind energy in the Indian, especially SR power system has changed this implied operation of the coal-fired fleet. In hours of low loads and high wind generation, previously baseloaded generators are now required to cycle and reduce their output to maintain economic system balance. With an ever larger wind portfolio, the depth of cyclical operation will affect more and more generators. The coal-fired fleet will be required to ramp down to their minimum capacity, or possibly be required to turn off entirely, more frequently. The previously baseload fleet will cycle deeper and more frequently to balance wind and load.

- On/Off Cycling

On/Off Cycles can be divided into hot, warm, and cold cycles with increasing number of hours off-line respectively. Compared with load following cycle, on/off cycles cause more damage to coal units and are therefore the most costly types of cycles. Hot start costs represent the type of cycle a unit would go through if it were decommitted overnight to lower system minimums and reduce cycling on other units in anticipation of large wind generation events.

The methodology described here for calculating cycling costs does not consider on/off cycles as a viable means to balance generation with net load due to both the high cycling cost and the cost associated with the unit being unavailable (more expensive generation could be required) in the event actual wind generation is significantly below forecast. The analysis described briefly below is the basis for this assumption.

The benefits of avoiding curtailments are equal to the cost of a curtailment (Rs/MWh) multiplied by the curtailed energy (MWh). In order to make an economic decision to shut a unit down, these benefits must outweigh the unit's hot start cost.

Hot start costs run into the hundreds of thousands of Rupees and are proportional to the size of the unit. As the size of the unit increases, both hot start costs and potential benefits from avoided curtailments increase.

As an example, decommitting a coal unit with a 100 MW minimum would reduce the system minimum generation level by 100 MW at a cost of over Rs 25,00,000 for a hot start. Assuming curtailment costs of Rs 3000/MWh, a curtailment event of 833 MWh (Rs 2500000/3000), or 8.3 hours, is required to make the decommit decision better than break-even.

Wind curtailment events in the year of implementation (say, 2013) are classified by depth (MW) and duration (hours) to determine the size of the pool of potentially avoidable curtailment energy (MWh). Events of the size described above are required to be forecast in 2013 although accurately forecasting these infrequent events for operational purposes would be difficult and the economic benefit small compared to the operational risk incurred by decommitting the unit. Based on this poor risk/reward dynamic, unit decommittment is not considered as an option for balancing generation with net load to accommodate wind generation in this proposal.

- Load Following Cycling

Load following cycles can be divided into two general categories: shallow cycles and deep cycles. Shallow load follow cycles maintain the unit's design temperatures causing far less stress to components and equipment. A shallow load follow cycle reduces output as low as the unit's economic minimum, but not below. Deep load follow cycles take the unit to its lowest output level where the unit is still stable, safe and environmentally compliant – called the emergency minimum.

Running at emergency minimum will increase costs for several reasons:

Pulverizers and related machinery necessary to supply the boiler with fuel may have to be stopped and re-started;

Temperatures for certain plant components fall below their design specifications causing increased thermal cycle stresses and thermal fatigue damage;

Pressure variations and pressure related stresses and fatigue increase;

Corrosion fatigue risks increase due to water chemistry changes caused by process changes, i.e. - oxygen ingress, exfoliation transfer;

Units are less efficient at emergency minimums (higher heat rates) and, therefore, both fuel usage and CO2 emissions rates increase;

Flue gas temperatures drop toward dew point causing fabric filter bag fouling and equipment corrosion;

Air preheater baskets foul;

Fuel costs increase per megawatt produced due to need for stabilization fuel and deterioration in heat rate.

- Estimating the Number of Cycles

To estimate the number of coal unit cycles attributable to wind, requires forecasts cycles based on hourly obligation load, wind generation forecasts and power system's baseload unit generation profiles. This information is required to estimate the frequency and intensity of cycles. Inputs needed to calculate cycles are as follows:

- Load Forecast

The hourly obligation load forecast and wind generation forecasts are based upon historically coincident hourly load and wind profiles from a one year period ending in March. Using hourly wind and load data from the same historical period ensures that correlations between wind and load due to meteorology are accounted for properly in the modeling. The base year data is scaled to meet the energy and peak load forecasts that are used in planning models, while maintaining the historical hourly load shape. With this method, the correlation between load and wind generation is maintained while the effects of load changes over time are captured.

- Generating Unit Characteristics

Unit level detail of base load and must take units including: unit minimum and maximum output levels, typical outage schedules, expected forced outage rates and planned capacity changes (additions and retirements).

- Wind Generation Profile

Actual wind generation – at an hourly level is available from various sub-stations. The data for such sub-stations at Andhiyur and Ponnapuram were collected by AF-Mercados for the purposes of this study. Hourly wind profile data are also available at the level of the SLDC.

- Counting the Cycles

The number of coal unit load follow cycles (for both shallow cycles and deep cycles) directly attributable to wind generation can be estimated using the following methodology:

An hourly net load forecast is created for each year. The net load is the difference between the forecast obligation load and the forecast wind generation.

For each hour of the year, the net load is compared to the maximum aggregate generation capacity of the baseload plants for that hour. If the net load is lower than the maximum aggregate baseload capacity, then it is assumed that one or more baseload units will have to decrease output, or cycle, to follow load. Unit maintenance schedules, scheduled power purchase contracts and estimated forced outages (EFOR) are accounted for in the calculation (EFOR by derating each unit). Therefore the maximum baseload capacity for a given hour is the sum of the expected online units only.

For each day of the year, the maximum load follow, in MW, is determined based on the hourly calculations above. The model then determines how many baseload units are required to cycle to balance net load and generation. Annual cycles are the sum of this daily calculation. This method assumes baseload units cycle a maximum of once per day. These calculations are repeated assuming there is no wind generation on the system, i.e. the net load is equal to obligation load to count cycles that would have occurred absent any wind. The difference between these two cycle counts (with and without wind) is the estimate of the number of cycles attributable to wind.

- Calculating the Cost per Cycle

The assessment is a top-down analysis using a statistical approach and baseline historical data. In this assessment, the relationship between cycling operations (hot starts, warm starts, cold starts, shutdowns, load changes) and costs (capital, operations, maintenance, etc.) using the current plant configuration and historical operations and maintenance costs is determined.

Baseline costs can then be established for each power plant or type of power plant based on past data.

- Calculating the Wind Curtailment Cost Component

In addition to load following by baseload units to accommodate wind generation, wind curtailment may be required when the cycling capabilities of the baseload fleet have been maximized. Wind curtailment costs are calculated by multiplying quantity of wind curtailed (MWh) by the cost per MWh of curtailment. The costs are calculated on an annual basis and divided by the associated MWh of annual wind generation (including curtailed hours) resulting in a Rupee per Megawatt-hour metric for ease of discussion and implementation.

- Forecasting Wind Curtailment MWhs

The MWhs of curtailed wind generation may be estimated by determining, for each hour of the year, the quantity of excess wind remaining on the system after all baseload coal units have cycled down to their minimum loads. This quantity of wind must be curtailed to balance load and generation. The calculation is dependent on the operational protocol, Curtail or Deep Cycle.

- Per MWh Curtailment Costs

Costs per MWh of curtailed wind are comprised of the following four components:

- Avoided Energy Cost

Avoided energy or replacement energy cost is the cost of the coal generation that would have been avoided if not for the wind curtailment. This cost is based on the annual average coal dispatch costs for the fleet in the power system. While this method is a simplification and does not explicitly capture the reduced coal plant efficiencies caused by operating at lower output levels when cycling due to wind, it does capture some of these effects of cycling in as much as typical cycles are captured in the dispatch models. Avoided energy costs are multiplied by all curtailed wind MWhs.

- CO2 Emissions Cost

The CO2 emissions costs are the costs incurred due to the emissions from the energy that replaced the curtailed wind. The weighted average of the emission rates (tons/MWh) of the units online in a given year is used to derive the CO2 emissions cost.

- Renewable Energy Credit Opportunity Cost

The opportunity cost of the Renewable Energy Certificates (REC) that was not generated as a result of the curtailment is applied to all curtailed wind. This assumes the REC has value either for compliance or for sale into the market. This would require forward curves for REC prices.

Annex 4: Cycling: International Experience

Any coal unit can be operated dynamically, yet modulating steam plants introduces stress to the plant that in many cases the unit is not designed for. However, a growing body of international evidence has shown that coal-fired units may be operated dynamically without dramatically lessening the plant's operational lifetime.

Two 680 MW coal fired units in China have been cycling heavily for over fifteen years, with daily two-shift operation. The plant was designed for cyclic capabilities and is equipped with a turbine bypass system that the plant operators cite as providing the plant's cyclic durability. Over the plant's lifetime, significant operational experience has been gained and the engineers have concluded that the plant "convincingly affirmed that large coal-fired generating units can perform extensive two-shift operation without requiring replacement of major components of boilers or turbines."[14]

Other studies find higher costs attributable to dynamic operation, but also acknowledge the potential to mitigate them. Along with the report from China, two EPRI studies lend credence to the idea that costs can be managed. In 2003 the study Feasibility of Wear and Tear Sensors for Flexible Plant Operations researched how sensor installations could inform control schemes to diminish cyclic damage. The study determined that new sensor technologies and software control applications could, in a cost effective manner, "enable most fossil-fueled plants to make the transition from base-loaded operations to flexible operations without any significant events or significant increases in undesirable effects."[15]

An unrelated EPRI study in 2004 studied the potential to reduce boiler damage resulting from cyclic operation. Their conclusions echo the previous research effort and suggest that by conducting specific plant analysis and implementing tailored operational changes or retrofits, "many cycling-induced boiler failure mechanisms… can be eliminated, minimized, or controlled."[16]

[14] J. Chow, M, Pearson. "EXPERIENCE FROM EXTENSIVE TWO-SHIFT OPERATION OF 680MW COAL / GAS-FIRED UNITS AT CASTLE PEAK Power Station - HONG KONG." Operation Maintenance and Materials. Volume 1 Issue 2. August 2002. Web. July 7 2010. < http://www.ommi.co.uk/PDF/Articles/55.pdf>

[15] R. Shankar. "Feasibility of Wear and Tear Sensors for Flexible Plant Operations" EPRI. December 2003. Web. 16 June 2010 < http://mydocs.epri.com/docs/public/000000000001003732.pdf >

[16] State-of-the-Art Boiler Design for High Reliability Under Cycling Operation, EPRI, Palo Alto, CA: 2004. 1009914. Web. July 21, 2010. < http://mydocs.epri.com/docs/public/000000000001009914.pdf>

Annex 5: Ramp Rates of Various Technologies

Ramp up Rate reflects the ability of a power plant to increase its generation in response to change in system demand, when required by the system operator. High ramp rate technologies are utilized for balancing generation from VRE sources. Typical ramp-up rates for various types of power plants (in % of capacity per minute) is:

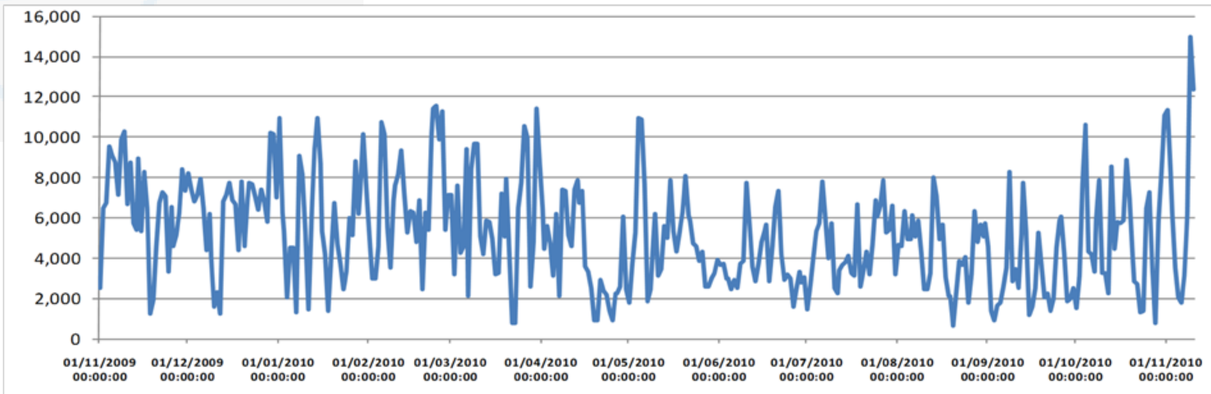
Diesel Engine	40% / minute
Gas Engine	20% / minute
Aeroderivate GT	20% / minute
Industrial GT	20% / minute
GT Combined Cycle	5-10% / minute
Steam Turbine Plants	1-5% / minute
Nuclear Plant	1-5% / minute

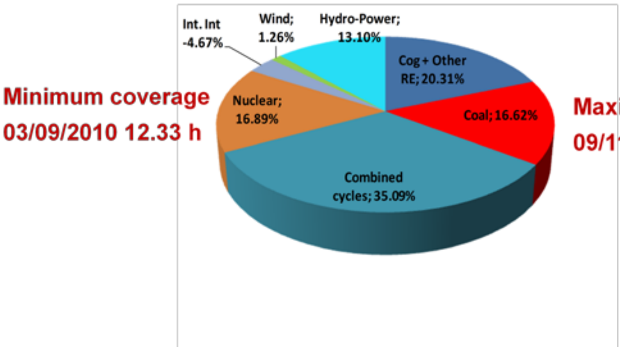
Such generation is nevertheless costly, and as suggested in this report pricing mechanisms for sharing of these costs must be developed to incentivize the states with huge renewable potential to integrate VRE sources in their state network.

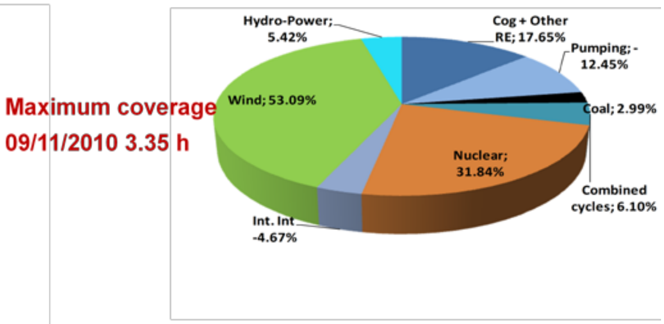
Annex 6: Management of RE on Large Scale: Spanish Experience

Spain has a large renewable energy program and features a very high penetration level of RE resources – particularly wind. It is a must run primary energy resource Very variable production output. Downward ramps in wind production in the mornings often increase morning ramps of conventional generation.

Penetration in 2010 of wind in crossed 53% for the country as a whole, as is apparent from the charts below. In combination with other RE resources, the total contribution touched 70% in September 2010.







The large penetration of RE and its high contribution is managed by REDELECTRICA, the system operator effectively through a combination of measures related to:

a. Demand Coverage
b. Forecasting
c. Generation Control and Supervision
d. Dynamic behaviour management during disturbances
e. Generation management
f. Ancillary Services provision

The power system must be maintained in regulation through the availability of adequate reserves. VRE affects the reserves to varying degrees[17].

[17] This is apparent even in Indian states like Gujarat where even as the system has adequate reserves, absence of running reserves or hot stand-by causes power outages when generation or demand changes suddenly.

Type	Definition	Influence of Wind Power on Reserve
Primary Regulation	Action of speed regulators from generator units responding to changes in system frequency (<30 s to 15 minutes)	Not influenced by wind power
Secondary Regulation	Automatic action of central algorithm and AGCs in the generation units that provide this service responding to changes in system frequency and power deviations with respect to France. (≤100 s to 15 minutes)	Only slightly affected by wind generation ramps when these ramps are opposite to system demand. Presently, no need to contract further reserve bands.
Tertiary Regulation	Manual power variation with respect to a previous program in less than 15 minutes. (<15 min to 2 hours)	Only slightly affected by wind generation ramps when these ramps are opposite to system demand.
Running Reserves or Hot Reserves	Manageable generation reserves that can be called upon within 15 minutes to approximately 2 hours. Include tertiary reserves and consist of the running reserves of connected thermal units and hydro and hydro pump storage reserves. (15 min-2 hours to 4-5 hours)	Significant influence of wind power. Reserve provision must be increased to take into account wind power forecast errors. Reserves are checked from day D-1 once market results are received until real time.

The Spanish system is extremely diverse with more than 700 wind parks. The plants belong to different companies with different policies for operation, switching and maintenance. However there is a need for planning and real-time communication. In the past, very slow contact in case of emergency reductions, outages or maintenance planning of the transmission assets next to connection points for generation. SO actions had to be always manual leading to longer execution times. When actions and supervision takes longer and risks are higher, stricter limitations must be in place and planned further in advance. This would lead to reduction in generation and installations. **This was addressed by REDELECTRICA by grouping facilities in control centers with real-time contact with the System Operator through the Control Centre for Renewable Energies (CECRE), a dedicated Renewable Energy management facility within the SO**.

Organisation of the SO function for renewables

CECRE has the mandate for control and supervision of special regime generation. It is required to maximize RES production, but always keeping the electric system in a secure state.

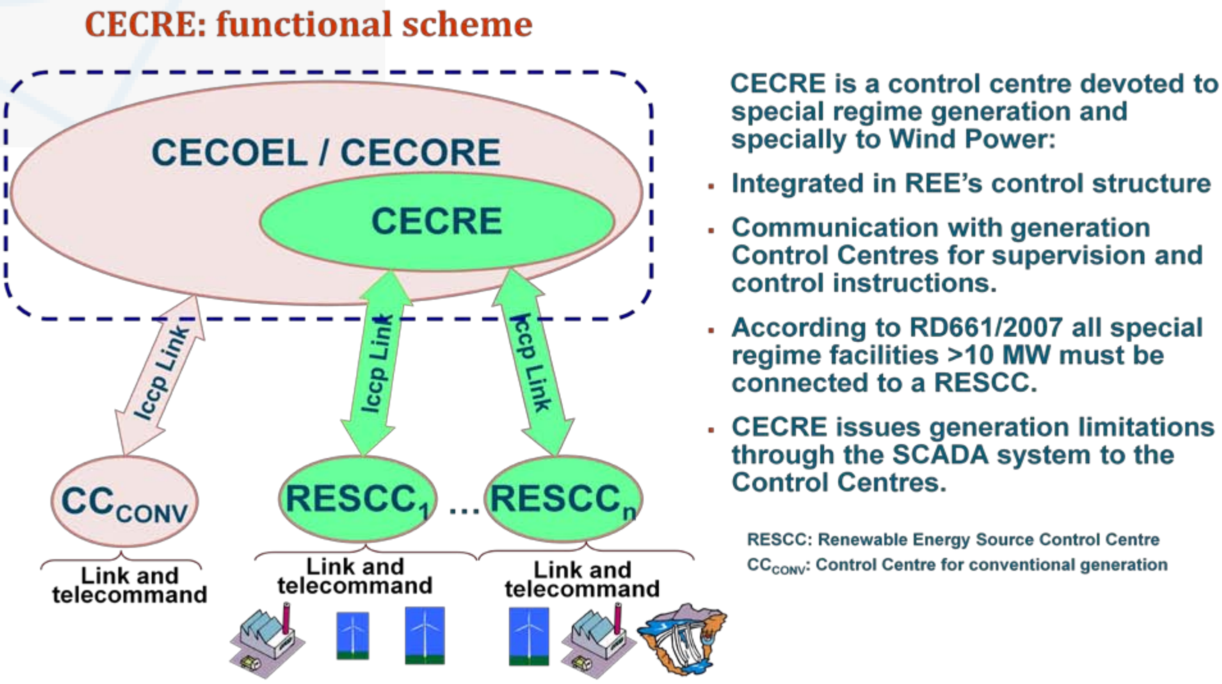
The specific roles of CERC are to:

- Organise special regime electric production according to the needs of the electric system.
  - Be the only real time communication channel with the main system operator (CECOEL) and with the Control Centres (RESCC), which would be the entities in charge of switching operations in the facilities.
  - Receive the relevant production information of generation units in real time and send it to CECOEL.
  - Coordinate, control and supervise all generation units by means of grouping them in Control Centres.
  - Contribute with security and effectiveness in System Operation.

- o Change zone simultaneous production hypothesis and preventive criteria (conservative) by real-time production control and therefore allowing:
  - Higher energy production
  - Higher installed power (agent decision)

The functional scheme of CECRE's operations is schematically presented below:

Figure: Scheme of operations of CERC for RES management



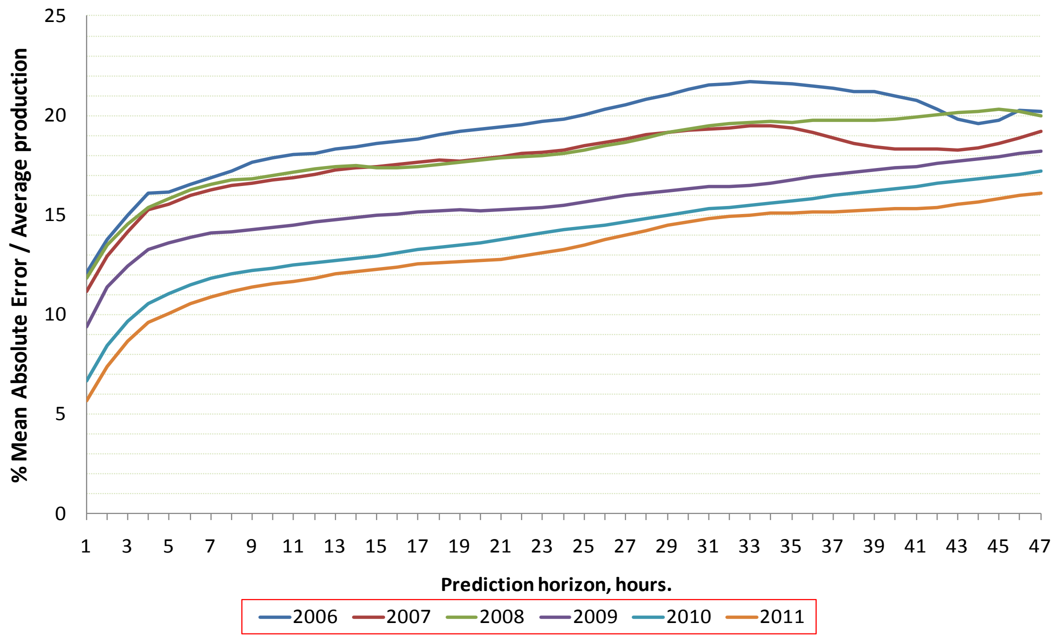
Forecasting

REDELECTRICA has an internal forecast of all wind parks. It produces hourly forecasts of next 48 hours by region or transmission system node (update 15 min.). It also produces total hourly forecast of next 10 days (update 1 hour).

The forecasts produced are matched daily with the forecasts submitted by the wind farms. Critical time horizons are 24 or 32 hours in advance for D-1 (previous day) reserve evaluation and 5 hours for real-time evaluation. Positive evolution in forecast error in the last years has resulted in fewer needs for reserves to cover wind forecast errors, especially in D-1.

Thus a combination of centralised and de-centralised forecasting is used. The accuracy of forecasting has improved significantly over time, with the use of better techniques, multiple models and better commercial organisation in processes (use of aggregators and permitting forecasts on an aggregated scale instead of local farm level forecasts.

Figure : Improvement of forecasting capabilities in the Spanish Wind Industry



Weekly and short term work planning is done in REE's transmission network.

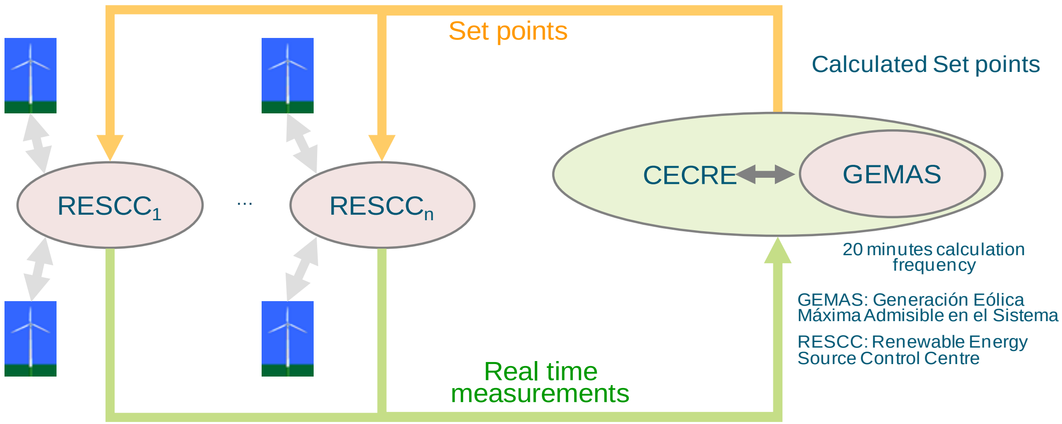
- 10 day wind forecast: used for weekly programming in some areas
- 48 hour wind forecast: used for short term programming in some areas

73% of installed wind capacity is connected directly to the transmission network or to observable levels. There is significant system visibility in EMS and state estimator. Rest can be modeled in state estimator on its closest transmission system mode using PSS/E. Forecast by transmission system node can be modelled for future scenarios in PSS.

System Management

Even with the predictions being refined over time there are various conditions where the reduction of wind generation become inevitable. These are largely due to sudden climactic changes which cause the system to run out of reserves due to wind and demand forecast error during off-peak hours. In such events SO intervenes actively.

Use of tools (GEMAS) maximizes the renewable energy resource use while avoiding risky situations by sending out wind power output curtailments in extreme situations.



The target of CECRE is to achieve a greater level of integration for renewable energy sources without compromising system security.