Explanatory Memorandum

Central Electricity Regulatory Commission (Deviation Settlement Mechanism and related matters) (Third Amendment) Regulations, 2015

Introduction

The Central Electricity Regulatory Commission (hereafter referred to as 'the Commission') notified the Central Electricity Regulatory Commission (Deviation Settlement Mechanism and related matters) Regulations, 2014 in January 2014, which were thereafter amended via the first amendment (notified in December 2014) and the second amendment (notified in August 2015). The objective of these regulations is to "maintain grid discipline and grid security as envisaged under the Grid Code through the commercial mechanism for Deviation Settlement through drawal and injection of electricity by the users of the grid".

Analysis of the grid frequency, which is a primary indicator of the health of the grid, suggests that the frequency has stabilized closer to 50 Hz over time. Progressive tightening of the frequency band, volume limits on deviation along with other deterrents and enforcement of DSM regulations are the factors contributing to this improvement in frequency profile. Currently as per the existing volume limits for deviation, the States may deviate from schedule up to 150 MW or 12% of schedule, whichever is lower, when the frequency is between 49.7 Hz and 50.1 Hz with a minimum of deviation allowed as 48 MW under CERC Order dated 20.1.2015 in Petition No. 6/RP/2015. Beyond these frequency limits, no deviations are permitted.

However, many states continue to deviate heavily from schedule on a consistent basis (Annexure I- 'Trends of Deviation' for a few states). This is primarily due to absence of or poor load forecasting, lack of planning, procedures for calling in reserves and non-adherence to schedule by grid-connected entities such as conventional generators and DISCOMs in the State. The plots also illustrate that deviations are irrespective of windy vs non-windy season, or whether the State has large renewable capacity installed or not. Additionally, volume of these deviations in the past has been shown to be statistically uncorrelated to renewable penetration for specific Renewable-rich states (Annexure II- Analysis on correlation of State boundary deviations with variation in wind and solar sources). Notwithstanding the above, several states have emphasized that managing renewables, especially wind, is posing a huge challenge, which is causing the States to deviate from schedule, and resulting in huge financial burden. In this context, several States have made presentations in meetings with CERC, Ministry of Power, MNRE, POSOCO, and other stakeholders, wherein it has been stated that the deviation limit is causing huge financial burden and preventing more renewable capacity being commissioned by the States. Subsequently, the Commission engaged in several rounds of discussions with all stakeholders, including renewable energy (RE) rich states.

Existing provisions of DSM Regulations

Regulation 7 of the Deviation Settlement Mechanism Regulations as amended provides as under:

"7. Limits on Deviation volume and consequences of crossing limits:

(1) The over-drawal/under-drawal of electricity by any buyer during a time block shall not exceed 12% of its scheduled drawal or 150 MW, whichever is lower, when grid frequency is "49.70 Hz and above" and "below 50.10 Hz":

Provided that no overdrawal of electricity by any buyer shall be permissible when grid frequency is "below 49.70 Hz" and no under-drawal of electricity by any buyer shall be permissible when grid frequency is "50.10 Hz and above".

(2) The under-injection / over-injection of electricity by a seller during a time-block shall not exceed 12% of the scheduled injection of such seller or 150 MW, whichever is lower when frequency is "49.70 Hz and above and below 50.10 Hz":

Provided that –

no under injection of electricity by a seller shall be permissible when grid frequency is "below 49.70 Hz" and no over injection of electricity by a seller shall be permissible when grid frequency is "50.10 Hz and above".

any infirm injection of power by a generating station prior to COD of a unit during testing and commissioning activities shall be exempted from the volume limit specified above for a period not exceeding 6 months or the extended time allowed by the Commission in accordance with the Connectivity Regulations.

any drawal of power by a generating station prior to COD of a unit for the startup activities shall be exempted from the volume limit specified above when grid frequency is "49.70" Hz and above".

(3) In addition to Charges for Deviation as stipulated under Regulation 5 of these regulations, Additional Charge for Deviation shall be applicable for over-drawal as well as under-injection of electricity for each time block in excess of the volume limit specified in Clause (1) and (2) of this regulation when average grid frequency of the time block is "49.70 Hz and above" at the rates specified in the table A & B below in accordance with the methodology specified in clause (7) of this regulation:"

2. The limits as provided above were relaxed vide CERC Order dated 20.1.2015 in Petition No. 6/RP/2015 as follows:

"(a) In case of utilities having schedule of 400 MW or below, Deviation Charges shall be receivable:

for under-drawal upto 48 MW in relaxation of Regulation 5 (1) (iii) of the DSM Regulations, and

for over-injection upto 48 MW in relaxation of Regulation 5 (1) (iv) of the DSM Regulations.

(b) Proviso below Table II under clause (3) of Regulation 7 of DSM Regulations is relaxed to provide as under:-

"Provided further that when the schedule is less than or equal to 400 MW, the additional charges for deviation shall be based on percentage of deviation worked out with reference to schedule of 400 MW as per Table-I (A) and Table-II (A) above."

Concerns raised by States

Several states have highlighted the problems they face with meeting the deviation limits as stipulated by the regulations. Specifically:

Madhya Pradesh has stated that the State presently has 1073 MW of wind and 667 MW of solar installed capacity. This is further expected to increase to 5800 MW and 3500 MW, respectively, by 2020. RE generators are outside the purview of DSM, and given that CERC has allowed 15% deviation to wind and solar generators, the State regulators are likely to follow the same. This would imply that the State has to absorb 15% deviation, resulting in negative impact on the intra-state entities and DISCOMs. They have requested for a mechanism to compensate RE rich states. In particular, Madhya Pradesh has suggested that:

a) Volume limits for RE rich states could be 12% of schedule or 150 MW, whichever is higher; or

b) 15% of total RE installed capacity, plus 2% of forecasting error

c) States may be compensated from Regional DSM account for variation in RE generation at the State level, by determining the difference in deviation charges payable by intra-state generators, and frequency-based DSM charges levied by RPC.

Gujarat has pleaded that present deviation limit is too small for larger States. They have also emphasized the challenge of managing wind energy in their state.

a) Additionally, they have objected to the new calculation of 'error' for RE generators. 15% tolerance band, on capacity of 4000 MW would imply an acceptable deviation of 600 MW, of which State has to bear financial loss for 600-150=450 MW.

b) Gujarat has also stated that sale of RE power from one state to another should be covered under CERC regulations, so host state does not have to pay penalty for deviation by such generators under DSM.

c) The State has recommended that deviation at the State boundary should exclude deviation on account of infirm generation, especially wind, in case of RE-rich states.

d) It has been highlighted that a limit of 150 MW is just 1% for Gujarat having demand of more than 15,000 MW. The suggestion is this limit should be at least equal to capacity of single largest generating unit in the State, and that no penalty should be levied for 2 hours in case of outage of such a unit.

Maharashtra has underlined that large variation in demand while balancing and ramping capacity is limited makes it difficult to manage within 150 MW limit. E.g. even 2-3% variation in demand would result in over 400-600 MW deviation. Other issues include State generators do not have FGMO operation to provide primary response, mismatch between ABT meter and SCADA data, no visibility of RE, lack of proper demand forecasting by DISCOMs, etc. In addition, Maharashtra has argued that DSM limits are depriving the system from benefits of integrated grid operation in contingency situation, and that the rationale for fixing the limit at 150 MW is unknown.

Maharashtra has proposed the following graded scheme for States:

Schedule below 400 MW	48 MW
Schedule between 401 to 1250 MW	12% of schedule or 150 MW, whichever is lower
Schedule between 1251 to 1500 MW	150 MW
Schedule greater than 1501 MW	10% of schedule or 400 MW, whichever is lower

Analysis of the suggestions of States

The Commission has in the Statement of Reasons (SOR) for the previous UI/DSM Regulations mentioned the rationale for introducing limits on deviation. In this context, following extract is quoted from the SOR to the Draft CERC UI Regulations 2009:

"In this context, the key issue is how to bring discipline among the beneficiaries, and at the same time, what measures should be taken for reducing the gaming practices? One of the solutions for handling this issue is that maximum limit for variation from scheduled drawal, should be specified. Imposing the over-drawal limit will serve both the purposes, as it will deter the beneficiaries from indiscriminate overdrawal and at the same time, lower over-drawal by such overdrawing beneficiaries will automatically result into lower under-drawal by other beneficiaries. However, several considerations need to be addressed in case limit (or volume cap) is sought to be imposed on beneficiaries, as outlined below:

- *What should be over-drawal limit?*
- *Should it be specified in terms of MW for a particular time-block or daily limit in MWh terms or both?*

- *Should over-drawal limit (or volume cap) be specified for entire frequency range or only for the low frequency period?*

In this regard, it also needs to be borne in mind that under the prevailing severe supply constrained environment, load management and control by beneficiaries, particularly distribution licensees is an extremely difficult task, and planned measures and initiatives of load management and control need to be rewarded. Further, short-term (or hourly) demand forecasting practices at distribution level are yet to be established in the country with little experience available with some distribution companies. Therefore, the variation limit should not be as stringent for beneficiaries. Further, there are several other factors beyond the control of distribution licensees that may be responsible for over-drawal, such as seasonal variation, change in climatic conditions, festive season, variation in agricultural load, etc. Therefore, it may not be proper to specify a static over-drawal limit. The overdrawal limit should be specified by the Commission from time to time considering various factors as discussed above. Based on above, it is considered that a volume cap of 12% of the schedule of beneficiary in MW terms (or 150 MW, whichever is lower), for any time block, particularly, when grid frequency is below 49.5 Hz, should be reasonable to be introduced. RLDCs should monitor beneficiaries' drawal below 49.5 Hz and exercise control to ensure overdrawing beneficiaries whose over drawal exceeds 12% in any time block and direct them to curtail their drawal first."

From the above, it is clearly evident that the Commission has been considerate of the various factors and accordingly the limits have been provided. The deviation limit was fixed with due regard to the supply constrained environment at that time, demand forecasting practices, load management & control by utilities, seasonal variation, change in climatic conditions, RE variability, etc. This was the overarching philosophy behind putting the DSM limit in 2014.

There are several potential models for fixing State boundary deviation limits that have been proposed in the meetings, and captured in comments above. Suggestions such as '12% of schedule or 150 MW, whichever is higher' or '15% of RE capacity + 2% of peak load' are impossible to implement from a grid management perspective. Such huge deviations, if allowed on the grid without proper automated controls (primary & secondary frequency controls), balancing measures and proper defense mechanisms, will certainly endanger grid stability.

Gujarat has also brought up the point of 'acceptable deviations' of RE generators. It is very important to note here that while the Commission has provided a framework where solar & wind regional entity generators are not penalized up to 15% of error, it is keeping in view their intermittent nature. However, this does not imply that the RLDCs should just let these deviations reflect as is on the grid. Instead, they must monitor forecasting accuracy to anticipate and deploy ancillary services to balance these deviations. To that extent, the cost of balancing these deviations would be socialized. Accordingly, the Commission has released Ancillary Services Operations Regulations in August 2015, and has notified suo-motu Order on Reserves, on 13.10.2015. Both these steps are to enable the grid operators to deploy reserves for maintaining load-generation balance. Similarly, the States must draft regulations to operationalise a framework for spinning reserves and ancillary services in respective States. Furthermore, State grid operators must plan to balance variation due to RE

sources connected to the State grid, and not let those deviations pass through to the State boundary as is. For this, more accurate RE forecasting in addition to load forecasting and flexibility in the existing conventional generation is needed.

Gujarat has suggested that limit should be "at least equal to capacity of single largest generating unit in the State". International best practices suggest that this amount of spinning reserves should be planned for, in case of unexpected outage. Thus, this calculation should be utilized in planning for reserves by the State. The Commission reiterates that the grid does not generate electricity.

While the point on reaping benefits of a large interconnected grid made by Maharashtra is well taken, the approach here has to be real-time deployment of reserves as well as taking advantage of short-term transactions in the market to counter contingencies such as outage of generating units or transmission lines. Solution lies in pro-active contracting for balancing resources, and sharing of balancing resources across states, and not in allowing huge deviations for several hours, as that would certainly put burden on tie-lines as well as threaten grid stability due to frequency and voltage fluctuations.

Maharashtra has further proposed that for States with schedule over 1500 MW, DSM limit should be 10% of schedule or 400 MW, whichever is lower. For the 18 states which had a max schedule greater than 1500 MW during FY 14-15, this would imply a sum total of about 6000 MW of deviation allowed. If one adds deviation allowances of the remaining States, this would well exceed safe limits of grid operation.

Notwithstanding that errors in load forecasting are possible, as pointed out by Gujarat & Maharashtra, the States must ensure that load-serving entities are investing in improving load forecasting methods by analyzing accuracy of their forecasting algorithms over time. If a fairly good load forecast is made, the standard deviation of the forecast error is expected to be of the order of 2% or less and this is known upfront, i.e., before despatch. Such anticipated variations in the load need to be taken care of through deployment of reserves in the system. There are many states where scientific methods of load forecasting are yet to be put in place. Such States must first take the requisite steps, and then proceed to show the inadequacy of these processes, if any remains. Long, medium and short term load forecasting and generation planning, peak vs off-peak planning, streamlined energy accounting for all entities, RE forecasting and scheduling- these are critical and fundamental steps for sound grid management. There cannot be any excuse for not undertaking each one of these actions at the State level, and thereafter not taking responsibility for grid indiscipline that results due to absence of the above.

While the Commission is concerned about the lack of planning by stakeholders on dimensions stated above, it appreciates that putting these processes, hardware and software upgrades in place will take some time. Particularly, utilization of Free Governor Mode of Operation (FGMO) for generators to provide primary frequency response, and deployment of Automatic Generator Control (AGC) for secondary response, both these essential components must be planned for. Accordingly, in the suo-motu Order dated 13.10.2015, the

Commission has laid out a roadmap for operationalizing reserves for ISGS, briefly summarized as follows:

- To start with, a regulated framework in line with the Ancillary Services Regulations may be evolved for identification and utilising of spinning reserves and implemented with effect from **1st April, 2016.** This framework may continue till 31st March, 2017. This can be initially for generating stations regulated by CERC, which could be started off with a manual process for secondary reserves.

- All generating stations that are regional entities must plan to operationalise AGC along with reliable telemetry and communication by **1st April, 2017.** This would entail a one-time expense for the generators to install requisite software and firmware, which could be compensated for. Communication infrastructure must be developed in parallel, in a cost-effective manner.

- On the other hand, Regional Load Dispatch Centres (RLDCs) would need technical upgrades as well as operational procedures to be able to send automated signals to these generators. NLDC and RLDCs should plan to be ready with requisite software and procedures by the same date.

- In the long term, however, a market based framework is required for efficient provision of secondary reserves from all generators across the country. For this, POSOCO is directed to commission a detailed study and suggest a proposal to the Commission for implementation w.e.f. 1st April, 2017.

- The Commission has also re-iterated the importance of smart metering, telemetry, and separate scheduling/energy-accounting of all entities embedded inside the state, such as DISCOMs, open access consumers, conventional and RE generators, etc. by the concerned SLDC.

For large-scale integration of solar and wind generators into State grids, the Forum of Regulators (FOR) has evolved a State Model Regulation, which outlines a model for operational and commercial management of variable RE sources. The proposed framework for forecasting, scheduling, and deviation settlement of solar & wind generators is similar to that notified by CERC for regional entities in August 2015. However, it is pertinent to explicate the commercial arrangement suggested for the States. In the Model Regulation, it has been recommended that if the State DSM pool goes negative due to implementation of the regulation, the States may approach national funds such as NCEF or PSDF for covering the deficit. It has been underlined that this would be only to the extent of deficit caused by RE generators. Hence, to qualify for such compensation, the States must undertake separate scheduling and energy accounting of all entities, as explained in the document. The Commission feels that this will address a major part of the problem, as currently stated by the RE-rich states.

Proposed Way-forward

Medium to Long term Solution

International experience from US and Germany suggests that managing a large interconnected grid, with or without renewables, is a tight-rope affair demanding high precision. Federal Commission in the US requires each balancing authority (BA) to operate such that average area control error (ACE) is less than specified limits (L_{10}) for 90% of the time (explained further in Annexure- III). Example values for Eastern Interconnection, as a function of balancing authority size, are as below:

BA Size (MW)	$L_{(10)}$ (MW)
10	2
50	5
100	7
250	12
500	17
1000	23
2500	37
5000	52
10000	74
15000	91

Table 4 Approximate L10 Limits vs. Balancing Authority Size (Eastern Interconnection)

It can be observed that while smaller BAs are allowed up to 10% limit, for larger BAs, the limit drops to 0.6%, with only ~90 MW for a BA of size 15,000 MW. This is designed keeping in mind that larger states also have access to a larger variety and pool of balancing resources.

In Germany, all generators and load-serving-entities are categorized into 'balancing groups', which are responsible for balancing within themselves perfectly, up to 15 minutes before dispatch. That is, each balancing group has to ensure its net schedule is zero, and has to manage the same up until 15 minutes before dispatch. Balancing costs for real-time corrections are recovered from the responsible entity, and can be very high. Balancing groups are a commercial construct, and balancing is achieved primarily through trades. This concept illustrates that it is feasible to balance even within much smaller balancing areas.

As a country, we aim to integrate large amounts of renewable energy on the grid, which is feasible only once a strong foundation is in place. The Commission appreciates the financial consequences of the unpreparedness of the States in the current scenario. Thus, the Roadmap below is being put forth for the States to plan for, with the objective of advancing towards reliable and sustainable grid operation:

I. Load Forecasting: short, medium and long term

II. Intra-State Deviation Settlement

   a. Procedures for Scheduling, Metering, Accounting, Settlement- of all generators & buyers

   b. Interface Metering for intra-state entities

   c. Software Requirement for scheduling, metering, accounting and settlement

   d. Capacity building of stakeholders

Timeframe for implementation for all this is estimated to be in the range of 3- 6 months.

III. Forecasting & Scheduling of RE sources

a. Adopt Model Regulation for intra-state solar and wind generators

b. Process & software modifications at SLDC to implement frequent schedule changes, closer to dispatch

IV. Regulation on Spinning Reserves and other Ancillary Services within the State

a. Timeline and directive to utilize FGMO on all generating units

b. Operationalize manual operation of secondary reserves by April 1st, 2016

c. Installation of AGC and associated communication infrastructure, software & procedures at SLDC, by April 1st, 2017

d. Market based framework for Ancillary Services by April 1st, 2017

V. Process changes to enable frequent and faster intra-day trading at power exchanges

a. Current process takes too long for intra-day trades; States must examine procedures to shorten it

b. DISCOMs must align their decision-making processes with extended market session availability to correct for intra-day imbalances

VI. Cooperation with neighbouring States for sharing balancing resources

a. States and Regional Power Committees should facilitate regional cooperation for sharing flexible generation and other balancing resources among the States

Transitional Arrangement

Taking into consideration the time required to put the above recommendations in place, and the difficulties of the States under existing DSM limits, the Commission is proposing a revised set of DSM limits for the States, as outlined below, as a one-time measure. It must be noted that these relaxations are being offered only until 1st April 2017, by which time the Commission expects the States to have attained significant progress on all dimensions of robust grid management, as summarized in the Roadmap above.

The Commission proposes to fix the State DSM limit according to the peak demand values of FY 2014-15. The model follows the L(10) model as briefly described above, wherein the limit as a percentage of peak load of the State reduces as the magnitude gets bigger. In the table below, the States with peak demand in the range of 6000-10,000 have a suggested limit which is approximately 2% of their peak demand met. This % increases as we go down the list of States with lower peak demands, and States with less than 1000 MW of peak demand

are assigned a deviation limit of 50 MW. Maximum limit allowed for the larger States is set to 250 MW. State-wise allocation of DSM limits (for the period from the date of notification of these amendments until 31.03.2017) shall be as follows:

S.No	State	Peak Demand Met (MW)	Revised DSM Limit:
1	Maharashtra	19,804	250
2	Gujarat	13,499	250
3	Tamil Nadu	13,498	250
4	Uttar Pradesh	13,003	250
5	Rajasthan	10,642	250
6	Punjab	10,023	200
7	Madhya Pradesh	9,717	200
8	Karnataka	9,549	200
9	Haryana	9,152	200
10	West Bengal	7,524	150
11	Telangana	6,755	150
12	Andhra Pradesh	6,784	150
13	Delhi	5,925	150
14	Odisha	3,892	100
15	Chattisgarh	3,638	100
16	Kerala	3,594	100
17	Bihar	2,874	100

18	DVC	2,590	100
19	Jammu & Kashmir	2,043	100
20	Uttarakhand	1,930	100
21	Himachal Pradesh	1,422	100
22	Assam	1,257	100
23	Jharkhand	1,055	100
24	Dadar Nagar Haveli	714	50
25	Goa	489	50
26	Meghalaya	367	50
27	Chandigarh	367	50
28	Puducherry	348	50
29	Daman & Diu	301	50
30	Tripura	266	50
31	Manipur	146	50
32	Arunanchal Pradesh	126	50
33	Nagaland	128	50
34	Sikkim	83	50
35	Mizoram	88	50

The limits have been arrived considering the security of the grid, the issues/concerns raised by the states and their suggestions in this regard. So far as the lower limit of 50 MW is concerned, this is in line with the earlier decision of the Commission taken in Petition RP/06/2014. It must however be borne in mind that secure and reliable operation of the grid is of paramount importance and rationality pre-supposes existence.

The Commission is being very liberal, and is going against international best practices, but it must be reiterated that this measure is meant as a one-time measure for a specified period. These limits have been relaxed only up to April 1st, 2017,. The States must plan to have sound grid management practices as well as firm up their strategy for maintaining load-generation balance in the wake of increasing share of renewables by then. The limits shall be revised towards more stringent norms post April 2017.

The draft amendment includes changes required to incorporate CERC Order in Petition No. 6/RP/2015 dated 20.1.2015 which is already effective from 1.2.2015.

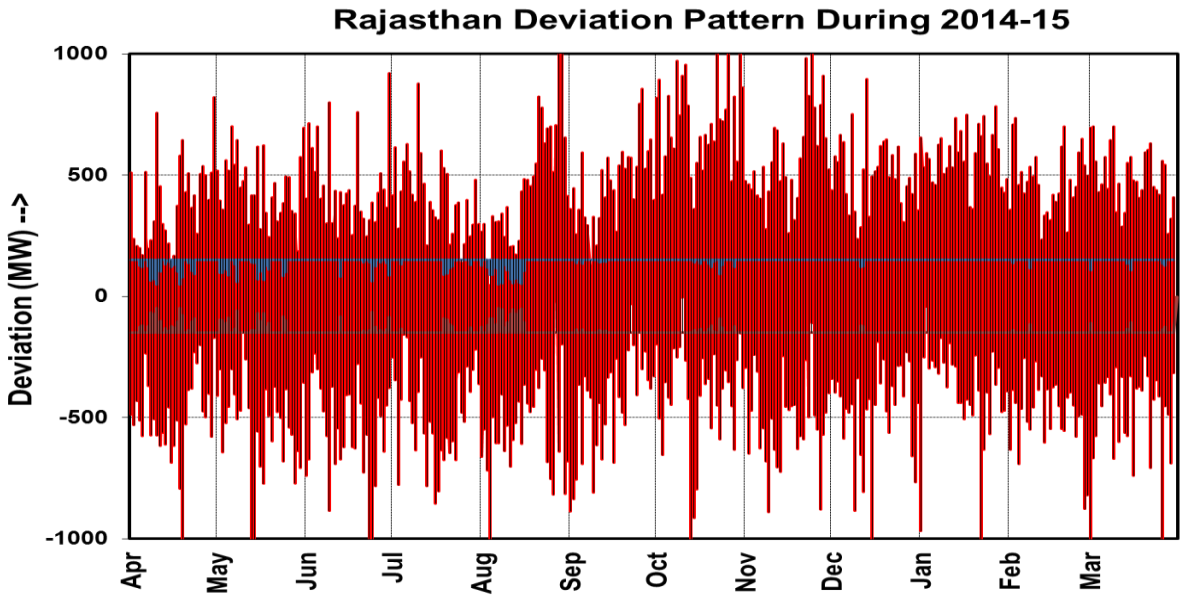
It is also clarified that the limits as specified in Annexure-II to the draft amendment are not applicable to generating stations which shall continue to be governed under the limits of 12% of SG or 150 MW whichever is lower (subject to a minimum of 48 MW). These limits shall be applicable in case a generating station is making a transaction by itself or through a trader.

Accordingly Regulations 5(1) (iv) , 7(2), 7(3), Annexure-I, I-A, II, II-A has been modified to provide for limits for sellers except generating stations and sellers separately. In case State as a regional entity is selling in a particular block, it shall be treated as a seller and limits as specified in Annexure-III shall be applicable. These limits shall be applicable in case State is making a transaction by itself or through a trader.

Accordingly changes have been made wherever required in the CERC (Deviation Settlement Mechanism and related matters) and proposed vide the Draft CERC (Deviation Settlement Mechanism and related matters) (Third Amendment) Regulations, 2015.

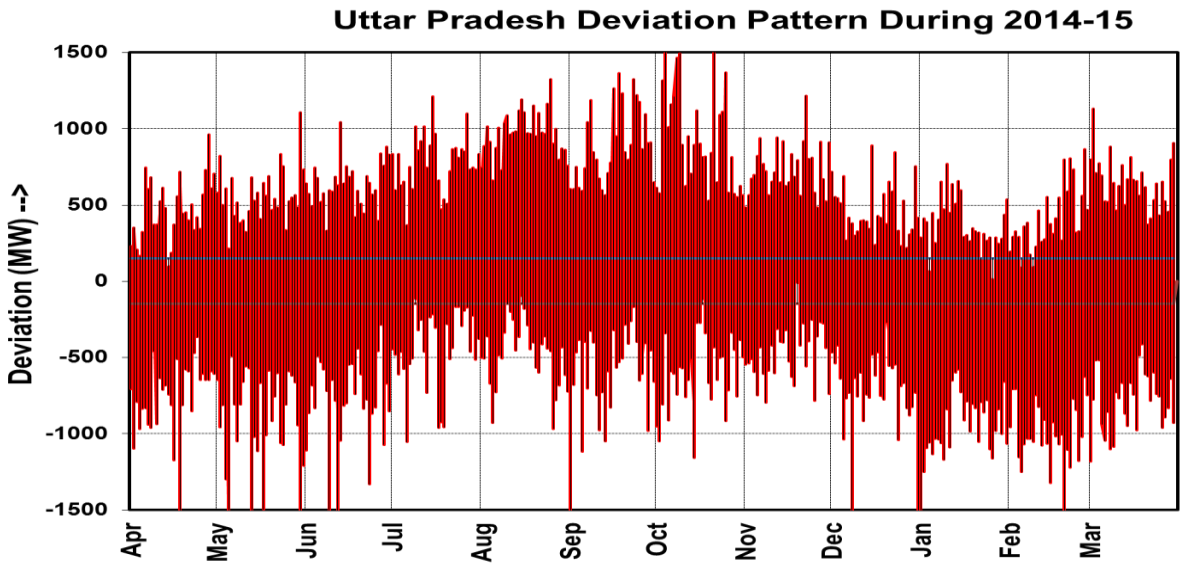
Annexure I: Trends of Deviation of selected States

RAJASTHAN



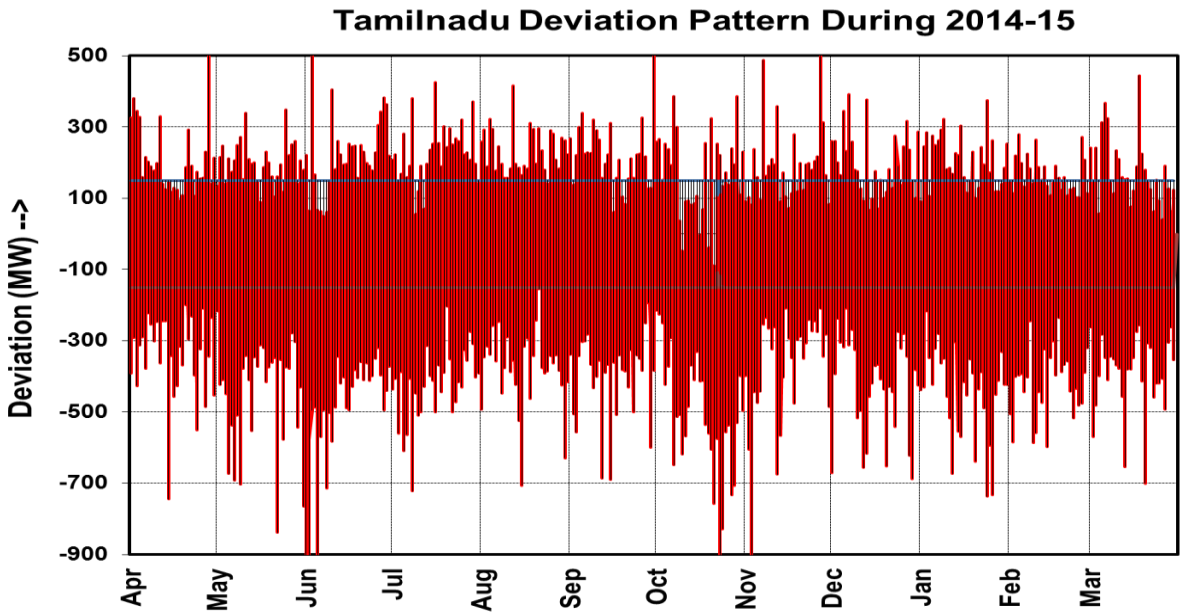
HEAD	MAX (in MW)	MIN (in MW)	AVG (in MW)
Schedule	5047	-17	2390
Actual	5257	-161	2430
Deviation	1202	-1324	-
Note: +Ve indicates O/d & –Ve indicates U/d			

UTTAR PRADESH



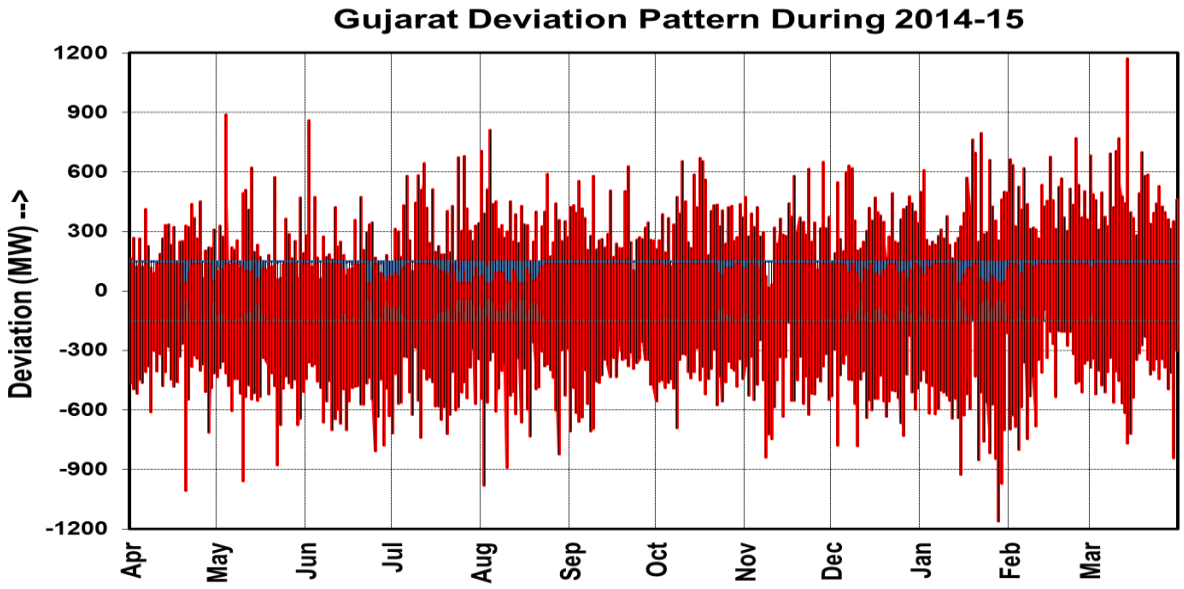
HEAD	MAX (in MW)	MIN (in MW)	AVG (in MW)
Schedule	7275	1903	4334
Actual	8046	1472	4337
Deviation	1613	-2291	-
Note: +Ve indicates O/d & –Ve indicates U/d			

TAMIL NADU



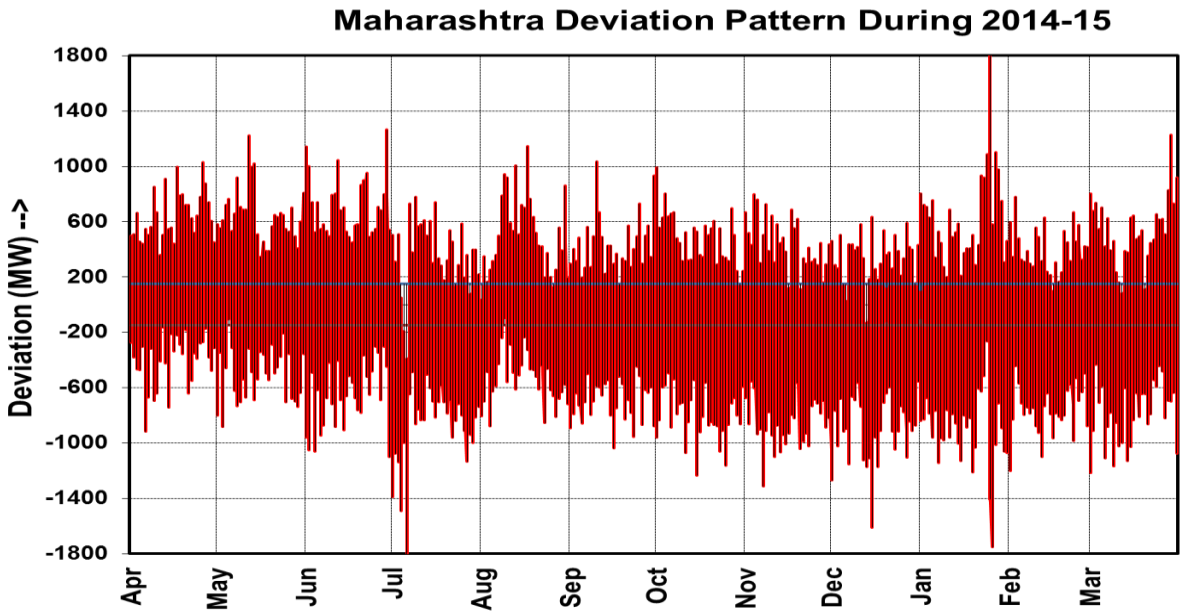
HEAD	MAX (in MW)	MIN (in MW)	AVG (in MW)
Schedule	5073	903	3448
Actual	5148	320	3376
Deviation	546	-990	-
Note: +Ve indicates O/d & –Ve indicates U/d			

GUJARAT



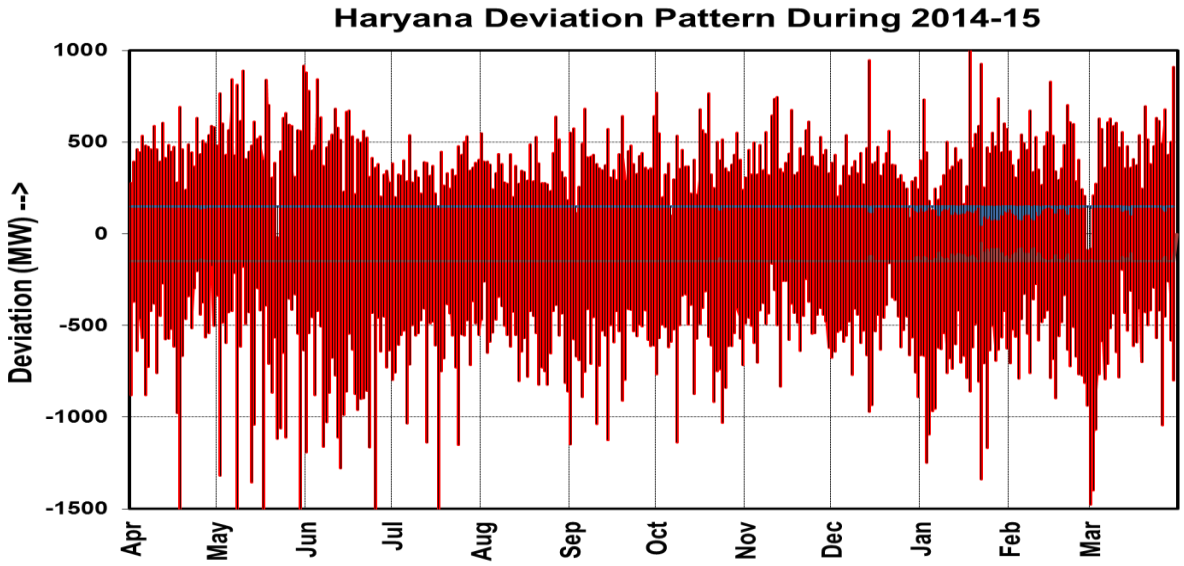
HEAD	MAX (in MW)	MIN (in MW)	AVG (in MW)
Schedule	4448	-259	2234
Actual	4516	-766	2161
Deviation	1174	-1162	-
Note: +Ve indicates O/d & –Ve indicates U/d			

MAHARASHTRA



HEAD	MAX (in MW)	MIN (in MW)	AVG (in MW)
Schedule	7804	909	4669
Actual	8001	561	4584
Deviation	2072	-1802	-
Note: +Ve indicates O/d & –Ve indicates U/d			

HARYANA



HEAD	MAX (in MW)	MIN (in MW)	AVG (in MW)
Schedule	5695	281	3017
Actual	5858	128	2970
Deviation	1053	-2419	-
Note: +Ve indicates O/d & –Ve indicates U/d			

Annexure II: Analysis on correlation of State boundary deviations with variation in wind and solar sources

(As deliberated at the 49th Meeting of the Forum of Regulators, held at Ahmedabad, 27th June 2014)

Data analysis was conducted by POSOCO, wherein SCADA data for 2013-14 was taken at an interval of 5 minutes each for

- State's own generation in MW
- State's wind generation in MW
- State's drawal from the grid in MW
- State's demand in MW

Impact of variability on deviation was captured through Karl Pearson correlation coefficient.

5 minute changes in deviation, demand, conventional generation and wind generation taken for analysis (288 values for each day). The results for correlation of schedule deviations with change in demand vs change in conventional generation vs change in wind generation are given below. It was observed that there was little correlation of observed deviations on State boundary with change in wind generation, instead, much higher correlation was observed with demand change.

GUJARAT

Month	Co-relation coefficient between		
	Deviation change with demand change	Deviation change with conventional generation change	Deviation change with wind generation change
April 2013	**0.68**	-0.16	-0.06
May 2013	**0.69**	-0.19	-0.04
June 2013	**0.53**	-0.15	-0.11
July 2013	0.42	-0.13	-0.09
Aug 2013	0.46	-0.13	-0.05
Sep 2013	**0.53**	-0.20	-0.03
Oct 2013	**0.52**	-0.17	-0.03
Nov 2013	0.47	-0.21	-0.03
Dec 2013	0.38	-0.16	-0.02
Jan 2014	0.42	-0.18	-0.03
Feb 2014	0.51	-0.17	-0.01
Mar 2014	0.48	-0.27	-0.04
Average	**0.51**	**-0.18**	**-0.05**

Conclusions for Gujarat:

On an annual basis for Gujarat, based on 2013-14 data:

- Wind generation variability has negligible adverse effect on deviation from the schedule
- Conventional generation change affects deviation 4 times more than wind generation
- Demand changes affects deviation 10-11 times more than wind generation

TAMIL NADU

Month	Co-relation coefficient between		
	Deviation change with demand change	Deviation change with conventional generation change	Deviation change with wind generation change
April 2013	0.67	-0.15	0.01
May 2013	0.58	-0.17	-0.07
June 2013	0.52	-0.06	-0.10
July 2013	0.52	-0.12	-0.15
Aug 2013	0.33	-0.15	-0.09
Sep 2013	0.53	-0.08	-0.05
Oct 2013	0.52	-0.16	-0.06
Nov 2013	0.67	-0.23	-0.01
Dec 2013	0.59	-0.22	-0.06
Jan 2014	0.57	-0.17	-0.15
Feb 2014	0.62	-0.29	-0.03
Mar 2014	0.67	-0.22	0.01
Average	**0.56**	**-0.17**	**-0.06**

Conclusions for Tamil Nadu:

On an annual basis for Tamil Nadu, based on 2013-14 data:

- Wind generation variability has negligible adverse effect on deviation from the schedule
- Conventional generation change affects deviation 2-3 times more than wind generation, though in high wind season, the two are comparable.
- Demand changes affects deviation 8-9 times more than wind generation, which drops to 3-4 times in high wind season.

Annexure III- Balancing metrics used by NERC

The North American Reliability Council (NERC), USA uses the following standards as metrics for control area performance in terms of Area Control Error (ACE)[1]

- **Control Performance Standard 1 or CPS1**
  - Uses **1 minute averages** of ACE in the calculation.
  - Measure whether a Control Area is doing their part to help control frequency over the long-term.
  - **CPS1 (in %) = 100* [2 – (a Constant)* (frequency error)*(ACE)]**
- **Control Performance Standard 2 or CPS 2**
  - Uses **10 minute averages** of ACE in the calculation.
  - Measure how well a Control Area is balancing over a period of a month.
  - 90% of the 10 min. periods in a month must be within a certain limit (L_{10})
  - **CPS2 (in %) = 100 * (periods without violations)/(all periods in month)**
- **Disturbance Control Standard or DCS**
  - Uses two ACE readings (before and after).
  - Measures how well a Control Area or a group of Control Areas respond to sudden loss of supply.
  - Basically, a Control Area or reserve sharing group has 15 minutes to replace the sudden loss of supply.

In the Indian system, the volume limits are in line with the CPS1 standard.The zero crossing violation is in line with the CPS2 standard of NERC. The DCS could be based on the Frequency Response Characteristics (FRC) which factors both load and governor response. The Commission would like to introduce suitable provisions for DCS in the Indian Grid in the future as the system matures.

[1] "Balancing and Frequency Control- A Technical Document", January 2011, NERC