केन्द्रीय विद्युत विनियामक आयोग
CENTRAL ELECTRICITY REGULATORY COMMISSION

Report of the Expert Group
Volume – II

Review of the Principles
of
Deviation Settlement Mechanism (DSM),
Including Linkage with Frequency,
In light of Emerging Markets

New Delhi
December 2017

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Acknowledgement

The Expert Group would like to thank the Hon’ble Commission for motivating and guiding the expert groupin compilation of this report. The Expert group would also like to acknowledge the contribution of each and every member of the committee in preparation of this report.

The ExpertGroup is extremely grateful to the Staff of the Commission and subject matter experts including Dr. Puneet Chitkara from KPMG and his team. The Committee also acknowledges the valuable inputs given by Professor Nick Ryan, Yale University, USA for sharing the international experience with the group.

The Committee also acknowledges the wealth of information available in the literature & international experience in different countries which has provided deep insights into the finer aspects of designing imbalance settlement mechanism.

The contribution of the POSOCO executives from NLDC and RLDCsis also acknowledged.

A S Bakshi

Chairman of the Expert Group

Executive Summary

CERC vide order dated 27th April 2017 constituted an Expert Group chaired by Shri A S Bakshi, Member, CERC with representatives from CEA, POSOCO and CTU and others with the mandate to suggest further steps required to bring power system operation closer to the national reference frequency of 50 Hz and review of the principles of Deviation Settlement Mechanism (DSM).

This report deals with the review the principles of DSM rates, including their linkage with frequency, in the light of the emerging market realities.The Expert Group held deliberations on the various aspects associated with DSM in the 3rd and the 4th Meetings held on 19th July and 3rdNovember 2017 respectively apart from many rounds of informal deliberations.

The various features of inadvertent interchange in India as well as international market were surveyed and analyzed alongwith practical implementation aspects. From the analysis of the prices over the last decade in the Indian electricity market, it has emerged that the Deviation Price is the lowest amongst bilateral, Power Exchange (DAM), DSM Prices and the Ancillary Services during the recent times. It was felt that interplay between different market segments may encourage participants to lean on the system (grid) and this has the propensity to disrupt in terms of grid security issues.

In view of aforesaid limitations, it was felt that the present DSM needs design enhancementsin terms of market linked price vector, factoring Value of Lost Load (VOLL), consideration of interplay of prices in various market segments, harnessing time value of electricity, capturing geographical location and transmission congestion so as to make the DSM prices capture the market realities.

The expert group felt that in order to address the limitations mentioned above, there is a need to link the DSM rate vector to the prices discovered in an available organized market which operates closest to the real time. In India, power exchange markets are organized markets operating on a day-ahead basis where prices are discovered competitively in a double sided closed bid auction for every 15-minute time interval. Hence, it is proposed to link the DSM prices to the Day-Ahead Market (DAM) prices discovered in the Power Exchange.

The expert group deliberated the design considerations for the proposal viz. reference prices, size of market segments, multiple power exchange prices, Unconstrained Market Clearing Price (MCP) or Area Clearing Price (ACP), granularity/periodicity of prices to be linked, frequency band, slope of the DSM Rate Vector along with the Ceiling and Floor, volume limits & cap rates, single or dual imbalance pricing: Different rates for drawl and injection and establishment of true inadvertency in deviations.After detailed deliberations and analysis, the expert group recommended the following:

- **Need for improved forecasting and planning for procurement by the utilities.**
- **Implementation of the quantum of reserves as per CERC Roadmap for Reserves**
- **Implementation of more iterations of the Electricity Market in Power Exchanges e.g. evening market, four/six-hour ahead market**
- **Change in monitoring of simple deviations to monitoring of 'Area Control Error (ACE)"**
- **Need for introduction of gate closure concept in the scheduling process**
- **Linkage of DSM Price Vector to the existing market discovered prices (day-ahead market). It is suggested that the average daily ACP be used as a reference and linked to the DSM rate at 50 Hz for the time being.**

Imbalance is inevitable in real time operations and the imbalance price plays an important role in ensuring system balance and secure and reliable grid operation. Hitherto, the imbalance price was often interpreted as a penalty mechanism, but with improved adequacy being achieved and better system parameters, the Expert Group feels that the imbalance should be dynamic and capture the market realities. Presently, the day-ahead market prices are the prices discovered closest to the time of delivery. In order to improve the imbalance price discovery the market needs to function in multiple iterations. Hence, it is suggested that 4-hour ahead or 6-hour ahead markets need to be introduced so as to get a better price discovery closer to the time of delivery. The linking of DSM prices to DAM prices may be implemented for 6-months on a pilot basis from 01st April, 2018. Based on the experience gained during this 6-month pilot run, CERC may refine the market linked imbalance pricing mechanism.

1. Background

Central Electricity Regulatory Commission (CERC) vide order dated 27th April 2017 constituted an Expert Group chaired by Shri A S Bakshi, Member, CERC with representatives from CEA, POSOCO and CTU and others with the mandate to suggest further steps required to bring power system operation closer to the national reference frequency of 50 Hz and review of the principles of Deviation Settlement Mechanism (DSM). The Terms of Reference (TOR) of the Expert Group are as under:

a. Review the experience of grid operation in India.
b. Review international experience and practices on grid operation including standards/requirement of reference frequency.
c. Review the existing operational band of frequency with due regard to the need for safe, secure and reliable operation of the grid.
d. **Review the principles of Deviation Settlement Mechanism (DSM) rates, including their linkage with frequency, in the light of the emerging market realities.**
e. Any other matter related to above.

This report deals with the review of the principles of Deviation Settlement Mechanism (DSM) rates, including their linkage to frequency in light of the emerging markets and a separate report has been submitted for the items (a), (b) and (c).

The Expert Group held deliberations on the various aspects associated with DSM in the 3rd and the 4th Meetings held on 19th July and 3rd November 2017 respectively apart from many rounds of informal deliberations. The Minutes of Meetings are enclosed at ***Annex – I***.

2. Evolution of Imbalance Handling Mechanism in India

Any power system needs to balance the generation and consumption of energy over multiple timeframes from seconds, hours, days and even years ahead. There is always deviation in actual generation from scheduled generation and actual drawal from scheduled drawal. There will always be differences between the contracted volumes and the actual metered volumes. Thus, to handle these differences (or imbalances) in real time, there is a need for imbalance handling mechanism.

Sally Hunt in her book titled" Making Competition Work in Electricity"[1], mentioned that the four pillars of good electricity market design are Imbalances, Congestion management, Ancillary services and Scheduling and Despatch as depicted in the Figure 1 below. All of these must work together for a vibrant electricity market.

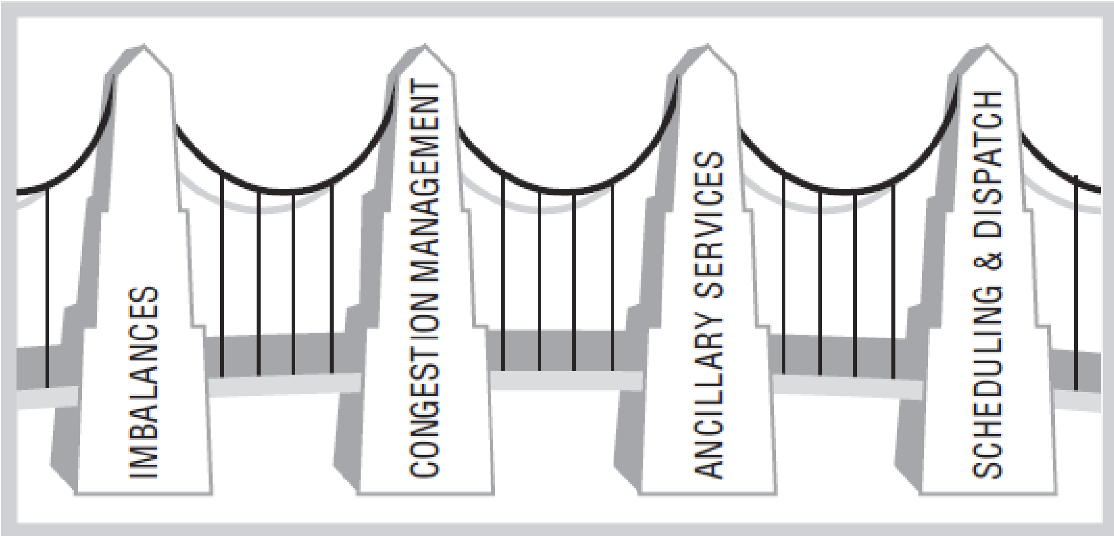

Figure 1: Pillars of Electricity Market Design

CERC introduced the Availability Based Tariff (ABT) Mechanism vide its Order dated January 4, 2000 at inter-State level [2]. The ABT Mechanism was implemented in different regions in a phased manner in the period from 2002-2003. ABT Mechanism was implemented in Western Region and Northern Region in 2002 and in Southern Region, Eastern Region and North-Eastern Region in 2003.

The imbalance handling mechanism has been in operation at the inter-state level for nearly 15 years. The evolution of Deviation Price (erstwhile Unscheduled Interchange (UI)) Vector over the years is tabulated in the Table 1 below.

A coordinated multilateral scheduling model has been adopted in India. Schedules can be revised and the entities are allowed to deviate within specified limits from the schedule. Large quantum of deviations from scheduled power flows may lead to uncertainties in power flow and consequential power system security issues. The deviations are settled as per the UI/DSM Rate Vector administered by CERC.

Table 1: Evolution of Deviation Price (erstwhile UI) Vector

Period	Operational Frequency Band	Ceiling Rate (paise/kWh)	Benchmarking of Ceiling Rate	Slope (paise/kWh)	Step size
1st July 2002 – 31st March 2004	49.0 Hz – 50.5 Hz	420	DG set	5.6	0.02 Hz
1st April 2004 – 30th Sept 2004	49.0 Hz – 50.5 Hz	600	DG set	8	
1st October 2004 – 29th April 2007	49.0 Hz – 50.5 Hz	570	DG set	9	
30th April 2007- 6th Jan 2008	49.0 Hz – 50.5 Hz	745	Domestic Naphtha (Liquid Fuel)	6 (50.5-49.8) 9 (49.8-49.5) 16 (49.5-49.0)	
7th Jan 2008 – 31st March 2009	49.0 Hz – 50.5 Hz	1000	Combined cycle plants -Naphtha/RLNG	8 (50.5-49.8) 18 (49.8-49.0)	
1st April 2009 – 2nd May 2010	49.2 Hz – 50.3 Hz	735	RLNG based generating station with variation in fuel prices of around 5%	12 (50.3-49.8) 17 (49.8-49.2)	
3rd May 2010 to 16th Sep 2012	49.5 Hz – 50.2 Hz	873	Gas/liquid fuel based thermal generating stations of NTPC & NEEPCO	15.5(50.2-49.7) 47 (49.7-49.5)	
17th Sep 2012 to 16th Feb 2014	49.7 Hz – 50.2 Hz	900	Highest cost of generation is 896.02 Paise/kWh @Auraiya CCGT Station	16.5 (50.2-50.0) 28.5 (50.0-49.8) 28.12 (49.8-49.5)	
17th Feb 2014 onwards	49.90 Hz - 50.05 Hz	824	Highest cost of generation is 8.24 Rs/kWh @ Auraiya Gas Power Station	20.84 (49.70 - 50.00) 35.60 (50.01 - 50.05)	0.01 Hz

TheUI/DSM Rate Vectorhas been tinkered/fine-tuned over the years with introduction of different slopes, kinks, volume caps, additional charges, cap rates etc., as depicted in the Figures2-7 below. The system operator i.e. POSOCO has given feedback to the CERC regarding revision in DSM rates from time to time (***Annex –II***).

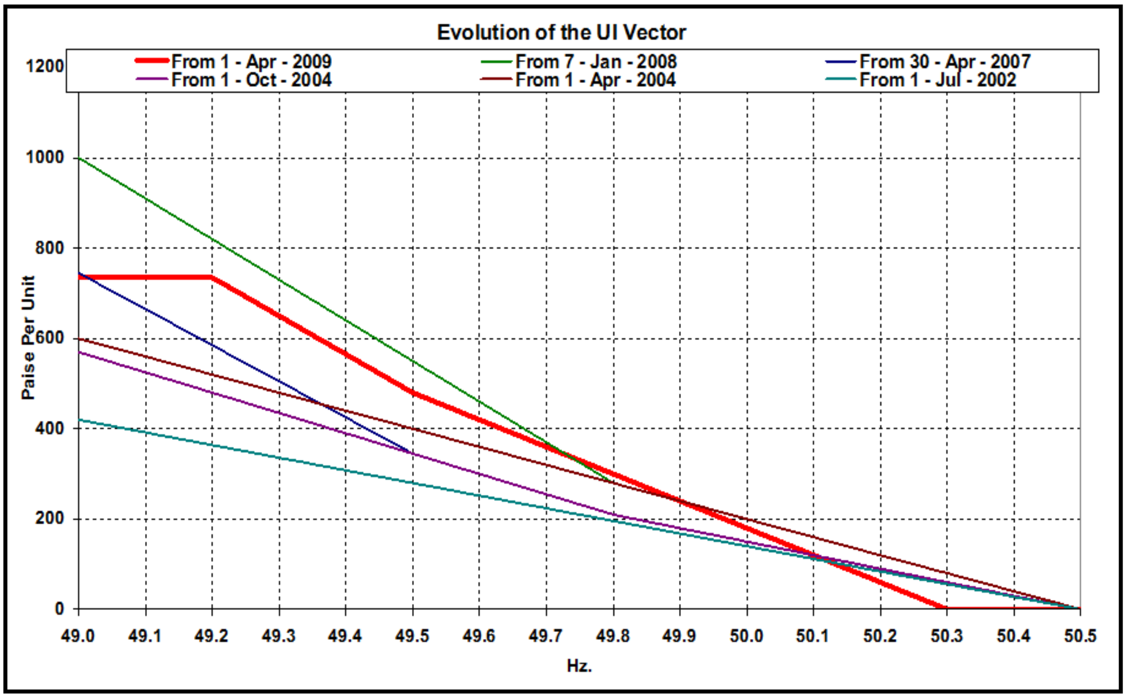

Figure 2: UI Vector from 2002 – 2010

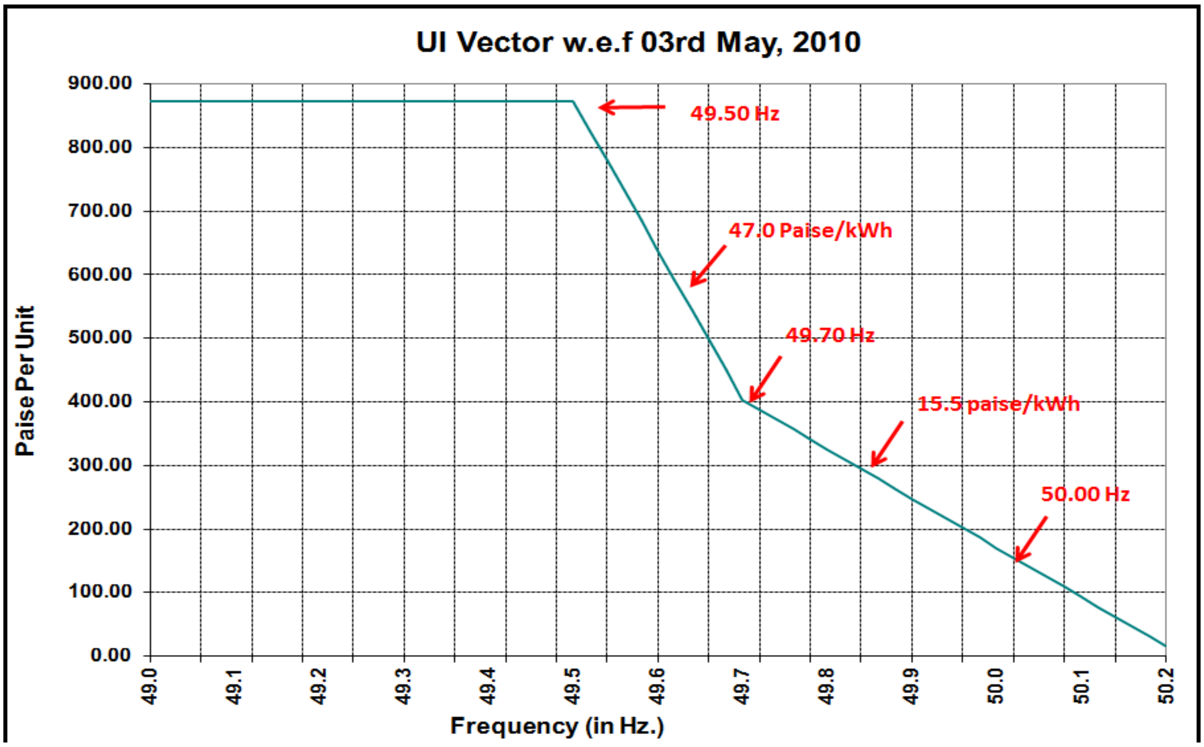

Figure 3: UI Vector from 2010 – 2011

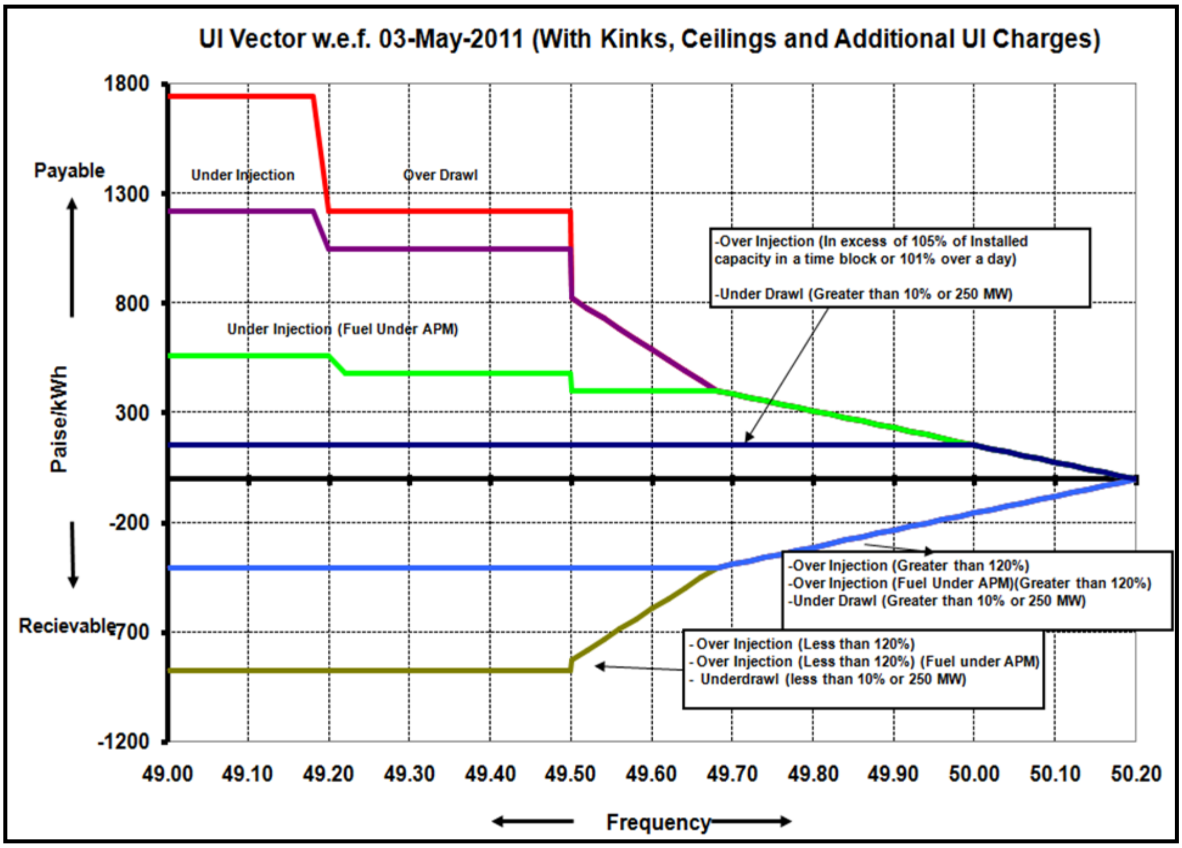

Figure 4: UI Vector from 2011 - 2012

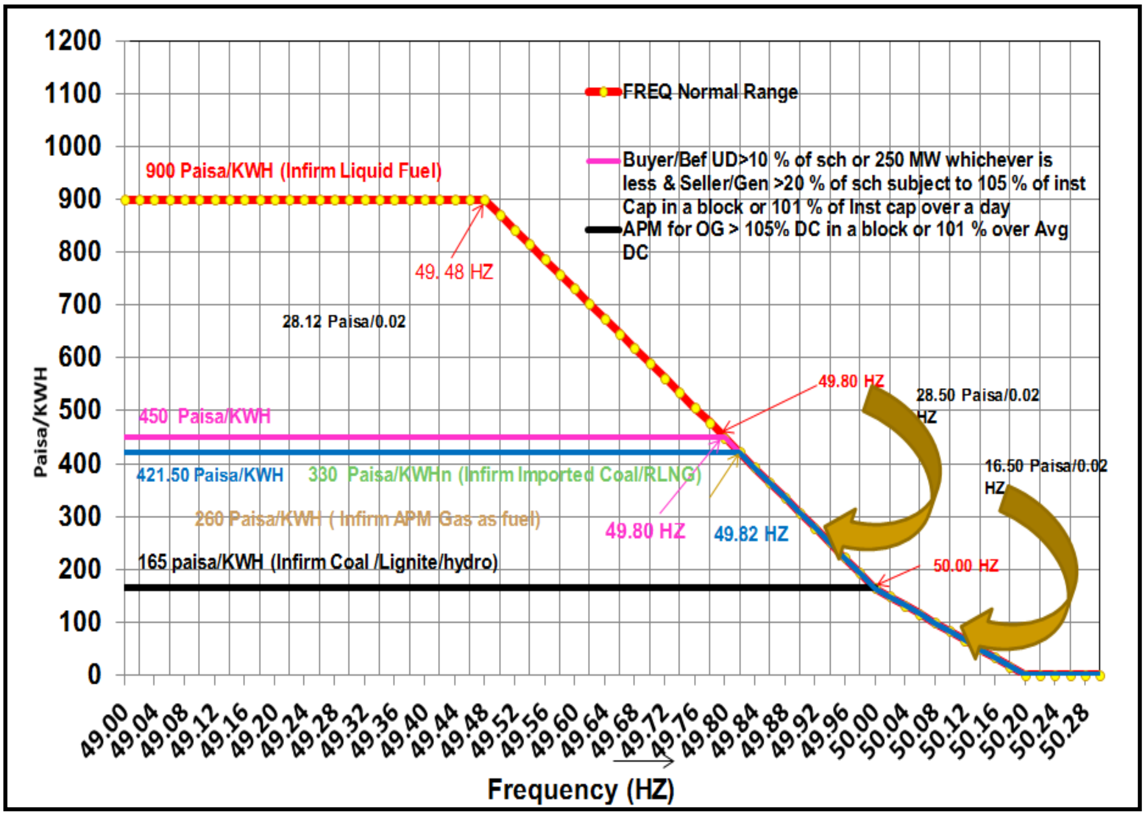

Figure 5: UI Vector from 2012-14 (Receipt Side)

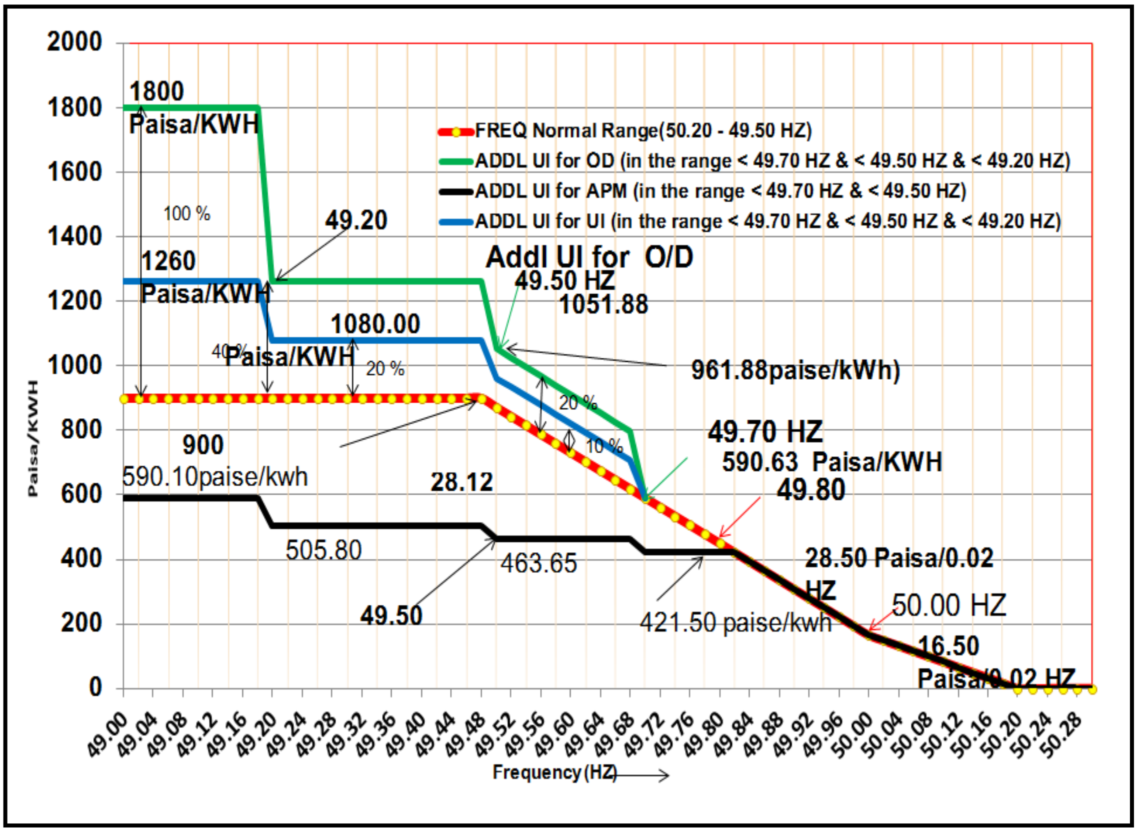

Figure 6: UI Vector from 2012-14 (Payment Side)

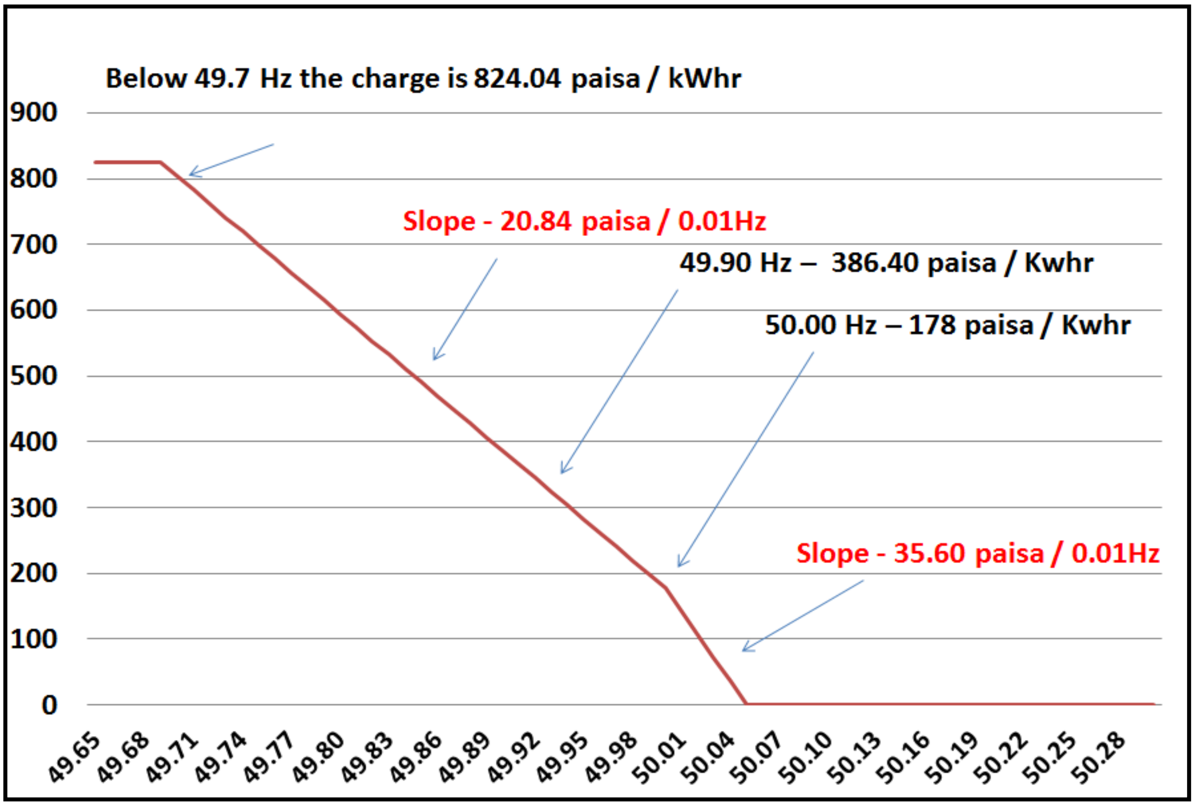

Figure 7: Present DSM Vector w.e.f 17 February.2014

The present Deviation Settlement Mechanism in India came into force with effect from 17th February, 2014 [3]. The salient features are as follows:

- Operational Frequency Band has been tightened to 49.90 - 50.05 Hz.
- Step size changed from 0.02 Hz to 0.01 Hz.
- The charges for deviation for each 0.01 Hz step is 35.60 Paise/kWh in the frequency range of 50.05 - 50.00 Hz, and 20.84 Paise/kWh in frequency range 'below 50 Hz' to 'below 49.70 Hz' (Depicted in Figure 4) and detailed at *Annexure - II*as per the methodology specified in the Regulations.
- The volume of deviation from scheduled to actual injection/drawal is 150MW or of 12% of the schedule, whichever is low.
- Continuous over drawal / under drawal has also been prohibited.
- Within 12 time blocks, the polarity of deviation should be reversed (in case of over drawal to under drawal and vice versa).
- Generating stations regulated by CERC using coal / lignite / APM gas have cap rate of 303.04 p / unit irrespective of frequency.

- There are no charges for Under-drawal or Over-injection (except infirm generation) in excess of 150MW or 12% of schedule, whichever is less in a time block.
- Additional Charges for Deviation for Over-drawl by any buyer or Under-injection by any seller has been stipulate by the CERC Regulations.
- Limit on Deviation Volume has been imposed.
    - Over-drawal by Buyer, Under-injection by Seller below 49.70 Hz and Over-injection by Seller at 50.10 Hz & above is not permitted.
    - Deviation of only 12 % of the Schedule or 150 MW, whichever is less has been allowed for Over-drawal by Buyer, under-drawal by buyer Under-injection by Seller at 49.70 Hz & above and Over-injection by Seller below 50 Hz.
    - 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 Connectivity Regulations.
    - In case of start-up drawal power exemption from volume limits for frequency greater than or equal to 49.70 Hz has been allowed.

3. Regulatory Framework for Deviation Settlement for RE

CERChas provided the regulatory framework for Forecasting, Scheduling & Imbalance Handling for wind and solar at Inter-State Level in August, 2015 [4].In case of deviations from the schedule, CERC has fixed a percentage of error in a 15-minute time block and Charges for Deviation payable/receivable to/from Regional DSM Pool by the renewable generators. The percentage error as defined in the CERC Regulations isas follows:

" (aa) Absolute Error" shall mean the absolute value of the error in the actual generation of wind or solar generators which are regional entities with reference to the scheduled generation and the 'Available Capacity' (AvC), as calculated using the following formula for each 15 minute time block: Error (%) = 100 X [Actual Generation– Scheduled Generation] / (AvC)

"…(r) 'Available Capacity (AvC)' for wind or solar generators which are regional entities is the cumulative capacity rating of the wind turbines or solar inverters that are capable of generating power in a given time-block…"

These charges for deviations by renewable generators have been delinked from the frequency. When the error is less than or equal to 15%, the charges for deviation are computed at a pre-defined rate for the deviation in energy terms for an absolute error upto 15%. When the error is more than 15%, there are additional charges for deviation along with the fixed rate. The methodology for computation of fixed rate has been specified by the Central Regulator in the regulations.

Also**,** CERC, vide order in the Petition No. RP/06/2014 dated 20th January, 2015 [5],has provided relaxation to all the sellers/buyers whose schedule is less than 400 MW wherein the deviation limit has been notified as 48 MW.

4. Literature Review

The various aspects of inadvertent interchange available in the literature are quoted as below.

Table 2: Summary of Literature Review

S.No.	Author/Source	Relevant Extract
1.	**NERC Joint Inadvertent Interchange Task Force (JIITF)** *White Paper, Recommendations for the Wholesale Electric Industry of North America, May 2002 [6]*	*"...Inadvertent Interchange consisted of three components. The first component, the "**Energy Component**", represented the value of the energy included in the Inadvertent Interchange and is represented in the energy price. The second component, the "**Transmission Component**",represents the reliability value of the transmission congestion and in present markets this is also included in the energy price. The third component, the "**Frequency Control Component**", represents the value of the response and underlying reserves used to deliver the balancing energy necessary to offset unscheduled energy...."* *"...The proposed standard addressing frequency control contribution will have incentives and penalties that will reward good control and penalize poor control. The incentives and penalties need to be*

		sufficient to promote good performance….” *“...Zero UI is a coincidence rather than expectation….”*
2.	**Mark Lively** *Consulting Economist, to Federal Energy Regulatory Commission, USA* *Article - “Creating an automatic market for unscheduled electricity flows”[7][8]*	*“…Unscheduled market has not only allowed the new players in the market to participate economically in the inadvertent market between utilities but also offered the customers an alternative way to buy their electricity. The customer being able to buy electricity in the unscheduled market would diminish any market power that the local utility has. Further even the customers can assume a role of a seller in this market by under-drawing from the grid during shortages. Generators need not sell their output at a price lower than the UI rate. Similarly, customers need not agree to buy electricity at any price higher than the value (tangible or intangible) of feeding that loads. A win-win situation for everyone!* *“Market is somewhat of a masonry wall. We have bricks with cement around it. Sometimes these bricks are maybe a 100-megawatt contract for an hour or for a day. If you want the wall to stay up, you've got to have this masonry, this mortar, cement to fill up the seams and also a way to price it. Else the wall will fall down. I noticed that about a year and a half a go, India decided that they were going to put in a way to price what they call unscheduled interchange where they provided liquidity for the market and improved their operations by a factor of 5 or 10.”*
3.	**Robert Blohm**	*“...Inadvertent interchange isn't a standard*

	Solving the Crisis in Unscheduled Power *Public Utilities Fortnightly* *August 2004* *&* *'Economist's Assessment'* *North American Electric Reliability Council Joint Inadvertent Interchange Taskforce* *10th April 2002[7][9]*	*commodity transaction: It occurs without specific mutual consent. The total inadvertent interchange on an interconnected system always sums to zero because a single reading of a common meter on any tie-line is counted twice, once as one BA's outflow and again as the other BA's inflow. Since inadvertent interchange always clears, its price must be driven by something else…."* *"…True economic dispatch decisions for reliability are based not just on energy cost, but also on Frequency Contribution Component (FCC) cost. Two-part pricing of inadvertent interchange (into energy and FCC) makes the price of inadvertent interchange greater when there is under-frequency than when there is over-frequency…."* *"…Inadvertent interchange flows reflect the sudden loss of resources as well as the sudden deployment of resources…."* *"…Unscheduled power occupies the interface between markets and reliability; real-time is the proper domain for management of honest scheduling error, not for markets for energy. A market for FCC is the only market needed for incenting reliable behavior. Markets for energy alone do not efficiently incent behavior that is compatible with good frequency control. Moreover, allowing suppliers to increase real-time risk by taking real-time energy delivery risks in an energy-only spot market winds up unfairly penalizing customers if there are no resources available...."*

		"Inadvertent and energy imbalance are "unscheduled energy" which is two things: (i.1) the "energy" part, and a related (i.2) transmission congestion (loading component, and (ii) the "unscheduled aspect". The unscheduled part is the "inconvenience" factor, "hassle" factor, or degree of suddenly needing the energy." *"…The California market meltdown may be attributed in significant part to improper pricing of unscheduled power…"*
4.	**Steven Stoft** *'Power System Economics'-* *Chapter-Power Supply and Demand* *&* *Chapter-The Two-Settlement System [7]*	*"Because frequency indicates the discrepancies between supply and demand, frequency is the right guide for interconnection-wide price adjustment. When frequency is high price should be reduced; when frequency is low price should be raised. This is the classical adjustment process for keeping supply equal to demand."* *"In a competitive market the real time prices are true marginal cost prices, and the forward prices are just estimates"*
5.	**Arthur Berger & F.C Schweppe** *'Real time pricing to assist in load frequency control' (IEEE Transactions on Power Systems, Vol.4, No. 3, August 1989)[7]*	*"A key feature of this pricing scheme is that the independent power plants can themselves monitor the frequency deviations and thus no real time signal needs to be sent by the electric utility. This eliminates the problem of how the utility could compute and transmit the price faster than the time scale to be controlled."*
6.	**Sally Hunt**	*"The right price for imbalances is a market-based*

	'Making Competition Work in Electricity' *Chapter - Trading Arrangements Section – Imbalances* *&* *Chapter- Trading Arrangements* *Section-Imbalances [7]*	*price. A market-based price for imbalance energy is incentive-compatible... It means...that if price is low, it is a good thing that the generator reduces output from its contracted level because imbalance market is a cheaper provider of energy. It means that if the price is high, it is a good thing that the generator increases output from its contracted level because it is a cheaper provider of energy than the alternative imbalance energy providers. And it means equivalent signals are sent to loads."* *"If the imbalance price is too low, generators would produce less and rely on the imbalances to meet their customers' load. A cheap generator might be better off backing down, creating further imbalance"*
7.	**Sally Hunt & Graham Shuttleworth** *'Competition & Choice in Electricity'* *Chapter- Spot Market & Organization of Trade[7]*	*"The market for imbalances competes with longer-term transactions as a means for trading electricity."* *"The imbalances must be settled as if they were instantaneous spot transactions i.e. sales of electricity arranged at (infinitesimally) short notice for immediate delivery."* *"There must be some pricing rules for imbalances…These pricing rules become central to the character of the whole electricity market"* *"The main tool available to the Market Operator to encourage efficiency is the price charged or paid for imbalances between contracts and actual flows."* *"If these imbalances are priced at punitive rates, generators may be reluctant to offer any flexibility of*

		output. The task of maintaining system security would then be rendered difficult, if not impossible."
8.	**Howard F. Illian** *"Defining Good and Bad Inadvertent"Jan 2002[7]*	*"A market requires an a priori determination of Good and Bad Inadvertent."*
9.	**LDK Consultants** *FINAL REPORT - Study on Development of Best Practice Recommendations for Imbalance Settlement – January, 2013[10]*	*The best practice recommendations for allocation of balancing costs in the 8th Region include:* • *Gross model for energy imbalance settlement.* • *Single Imbalance price.* • *Average price of accepted bids in system imbalance direction but long term aim to move to* • *a marginal price.* • *Weight activated reserve bids by reservation fee.* • *Remove Transmission constraint resolving bids and make the TSO pay for them.* • *Non Delivery Rule for high price Offers and low price accepted Bids.* • *RES to be exposed to imbalance settlement on an equal basis to other system users.*
10.	**BhanuBhushan** *Comments to ECC Task Force Report on UI tariff, 08th November 1993[7]*	*"It is not always possible to establish whether a deviation from schedule is inadvertent or deliberate. Besides, a deviation may have inadvertent and deliberate components and it may be very difficult to assign values to them."* *"All UI is not bad. Under certain circumstances, UI of a particular polarity would be desirable and should be encouraged"*

5. Features of Deviation Settlement Mechanism

The DSM price vector has been designed to bring in economy and efficiency during real time operations in a decentralized manner.

(a) Some of the unique features and the strengths of the present mechanism are:

- Real Time Imbalance Pricing
- Promotes Efficiency and Merit Order Despatch
- Perfect Information
- Known ex ante to everyone
- Provides a negative feedback for automatic correction
- Facilitates achieving marginal cost despatch
- Diffusion of market power and choice to buyers & sellers
- Simple to calculate
- No post facto adjustment
- Discourages advertent deviations
- Highest priority in payment
- Hysteresis to disincentive possible misuse

(b) The features lacking in the present mechanism are as follows:

- Market linked Price Vector
- FactoringValue of Lost Load (VOLL)
- Interplay of Prices in various market segments
- Time value of Electricity
- Geographical Location and Transmission Congestion

Some of the other key aspects which are related to the larger electricity market design inhibiting the market are non-availability of adequate Market Opportunities for Balancing and implementation of Gate Closure

The desired features of a good imbalance handling mechanism design in future should incorporate the strengths of the present mechanism as well as address those features which are lacking in the present mechanism.

6. DSM Volumes of Market Participants

The All India DSM volume (MU / day) is shown in figure 8 below. The average volume in DSM is about 60-70 MU/day (in the range of 1.5% – 2% of all India energy generated).

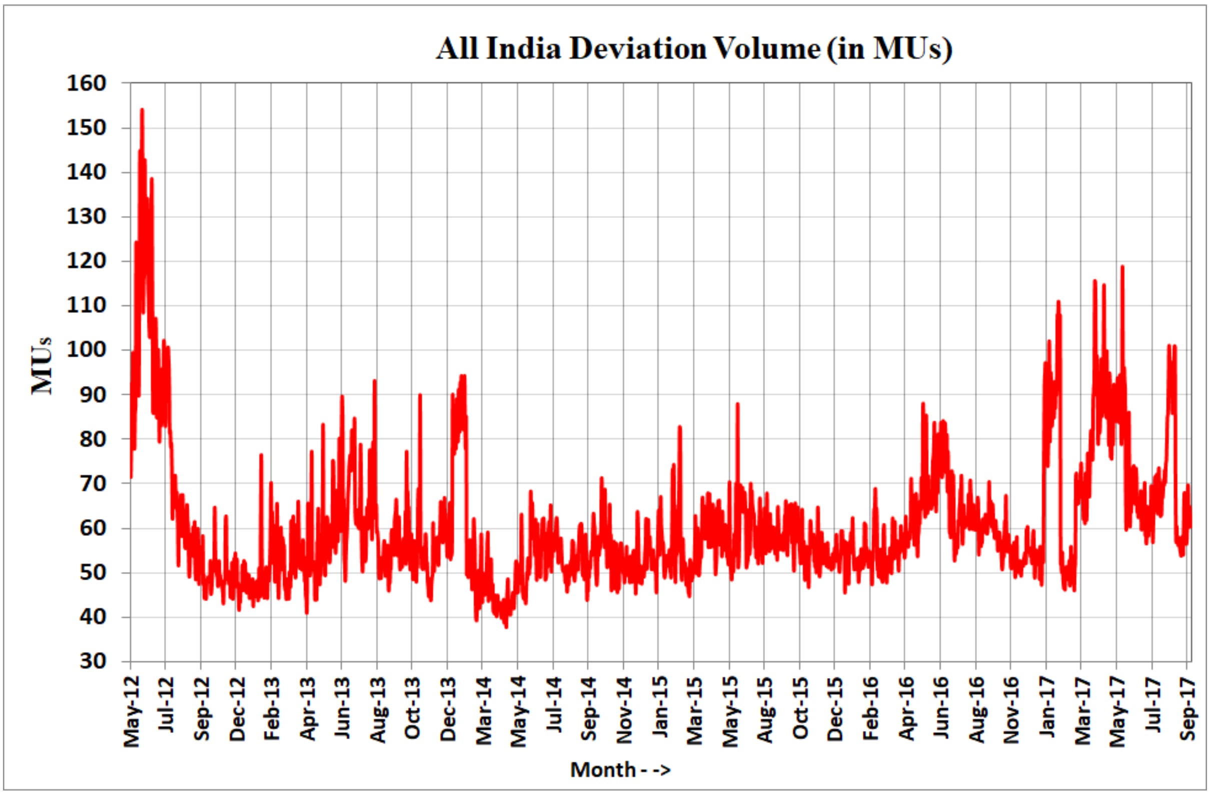

Figure 8: All India DSM Volume MU/Day

The following statistical analysis of the actual metered DSM volumes of the states was carried outfor the period between January - August 2017*(Annexure – III)*:

a) Deviation Vis- à- visLimit on Deviation Volume asper DSM Regulations
b) Deviation Duration Curve
c) Zero Crossing Violation perday
d) Deviation distribution

It is found that consistent high mean value and/or a high standard deviation indicates a further scope for improvement in terms of controllability of the deviations with respect to schedule. The summary of the results sorted on the mean DSM is shown below.

Table 3: Distribution of Deviation Volumes (January – August 2017)

Mean and Standard Deviation of Deviation Volume of States in MW		
States	**Mean**	**Std. Deviation**
ANDHRA PRADESH	-58.34	186.54
ARUNACHAL PRADESH	-1.74	26.76
ASSAM	56.69	68.93
Bihar	33.81	1.01
Chandigarh	9.30	22.24
CHATTISGARH	0.31	107.82
DD	18.59	22.49
Delhi	-3.41	99.96
DNH	3.18	27.87
DVC	-2.21	0.74
ESH	15.03	76.24
GOA	9.26	39.58
GOA-SR	3.11	13.47
GUJARAT	-64.59	226.53
Haryana	-20.17	222.63
Himachal Pradesh	18.97	100.08
Jharkhand	33.97	0.54
KARNATAKA	-49.40	162.44
KERALA	-80.96	52.40
MADHYA PRADESH	-18.18	193.47
MAHARASHTRA	1.79	276.73
MANIPUR	-1.12	16.37
MEGHALAYA	-12.08	24.64
MIZORAM	4.92	11.44
NAGALAND	5.64	16.04
Odisha	37.50	0.74
PDD J&K	-27.54	141.29
PUDDUCHERRY	9.05	20.09
Punjab	-36.52	234.76
Rajasthan	83.02	217.53
Sikkim	-5.15	0.11
TAMILNADU	97.93	263.00
TELANGANA	84.91	164.86
TRIPURA	0.26	38.45
Uttar Pradesh	73.54	309.92
Uttarakand	18.93	100.67
West Bengal	86.23	0.86

7. Prices in the Difference Market Segments

Market Monitoring Cell (MMC) of CERC publishes the prices in the different market segmentand these are shown in Figure- 9 below. Ancillary Services has been introduced in the country in April 2016. The plot of RRAS Provider Cumulative Capacity and Variable Chargeis shown in Figure- 10 below. The highest variable cost generator despatchedin Ancillary Services on daily basis during the period April 2016 to October 2017 is shown in Figure- 11 below. At times, there has been a requirement to despatch generators whose variable charges are more than Rs. 8 per unit.

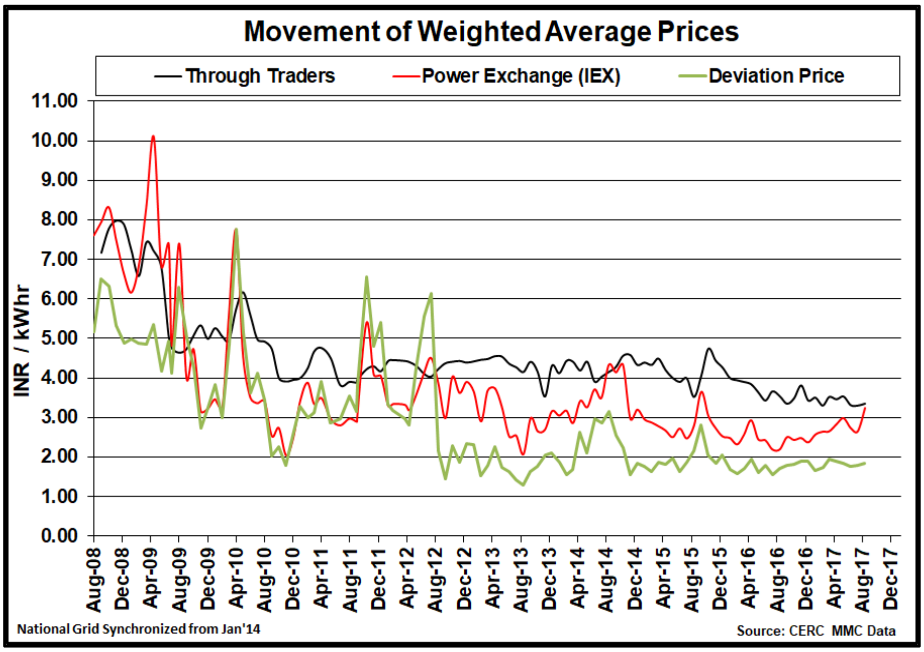

Figure 9: Weighted Average Prices in Different Market Segments

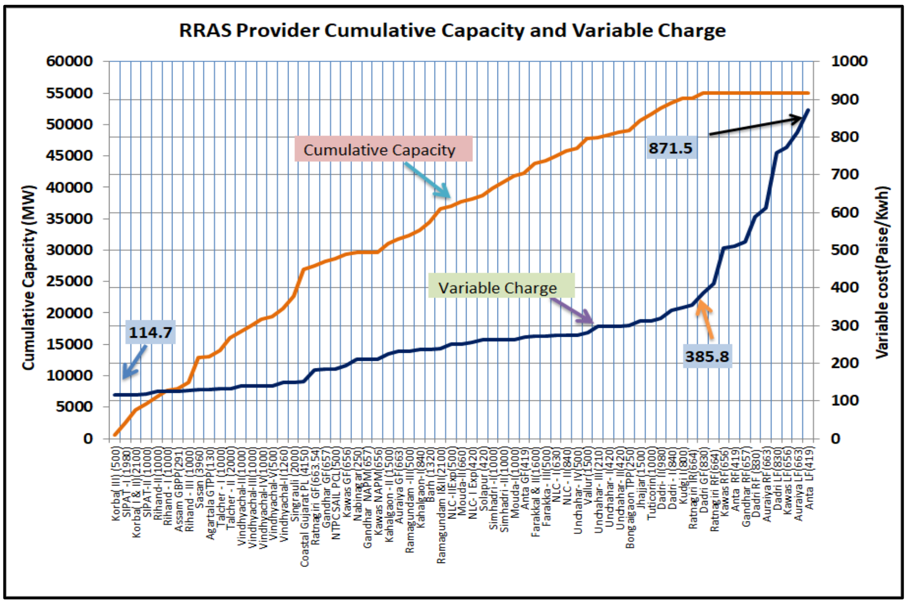

Figure 10: RRAS Provider Cumulative Capacity and Variable Charge

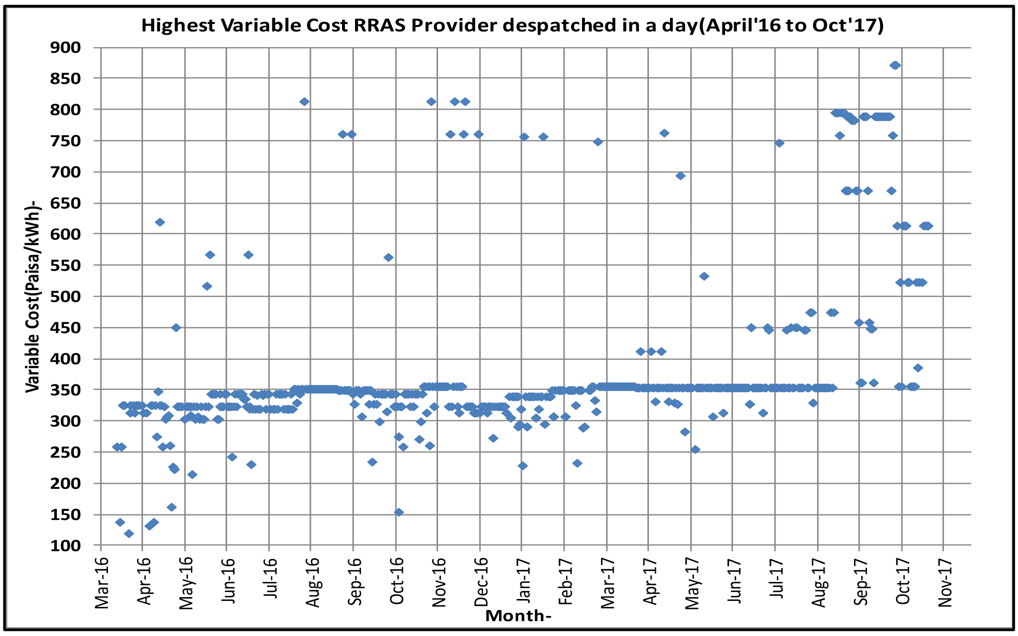

Figure 11: Highest Variable Cost Generation Despatched under Ancillary

The System Marginal Price (SMP) as computed by NLDC is shown in figure – 12 below. The SMP computation is presently limited in the sense that it is based on the variable charges of only those generators whose tariff is determined or adopted by CERC. There could be costlier sources which are despatched and not accounted in the computation.

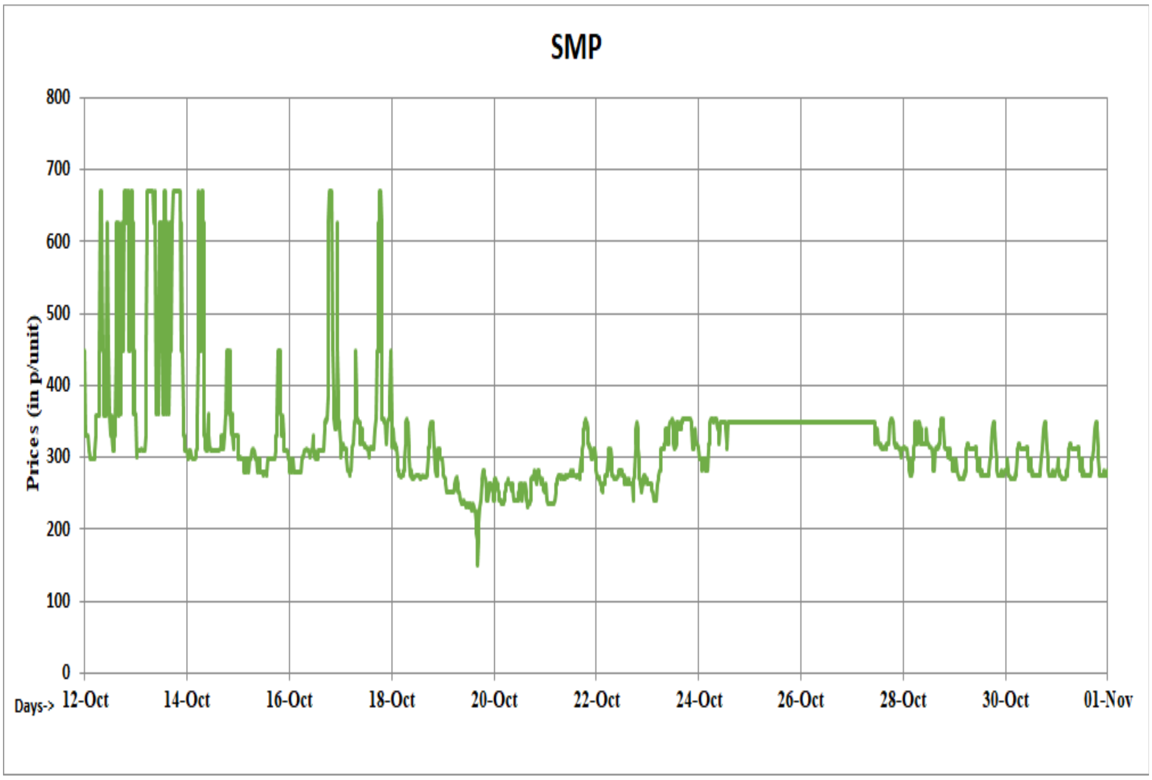

Figure 12: System Marginal Price (SMP)

As is evident from the above figures, the Deviation Price is the lowest amongst bilateral, Power Exchange (DAM), DSM Prices and the Ancillary Services. From a design perspective, the prices for deviation from schedules are the real real-time prices and should be such that they provide enough incentive to the market participants to plan and procure adequately in the market in advance.Interplay between different market segments may encourage participants to lean on the system (grid) and this has the propensity to disrupt in terms of grid security issues. *Hence, the present DSM Rates need to be reviewed.*

8. Limitations in the Present Deviation Settlement Mechanism

The present DSM has some inherent design limitations which need to be addressed so as to make the DSM prices capture the market realities. These limitations are briefly discussed below:

8.1. Regulated Price Vector

The present DSM price vector is decided by the Regulator based on the fuel prices such coal, RLNG, liquid, etc. The rates presently applicable were decided by CERC in 2014. Regulation 5(4) mentions the following:

"(4) The Charges for Deviation may be reviewed by the Commission from time to time and shall be re-notified accordingly."

However, the process of reviewing the charges for deviation takes time under the regulatory process and the prices in other market segments change faster thereby increasing the interplay.

8.2. Value of Lost Load (VOLL)

The present DSM rates at 50 Hz (178 paise/unit) are linked to the variable charges of a pit-head thermal (coal fired) station whereas the highest DSM rate (824 paise/unit) is linked to the variable charges of the costliest generator (liquid fired). Ideally, the DSM price should capture the VOLL so that utilities procure adequately in advance so as to meet their universal service obligations.

The relevant extracts from the Peter Cramton* Oxford Review of Economic Policy, Volume 33, Number 4, 2017, pp. 589–612 are quoted as below:

> "*Scarcity pricing:…*
>
> *Sending the right real-time price signal is critical to motivate efficient behaviour in realtime, as well as further forward decisions, including long-term investment. In normaltimes, this price signal follows from the marginal cost of supply or the marginal valueof demand. However, in instances of scarcity where the system operator has limitedreserves to maintain power balance, the value of the reserves—and the price of energy—should reflect the value real-time reserves create in avoiding load-shedding events. Themarginal value of reserves is equal to the value of lost load (VOLL) in extreme shortagesituations and then falls as the scarcity is less and therefore the probability of lost loadis less….*"

The VOLL for Indian scenario needs to be notified.

8.3. Interplay of Prices

The deviations in real time for an entity lead to balancing of its actual supply-demand. It is a transaction of electricity in real time at very short notices and should be priced in a way which encourages participant's behavior to move towards organized markets, thereby implying, incidences of deliberate deviations are signaled commercially unviable. As shown in Figure – 13 below, the present DSM prices are much below the market prices and this is providing a contrary price signal.

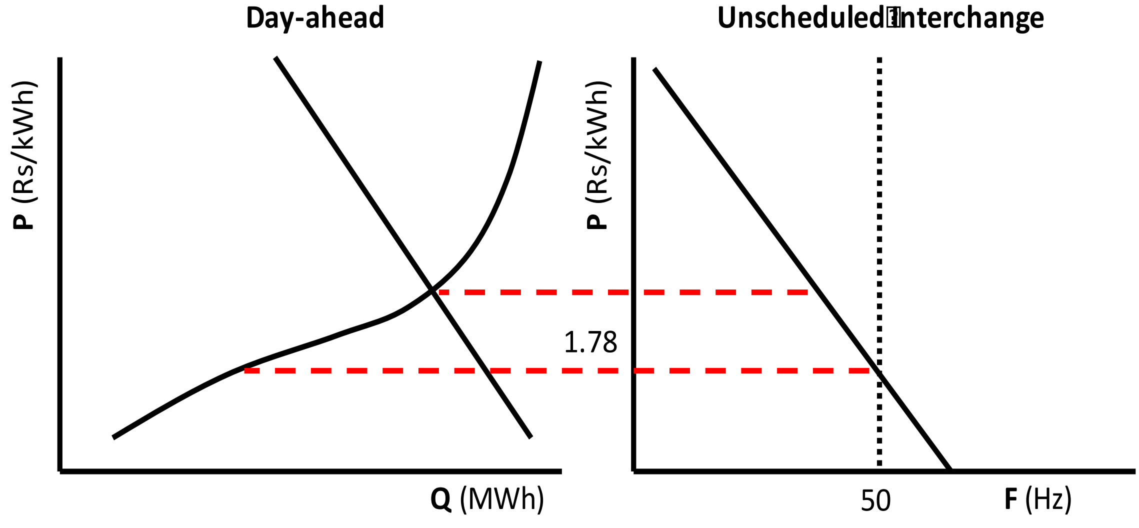

Figure 13: Interplay between DAM and DSM Prices (Symbolic)

With frequency remaining close to 50 Hz, the applicable DSM rate with 100% surcharge is providing an inadequate price signal. Thus, the markets are not in equilibrium as shown in Figure-8 and there may bea tendency to lean on the DSM mechanism for balancing by the utilities. This also poses a threat to the grid security.

8.4. Time Value of Electricity

The current DSM prices do not capture the difference between the peak and the off-peak value of electricity, whereas the market prices clearly present this in terms of different prices discovered for different time periods in a day. The present DSM prices are constant over very long periods (till review of the vector itself). DSM prices should have some mechanism to capture the time value of electricity.

8.5. Factoring Geographical Location andTransmission Congestion

Pricing unscheduled flows of electricity on a locational basis could be effectively used for congestion management. A locational pricing plan for unscheduled flows of electricity would provide rewards for generators and loads to change their operations in ways that provide that relief without having to resort to the undesirableoption of load regulation from the regional control centre.

The present deviation settlement mechanism is based on the premise that a congestion free transmission network exists and any amount of power can flow. In reality, this is not the case. The day-ahead market in the Power Exchange(s) discovers transmission congestion one-day in advance and manages this through an implicit auction and market splitting. This provides a price signal regarding the valuation of transmission. DSM prices are the real-time prices and these must factor transmission congestion or in other words, capture the geography in terms of price differential.

8.6. Market Opportunities for Balancing

Presently, close to the real time, a day-ahead collective market through Power Exchange operates which is used to balance the system. During the intra-day, day-ahead bilateral and contingency category contracts are available. However, there is a need for more iterations of the collective market so as to provide more opportunities to balance the system.

8.7. Gate Closure

With coordinated multilateral scheduling process and continuous revisions, overlapping of the scheduling and ancillary instructions being carried out by the concerned RLDC is taking place. For example, re-scheduling of un-despatched surplus on the request of one of the beneficiary, tripping of power system elements, natural variations etc. The available URS is thus changing continuously also and simultaneous ancillary dispatch has added another dimension of complexity to the process as there could be overlapping changes by the NLDC (for ancillary) and the RLDCs (schedules). Therefore, there is need for introduction of gate closure concept in the scheduling process so that system operator has the clarity of the quantum of reserve and resources at hand at any given point of time. Better optimization of the scheduled despatches and the real time ancillary despatch needs to be formulated.

9. International Experience

9.1 Nord Pool Spot

Internationally, Nord Pool Spot operates the leading markets for buying and selling power in Europe [11]. It operates Elbas which is a continuous balancing market where power trading takes place until one hour before the power is delivered. Members can adjust their power production or consumption plans close to delivery. Every day, transmission system operators publish their power transmission capacity to Elbas. Members ‘offer’ how much power they want to sell and buy and at what price. Trading is then set based on a first-come, first-served basis between a seller and a buyer. If transmission capacity is available, neighbouring countries can also trade on the Elbas market.

9.2 United Kingdom

National Grid uses the term “Balancing Services” to refer to the range of products it uses “to balance demand and supply and to ensure the security and quality of electricity supply across the GB Transmission System.” National Grid currently procures over 20 different balancing services products across the categories of System Security, Reserve, Frequency Response, and Reactive Power [12]. The Imbalance Pricing mechanism in UK [13] is briefly summarized as follows.

The summation of the disparity between market participants notified contractual positions and their physical delivered or taken electricity indicates the level of energy imbalance on the system. It is this imbalance that must be resolved by the SO as the residual balancer. Participants are exposed to this contractual disparity at a level determined by one of two imbalance prices derived in each settlement period.If a participant has a long position, that is to say the difference between contractual value and metered position has contributed to a surplus of electricity flowing on to the system, they are paid for that spill at System Sell Price (SSP).If a participant has a short position, that is to say the difference between contractual value and metered position has contributed to a deficit of electricity flowing on to the system, they are charged for that short-fall at System Buy Price (SBP).

9.3UCTE – Europe (Now ENTSO-E)

The relevant extracts from the Hirth, Lion & Inka Ziegenhagen (2015): "Balancing Power and Variable Renewables: Three Links", Renewable & Sustainable Energy Reviews 50, 1035-1051. doi:10.1016/j.rser.2015.04.180[14][15]are quoted as below:

"…In Europe, four types of actors interact in balancing systems: balance responsible parties, transmission system operators, suppliers of balancing power, and regulators.

Balance responsible parties (BRPs) *or "program responsible parties" are market entities that have the responsibility of balancing a portfolio of generators and/or loads. BRPs can be utilities, sales companies, and industrial consumers. Each physical connection point is associated with one BRP. BRPs deliver binding schedules to system operators for each quarter-hour of the next day,5 and are financially accountable for deviations from these schedules.*

Transmission system operators (TSOs) *operate the transmission network and are responsible to balance injections and off-take in their balancing area. TSOs activate balancing power to physically balance demand and supply if the sum of BRP imbalances is non-zero. Specifically, TSOs have four obligations:*

1. determine the amount of capacity that needs to be reserved as balancing power ex ante

2. acquire that capacity; determine its price (capacity and/or energy) ex ante

3. activate balancing power; determine the imbalance price (energy) in real time

4. financially clear the system and allocate costs (via imbalance price and/or grid fees) ex post

__Suppliers of balancing power__ supply reserve capacity, and deliver energy if dispatched by the TSO. They are obliged to deliver energy under pre-specified terms, for example within a certain time frame, with certain ramp rates, and for a specific duration. Suppliers are traditionally generators, but can also be consumers. Typically, suppliers of balancing power receive a capacity payment (€/MWh) because capacity reservation incurs opportunity costs, and/or energy payment (€/MWh) since activation is costly.

__Regulators__ determine the balancing power market design. They also monitor market power and prescribe the pricing formula of the imbalance price. Unlike most in other markets, the rules that govern trade of balancing power are set by authorities and have not emerged bottom-up from market interaction.

In the UCTE, balancing power is called "control power" (UCTE 2009), and three different types are used: primary control, secondary control, and tertiary control. They differ in purpose, response time, and the way they are activated (Table 2).

Table 2: Types of balancing power in the UCTE

	Primary Control	**Secondary Control**	**Tertiary Control (Minute Reserve)**
Response Time	30 secs, direct (continuous)	15 min or less[7], direct	15 min, direct or scheduled
System	UCTE	UCTE and balancing area	UCTE and balancing area
Target Variable	Frequency	ACE and frequency	Current and expected level of SC activation
Activation	Based on local frequency measurement	Centralized (TSO); IT signal (AGC)	Centralized (TSO); phone / IT signal
Suppliers (typical)	Synchronized generators, (large consumers)	Synchronized generators, stand-by hydro plants, large consumers	Synchronized and fast-starting stand-by generators, large consumers
Reserved Capacity	3000 MW in UCTE (600 MW in Germany)	Determined by TSO (2000 MW in Germany)	Determined by TSO (2500 MW in Germany)

In Europe, TSOs have started Imbalance Netting cooperation with focus on the pilot projects "International Grid Control Cooperation" (IGCC)[16], "e-GCC" and the "Imbalance Netting Cooperation" (INC). In order to start the implementation of this European process, TSOs have agreed to use the IGCC as a reference project and thereby as starting point.The IGCC is a regional project operating the imbalance netting process which currently involves 11 TSOs from 8 countries. These are the TSOs from AT (APG), BE (Elia), CH (Swissgrid), CZ (CEPS), DE (50Hertz, Amprion, TenneT DE, TransnetBW), DK (Energinet.dk), FR (RTE), NL (TenneT NL).

The objective of the international settlement model is to determine a settlement price per MWh and per 15 minutes for the energy volumes exchanged within the IGCC framework. Each MWh acquired as well as delivered by a participant within the same 15 minutes is invoiced at the same settlement price. The settlement price is calculated as the volume-weighted average of the opportunity prices, based on the opportunity costs, of the participating countries. This means that the energy volumes delivered and acquired for each country are multiplied by the corresponding opportunity prices, after which the opportunity costs determined in that manner are added up. To determine the settlement price, the sum of the opportunity costs is then divided by the total volume of positive and negative deliveries of energy. The settlement price can be positive as well as negative. Settlement prices reach negative values when the negative opportunity prices exceed the positive ones.

9.4PJM, USA

North American Electric Reliability Corporation (NERC) defines Balancing Authority as “One of the regional functions contributing to the reliable planning and operation of the bulk power system [17]. The Balancing Authority integrates resource plans ahead of time, and maintains in real time the balance of electricity resources and electricity demand.”

Pennsylvania – New Jersey – Maryland (PJM), USA Regional Transmission Operator (RTO) coordinates Balancing Authorities and Transmission Operators operation with PJM Reliability Coordinator (RC)[18]. The generation dispatching is performed for the PJM balancing authority area by the PJM Generation Dispatcher using the Security Constrained Economic Dispatch (SCED) application, which is a single economic constraint controlled dispatch for the entire PJM RTO area. The projected hourly energy, Operating Reserves, and other Ancillary Services requirements of the Market Buyers, including the reliability requirements of the PJM Balancing Area, are met through this economic despatch.

9.5CAISO, USA - Energy Imbalance Market (EIM)

The Western EIM, launched in 2014, is a real-time wholesale energy market, the first of its kind in the western United States [19]. It allows participating balancing authority areas to buy and sell the final few megawatts of power to satisfy demand within the hour it’s needed. EIM’s advanced market systems automatically find the lowest-cost energy to serve real-time customer demand across a wide geographic area. Utilities will maintain control over their assets and remain responsible for balancing requirements while sharing in the cost benefits the market produces for participants. The EIM does not participate in the Day Ahead market.

For most participants prior to EIM, optimization was typically on hourly basis. With EIM, CAISO optimizes within the hour to bring economic and reliability benefits to market participants. There is a 15 minute real time CAISO "RTPD" optimization and then within each 15 minutes there is a 5 minute CAISO despatch optimization. The 15 minute process and the 5 minute processes are not independent. Out of the RTPD comes the commitment and the LMP, however the 5 minute process is the one that sets the dispatch instruction. Every 5 minutes the security constrained economic dispatch runs along with a contingency analysis to ensure no reliability constraints are being violated.EIM relies on a market based business model based on clearly defined roles.

9.6France

The balancing mechanism [20] is based on the global vision of all the imbalances seen from theelectric system and thus enables the emergence, for each half-hourly step, of a reference priceapplicable for the settlement. This reference price is calculated on the basis of the averageweighted prices of the upward balancing tenders (AWPu) and the downward balancingtenders (AWPd) unless the imbalance of the balance responsible reduces the global imbalanceof the system, in which case the Powernext price applies.

The following table sums up the prices applied to imbalances in France:

	Upward balancing trend	**Downward balancing trend**
Positive imbalances (I>S) RTE pays Bal. resp.	**Powernext spot price**	**AWPd / (1+k)***
Negative imbalances (I<S) Bal. resp. pays RTE	**AWPu x (1+k)****	**Powernext spot price**

*upper limit is Powernext spot price/ ** Powernext spot price is lower limit / k weighting factor k=0,2

10. Recommendations for Revision in DSM Vector

The report of the Ministry of Power, Government of India High level Technical Committee on 'Large Scale Integration of Renewable Energy, Need for Balancing, Deviation Settlement Mechanism (DSM) and associated issues' [21] highlights the need for a regulatory framework for intra State deviation, metering, accounting and settlement mechanism amongst the different entities including renewable. It also recommends the linkage of deviation price to market linked mechanism with suitable price discovery process. The relevant extracts are quoted as follows:

> *"…1. Appropriate Regulatory Framework for handling Inter-State Deviations especially for Large and High RE Penetration States….The deviation limits for inter-state and intra-state entities, especially for Large and High RE Penetration States, stipulated by the Appropriate Commission, may take into account the stakeholder's concerns and international best practices. The regulatory framework for intra-state deviation, metering, accounting and settlement mechanism amongst the different entities including renewables must be in place and implemented at state level in 2016. Subsequently, say by 2017, deviation price may be linked to market linked mechanism with suitable price discovery process…."*

The significance of balancing has been recognized by NitiAyog in the "Report of the Expert Group on 175 GW RE by 2022" [22]. The relevant extracts are quoted as follows:

> *"….Balancing in India is overseen by a state LDC, and is done by each state as a whole. Given that some states are very large indeed – comparable to many countries in scale– this is already a very significant task….."*

11. Design Considerations for the Market linked DSM Rates

In order to address the limitations mentioned above, there is a need to link the DSM rate vector to the prices discovered in an available organized market which operates closest to the real time. In India, Power Exchange Markets are organized markets operating on a day-ahead basis where prices are discovered competitively in a double sided closed auction for every 15-minute time interval. Hence, it is proposed to link the DSM prices to the day-ahead market (DAM) prices discovered in the Power Exchange.

However, before attempting to link the DSM price to the DAM prices, it is essential to deliberate the following design considerations:

a) Prices available for use as a reference for DSM
b) Size of Market Segments (DAM and DSM) proposed to be linked
c) Multiple Power Exchange Prices
d) Unconstrained Market Clearing Price (MCP) or Area Clearing Price (ACP)
e) Granularity/periodicity of prices to be linked
f) Frequency Band
g) Point of linking DSM Vector and DAM prices
h) Slope of the DSM Rate Vector along with the Ceiling and Floor
i) Volume limits& Cap Rates
j) Single or Dual Imbalance Pricing: Different rates for drawl and injection
k) Establishment of truly inadvertent deviations

Each of the above-mentioneddesign aspect is deliberated below in detail.

11.1 Prices Available for use as a reference for DSM

The following prices are available for use as a reference for the DSM price vector.

(a) Power Exchange day-ahead market price
(b) Costliest generator dispatched under ancillary services.

The day-ahead market in the Power Exchange comprises about 3-3.5% of the all India generation. More than 1000 participants are voluntarily participating in this double sided closed auction and price for each 15-minute time block is being discovered.

Considering the fact that ancillary services are being used to balance the system in real time, the costliest generator dispatched represents the system marginal price. The ancillary services introduced in India are limited version which only utilizes the un-requisitioned surplus generation available in generators whose tariff is determined or adopted by CERC. These generators are required to declare their charges upfront in advance for facilitating the despatch decision during the the next month. Hence, the price discovered in the despatch of ancillary services does not reflect a competitively discovered market based price. The Committee understands that separate efforts are being made for expanding the ambit of the present ancillary services mechanism and facilitate market based procurement of ancillary services.

Hence, under the present circumstances, it is felt prudent to use the price discovered in the day-ahead market as a reference for the DSM price vector. In the future, when market based procurement of ancillary services matures and robust discovery of prices takes place, then, other alternatives may be examined.

11.2 Size of Market Segments (DAM and DSM) proposed to be linked

Linkage of prices in two market segments also needs to consider the sizes of the segments being linked. In India, about 90% is in long-term & medium-term contracts and the balance is under short-term market which comprises of about 5% through bilateral (OTC) market, about 3-3.5% in the day-ahead Power Exchange market and the balance 1.5-2% in deviations. The proposal is to link the prices in the DAM segment in Power Exchange with the DSM segment. Both these are of a comparable size with the DAM segment being larger in size as compare to the DSM. Moreover, the participants in the DSM segment are all participating in the DAM also. There are apprehensions that DSM prices will influence long-term prices of electricity. However, it also needs to be appreciated that prices in different market segments must ultimately show convergence.

Hence, the linking of prices in DAM and DSM market segments may be considered.

11.3 Multiple Power Exchange Prices

India has implemented multiple Power Exchanges and thus, multiple day-ahead prices are being discovered. The natural corollary is the question as to day-ahead price of which Power Exchange should be considered? The two operational Power Exchanges presently in India are Indian Energy Exchange (IEX) and Power Exchange India Ltd. (PXIL). One of the Power Exchanges (IEX) has a dominant market share presently (more than 95%), indicating higher liquidity and more robust price discovery. Power Market Regulations 2010 (Regulation 34) provide the following:

"A Power Exchange which has less than 20 % market share for continuously two financial years falling after a period of two years of commencement of its operations shall close operations or merge with an existing Power Exchange with in a period of next six months.

(For this purpose, Market size is defined as the total Annual Turnover in Million Units of all contracts transacted in all the Power Exchanges in each financial year)

Provided that this regulation shall not apply if there are only two Power Exchanges in operation."

Taking a cue from the provisions of the above Regulation, it is proposed that day-ahead market price of the Power Exchange having a market share of 80% or more in energy terms on a daily basis shall be linked to the DSM price. If there is no single Power Exchange having a market share 80% or more, then, the weighted average day-ahead price shall be used for linking to the DSM price.

11.4 Unconstrained Market Clearing Price (MCP) or Area Clearing Price (ACP)

It has been mentioned above that "geography" in terms of transmission congestion is not being captured in the present mechanism. If there is no congestion, the ACP will be the same as the MCP. However, in case of congestion ACP shall be different from MCP and the market discovers congested corridors on a day-ahead basis. In all likelihood, actual congestion will be taking place in the real if there is no substantial change in the load-generation balance in the grid. Hence, the real-time prices (DSM) should be reflective of the transmission congestion.

Hence, the Area Clearing Price (ACP) should be linked to the DSM Price so as to factor geographical aspect and congestion.

11.5 Granularity/Periodicity of Prices to be linked

Bidding in the Power Exchanges takes place for every 15-minute time-block and accordingly, prices are discovered for each 15-minute time block. Figures 14-15 show the typical day-ahead market prices (IEX) on a block-wise basis and on a daily basis respectively.

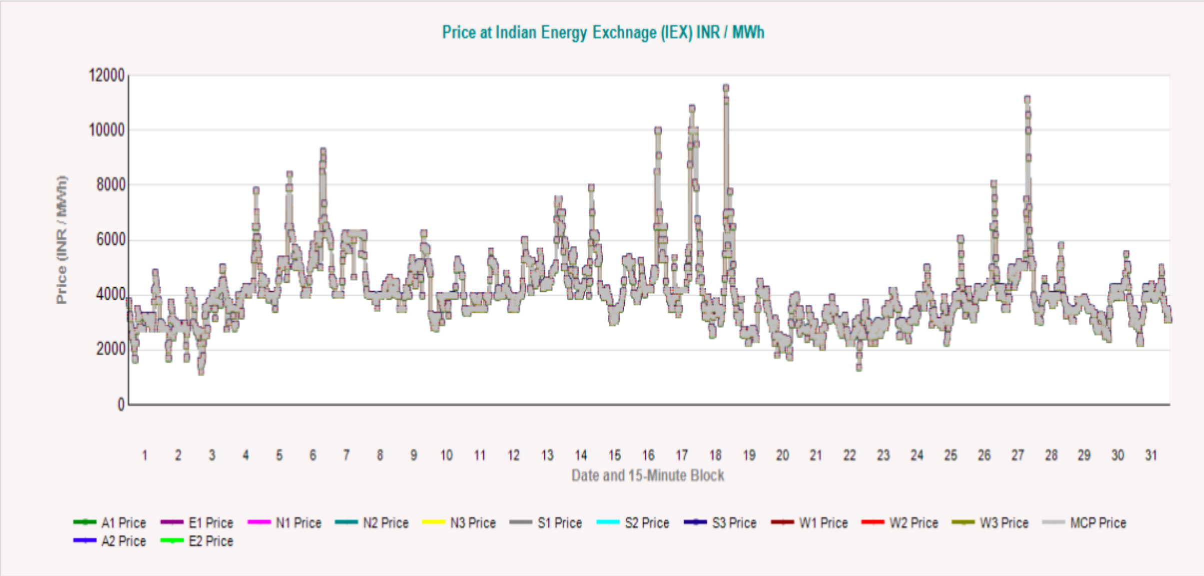

Figure 14: Interplay between DAM and DSM Prices (Sample - Block-wise)

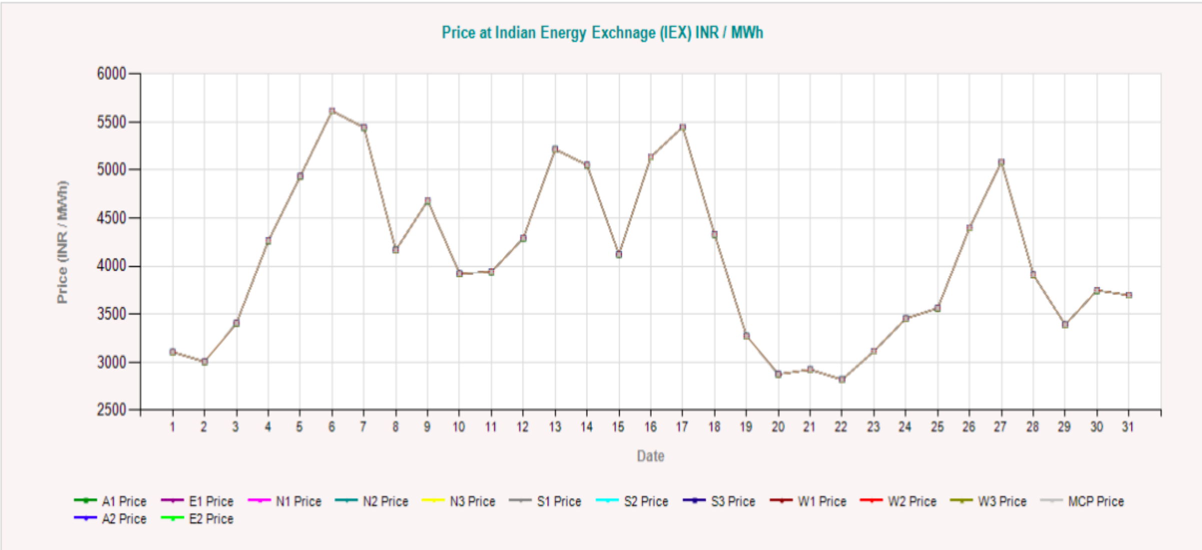

Figure 15: Interplay between DAM and DSM Prices (Sample - Over a Day)

Using the block-wise prices provides a signal differentiating the diurnal variation in supply and demand. However, it is observed that the block-wise prices are volatile and this volatility will reflect in the DSM prices. On the other hand, the daily prices show lesser volatility but these do not capture the diurnal variation. The proposal to shift from regulated DSM price vector to a market based DSM price vector is itself a major change for the entire sector. For the time being, some experience needs to be gained in respect of using market discovered prices for DSM before the granularity of market linkage is made block-wise.

Hence, it is suggested that the daily average area clearing prices in the day-ahead market should be used as the basis for market linked DSM price.

11.6 Frequency Range

Practices in the North American system for frequency control

"What frequency is to the Interconnection, Area Control Error or (ACE) is to the Control Area' is the basic principle on which the Frequency control and its various performance metrics are designed."

In respect of primary response, the NERC Reliability Standards (BAL-003-1) define the Interconnection Frequency Response Obligation (IFRO) which usually considers the largest generation loss possible and the Under Frequency Load Shedding (UFLS) setting. In case of Eastern Interconnection (the largest system in US), this is 4500 MW and 59.5 Hz giving an IFRO of 1002 MW/0.1 Hz. This IFRO is apportioned amongst all entities depending on their load and generation. The actual Frequency Response Characteristics (FRC) observed for the Eastern Interconnection as well as Western Interconnection is much above the IFRO, at least 2.5 to 3 times the IFRO.

Primary response is a mandatory service in the US with no explicit payments made for providing this service. However recently, CAISO in the Western Interconnection has apprehended that under a high RE scenario, it might be difficult for CAISO to even provide the IFRO and a proposal has been placed before the Federal Energy Regulatory Commission (FERC) for payments for primary response. This has been recently approved by the FERC in February 2017 and awaiting implementation.

In respect of secondary control through AGC, termed as regulation services, standards exist for setting the frequency bias (BAL-003-1.1) as well as Control Performance Standard 1 or CPS1. CPS1 is calculated on monthly basis and has to remain above 100 for a Control Area to ensure compliance. CPS1 is mainly calculated from the Area Control Error (ACE). Apart from CPS1, a balancing area must also ensure that its ACE does not exceed the Balancing Authority ACE Limit or BAAL for more than 30 minutes. Violations of CPS1 and BAAL would make the Balancing Authority liable for penalties.

As regards payments to entities for providing regulation services, FERC Order 755 dated 20th October 2011 lays the foundation of pay as per performance. So depending on the extent to which the generators follow the regulation signals, a multiplying factor is added for AGC payments. This multiplication factor would be less than one. Secondary regulation is usually obtained through the market by the Independent System Operators (ISOs).

The third category of reserves deployed as part of any contingency is termed as contingency reserve or supplemental reserve. This is again procured by the ISO through markets.

IEGC Regulation 5.2(m) mandates the operational frequency band as 49.90-50.05 Hz. The present DSM price vector covers the frequency range 49.70-50.05 Hz, which is far beyond the mandated operational frequency band. This needs to be aligned with the IEGC mandated frequency band. From the perspective of the drawee utilities, this would require more accurate load and RE forecasting and the utilities need to gear up for this. Further, steps are being taken to implement secondary control through automatic generation control

Hence, it is suggested that the frequency band for the purposes of the DSM price vector may be taken as 49.85-50.05 Hz to begin with. A time period of 6 months may be given as an advance notice period to the utilities to gear up. At the end of 6-month period, the frequency band for DSM price vector should be changed to 49.90-50.00 Hz so as to align with the IEGC mandated operational frequency band.

11.7 Point of Linkage of DSM Price Vector and DAM prices

Having considered using the daily average ACP for linking to the DSM price vector, next aspect to be addressed to the frequency at which the daily average ACP shall be used as reference for the DSM rate. The portfolio of buy-sell in the Power Exchange is a balanced portfolio at 50 Hz frequency. The present DSM rates do not factor the transmission charges and transmission losses. Any transaction made in the DSM also offers an advantage over other transactions in terms of the absence of the ‘hassle factor’.

Hence, it is suggested that the average daily ACP be used as a reference and linked to the DSM rate at 50 Hz.

11.8 Slope of the DSM Rate Vector along with the Ceiling and Floor

The mandated frequency band may be fixed as mentioned above from 49.85-50.05 Hz (to begin with). This implies that the maximum DSM rate must be achieved at 49.85 Hz and the DSM rate should become zero (0) at 50.05 Hz in steps of 0.01 Hz (as is being done presently). The maximum DSM rate at 49.85 Hz should be such that all generation including costly liquid based generation must get dispatched by the time frequency falls to 49.85 Hz so as to ensure grid security. The present variable charges for liquid fired gas station are above Rs. 8 per unit. Above a frequency of 50.05 Hz, generation must a get a clear signal to back down and conserve fuel. However, in case of congestion, if the DSM rate becomes zero above 50.05 Hz, then based on this signal, some generators downstream of the congested corridor may also back down. This is undesirable and one method by which such a situation can be avoided is the imposition of congestion charges in advance once congestion has been discovered in the day-ahead market.

Hence, the DSM rate vector will have a dynamic slope determined by joining the identified price points at 50 Hz. (daily average ACP), low frequency of 49.85 Hz (Rs. 8 per unit) and 50.05 Hz (zero) on a daily basis.

11.9 Single or Dual Imbalance Pricing: Different rates for drawl and injection

Literature [23] suggests that there can be two imbalance pricing methods, namely single imbalance price or a dual imbalance price. The relevant extracts are placed below.

> *"A number of Member States have already adopted or are considering the adoption of single imbalance pricing. This is where a party whose imbalance is in the opposite direction to the overall direction of the system (e.g. a party that is long when the system is short, and therefore contributes to the reduction of the system imbalance) faces the same imbalance price as a party whose imbalance is in the same direction as the overall direction of the market (e.g. a party that is long when the system is long, and that therefore aggravates the system imbalance).*
>
> *In contrast, a dual imbalance price is where a party with an imbalance contributing to the system imbalance faces a price that reflects the cost of balancing, while a party with an imbalance reducing the system imbalance faces a different price – frequently a market price. The rationale of the dual price is that a party that has contributed to*

the system imbalance should contribute to the cost of balancing it, and should be exposed to the cost of balancing it. However, a party with a "reducing balance", i.e. one that has reduced the system imbalance, should receive or pay the price that it would have received or paid if it had traded out its imbalance in the intraday market. Dual prices have faced increasing criticism, however, on the grounds that the market price paid to parties that have reduced the system imbalance is not cost-reflective, and is inefficient because it over-incentivises parties to be in balance. The market price does not allow parties with helpful imbalances to share the cost-savings and benefits to the market.

A single imbalance price addresses these concerns, because it reflects the balancing costs avoided. This is thought to be particularly beneficial to smaller players who often have reducing imbalances. As the basis for the single imbalance price, the Commission favours marginal pricing (as it does for the pricing of balancing energy, discussed above). However, this is not expressly built into either the short-term rules for national imbalance pricing (because the reference price – the price of activated reserves - will not necessarily be the marginal price) or the long-termharmonised rules. The Commission's new energy market design proposals are expected to impose a requirement to develop an imbalance price that reflects the real-time value of energy."

Interplay in prices in the different market segments has already been flagged as an issue and there can be situations where gaming occurs. One of the ways to correct this situation is to have different rates for drawl (higher) and injection (lower). The present transition from administered DSM rate vector to a market is a paradigm shift and separate drawl and injection rates will further confuse the market participants.

Hence, for the present, it is proposed to have a single DSM rate for both drawl and injection, subject to cap rates for applicable generators. As the process of market linking matures and becomes stable, CERC may consider introduction of different rates for drawl and injection.

11.10 DSM Vector for Renewables

The present DSM vector for renewable generation is linked to the PPA rates of the concerned RE generator, with an emphasis on making more and more accurate forecasts.

Hence, it is suggested to continue with the present methodology of DSM rates for the renewables.

11.11 Volume limits and Cap Rates

The present DSM mechanism defines volume limits beyond violation of which attracts penalties in terms of additional charges varying from 20% to 100% of the applicable DSM rate for that time block. The utilities have been representing that there are instances such generating unit tripping etc. and in such cases, the volume limits get violated. However, during such an event, the violations can occur in the initial few blocks and the utility must quickly respond by taking actions to achieve balance once again. Another contention is that the deviation limits are violated because of variability of renewable generation. It needs to be appreciated that variation of renewables does not happen in the few-minute time frames and variability of renewables can be handled with better load and RE forecasting techniques as is being done elsewhere in the world.

In the interest of secure grid operation, all the volume limits along with associated surcharge/additional surcharge should be retained in the new market linked DSM price mechanism.

The volume limits for RE rich states have been relaxed by CERC based on the level of RE penetration and these vary from 150 MW to 250 MW. In this regard, Explanatory Memorandum issued by CERC along with the proposed amendment states the following:

> *"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."*

Further, the Explanatory Memorandum of the Draft CERC DSM Regulations 2013 mentions the following:

41. It has also been seen that generators often reduce generation when the UI prices are lower than the energy charges even if the grid frequency is lower than the 50 Hz, thereby affecting the load generation balance adversely. In order to arrest this tendency of generators, it is proposed to provide that the Charges for the Unscheduled Interchange/Deviation for under-injection by a generating station "below 50.0 Hz" shall be its energy charge of the previous month, if energy charge is higher than the charges for Unscheduled Interchange/Deviation corresponding to the grid frequency of the time block. In case of gas based generating stations, the energy charge for this purpose shall be considered starting from the highest to lower for the respective fuel. Each generating company shall furnish the energy charges of each of its station for the previous month to the respective RPC each month.

The cap rates for applicable generators should be linked to the variable charges for that generator as billed for the previous month.

11.12 Establishment of True Inadvertency in Deviations

The deviations from schedule, if inadvertent, will manifest as white noise with mean close to zero(0). The present DSM regulations mandate a change in the sign of the deviation once every 12 time blocks. However, there is no commercial mechanism for ensuring compliance to these provisions. There is also a need to clarify the methodology of counting the time blocks for change of sign such as fixed pre-identified block or rolling blocks, etc. The detailed accounting methodology can be specified in a procedure by National Power Committee (NPC) so as to ensure harmonious implementation by the RPCs. Further, the earlier CERC (Unscheduled Interchange charges and related matters) Regulations, 2009 had a provision restricting the total deviations in daily aggregatebasis to 3%.

"…7. Limits on UI volume and consequences of crossing the limits.-

(1) The over-drawal of electricity by any beneficiary or a buyer during a timeblock shall not exceed 12% of its scheduled drawal or 150 MW, whichever is lower,when frequency is below 49.7 Hz and 3% on a daily aggregate basis for all the timeblocks when the frequency is below 49.7 Hz

Explanation: The limits specified in this clause shall apply to the sum total of overdrawal by all the intra-State entities in the State including the distribution companies and other intra-State buyers, and shall be applicable at the inter-State boundary of the respective State.

(2) The under-injection of electricity by a generating station or a seller during atime-block shall not exceed 12% of the scheduled injection of such generatingstation or seller when frequency is below 49.7 Hz and 3% on daily aggregate basisfor all the time blocks when the frequency is below 49.7 Hz…"

Hence, it is suggested that the sign of the deviation must change once every 6 time blocks and an appropriate commercial provision to ensure compliance should be introduced (such as a 20% additional charge for violation). Further, in energy terms, the total deviation from schedule during a day should not be in excess of 3% of the total schedulefor the drawee entities and 1% for the generators and additional charge of 20% of the daily base DSM payable/receivable shall be applicable in case of the said violation.

12. Simulation Study

In order to understand the impact of proposed linking of DSM Price Vector with the ACP of DAM, the consultant carried out Price Vector simulations for three (3) days over the period of "01 Jan 2017 to 03 Sep 2017". The criteria used for selection was as under:

a) Day which observed the highest MCP (25 Aug 2017)
b) Day which observed the lowest MCP (02 Jul 2017)
c) Day which observed the median MCP from 1 Jan 2017 to 3 Sep 2017 (17 Jan 2017)

The Average ACP for each price region of Power Exchange (IEX) for the above days is summarized in the Table 1 below. IEX was selected since it formed more than 90% of the market clearing volumes for the selected days.

Table 1: Daily Average Area Clearing Price (ACP) of the selected days in IEX (Rs/MWh)

Date	A1	A2	E1	E2	N1	N2	N3	S1	S2	S3	W1	W2	W3	MCP
25-Aug-17	3,810	3,810	3,810	3,810	3,810	3,810	3,810	3,810	3,810	3,810	3,810	3,810	3,810	**3,810**
2-Jul-17	1,017	1,017	1,017	1,017	**1,023**	**1,023**	**1,023**	**1,991**	**1,991**	**1,991**	1,017	1,017	1,017	**1,115**
17-Jan-17	2,540	2,540	2,540	2,540	**2,870**	**2,870**	**2,870**	**2,939**	**2,939**	**2,939**	2,540	2,540	2,540	**2,665**

From the above table on ACP for the three selected days, it may be observed that there was market splitting on 02 July 2017 and 17 Jan 2017 indicating different ACP for Northern (N1, N2 and N3), Southern (S1, S2, S3) and Rest of India price areas.

The DSM Price Vectors were simulated using the actual block wise frequency data for all threedays and for the following three alternatives.

a) Existing DSM based on the regulated DSM rates

b) Average Daily ACP of Power Exchanges

c) Block wise ACP of Power Exchanges

The summary of the results is shown in the Table 2 below:

From the Table-2, it is evident that linking DSM Charges to the ACP of DAM providescorrect market signals for real time deviation settlements. This can be observed from the factthat the average and maximum DSM charges are higher for highest and median MCP day incase of ACP linked DSM Charges as compared to that of existing regulated DSM Charges.

Similarly, the DSM charges for the Lowest MCP Day in case of ACP linked DSM Charges areobserved to be lower for average and minimum cases as compared to regulated DSMCharges. The reasons for this may be attributed to the fact that the ACP / MCP in the DAM ofPower Exchanges would be higher when the demand is higher and vice versa.

Thus, linkingDSM Charges with DAM of Power Exchange is expected to ensure better estimation ofdemand and accurate scheduling by the DISCOMS, which may result in improved griddiscipline, avoid DSM being used as a trading route and provide the desired market signalsfor setting up of reserve and ancillary service based capacity.

One of the limiting conditions of the Study is that it assumes that there is no change behavior with the change in the DSM price vector. Details enclosed at *Annexure - IV*.

Table 2: Summary of DSM Charges under Existing DSM Charges, Block wise ACP and Daily Average ACP approach for the selected days

Case (Date)	Metric	Region	DSM Price Discovery Mechanism (Rs/MWh)		
			Existing (Regulated)	Block wise ACP (Market based)	Average Daily ACP (Market based)
Highest MCP Day (26 Aug 2017)	Average	NR	1,902	3,719	3,835
		WR, ER & NER		3,719	3,835
		SR		3,719	3,835
	Max	NR	5,114	8,032	8,032
		WR, ER & NER		8,032	8,032
		SR		8,032	8,032
	Min	NR	-	-1,950	-2,286
		WR, ER & NER		-1,950	-2,286
		SR		-1,950	-2,286
Lowest MCP Day (02 Jul 2017)	Average	NR	1,480	927	741
		WR, ER & NER		922	738
		SR		1,623	1,444
	Max	NR	4,698	5,998	2,454
		WR, ER & NER		5,998	2,442
		SR		8,032	4,779
	Min	NR	-	-999	-2,045
		WR, ER & NER		-999	-2,035
		SR		-4,401	-3,982
Median MCP Day (17 Jan 2017)	Average	NR	1,922	2,941	2,885
		WR, ER & NER		2,635	2,553
		SR		3,031	2,954
	Max	NR	4,489	8,032	6,601
		WR, ER & NER		7,999	5,841
		SR		8,032	6,760
	Min	NR	-	-2,504	-2,296
		WR, ER & NER		-2,503	-2,032
		SR		-2,800	-2,351

13. Case Studies - Market based Settlement of Imbalances

Market based price is being used both in India and abroad for settlement which are detailed below:

13.1 Within India – Delhi

SAMAST Report [24] details the implementation of ABT/UI mechanism in Delhi which was rolled out w.e.f. 01st April 2014. Initially it was applicable for Badarpur Thermal Power

Station (Central Sector Station with 100% allocation to Delhi) only. Installation of energy meters for all other intra State Entities was completed before 01st April 2007. Thus jurisdiction was clearly defined with placement of interface meters before commencement of intra State ABT for discoms and other intra State generators. Transition was handled successfully.

- Inter DISCOM Transfer-1. (Facilitation of Intra -state market by System Operator). Takes place on Day Ahead Basis. No revisions allowed.
    - Each DISCOM informs about its Surplus and Deficit to SLDC on Day Ahead Basis. Any excess capacity in the hands of any of the Distribution Companies / Agency, at any time, is offered to other Distribution Companies in Delhi, before it is sold outside the State.
    - The needy DISCOMs place their requisition to SLDC for the next day.
    - SLDC distributes the individual surplus to needy DISCOM based on Weighted Average Entitlements as per the DERC order dated 31.03.2007. Inter Discom power Transfer is finalized by SLDC.
    - The Inter Discom transfer takes place at the rate of IEX + 10 paise/unit (based on the order issued by DERC on 28.11.2013) with the settlement mechanism same as that of the Energy Exchange.
- Inter DISCOM Transfer-2 (Post Facto Settlement mechanism)
    - The Inter Discom Transfer of surplus energy is drawn out to avoid the penalties for Over-drawl and Under-drawl as stipulated in the Deviation Settlement Mechanism Regulation notified by CERC:
    - SLDC draws out the surplus / shortages of Individual Discoms from their Final Implemented Schedule and Actual Drawl based on SEM reading. Based on this shortage/surplus SLDC shall distribute the individual surplus to the needy Discoms when both surplus and needy Discoms violate the limits specified in Deviation Settlement Mechanism Regulations.
    - The rates would be as per the rates mentioned in Deviation Settlement Mechanism at each frequency regime.

13.2 Outside India – South African Power Pool (SAPP) under development

SAPP was created in 1995 with Inter-Governmental MOU. There are 12 member countries, represented by their national electric power utilities, covering 294 million people [25]. There are 16 SAPP members in total: 12 national power utilities (of which 3 are non-operating members), 2 IPPs, & 2 independent transmission companies. There is operating capacity of 46,522 MW with Peak Demand & Reserve of 53,036 MW in 2016.

Effectively, there are 3 markets: Bilateral (Long), medium, and short term. Electricity only product is traded. Market is open to all participants upon meeting a range of eligibility criteria. SAPP acts as the market operator and also provides financial settlement services.

SAPP started competitive day ahead market (DAM) using the Sapri IT system (developed by Nord Pool), operating in parallel with the bilateral market.SAPP specific trading platform (SAPP-MTP) was developed in 2015 which included a new Physical Forwards Market and a new Intra-Day Market. It incorporates the following:

- Handling of bilateral scheduling;
- Day-ahead market – live from 1 April 2015;
- Forward Physical Monthly & Weekly Markets (FPM-M & FPM-W) – Operating from 1 April 2016;
- Intra-Day Market (IDM) – Operating from 1 March 2016
- Energy Imbalance calculations and Bilateral Wheeling & Losses Settlement – Operating from 1 April 2016

The balancing services are handled within each control zone and are not linked to electricity prices. The current charges are Pool Average Generation Cost (Block C), Highest Gen. cost (Block A) and Zero (Block E) [26]. These costs are currently based on generic price data. SAPP is reviewing the energy imbalance charges prices in order to link them to market prices.

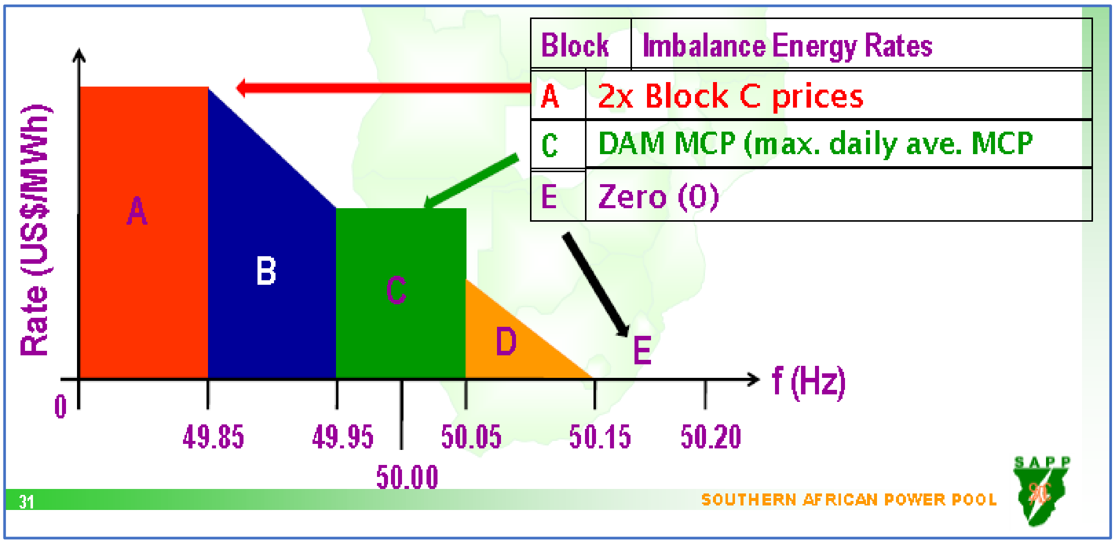

Figure 16: SAPP Imbalance Energy Rates Calculation

14. Conclusion and Recommendations

In view of the foregoing discussion, the Committee recommends the following.

14.1 There is a need for improved forecasting and planning for procurement by the utilities. The quantum of reserves mentioned in the CERC Roadmap for Reserves dated 13th October 2015 need to be implemented.

14.2 More iterations of the Electricity Market in Power Exchanges should be implemented so as to provide adequate opportunities to the market participants to balance their portfolio for example, evening market, four/six-hour ahead market in the Power Exchange. This would also facilitate moving to real time markets gradually in a phased manner.

14.3 Presently, only deviations are being monitored and the Committee feels that this change from monitoring of simple deviations to monitoring of 'Area Control Error (ACE)".

14.4 There is need for introduction of gate closure concept in the scheduling process so that system operator has the clarity of the quantum of reserve and resources at hand at any given point of time. This will facilitate better optimization of the scheduled despatches and the real time ancillary despatch.

14.5 The DSM price vector is presently administered by CERC and needs to be reviewed in view of the changing electricity market conditions. The Committee recommends that the DSM Price Vector should be linked to the existing market discovered prices (day-ahead market). The details of the design aspects associated with market-linked DSM price vector are as follows:

a. Under the present circumstances, it is felt prudent to use the price discovered in the day-ahead market as a reference for the DSM price vector. In the future, when market based procurement of ancillary services matures and robust discovery of prices takes place, then, other alternatives may be examined.

b. It is proposed that day-ahead market price of the Power Exchange having a market share of 80% or more in energy terms on a daily basis shall be linked to the DSM price. If there is no single Power Exchange having a market share 80% or more, then, the weighted average day-ahead price shall be used for linking to the DSM price.
c. It is suggested that the daily average area clearing prices (ACP) in the day-ahead market should be used as the basis for market linked DSM price at 50 Hz for the time being and not the time block ACP which could have high volatility.
d. It is suggested that the frequency band for the purposes of the DSM price vector may be taken as 49.85-50.05 Hz to begin with.
e. A time period of 6 months may be given as an advance notice period to the utilities to gear up. At the end of 6-month period, the frequency band for DSM price vector should be changed to 49.90-50.05 Hz so as to align with the IEGC mandated operational frequency band (as amended from time to time).
f. It is suggested that the average daily ACP be used as a reference and linked to the DSM rate at 50 Hz.
g. The DSM rate vector will be dynamic and slope determined by joining the identified price points at 50 Hz. (daily average ACP), low frequency of 49.85 Hz (Rs. 8 per unit) and 50.05 Hz (zero) on a daily basis.
h. It is proposed to have, for the time being, a reciprocal single DSM rate for both drawl and injection subject to cap rates for applicable generators. As the process of market linking matures and becomes stable, CERC may consider introduction of different rates for drawl and injection.
i. It is suggested to continue with the present methodology of DSM rates for the renewables.
j. In the interest of secure grid operation, all the volume limits along with associated surcharge/additional surcharge should be retained in the new market linked DSM price mechanism for the time being and tightened progressively in line with the international practice.
k. The cap rates for applicable generators should be linked to the variable charges for that generator as billed for the previous month.
l. It is suggested that the sign of the deviation must change once every 6 time blocks and an appropriate commercial provision to ensure compliance should be introduced (such as a 20% surcharge for violation). Further, in energy terms, the

total deviation from schedule during a day should not be in excess of 3% of the total schedule for the drawee entities and 1% for the generators and additional charge of 20% of the daily base DSM payable/receivable shall be applicable in case of the said violation.

A comparison of the existing DSM price vector vis-à-vis the DSM price vector as recommended by the Expert Group is depicted below

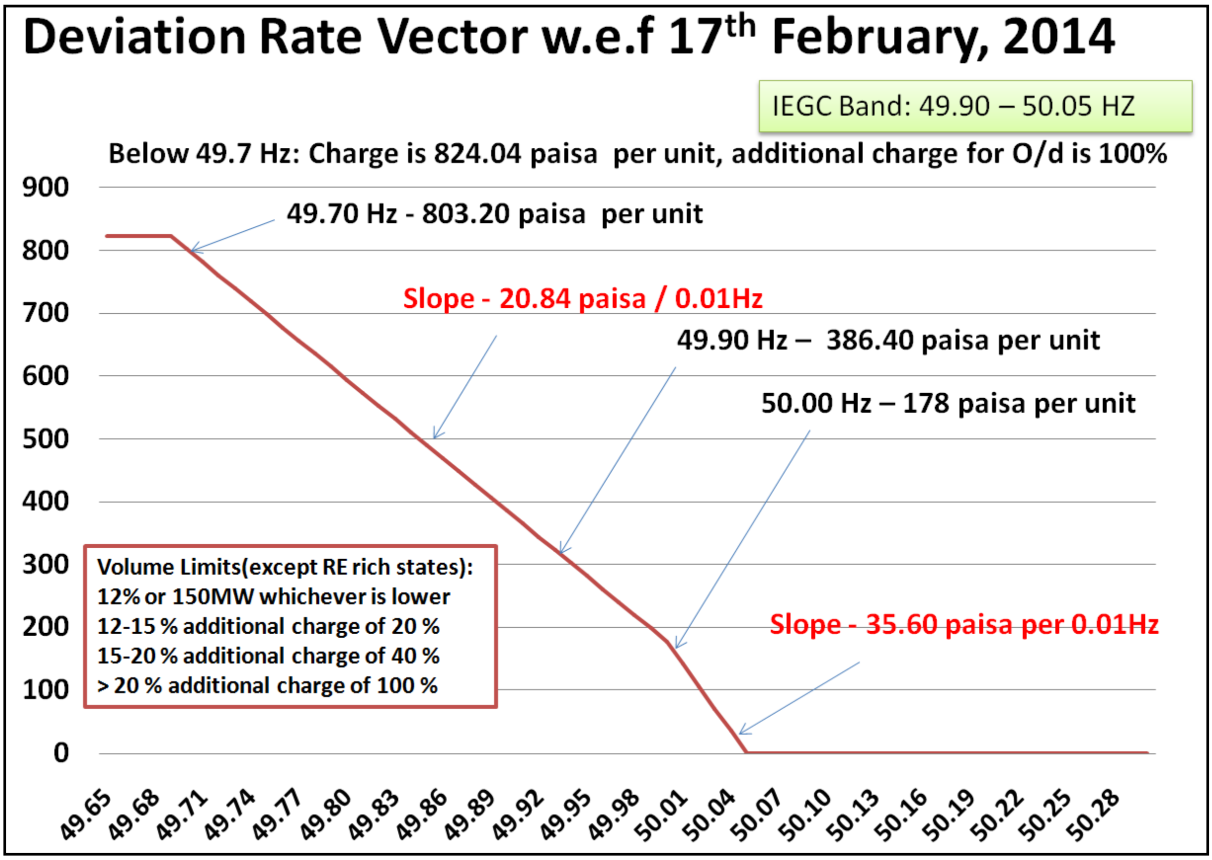

Figure 17: Existing Deviation Settlement Price Vector (effective since 17.2.2014)

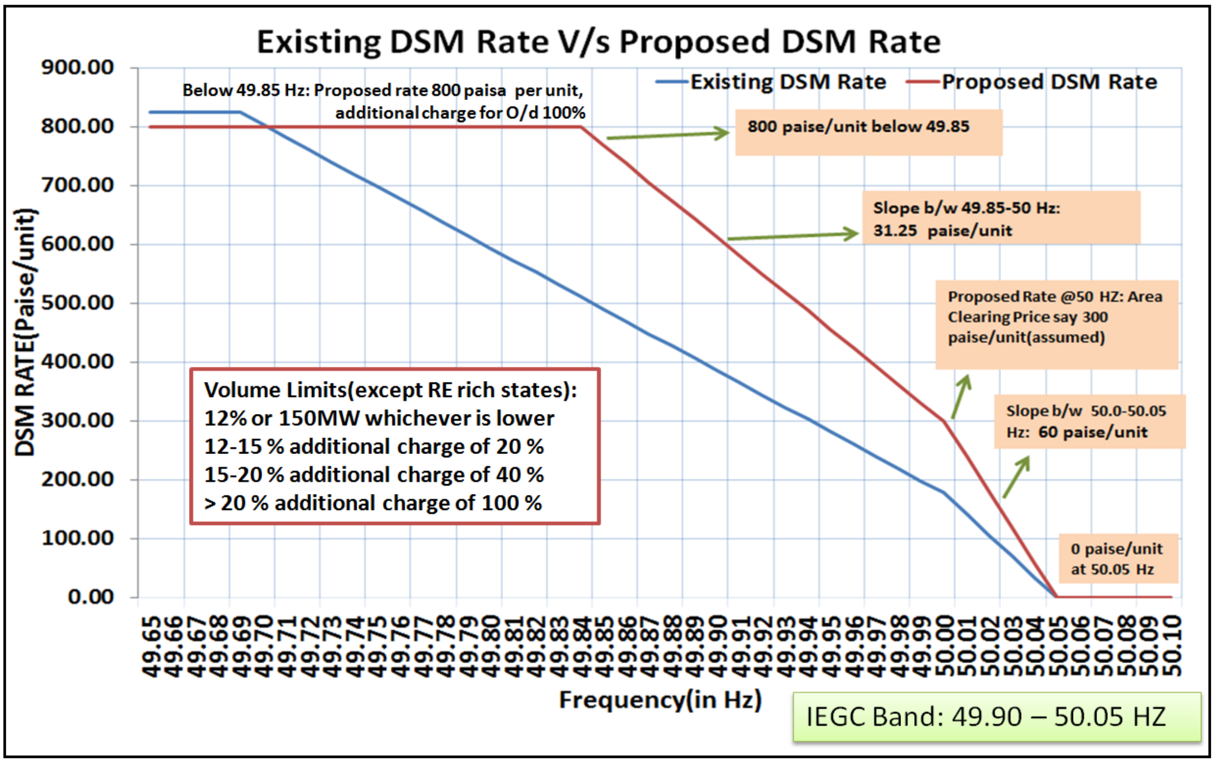

Figure 18: Comparison of the existing Deviation Settlement Price Vector (effective since 17.2.2018) and the Proposed Deviation Settlement Price Vector

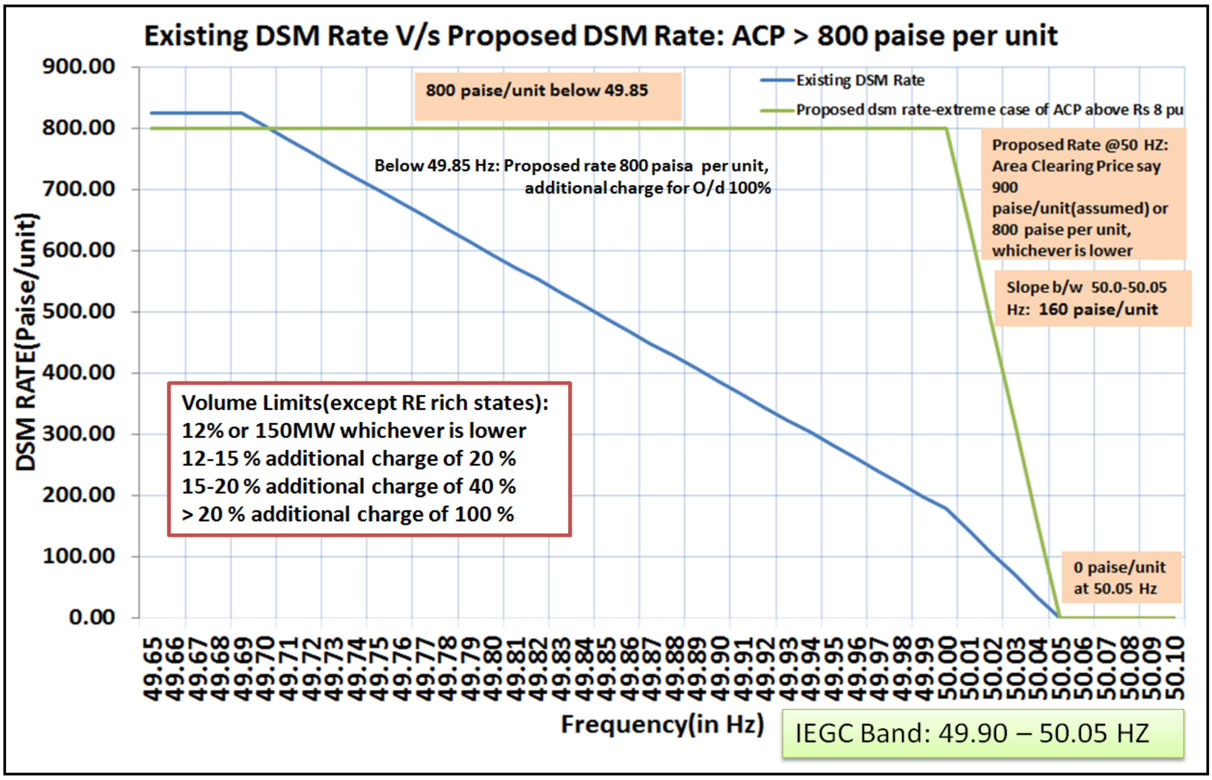

Figure 19: Comparison of the existing Deviation Settlement Price Vector (effective since 17.2.2018) and the Proposed Deviation Settlement Price Vector (assuming Area Clearing Price @ greater than 800 ps. Per unit)

Imbalance is inevitable in real time operations and the imbalance price plays an important role in ensuring system balance and secure and reliable grid operation. The Expert Group feels that the imbalance should be dynamic and capture the market realities. Presently, the day-ahead market prices are the prices discovered closest to the time of delivery. In order to improve the imbalance price discovery the market needs to function in multiple iterations. Hence, it is suggested that 4-hour ahead or 6-hour ahead markets need to be introduced so as to get a better price discovery closer to the time of delivery. The linking of DSM prices to DAM prices may be implemented for 6-months on a pilot basis from 01st April, 2018. Based on the experience gained during this 6-month pilot run, CERC may refine the market linked imbalance pricing mechanism.

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Minutes of the 3rd Meeting of "Expert Group to Review and Suggest Measures for Bringing Power System Operative Closer to National Reference Frequency"

The 3rd meeting of the "Expert Group to Review and Suggest Measures for Bringing Power System Operative Closer to National Reference Frequency" was held on 19th July 2017 at CERC, New Delhi under the Chairmanship of Shri A.K Bakshi, Member, CERC. Representatives from CEA, POWERGRID, POSOCO and CERC were present during the meeting. The list of participants is attached as **Annexe-1**.

Sh. A.S. Bakshi, Member, CERC welcomed the participants to the meeting.

Discussion

- **DSM Charges**

Dr. Sushanta Chatterjee, Joint Chief (Regulatory Affairs), CERC, initiated the discussion deliberating on what should be the Price Vector for Deviation Settlement Mechanism. He highlighted that during deliberations of the Committee on DSM, consensus was reached that the frequency band should be 49.9 Hz – 50.05 Hz and the Price vector at 50 Hz should be around the price on Power Exchange. Thus, price was suggested to be Rs. 2.50/unit for 50 Hz and then reduce it by 50 paisa for every increase of 0.01 Hz in frequency so that the price becomes 0 (Zero) for frequency above 50.05 Hz.

For frequency range from 50 Hz to 49.9 Hz, the price to be reduced in steps of 27.5 paise for every 0.01Hz decrease in frequency and Additional Deviation Charge to be introduced below frequency of 49.9 Hz. However, it emerged that the charges graph becomes very steep and can result in high resistance from the generators/buyers.

Shri Chatterjee, on the basis of analysis and principles from various international markets and Maharashtra DSM regulations proposed that for every 15 minute time block, the marginal cost of power dispatched in that time-block should be the DSM rate. He further elaborated that in some countries this marginal cost is declared by the system operator 90/60 minutes before the time block in which dispatch is scheduled and the same operating principle can be replicated in the Indian market. For example, for time block of 9:15 AM, the marginal cost will be ascertained by 7:45/8:15 AM. It was underscored that this model will be closest approximation to the actual cost of the deviation to the system operator, which the causer should pay.

Shri S.K. Soonee, Advisor, POSOCO, highlighted that determining DSM charges through this mechanism will involve a lot of calculations and number crunching and is prone to be disputed. Further, he suggested following points on DSM charge determination:

a) Price determination should be ex-ante and not post –facto

b) As future generation/projects will be more distributed, a need for homeostatic control is important and control should be faster the better
c) The time element and location of the plant should be factored in
d) The DSM charge should be based on marginal cost but should have minimum number crunching so that it should be easily implemented and there is minimum dispute

Further, he informed that having different marginal cost for different state and different region will create a lot of complication in the system as it will impact the decision making of the load dispatcher. Shri Soonee also informed that there will be huge variation in the marginal cost as at given point of time, there will be some plant running on the DG set. He suggested deliberating on bidding of such charge rather than going into too many calculations to derive the DSM Charge.

He suggested that the CERC can come up with monthly or quarterly order which will define the Marginal cost for 24 or 96 time blocks and then it can be implemented. POSOCO can provide the details of Ancillary Dispatch and the Commission can factor in all the required factors to calculate the Marginal Cost. This can be a good start and gradually the frequency of Marginal cost determination can be increased.

Shri Chatterjee clarified that in the proposed model, where generator will declare its own Marginal Cost as approved by the regulator, will be free of any complications, easy to implement and there will no need for the Commission to give any order on the Marginal Cost.

Shri Soonee also proposed to link the DSM charges with the power exchange prices. The other view point was that for linking it with energy market, the merit order dispatch for energy market needs to be evolved which needs time.

Shri B.S Bairwa raised the concern of DSM Charge with proposed model for those generators which are located in one region and have maximum contracts in another region, then DSM charge of which region should be considered for those entities? Shri Chatterjee suggested that since the energy flow follows the principle of displacement and in that case, the charge of that region should be implied in which it is located. Further, he suggested that these issues can be deliberated and resolved with discussion.

Need for linking grid frequency to the UI price vector also came up for discussion. One school of thought was that delinking without Primary control and Secondary response is very risky and also it will result in loss of feedback loop which is not desirable.

Another school of thought expressed that Frequency Control, nowhere in the world is decentralized or at the hands of market participants and is centrally controlled by the system operator. India has taken steps by introduction of Ancillary Services, mandating Primary response and Automatic Generation Control (AGC) pilot project by POSOCO. Frequency control should be ideally done in centralized and automatic way by:

- Ancillary Services
- Enforcing Primary control
- AGC

All of the above should be fully implemented within 1-2 years, after which the UI price vector should be delinked to frequency. This issue would need further deliberation.

Shri Bakshi asked the members to prepare a final report on the DSM Charges, wherein concerns of all the stakeholders can be addressed, based on the discussion of the Expert Group.

- **Ancillary Services**

Following points were discussed on Ancillary Services:

a) Introduction of Hydro in Ancillary Services – POSOCO to float a discussion paper
b) Removal of Fixed Charge Payment
c) Participation of IPPs
d) Harnessing Pumped Storage plants
e) Reactive Power and Black Start – POSOCO to float a discussion paper

Further, Shri Soonee stressed on the need of Secondary Control through AGC (Automatic Generation Control) and bringing Area Control Error (ACE) to Zero which is possible by having robust system of Reserves, Schedule, Primary Response and Secondary Control also the Zero Crossing limit to be reduced to 6 time blocks from 12 time blocks with additional charges of 10% to bring in further control.

Eventually, the objective is to introduce a market for Ancillary Services, which will include all types of generators and possibly energy storage. Design of such framework needs to be initiated now.

<u>Decisions</u>

- There was consensus that DSM Price Vector needs to be modified to correct the distortions arising due to the differential between power prices and DSM prices. Pros and cons of several options were debated. However, further deliberations would be needed to arrive at a conclusion on way forward.
- Zero crossing limit to be reduced to 6 time blocks from present 12 blocks.

Annexe-1: List of Participants

1. Sh. A.S. Bakshi, Member, CERC
2. Sh. S.K. Soonee, Advisor, POSOCO
3. Sh. K.V.S. Baba, CEO, POSOCO
4. Sh. S C Shrivastava, Chief (Engg.), CERC
5. Sh. Sushanta Chatterjee, Joint Chief (Regulatory Affairs), CERC
6. Ms. Shruti Deorah, Advisor (RE), CERC
7. Ms. Shilpa Agarwal, Dy. Chief (Engg.), CERC
8. Sh. Manish Chaudhari, Dy. Chief (Engg.), CERC
9. Sh. Ashok Pal, GM, Power Grid
10. Sh. S.C.Saxena, DGM, POSOCO
11. Sh. S.S. Barapanda, AGM, POSOCO
12. Sh. B.S Bairwa, Director CEA
13. Sh. Satyendra Kumar Dotan, Dy. Director, CEA
14. Sh. S. K. Roy Mahapatra, Chief Engineer, CEA
15. Smt. Rishika Sharan, CEA
16. Sh. Siddharth Arora, RO, CERC

4th Meeting of the Expert Group on Reference Frequency

The 4th meeting of the "Expert Group to Review and Suggest Measures for Bringing Power System Operative Closer to National Reference Frequency" was held on 3rd November 2017 at CERC, New Delhi under the Chairmanship of Shri A.K Bakshi, Member, CERC. Representatives from CEA, POSOCO, CERC and special invitees were present during the meeting. The list of participants is attached as Annexe-1

Sh. A.S. Bakshi, Member, CERC welcomed the participants to the meeting.

Discussions

I. Issues relating to Grid frequency and Related Matters

1. The Commission constituted the Expert Group consisting representatives from CEA, POSOCO and CTU with the mandate to suggest further steps required to bring power systems operation closer to the national reference frequency. The Terms of Reference of the Expert Group were:

- Review the experience of grid operation in India
- Review international experience and practices on grid operation including standards/requirement of reference frequency
- Review the existing operational band of frequency with due regard to the need for safe, secure and reliable operation of the grid
- Review the principles of Deviation Settlement Mechanism (DSM) rates, including their linkage with frequency, in the light of the emerging market realities
- Any other matter related to above

2. Draft report of the Expert Group covering the first three terms of reference was circulated in advance. Salient points covered in the draft report on measures for bringing power system operations closer to national reference frequency were presented. The transition of average grid frequency from highly volatile in 1990s to a disciplined average grid frequency over the last few years was highlighted.

3. The frequency variation of Indian Grid as compared to European Grid within a particular day was also presented. The graph displayed the high level of disorderliness of the Indian Grid Frequency in a day and stressed on bringing measures to control the indiscipline.

4. The Schematic of Reserves, Balancing and Frequency Control Continuum in India was explained. The features of each measure i.e. Inertial Response, Primary Response, Secondary Control, Fast Tertiary, Slow Tertiary, Generation Rescheduling/Real Time Market were discussed in detail. The schematic also described the response time, control area, quantum etc

of each measure. Based on the presentation and Continuum chart, following recommendations were proposed in the draft report:

a. Frequency Control Continuum chart be included in the IEGC
b. Reference frequency for the purpose of control be considered as 50 Hz
c. Inertia & Inertial response, Frequency Response Characteristics (FRC) and Area Control Error (ACE) should be monitored
d. Frequency band be revised to 49.95 – 50.05 Hz from 49.90 – 50.05 Hz
e. RGMO be phased out and replaced with 'speed control with droop' 'Free Governor Mode of Operation (FGMO)'
f. AGC be implemented throughout the country at the earliest
g. Ambit of Slow tertiary be expanded
h. Hydro be used as Fast tertiary control
i. Standards for cumulative time error be notified at an appropriate time based on the experience gained and considering cross border interconnections.

Decisions

Members of the Expert group unanimously endorsed the draft report with the following broad recommendations; and authorized Chairman of the Expert Group to finalize and present the same to Chairman CERC:

1. Reference frequency for the purpose of frequency control should be considered as 50.0 Hz;
2. Inertia of the system be monitored at the regional and All India level in real time so that a baseline is established, followed by suitable provisions in standards and code as required;
3. Primary Control needs to be implemented at the earliest. RGMO may be phased out at the earliest and replaced with 'speed control with droop';
4. IEGC should notify additional parameters, such as permissible frequency band, Reference contingency for primary response, nadir value, etc;
5. Roadmap for operationalizing reserves notified by the CERC vide order dated 13th October 2015 be implemented at the earliest;
6. AGC must be implemented throughout the country at the earliest;
7. Ambit of Ancillary Services (RRAS) should be expanded, including introduction of performance metrics;
8. Fast tertiary services through RRAS using hydro could be introduced suitably at the interstate level to start with;
9. Area Control Error (ACE) and time error be recorded and monitored

II. <u>Issues Related to DSM Price Vector</u>

1. A presentation was made on the DSM Price Vector and its alignment with DAM Prices. The existing DSM Price Vector follows a regulated price versus frequency curve for any real time deviation from schedule and is independent of Marginal Cost of the system and the location where electricity is being supplied.

2. State utilities are using existing DSM as operational mechanism to over-draw and are optimizing their Day Ahead decisions on the basis of DSM. The price differential between the Day Ahead Market (DAM) and the instant DSM price creates a perverse incentive for the States to rely on the grid to even meet anticipated load requirement, especially as the grid frequency has stabilized resulting in a DSM price of under Rs.2 at most times.

3. The proposed DSM Price Vector links it with the Average Clearing Price (ACP) discovered in the Day Ahead Market (DAM). This will induce the States to plan day ahead and invest in improving their load forecasting techniques.

<u>Decisions</u>

1. The DSM Price at 50 Hz (this will act as reference point) be indexed to the ACP of the DAM at power exchange. The DSM Price vector could extend from 49.85 Hz to 50.05 Hz as against the existing price band covering 49.70 Hz to 50.05 Hz. The DSM price at 49.85 Hz and 50.05 Hz should be fixed at Rs. 8 and Re. 0 respectively. With these conditions, DSM price at each step of 0.01Hz between 49.85 Hz and 50.05 Hz will be determined accordingly.
2. Area Control Error should reverse sign after every 4 time blocks instead of 12 at present. Violation or non-compliance will have 10% additional DSM charge for those four time blocks.
3. The recommendations as above will bring in the desired time & location attributes to DSM Price Vector. Indexation of DSM price to DAM price is being recommended as India still does not have any other Real Time price reference nor does the Ancillary Services Segment, with its limited coverage of generation resources, truly represent last mile system marginal price.

   The Committee felt that indexation of DSM prices to DAM price as also linkage of DSM price vector to frequency should be reviewed on introduction of Real Time market and operationalization of Ancillary Services market.
4. Based on the discussion, a report be finalized and presented by the Chairman of the Expert Group to the Chairman of CERC. This will fulfill the fourth item of TOR of this Expert Group – "*Review the principles of Deviation Settlement Mechanism (DSM) rates, including their linkage with frequency, in the light of the emerging market realities*".

Annexe-1: List of Participants

1. Sh. A.S. Bakshi, Member, CERC
2. Dr. M.K. Iyer, Member, CERC
3. Sh. P.S. Mhaske, Member(PS), CEA
4. Sh. S.K. Soonee, Advisor, POSOCO
5. Sh. K.V.S. Baba, CEO, POSOCO
6. Dr. Sushanta Chatterjee, Joint Chief (Regulatory Affairs), CERC
7. Sh. S.R. Narasimhan, GM, System Opreter, POSOCO
8. Sh. S.C.Saxena, DGM, POSOCO
9. Sh. S.S. Barapanda, AGM, POSOCO
10. Sh. B.S Bairwa, Director CEA
11. Sh. Manish Chaudhari, Dy. Chief (Engg.), CERC
12. Sh. Phanisankar Chilukuri, Sr. Engineer, NLDC
13. Sh. Siddharth Arora, RO, CERC
14. Sh. Puneet Chitkara, KPMG – Special Invitee
15. Sh. Yasir Altaf, KPMG – Special Invitee

CIN No.: U40105DL2009GOI188682

पावर सिस्टम ऑपरेशन कॉरपोरेशन लिमिटेड

(पावरग्रिड की पूर्ण स्वामित्व प्राप्त सहायक कंपनी)

POWER SYSTEM OPERATION CORPORATION LIMITED

(A wholly owned subsidiary of POWERGRID)

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Website : www.posoco.in, www.nldc.in, Tel: 011-26536832, 26524522, Fax: 011-26524525, 26536901

Dated: 8th Sep 2015

POSOCO/NLDC/CERC/

The Secretary,
Central Electricity Regulatory Commission,
3rd & 4th Floor, Chanderlok Building
36, Janpath, New Delhi – 110 001

Sub: Review of Charges for Deviation notified by the Hon'ble Commission under CERC (Deviation Settlement Mechanism and related matters) Regulations, 2014

Madam,

CERC (Deviation Settlement Mechanism and related matters) Regulations, 2014 was notified on 06th January, 2014. These regulations came into force w.e.f. 17th February, 2014. Clause 5 (4) of this Regulation provides that the Charges for Deviation may be reviewed from time to time and shall be re-notified accordingly. There is an urgent need to revise the charges for deviation due to the following reasons:

i. **Ensuring Demand and Supply Participation:** In a competitive market scenario the customers and the producers set the price. At present, the maximum Deviation Price corresponds to the variable charges of the costliest generation and the Deviation Price at 50.00 Hz is being determined based on the variable charges of pit head thermal stations. The charge for deviation at 50.0 Hz is 178 paise/kWh which provides incentive to the state utilities to persistently deviate from schedule. However Value of Lost Load (VOLL) for the entities has to be duly factored.

ii. **Market Responsive Prices linked to Variable Charges:** The deviations are the last resort for an entity to meet its actual demand after scheduling all the resources. It should be priced in a way which encourages participant's behaviour to move towards more organized demand and supply management. Deliberate deviations should ideally be commercially unviable. If we analyze the price trend in 2014-15, the highlights below indicate a tilt towards DSM.

- The DSM rate at 50 Hz is 178 paise/kWh
- Average DSM price was 263 paise/kWh in 2014-15 (average frequency 49.96-49.97 Hz)
- Average UnConstrained Market Clearing Price (UMCP) was 351 paise/kWh in 2014-15
- In the Day Ahead Market, UMCP was above 300 paise/kWh for 66.7% of the time.
- The DSM price was above 300 paise/kWh for only 38.5% of the time.
- The UMCP was above DSM prices for nearly 70% of the time.

contd/-

iii. **'Time-of-Day' Price Variability:** Electricity during the peak and other than peak conditions is a different product which needs to be priced differently. Deviation Vector does not recognize this aspect and remains static with respect to time of day. The same rate is applicable for peak and other than peak conditions provided the frequency is same. In contrast, there is a clear 150-250 paise/kWh differential in UMCP between peak & off peak.

iv. **Geographically Differentiated Price Signals:** Pricing deviations on a geographically differentiated basis gives a signal to dispatch high cost generation downstream of a congested corridor. The present deviation price should recognize the transmission constraints. Even if there is congestion, the deviation price is uniform apart from the case where congestion charge has been kicked in by system operator.

v. **Impact of DSM on reliability of the All India grid:** The present DSM rates have led to a situation where a significant generating capacity is off the system under Reserve Shut Down (RSD). The availability figures of these generators bring little comfort to reliability of the grid since a significant capacity is off-bar and cannot come to the rescue of the system in a contingency. Annexe-I indicates the poor plant load factors vis-vis variable charges and huge quantum of Un Requisitioned Surplus (URS) prevailing in respect of the power stations under RLDCs' jurisdiction and whose tariff is regulated by CERC. If more capacity has to be harnessed to meet higher power demand in the country, then the prices need to be higher and commensurate with the variable charges and/or UMCP prevailing in the Power Exchanges (PX). With the failure of South West monsoon, the power demand in the country has escalated to all time high levels and the frequency regime has deteriorated since the last week of August 2015.

Incidentally, POSOCO vide communication dated 28th June, 2012 to the Hon'ble Commission had given feedback regarding Imbalance Market Design and coupling with Power Exchanges. A copy of the same is enclosed at Annexe-II. In view of the above, the Hon'ble Commission may kindly review the Deviation Charges and possibly link the 50 Hz DSM price to the Day Ahead Market prices.

Thanking you,

Yours faithfully,

Encl: as above

(S K Soonee)
Chief Executive Officer

Copy for kind information to:

1) Member (GO & D), CEA, New Delhi
2) Joint Secretary(OM & Transmission), Ministry of Power, New Delhi

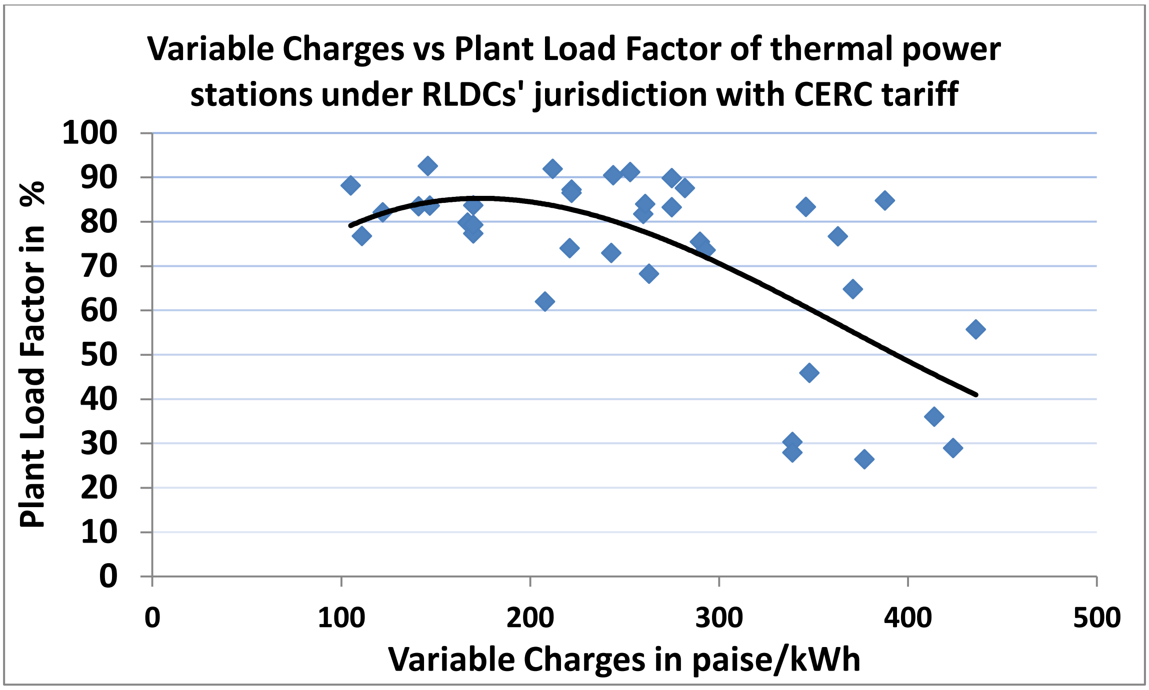

Fig 1: Variable Charges vs Plant Load Factor (PLF) of thermal stations scheduled by RLDCs

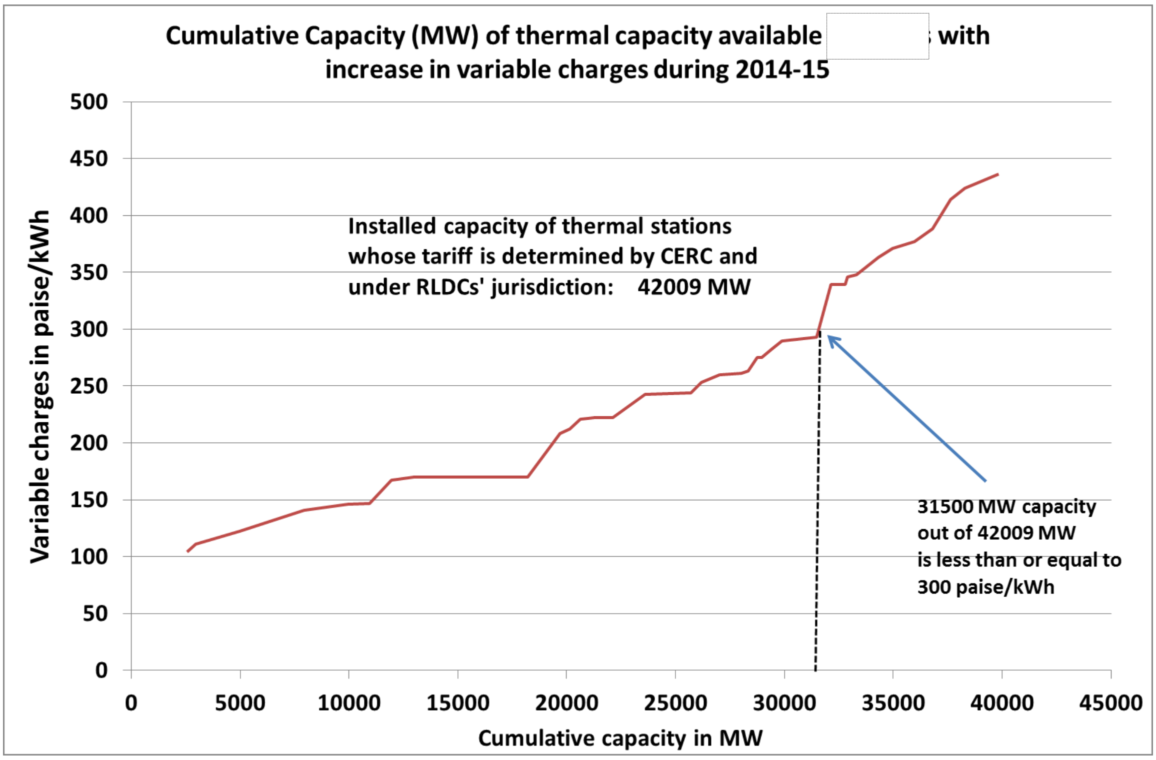

Fig 2: Cumulative Capacity (MW) of thermal capacity available to RLDCs with increase in variable charges during 2014-15

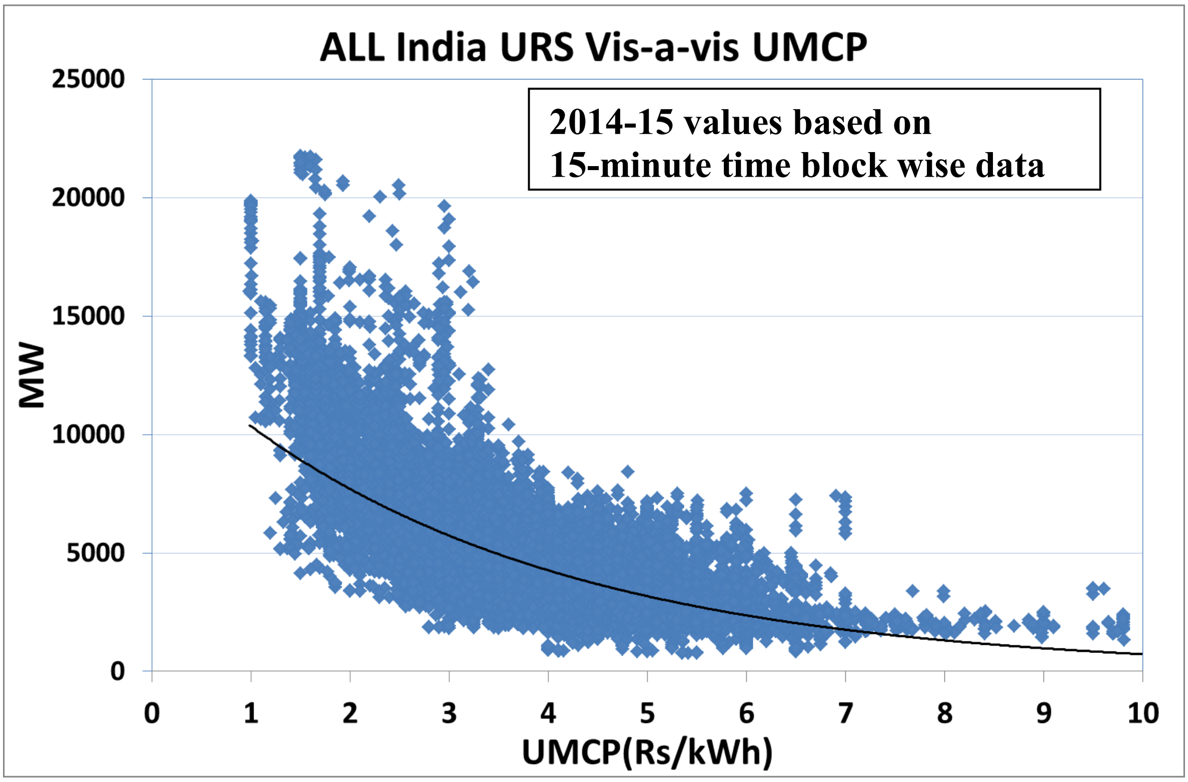

Fig 3: Un Requisitioned Surplus (URS) vs UnConstrained Market Clearing Price (UMCP)

Annexe-II

पावर सिस्टम ऑपरेशन कारपोरेशन लिमिटेड
(पावरग्रिड की पूर्ण स्वामित्व प्राप्त सहायक कंपनी)
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National Load Despatch Centre : B-9, Qutab Institutional Area, Katwaria Sarai, New Delhi - 110016
website : www.nldc.in, www.nldcindia.in,Tel.: 011-26536832, 011-26524522, Fax : 011-26524525, 011-26536901

Dated: 28th June 2012

To
Secretary
Central Electricity Regulatory Commission
3 rd & 4 th Floor, Chanderlok Building,
36, Janpath,
New Delhi- 110001

Subject: Feedback regarding Imbalance (UI) Market Design and coupling with Power Exchange

Sir,

UI Mechanism was introduced in India along with the implementation of ABT. The rationale for fixing the UI Price at 50 Hz is based on the variable charges for coal fired pit head base load stations. The designing of the UI Vector on this principle was generally prior to introduction of market mechanisms. However presently, a vibrant market exists in the country with Power Exchanges functioning and prices being discovered and disseminated for each 15 minute time block.

On this issue in a brainstorming session attended by various experts, the possibility of the coupling of prices discovered in the Power Exchanges and the imbalance price was debated. From the deliberations, it emerged that prices discovered in Power Exchanges could be linked with the UI Price through appropriate vector design.

Attached please find a preliminary brief note developed on the subject.

Hon'ble Commission may like to consider initiating further action in this regard and give further directions.

Regards,

(S. K. Soonee)
Chief Executive Officer

Enclosure: As above

Copy to:

1. **Member (Power System), CEA**
2. **Joint Chief (Engineering), CERC**

[Type the company name]

Designing Balancing Market in India

A Draft Discussion Paper

June 2012

Contents

1.0 Introduction

In electricity markets, supply and demand have to be balanced perfectly in real time. Every Control Area is required to control its load and/or generation to maintain its interchange schedule with other control areas. However, due to one reason or another there is at all times and in all circumstances be a smaller or larger mismatch between scheduled quantum and actual consumption or generation. This difference is called as imbalance which could be either inadvertent or sometimes even deliberate. Inadvertent imbalance may occur due to error by entities in either forecasting or unforeseen events whereas deliberate imbalance may be classified as a structural deficiency which is being exploited by entities as a part of power procurement. There are high incidences of deliberate imbalances in the Indian regional power system, primarily due to acute shortages. This imbalance poses problems to system integrity, security and frequency management. There is a need to curb incidences of deliberate imbalance and provide a suitable market platform for inadvertent imbalances. It is therefore essential to have a mechanism which would not only appropriately price imbalances but also complement reliability. A unique Unscheduled Interchange (UI) mechanism has been evolved in India to handle such imbalances.

2.0 Balancing Mechanism in India

Prior to the implementation of Availability Based Tariff (ABT), there was no mechanism to handle real time energy imbalances. The total generated quantum was booked to the beneficiaries on the basis of share allocation and payments were being made accordingly. The UI Mechanism was introduced as a Balancing Mechanism in India along with the implementation of ABT with the objective of facilitating grid discipline and achieves economy and efficiency in real time operation. It is a frequency linked real time pricing mechanism which charges the deviations from the schedules based on the prevalent frequency conditions. The UI Vector is designed in such a way that as the frequency goes down, the rate at which imbalance is priced ramps up, reaching a ceiling level and when frequency goes up to a threshold level, the rate at which imbalance (UI) is priced decreases till it reaches minimum floor level i.e. zero. The UI price vector has been designed to bring in economy and efficiency during real time operations in a decentralized manner. Some of the unique features of UI Mechanism are as follows:

I. Real Time Imbalance Pricing
II. Promotes Efficiency and Merit Order Despatch
III. Perfect Information : Known ex ante to everyone
IV. Provides a negative feedback for automatic correction
V. Facilitates achieving equalized marginal cost

The regional entity generators and state utilities are scheduled for every 15 minute time block on day-ahead basis based on the long term, medium term and short term contracted quantum. Special Energy Meters (SEMs) measures the actual net interchange of each entity every 15 minute which is compared to the scheduled quantum for the same time block to determine the unscheduled interchanges. The unscheduled interchanges are charged based on a frequency dependent rate and average frequency during the given time block. The frequency dependent rates are given by CERC which is revised periodically.

3.0 Evolution of UI Vector

The first UI Vector was notified by CERC in its order for implementation of Availability Based Tariff dated 4th January 2000. The rates were determined at the two ends viz., 50.5 Hz and above on the one hand and at 49 Hz on the other have been stated as 0 paise/kWh and 420 paise/kWh. Between 50.5 Hz and 49.00 Hz adjustment of 5.6 paise/kWh for each 0.02 Hz change. The maximum UI Rate was linked to the costliest form of generation which is usually diesel generation. Subsequently, several modifications have been done in UI Vector which is as given in Table I:

Time	Permissible Frequency Band	Ceiling UI Rate (paise/kWh)	Floor UI Rate (paise/kWh)	Slope (paise/kWh for each 0.02 Hz)
1st July 2002 – 31st March 2004	49.0 Hz – 50.5 Hz	420	0	5.6
1st April 2004 – 30th Sept 2004	49.0 Hz – 50.5 Hz	600	0	8
1st October 2004 – 29th April 2007	49.0 Hz – 50.5 Hz	570	0	9
30th April 2007- 6th Jan 2008	49.0 Hz – 50.5 Hz	745	0	6 (50.5-49.8) 9 (49.8-49.5) 16 (49.5-49.0)
6th Jan 2008 – 30th March 2009	49.0 Hz – 50.5 Hz	1000	0	8 (50.5-49.8) 18 (49.8-49.0)
1st April 2009 – 3rd May 2010	49.2 Hz – 50.3 Hz	735	0	12 (50.3-49.8) 17 (49.8-49.2)
3rd May 2010 to till date	49.5 Hz – 50.2 Hz	873	0	15.5(50.2-49.7) 47 (49.7-49.5)

Table 1: Evolution of the UI Vector

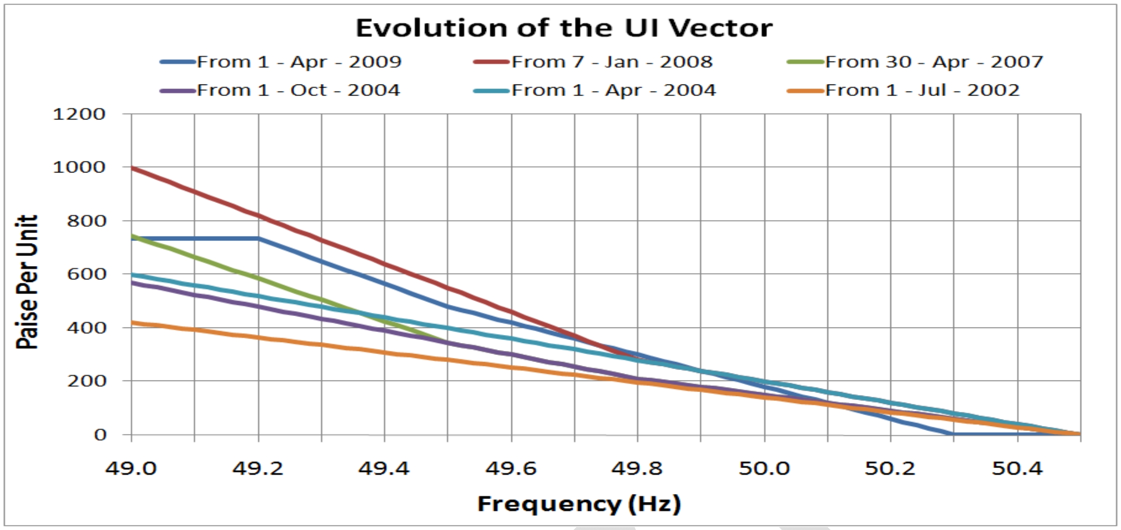

Chart 1: Evolution of the UI Vector

First time in 2009, a separate regulation for Unscheduled Interchanges came into force which introduced capping, additional surcharge and various limits for over drawl / under drawl and over generation / under generation. The present UI Vector which is in effect from 3rd May 2010 is shown below:

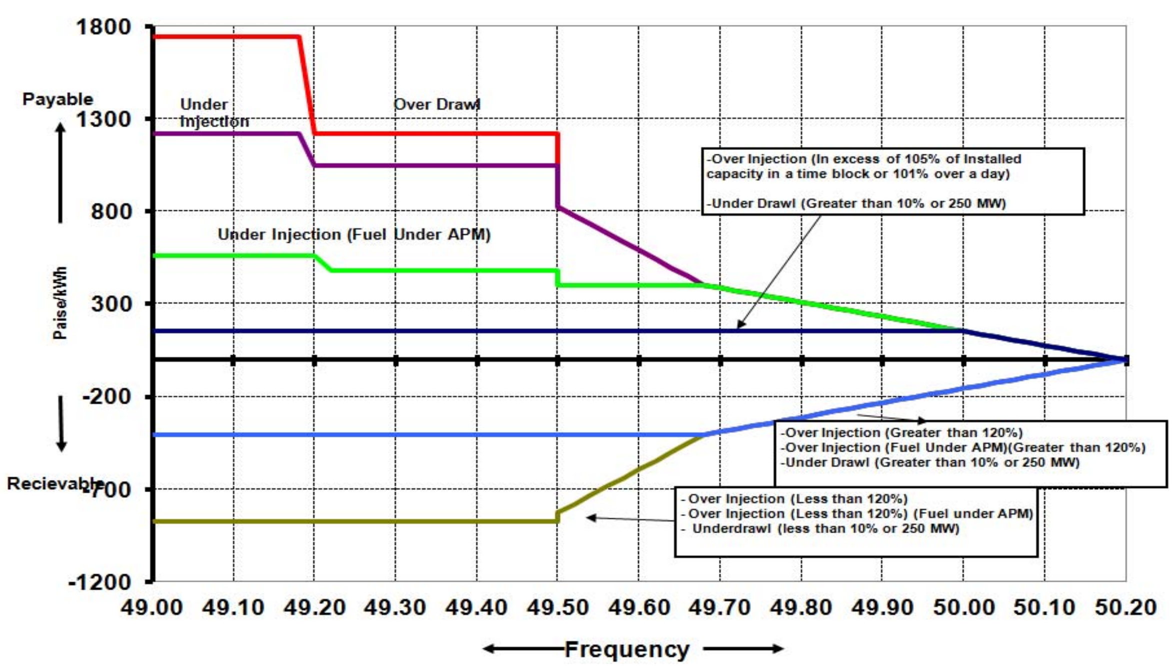

Chart 2: Existing UI Vector

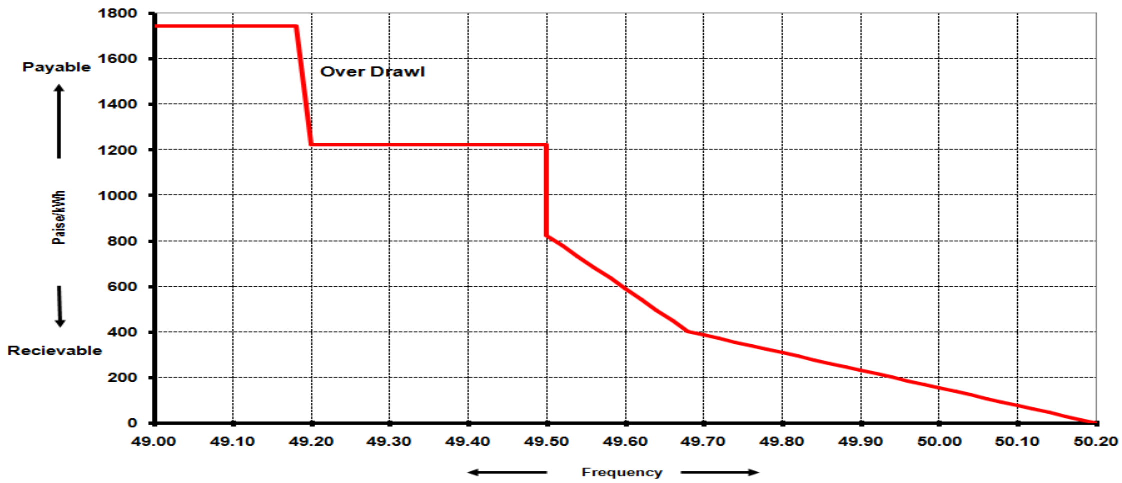

Chart 3: Existing UI Vector for over drawl

4.0 Missing Links in UI Mechanism

UI Mechanism has worked adequately in India up till now. It has helped in curbing the large deviations from schedule (frequent frequency fluctuations), improved reliability and most importantly, introduced a system which is self regulating as it provides commercial signals to stakeholders and thereby reducing necessity of regulatory intervention. The improvement in frequency profile since the implementation is shown below:

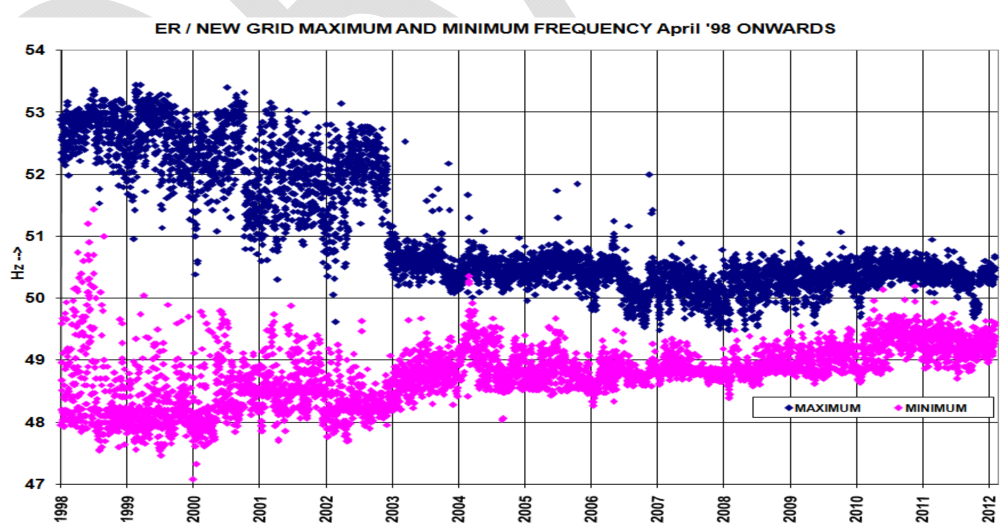

Chart 4 : NEW Grid Frequency Deviations

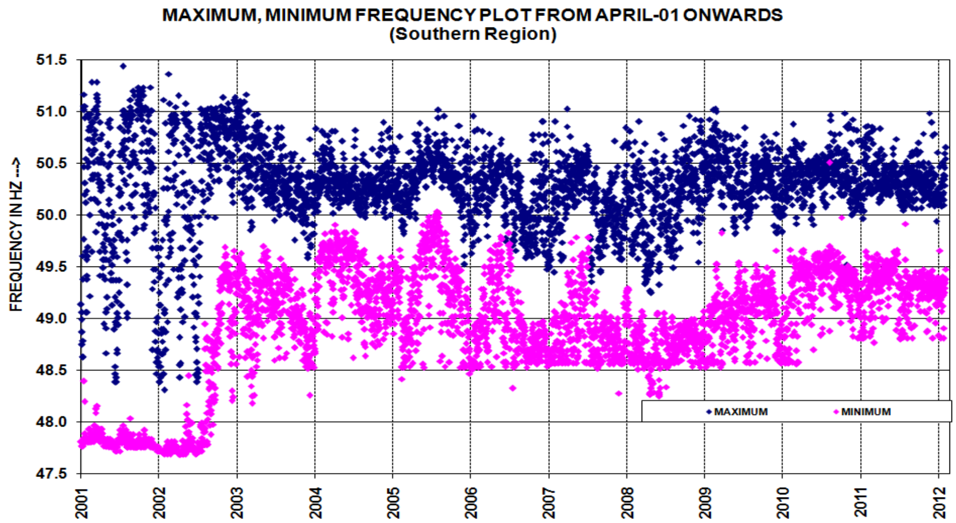

Chart 5 : SR Grid Frequency Deviations

Frequency is not the only consideration in reliable operation as there can be instances where system frequency is within range and large unscheduled power flows on certain elements can result in catastrophic grid failure. Other inadequacies and inefficiencies of the existing system have also become evident with increasing competition and development of organized electricity market. A few of these are summarized below:

I. **Demand and Supply Participation:** In a competitive market scenario the customers, just as the producers, set the price. At present, UI rate is linked to the variable cost of generation. The maximum UI rate corresponds to the variable charges of the costliest generation and the UI Rate at 50 Hz is being determined based on the variable charges of pit head thermal stations. However willingness, capacity to pay and value of lost load for the entities has been ignored which has led to under evaluation of UI Vector. The cost of load shedding would vary from consumer to consumer This is evident from the fact that the utilities are overdrawing even if the UI rate (including additional surcharge) is as high as Rs 16 – Rs 17 / kWh.
II. **Market Responsive Prices:** The unscheduled interchanges are the last resort for an entity to balance its actual demand with the schedule. It is a sale/purchase of electricity in real time at very short notices and should be priced in a way which encourages participant’s behavior to move towards more organized demand and supply management, implying, incidences of deliberate imbalances are signaled commercially unviable. It has been observed that at times UI rate is lower than the Market Clearing Price (MCP) in Power Exchanges which is giving a commercial signal to entities for deliberate deviations by making it economically attractive. Utilities are using UI & PX as a gaming platform by selling in Power Exchange at higher prices and

resorting to UI by shutting off the units in real time. A comparison of UI Rate with PX Price for 2011-2012 is shown below:

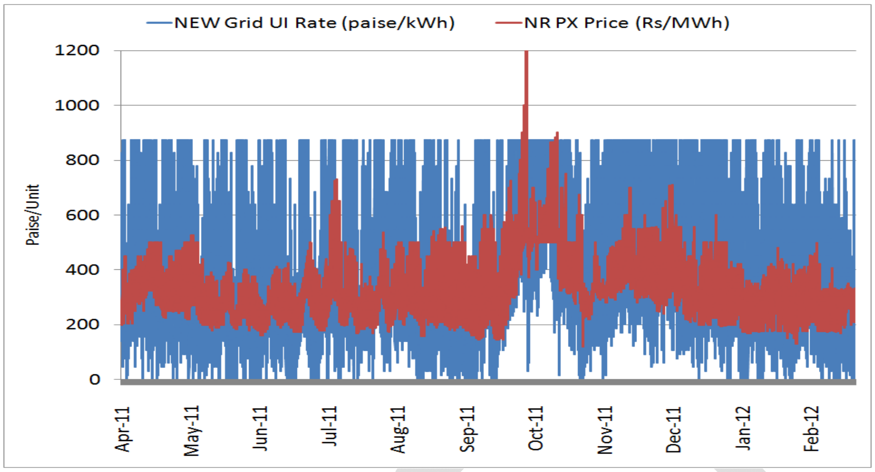

Chart 6: Comparison of NEW Grid UI rate with the PX Price of N1

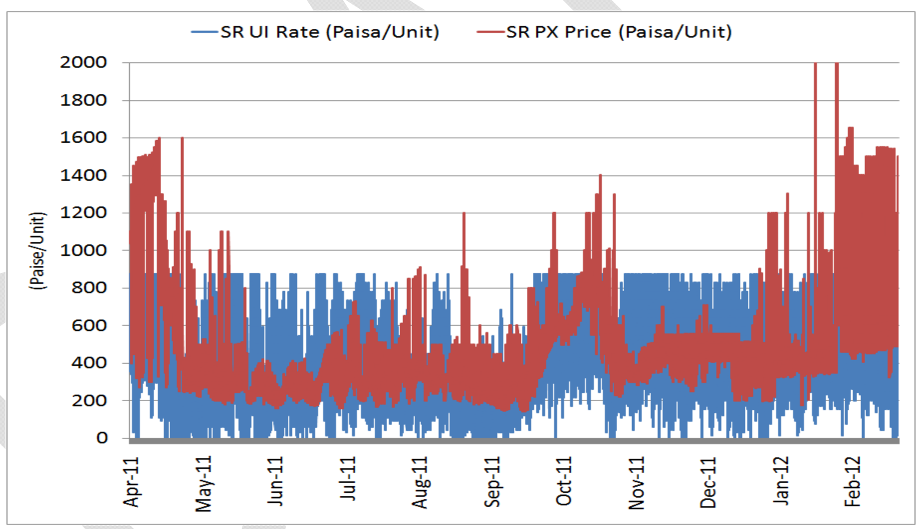

Chart 7 : Comparison of SR Grid UI rate with the PX Price of S1

III. **<u>'Time-of-Day' Price Variability</u>**: Electricity during the peak and other than peak conditions is a different product which needs to be priced differently. UI Vector does not recognize this aspect and remains static with respect to time of day. The same rate is applicable for peak and other than peak conditions provided the frequency is same in both conditions irrespective of volumes transacted.

IV. **<u>Geographically Differentiated Price Signals:</u>** Pricing Unscheduled Interchange on a geographically differentiated basis gives a signal to dispatch high cost generation in downstream of a congested corridor. The present UI rate is unitary and does not recognize the transmission constraints. Even if there is congestion, the UI rate is same as the frequency is same in a synchronous system apart from the case where congestion charge has been kicked in by system operator.

5.0 International Experience

Nord Pool: Nordic TSO's maintains and operate a balancing power market. The TSOs buy the "regulating power" to cover the net imbalances of the players. Generators and loads submit bids to the balancing power market operator concerning their capacity which can be regulated. The Balancing Bids are classified as Up-Regulating Bid (for increase in generation or decrease in load) and Down-Regulating Bid (for increase in load or decrease in generation).The bids are stacked based on the bid price starting with the cheapest bid. The cheapest up-regulating bid is used first, and correspondingly, the most expensive down-regulating bid is used first. If, because of the prevailing operating situation, a bid cannot be used, it is neglected. The prices of balancing power are determined on the basis of regulations carried out in the Nordic balancing power market. Both an up-regulating and a down-regulating price are specified for each hour. Up-regulating price is the price of the most expensive up-regulating bid used, at least Nord Pool Spot's price for the specified price area. Similarly Down-regulating price is the price of the cheapest down-regulating bid used, at the most Nord Pool Spot's price for price area.

UK: Balancing Services are procured by the TSO of UK i.e. National Grid either via market arrangements or bilateral contracts. For each settlement period, two distinct energy imbalance prices are computed namely System Buy Price (SBP) and System Sell Price (SSP). If a Party has under-generated or over-consumed compared to their contracted volume, it will be charged for that shortfall of energy at SBP. If a Party has over-generated or under-consumed compared to their contracted volume, it will have to sell that extra energy at SSP. The Energy Imbalance Prices are calculated either by main pricing method which reflects the cost of balancing or reverse pricing method which reflects the market price of that energy for that settlement period. If the frequency is above the rated frequency (too much power), SSP is calculated using the main pricing method and SBP using the reverse pricing method whereas If the frequency is below the rated frequency (not enough power), SBP is calculated using the main pricing method and SSP using the reverse pricing method.

Germany: The German model has several balancing markets associated to reserve markets. Each TSO has its own Reserve Markets for primary, secondary and tertiary reserve. Primary and Secondary Reserve markets are separated from Balancing Market and are based on 6 month tendering. Balancing Market is generally associated with procuring Tertiary Reserve which is also called "Minute Reserve". The Minute Reserve Market is a daily market where reserve availability is pre-selected on the day-ahead and then 'minute control energy' is selected in real-time for its delivery. The market participants bid two prices, an availability fee and an energy fee. The balancing bids are pre selected based on the availability fee. Every chosen bidder is paid an availability fee. Then the pre-selected bids are ranked and selected according to their energy fee.

System Operators are responsible for keeping balance between total generation and consumption of power real time. Single Buyer Model has been followed in most of the countries where Balancing Services are procured by System Operator for real time balancing through “Reserve Market” primary, secondary or tertiary reserve, based on the bids received from different entities. But floating frequency along with the high quantum of deliberate imbalances makes the problem of balancing more unique to India. Ancillary Services along with UI Mechanism could be considered as an option. However, in view of the inefficiencies mentioned in the previous section, there is a need to revisit and modify the UI Vector design to provide the right signals for security, economy and efficiency.

6.0 A Robust Day Ahead Market through Power Exchanges

Power Exchanges were introduced in the Indian Electricity Market in 2008. The first Power Exchange started its operation in June 2008 followed by second in October 2008. The third power exchange is also expected to start soon. The participation in Power Exchanges has increased manifold and around 40 MU of energy is traded per day.

Power exchange transactions are carried out on a day-ahead basis in which prices are discovered based on double sided bidding. Supply and demand curves are prepared for each 15 min time block based on the bids received. The intersection point of demand and supply curve is the Market Clearing Price and Market Clearing Volume. The Power Exchanges follows a Uniform Clearing Price Mechanism wherein all the cleared entities pay the same rate provided there is no congestion. Congestion is handled through Market Splitting mechanism in which prices upstream (surplus area) are reduced and the prices downstream (shortage area) are increased so that the flow on the inter-connector is restricted to the available capacity. The prices discovered in Power Exchanges are transparent, neutral and provide a good indication of the expected marginal cost of energy for the next day. The prices are declared on day-ahead basis and known to everyone.

7.0 Proposal to Link UI Price with Day Ahead Market in Power Exchange

The Unscheduled Interchange is a non standard product which is available on demand real time for 24*7 and should be priced such that the entities are encouraged to participate in market. This basic objective could be achieved by linking UI Vector with Market Clearing Price of Power

Exchanges. This could be possible now as the 15 minute bidding has started in Power Exchanges from 1st April 2012.

In order to evolve a suitable mechanism of linking Power Exchange Price with UI Vector, following questions need to be answered:

I. What should be the point of linking UI Vector and PX?
II. Should UI Vector become constant beyond permissible frequency band?
III. Should slope be fixed or Variable?
IV. Should there be capping of maximum and minimum fixed rate?
V. Which Exchange Price should be considered for linking UI Vector with PX?
VI. What should be the periodicity of variation of UI Vector?
VII. Unconstrained Market Clearing Price (UMCP) or Constrained Market Clearing Price (MCP)?
VIII. Same or Different UI rate for sell and buy?

There could be various alternatives in response to the above questions. Some Possible alternatives are discussed below:

7.1. Point of Linking UI Vector and PX

The prices discovered in Power Exchanges could be linked with the UI Price at any particular frequency. Power Exchange Transactions may be treated as 50 Hz transactions as there is always a balanced portfolio i.e. total buy is equal to total sell quantum.

The other option could be to link Power Exchange Price with Minimum UI Price. This would mean that at all frequencies; UI Rate would be higher than the rate discovered at Power Exchanges. Presently, the minimum UI Rate of Rs 0 per kWh is at 50.2 Hz. Fixing Maximum Power Exchange Price at 50.2 Hz would mean that there would be some price at 50. 2 Hz also which is against the intent of UI Mechanism.

7.2. UI Vector Beyond Permissible Frequency Band

UI rates are declared between the upper and lower limit of permissible frequency band. An additional surcharge is applicable in two steps for over drawl and under injection below the lower permissible frequency which makes the UI Vector divided into following three zones:

I. Permissible Frequency Band (50.2 Hz – 49.2 Hz)
II. Low Frequency Band (49.5 Hz – 49.2 Hz)
III. Very Low Frequency Band (Below 49.2 Hz)

An additional surcharge of 40% for over drawl and 20% for under injection is applicable in Low Frequency Band. Similarly an additional surcharge of 100% for over drawl and 40% for under injection is applicable in very low frequency band.

The additional surcharge comes in as a step change which indicates an “Entry Prohibited” zone. However, the additional surcharge is a step vector and remains constant between the bands unlike the UI Vector which varies inversely in the permissible frequency band. The additional surcharge could be introduced as a step at the boundary and vary inversely between the low and very low frequency band.

7.3. Maximum and Minimum UI Rate

At present, minimum rate is fixed zero at the upper limit of permissible frequency band and maximum rate is fixed at the lower limit of permissible frequency band based on the variable charges of the liquid fuel generation. Various possible options for maximum and minimum UI rate are listed below:

I. **Fixed Maximum Rate Vs Variable Maximum Rate**: The prices in power exchanges vary based on the supply and demand bids. Fixing Maximum Rate would give rise to a scenario where UI vector would become flat from 50 Hz and below when power exchange price is greater than the fixed maximum rate. This would be against the basic intent of the UI mechanism to have a rate which is inversely proportional to frequency. Removing cap on the maximum rate would mean that the maximum rate could rise to any value depending upon the market prices.

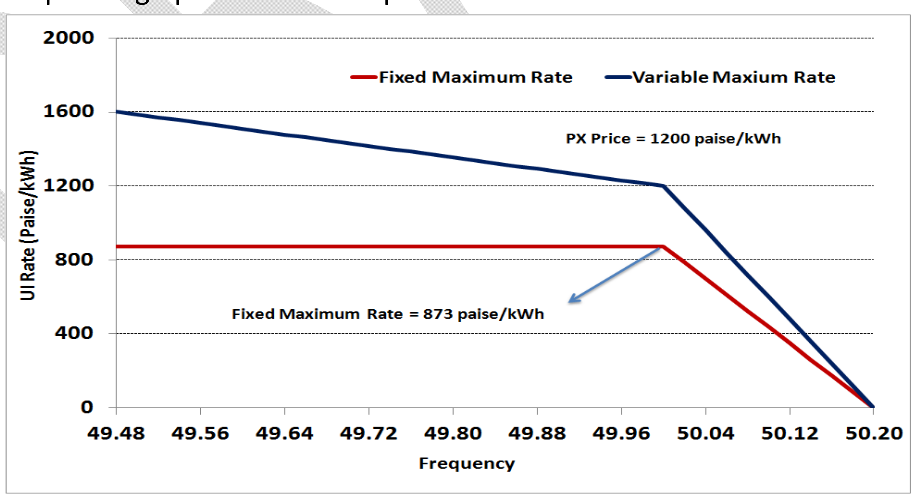

Chart 7: Comparison between Fixed and Variable Maximum Rate

II. **Fixed Minimum Rate Vs Variable Minimum Rate:** Variable Minimum Rate would mean that the minimum rate could go negative also. The power market in India is still in the early stages and frequency deviations ranging from 0.5 Hz-1 Hz. Minimum fixed rate of

Rs 0 per kWh at the upper limit of permissible frequency band may be a good option till the time market matures and frequency band is tightened to 0.2 Hz - 0.3 Hz. The merits and demerits of negative UI rate could be deliberated thereafter.

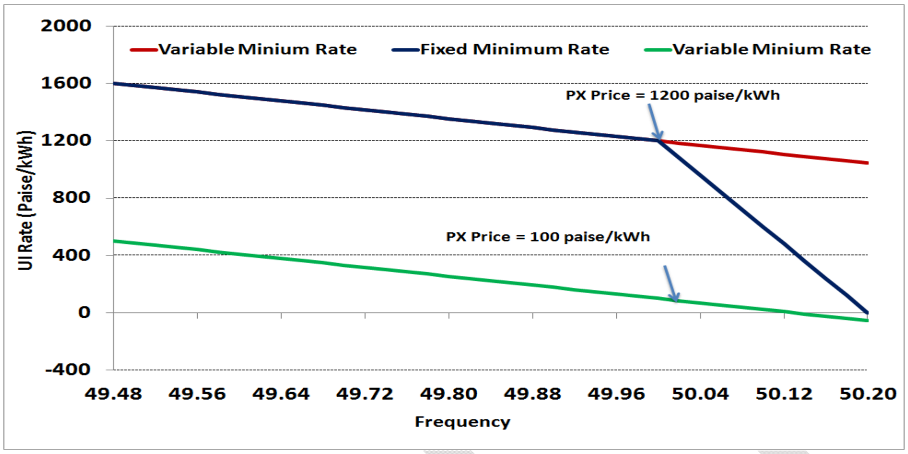

Chart 8: Comparison between Fixed and Variable Minimum Rate

7.4. Slope of UI Vector

Assuming 50 Hz UI rate to be linked with PX Price, UI rates below and above 50 Hz would be computed based on the initial value at 50 Hz and slope of the vector. In such case there will be two slopes in UI Vector:

I. Slope 1 : 50 Hz and above
II. Slope 2 : 50 Hz and below

Any of the above slopes could be either fixed by the regulator or vary based on the market price. Market based slope is possible provided maximum, minimum rate is fixed and 50 Hz UI rate is dependent on Market. In case there is no cap on maximum and minimum rate, a slope needs to be specified/fixed by CERC. This option may result in negative UI rate at frequencies above 50 Hz and very high rates at frequency less than 50 Hz.

7.5. Multiple Exchange Prices

Two Power Exchanges are in operation at present and third power exchange is expected to start its operation soon. Market Clearing Price is discovered separately for each exchange. The weighted average price of all the exchanges could be considered for linking UI Rate with PX Price. But there are different options for "weights" as well which are discussed below:

I. Cleared Volume for each Area (Buy + Sell)
II. Total Cleared Volume for areas having same Market Clearing Price (Buy+Sell)

III. Total Cleared Volume in a day (Either Buy or Sell)

Option I i.e. cleared volume for each area appears to be an ideal option but may lead to different rates between two bid areas even though there is no congestion between them. Option II is a refinement of Option I but may be complex if the UI Vector varies with each time block. Option III is simple and easy to implement but ignores impact of area volume.

7.6. Periodicity of UI Vector Variation

The periodicity of UI Vector variation could be either 15 min, daily or separate for peak and other than peak conditions. The bidding in Power Exchange is done on 15 min block wise basis and MCP is available for each time block. Separate UI Vector for each 15 min time block would give real signal for optimizing generation and load. However, it may be difficult to comprehend and complex to start as the prices would be very volatile. Daily variation of UI Vector could be simple but against the objective of Time of Day sensitivity and distort the price signals for each time block given by the market. Separate UI Vector for Peak and Other than Peak condition is a good compromise but it has other burdens such as identification of peak and other than peak conditions which may vary season to season, different peak times for different regions/states etc.

7.7. Unconstrained Market Clearing Price or Market Clearing Price

Unconstrained Market Clearing Price (UMCP) is the intersection of supply and demand curve in the unconstrained scenario. Based on the unconstrained results, provisional flows are worked out on each corridor. In case the provisional flow on any of the corridor is greater than the available margin (i.e. congestion), upstream prices are reduced and the downstream prices are increased so that the corridor flow is limited to the available margin. This price is called Market Clearing Price (MCP). UMCP will be equal to MCP provided there is no congestion.

Either UMCP or MCP could be considered for linking PX Price with UI Price. UMCP is same for all bid areas and does not take into account the constraints in the transmission system. MCP gives the locational signal as it is higher than UMCP in the downstream of congested corridor and lower than UMCP in upstream of congested corridor.

7.8. Differential between Sell and Buy Rate

The permissible frequency band would be tightened in near future and it is expected that the frequency would float close to 50Hz. In that scenario, UI rate would be close to the Market rate at most of the times which would not give any signal to move towards scheduled interchanges. The lack of decision making on the part of the sellers and buyers would continue and utilities may keep on treating balancing market as trading mechanism. A differential rate could be thought of where sell rate would be lower than the market rate and buy rate would be higher. The amount of differential could be 5%, 10%, 20% or any value and needs to be debated further.

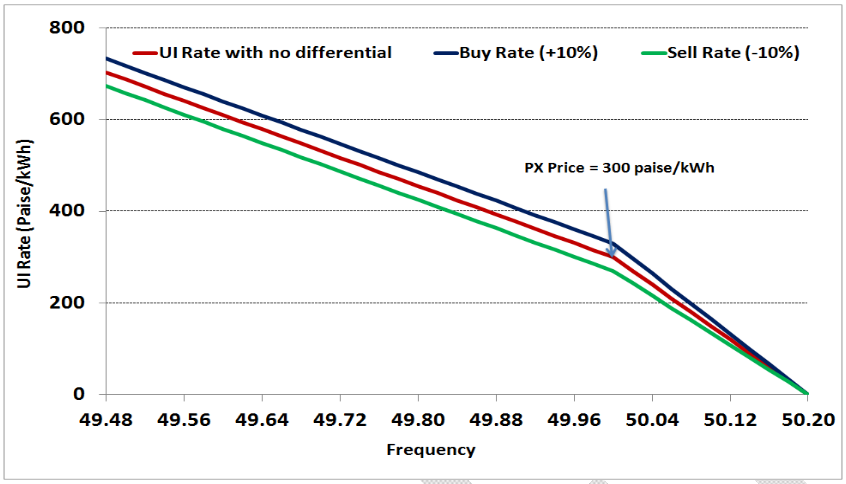

Chart 9: UI Vector with differential Sell and Buy Rate

8.0 <u>Benefits</u>

<u>Promote Economic Efficiency</u>: Linking UI vector to power Exchange Prices will provide economic efficiency to Energy Balancing Mechanism in the country. It will reduce the arbitration margin which currently is prohibitive for participants from entering the Short Term Open Access Market. The differential in UI and Power Exchange prices is effecting consumer behavior in a way which was not intended by the way of market design and structure. And a positive co-relation between these two rates is likely to positively influence consumer behavior and will increase market participation while augmenting market integrity and function.

<u>Social Welfare Maximization</u>: By linking UI with power exchange prices, a reduction in incidences of deliberate imbalances is envisaged, which will increase market participation (in both Power Exchanges and Bilateral by entities. This will increase competition, subsequently will also result in reduction in prices, leading to reduction in costs and ultimately passing the benefit on to the final consumers.

<u>Demand Response</u>: Evaluation of UI Vector based on the market prices would correctly evaluate the opportunity cost based on the expectations of buyers and sellers. This adequate compensation would help to extract the demand response and contribute positively towards system reliability.

9.0 Challenges

An efficient mechanism for handling Unscheduled Interchanges has been debated for decades but no standard solution has been evolved yet globally. An attempt was made by NERC in 2002 through a Joint Inadvertent Interchange Taskforce but no significant progress has been made on its recommendations till date. Billions of dollars have been accumulated in North America and never paid. The UI Mechanism in India has proved its worthiness but appears to have saturated. Improvements suggested in the paper are a step towards connecting the missing links in the UI Mechanism. The paying capacity and lack of decision making power of the entities has been a major challenge in handling energy imbalances. Entities are resorting to imbalance as it is a risk free option and payments are not required to be made before the delivery unlike other types of short term contracts.

The other associated challenge is pertaining to handling real time scenario which may be diametrically opposite to the anticipated scenario while price discovery in PX. This may be either due to either load crash or any other unforeseen circumstances. Reverting back to the normal UI vector may be an option in such scenarios.

10.0 Way Ahead

The above proposal could be deliberated further by forming a working group which would go into details and prepare a staff paper for proposed modifications. The staff paper could go for public debate and comments from all the stakeholders. Based on the comments, the group may identify the feasibility of the proposal and suggests the necessary regulatory changes.

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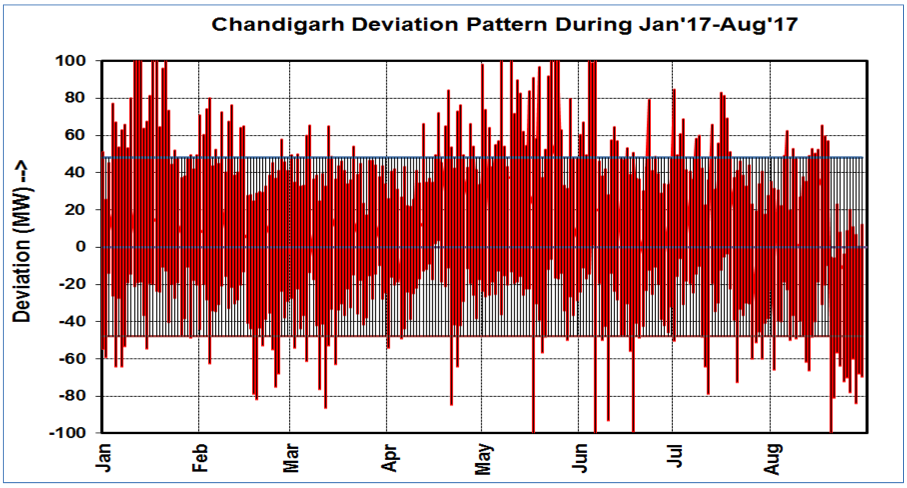
Annexure - III

Deviation of States and Regional Entities: 15 minute time block wise

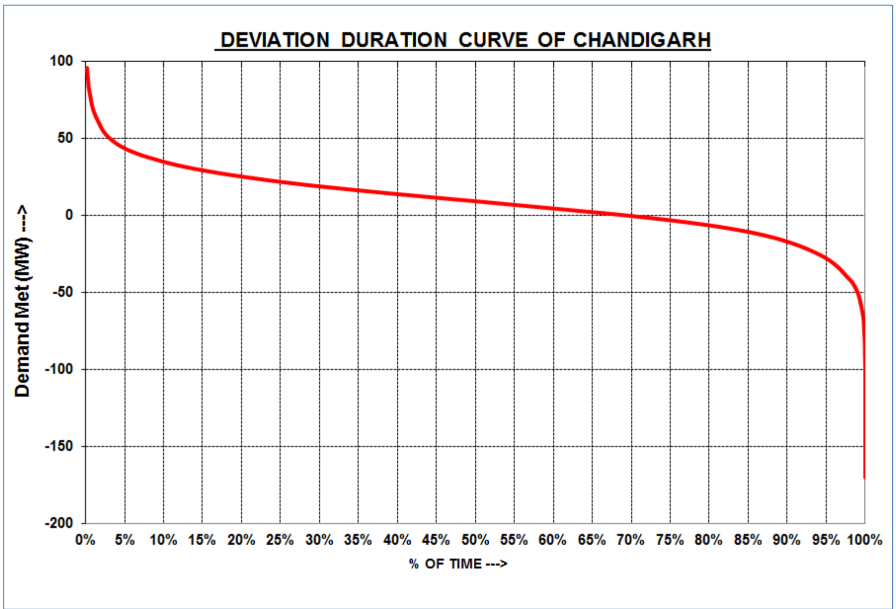
Period: January 2017- August 2017

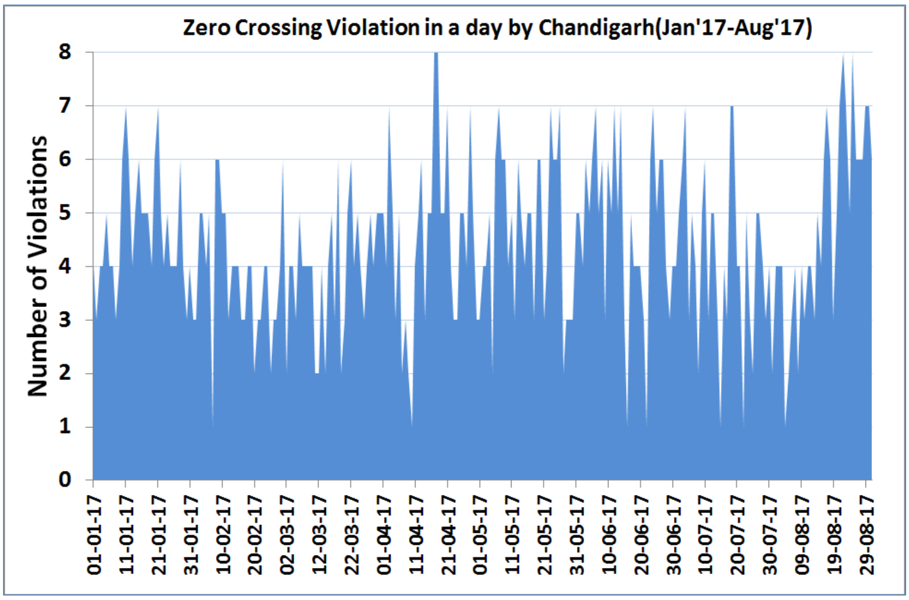
Northern Region

Period: January 2017- August 2017

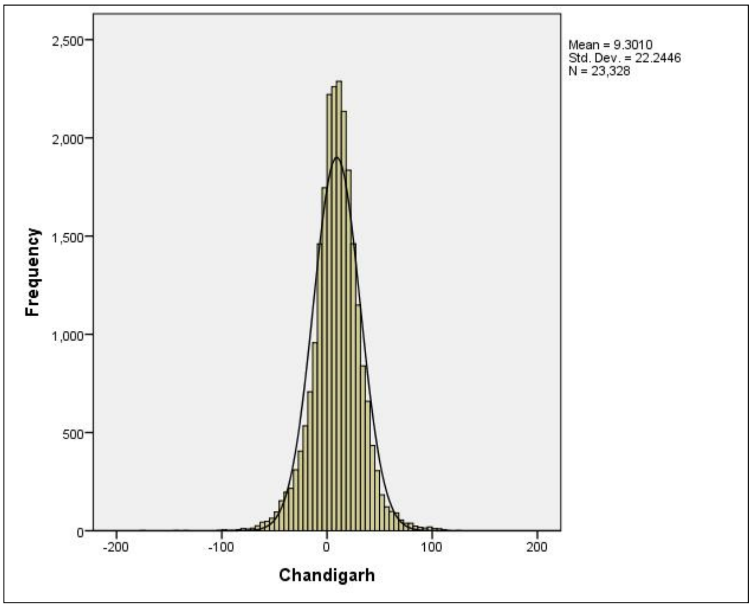


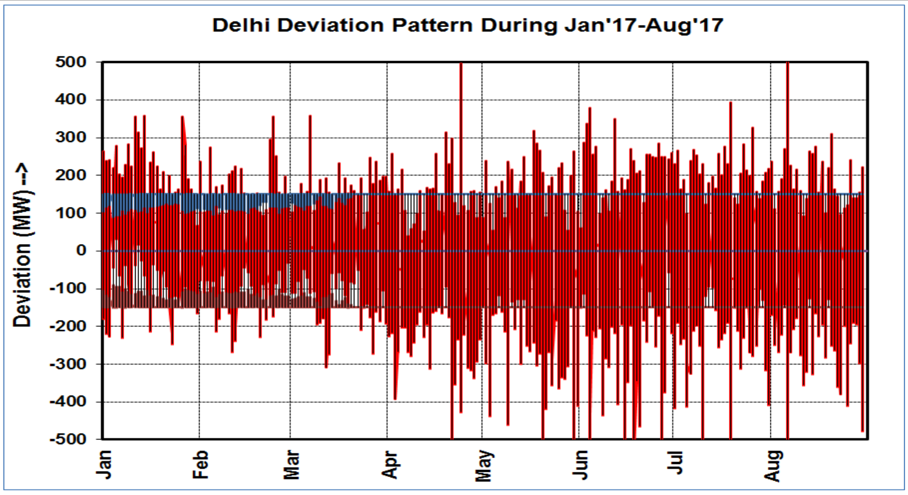
HEAD	MAX (in MW)	MIN (in MW)	AVG (in MW)
Schedule	370	62	210
Actual	399	75	219
Deviation	124	-177	-
Note: +Ve indicates O/d & –Ve indicates U/d			



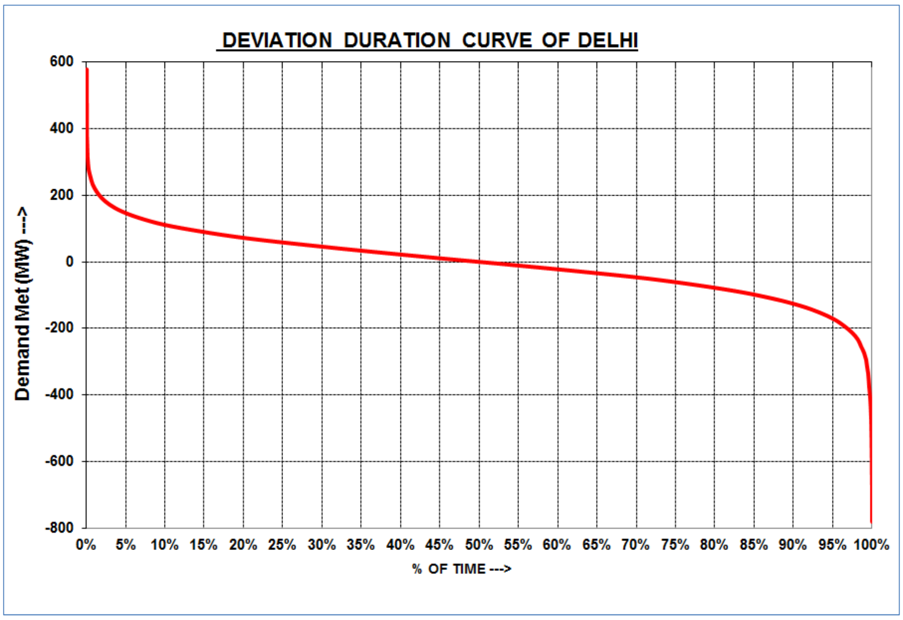


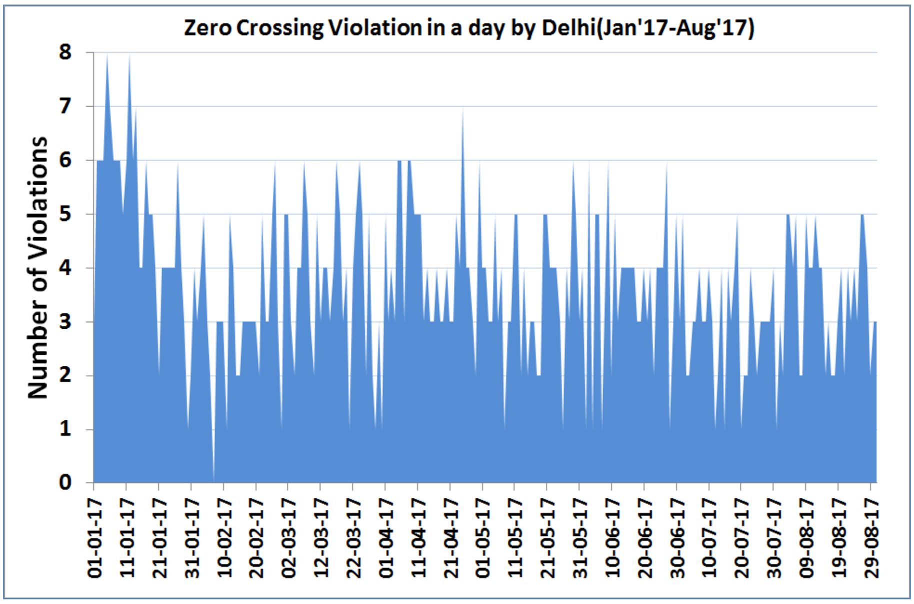
Chandigarh Deviation



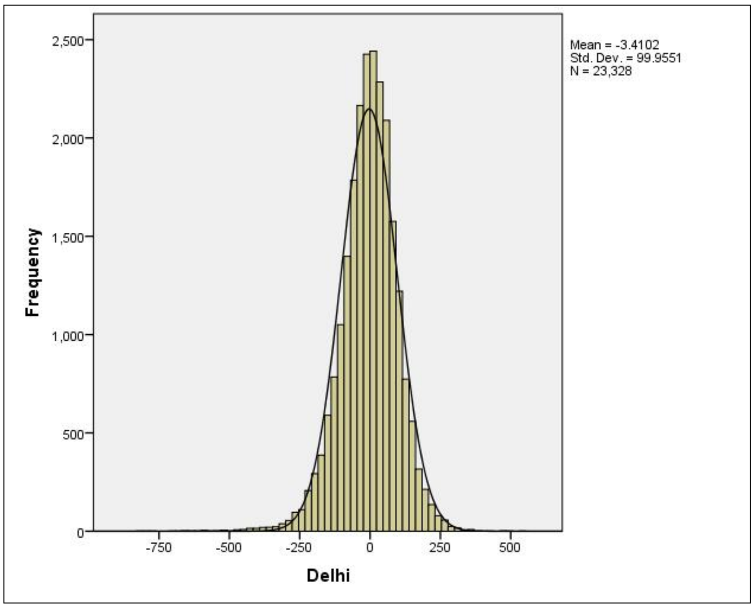


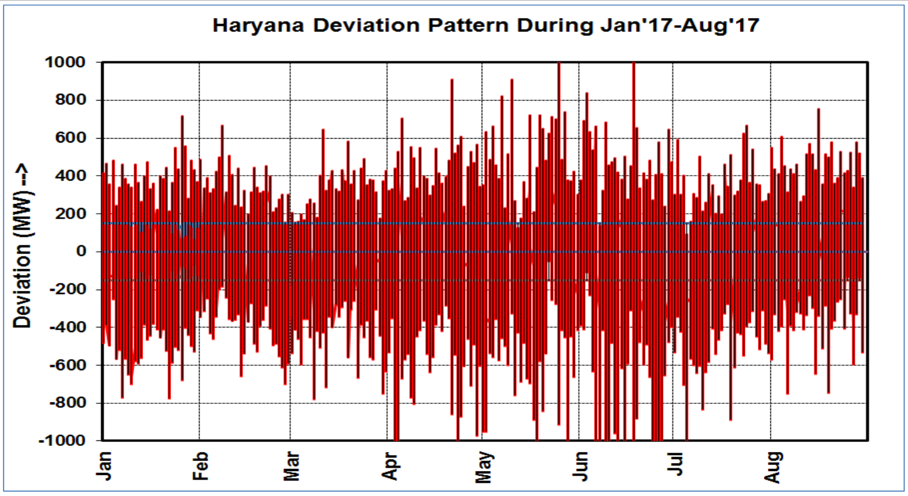
HEAD	MAX (in MW)	MIN (in MW)	AVG (in MW)
Schedule	5579	759	3033
Actual	5416	838	3030
Deviation	535	-823	-
Note: +Ve indicates O/d & –Ve indicates U/d			



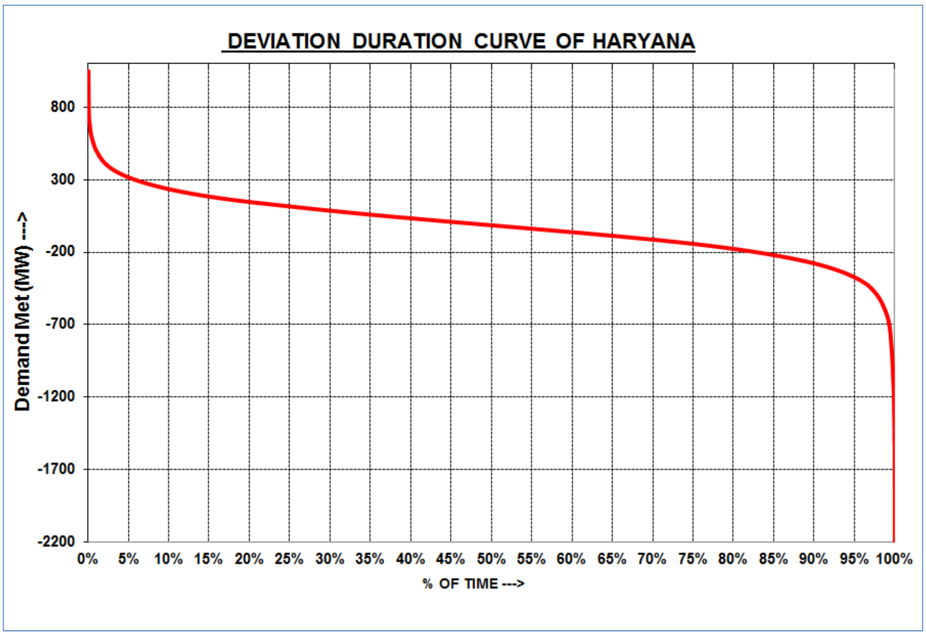


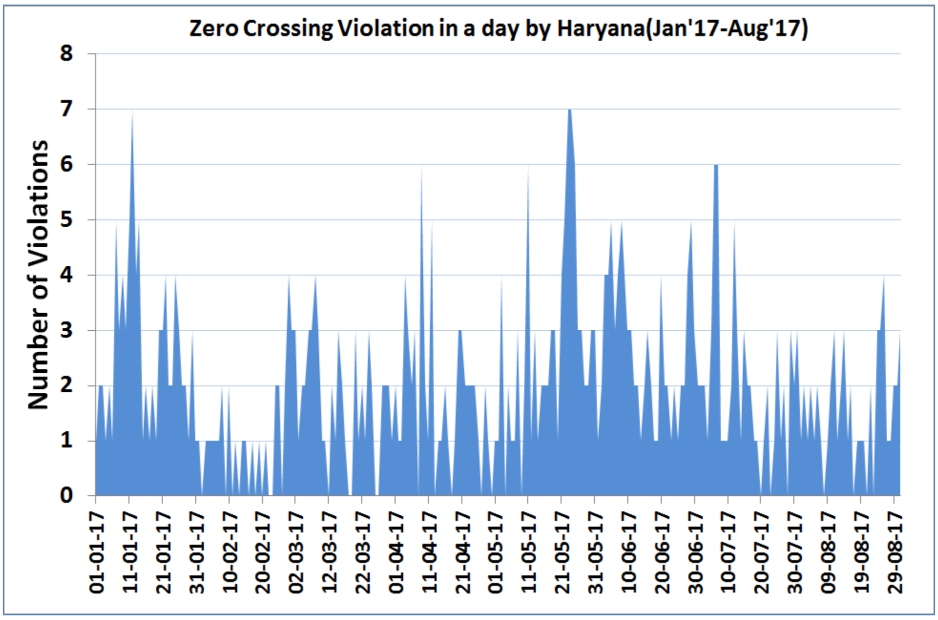
Delhi Deviation



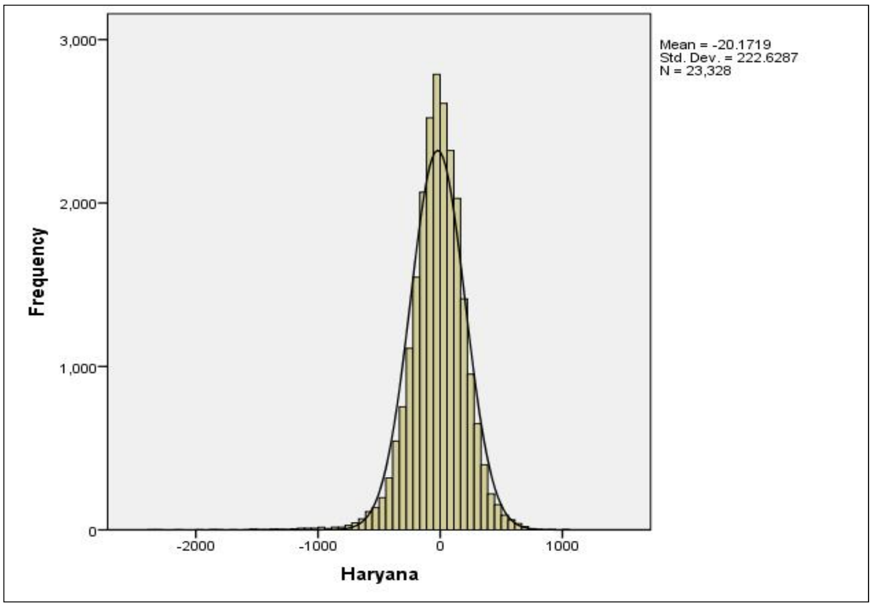


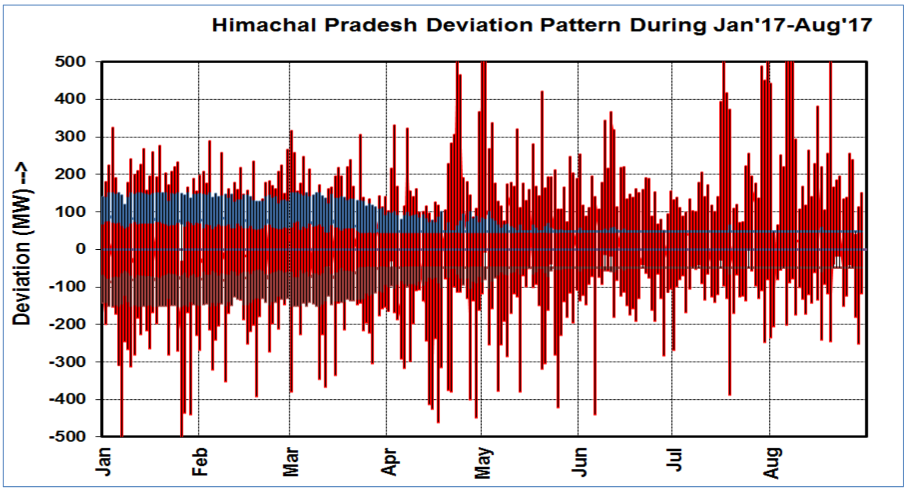
HEAD	MAX (in MW)	MIN (in MW)	AVG (in MW)
Schedule	6754	619	4260
Actual	6987	749	4240
Deviation	1031	-2362	-
Note: +Ve indicates O/d & –Ve indicates U/d			



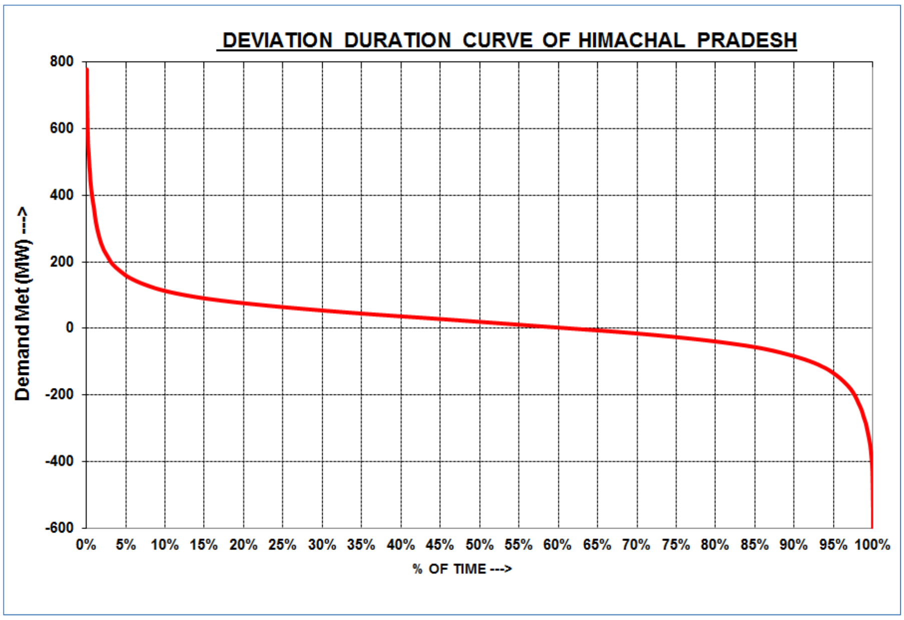


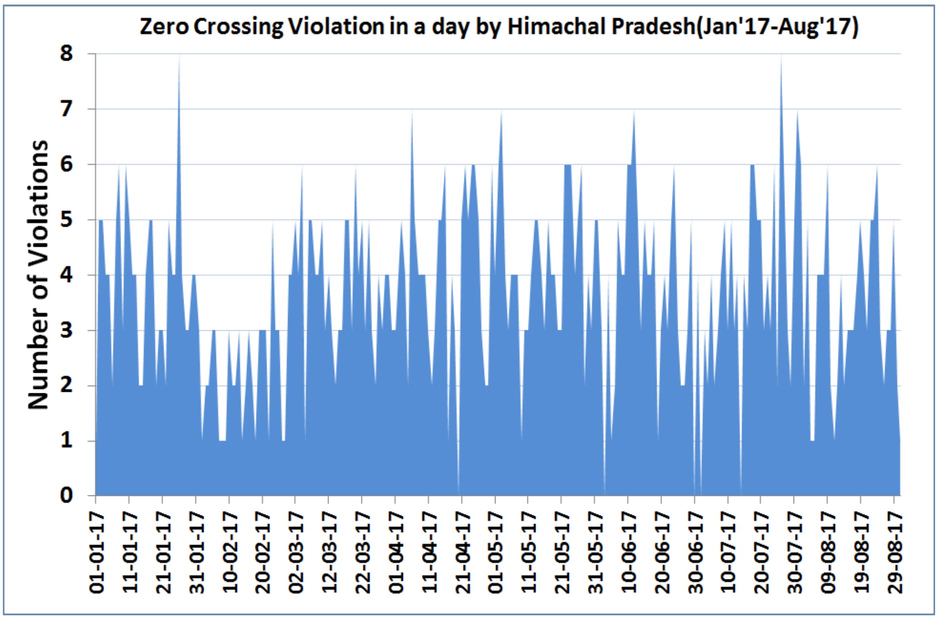
Haryana Deviation



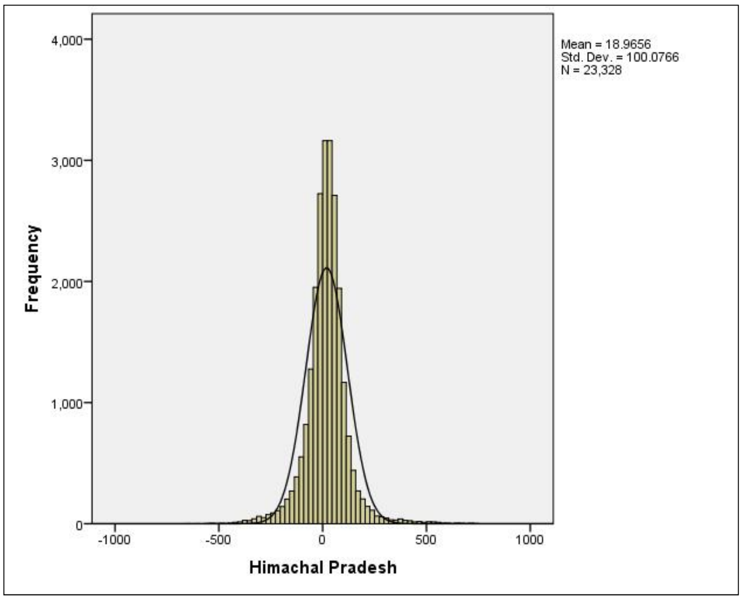


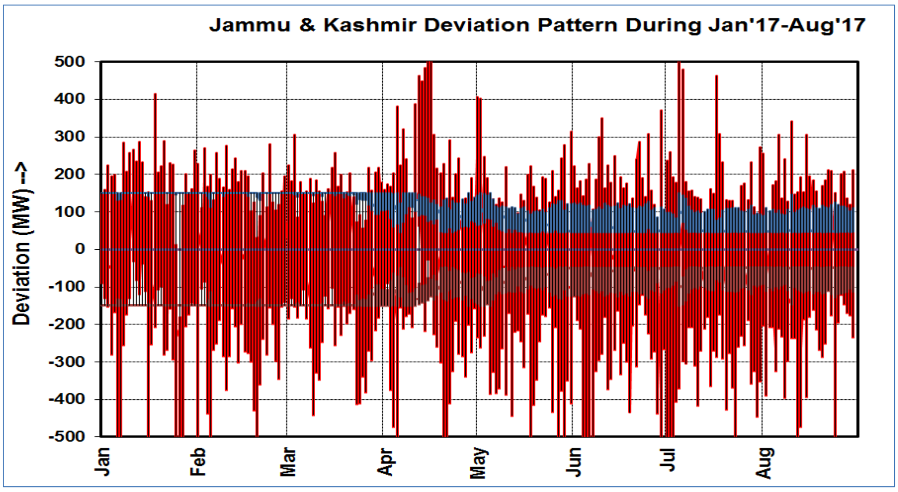
HEAD	MAX (in MW)	MIN (in MW)	AVG (in MW)
Schedule	1466	-929	348
Actual	1295	-542	367
Deviation	741	-658	-
Note: +Ve indicates O/d & –Ve indicates U/d			



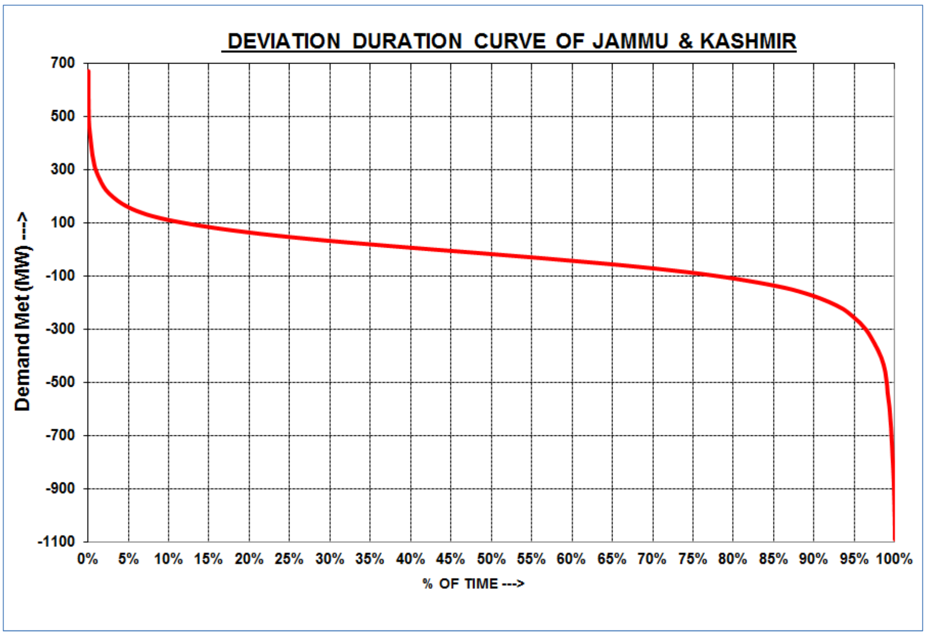


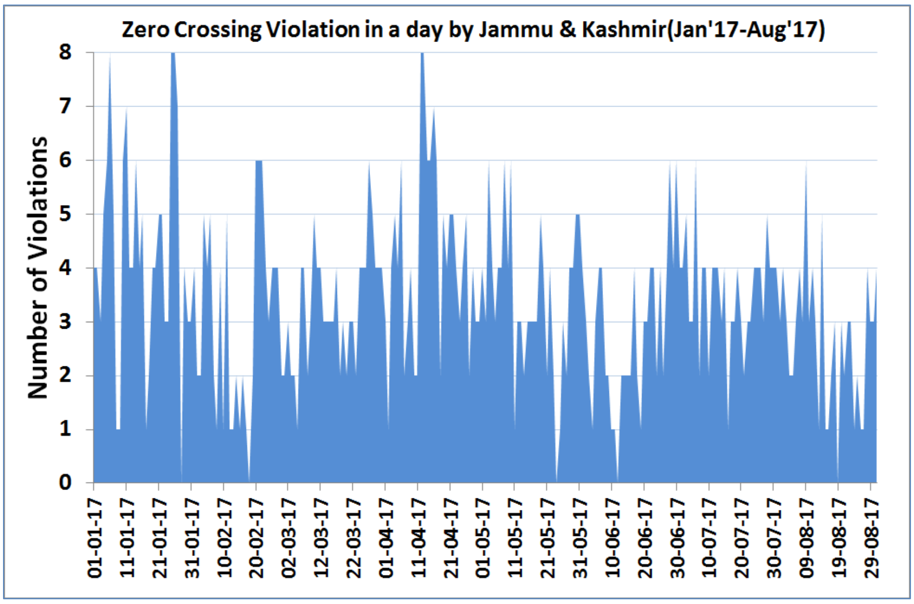
Himachal Pradesh Deviation



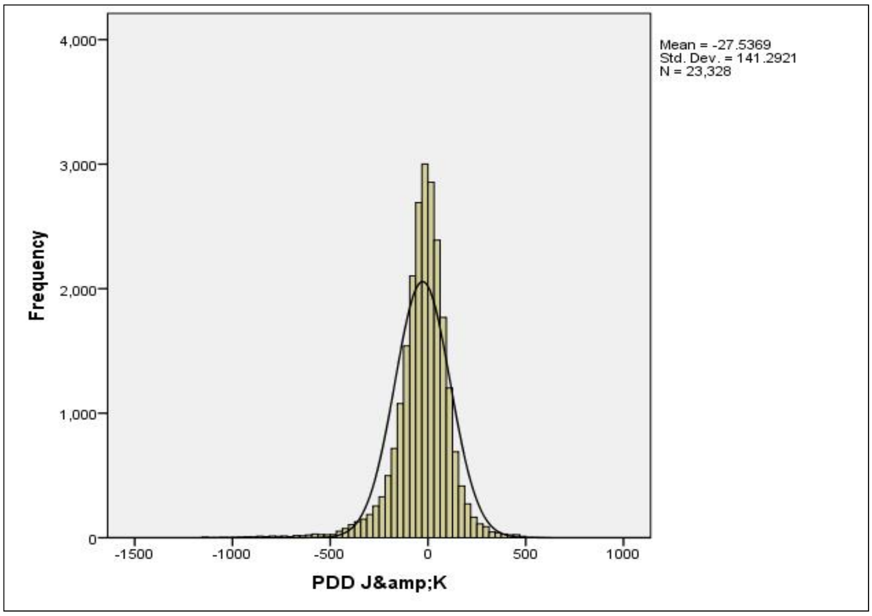


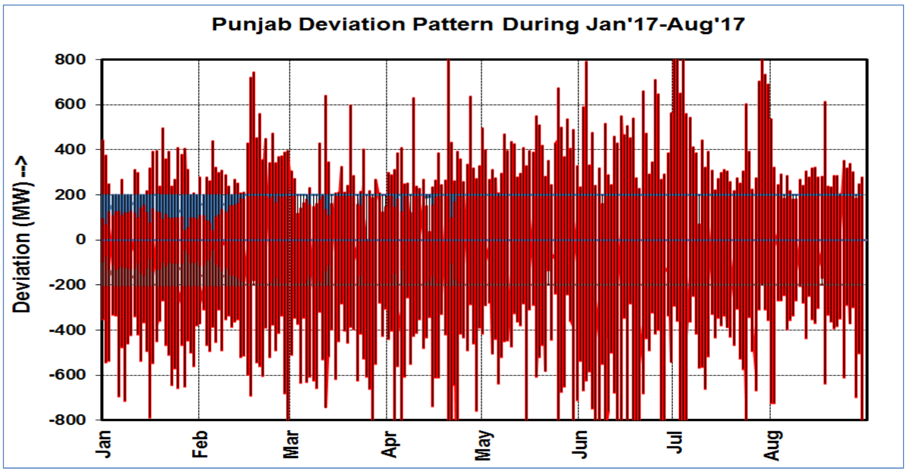
HEAD	MAX (in MW)	MIN (in MW)	AVG (in MW)
Schedule	1979	-60	962
Actual	1930	-314	934
Deviation	619	-1148	-
Note: +Ve indicates O/d & –Ve indicates U/d			



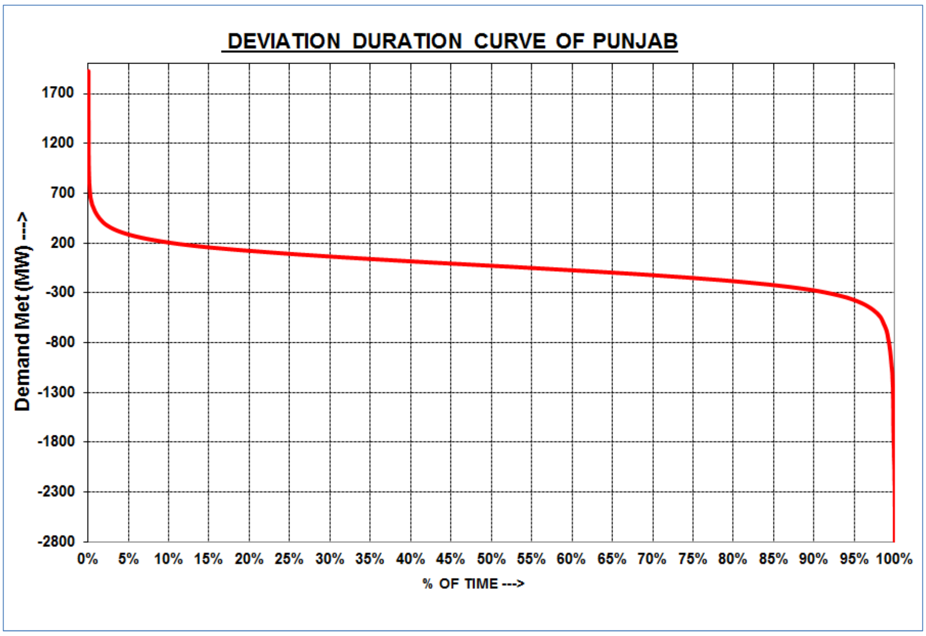


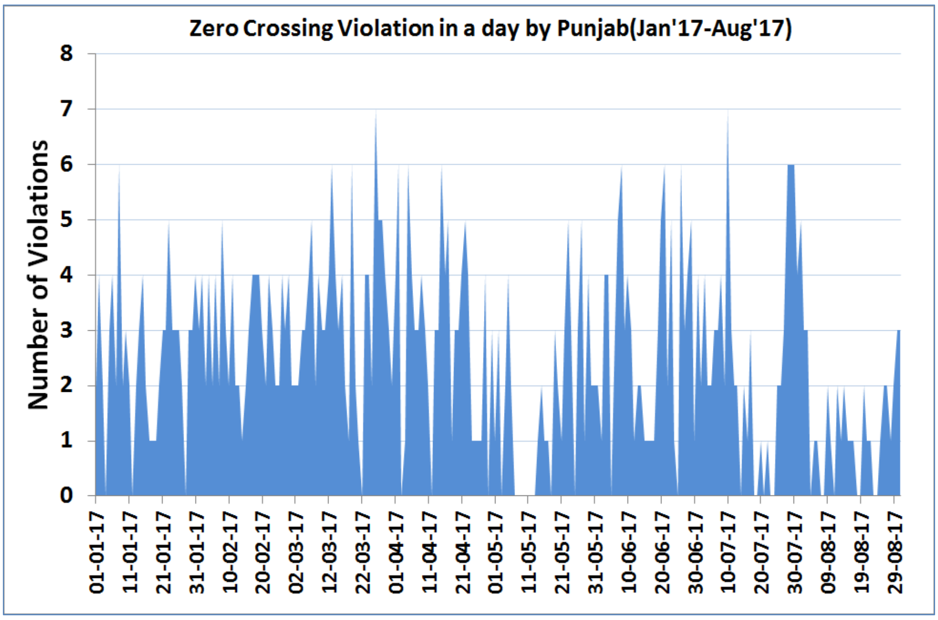
Jammu & Kashmir Deviation



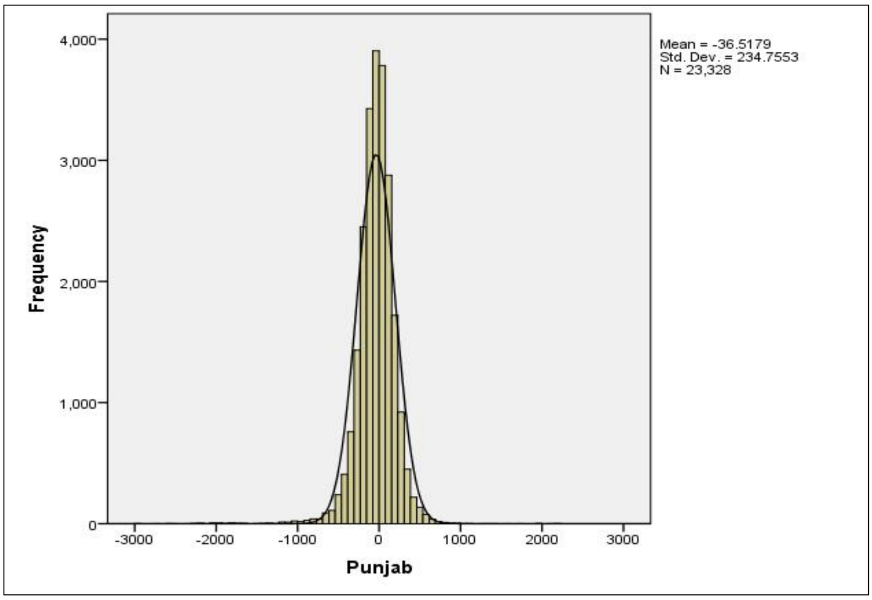


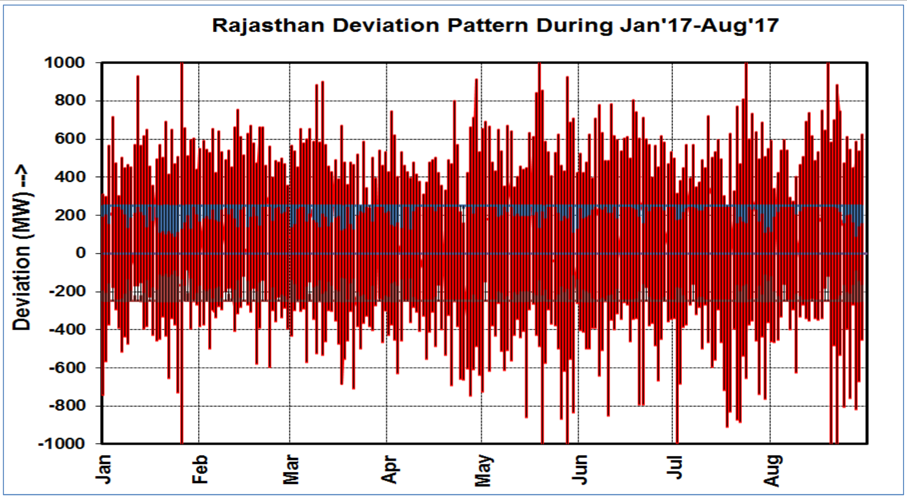
HEAD	MAX (in MW)	MIN (in MW)	AVG (in MW)
Schedule	6473	12	3535
Actual	6645	-44	3498
Deviation	2166	-2947	-
Note: +Ve indicates O/d & –Ve indicates U/d			



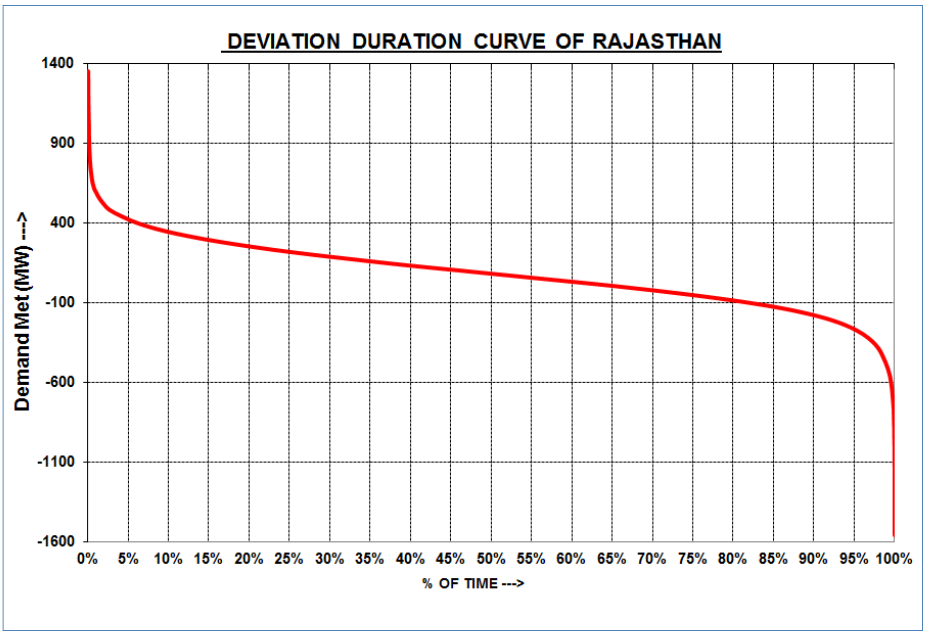


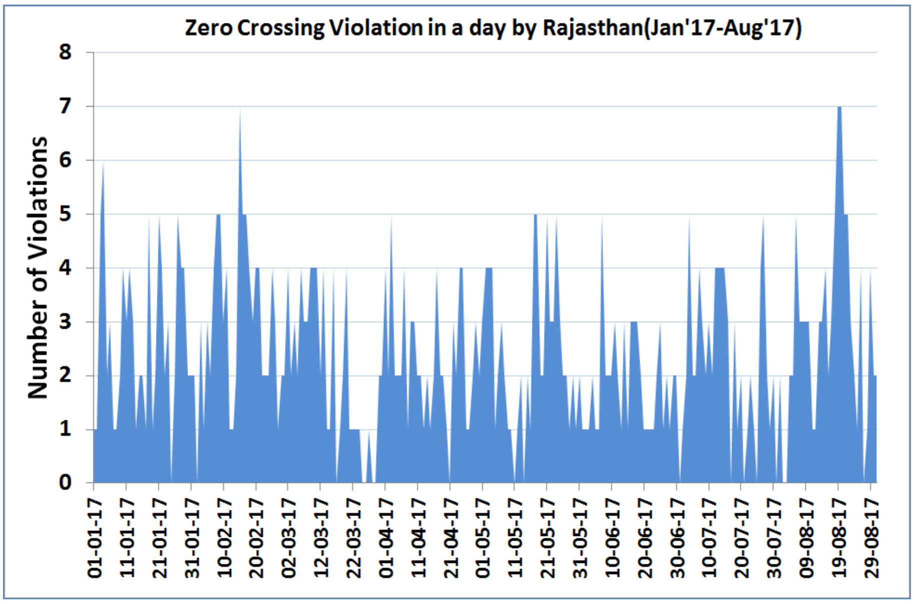
Punjab Deviation



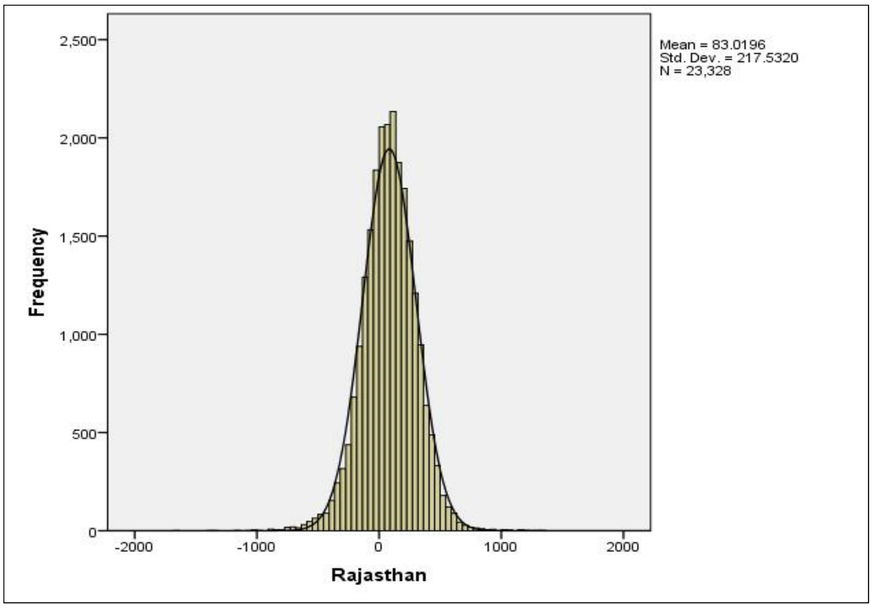


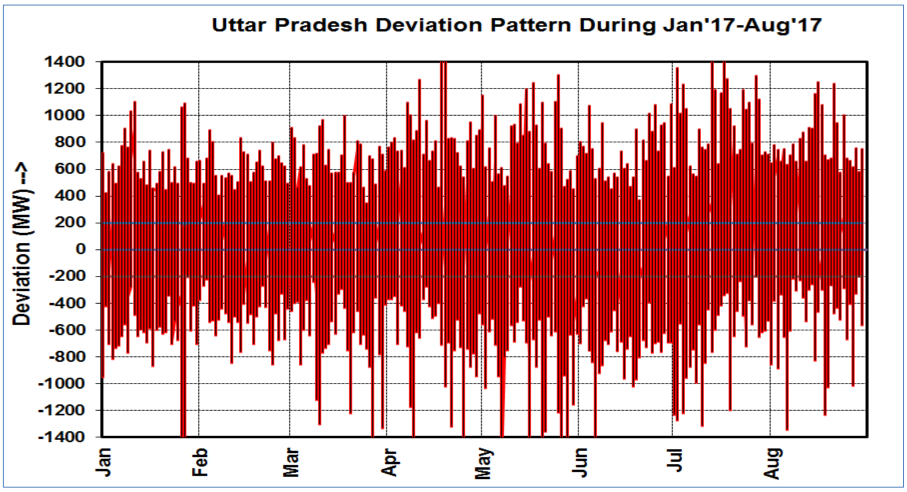
HEAD	MAX (in MW)	MIN (in MW)	AVG (in MW)
Schedule	4641	790	2829
Actual	4975	261	2912
Deviation	1338	-1638	-
Note: +Ve indicates O/d & –Ve indicates U/d			



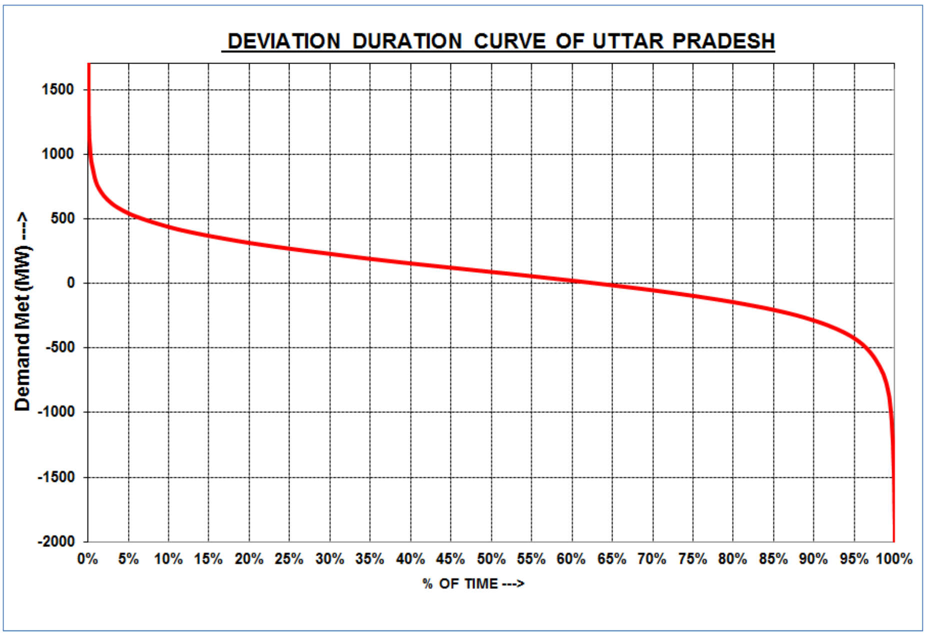


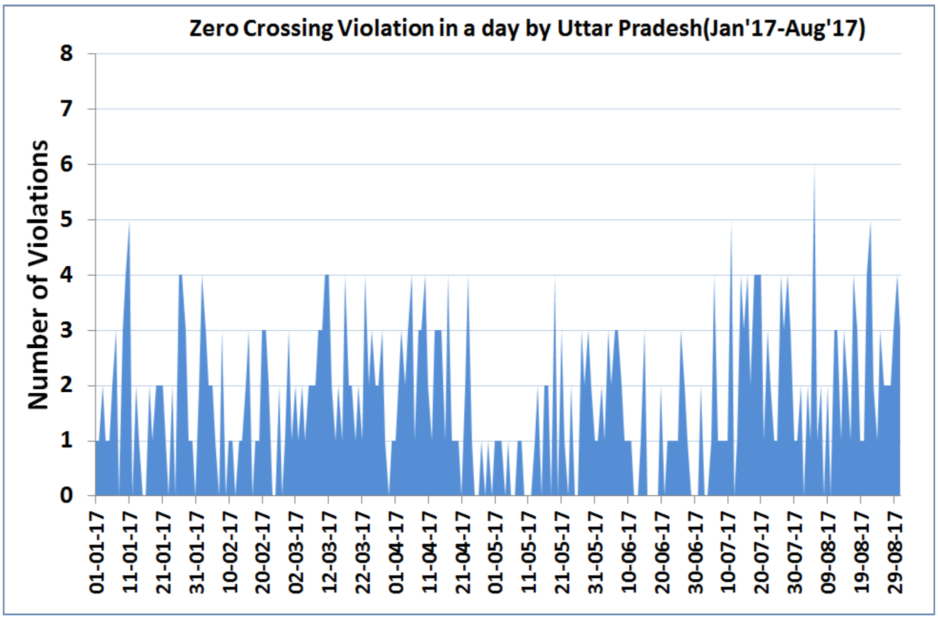
Rajasthan Deviation



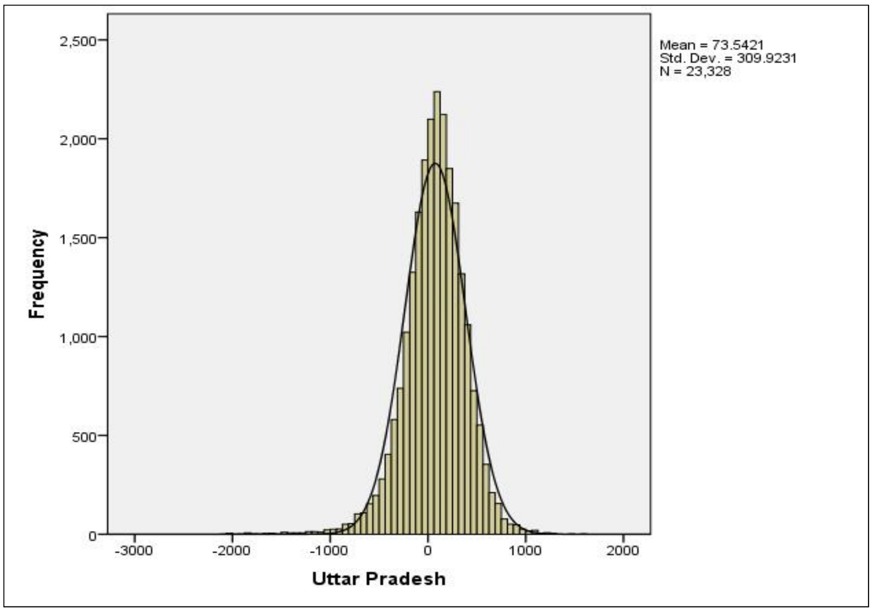


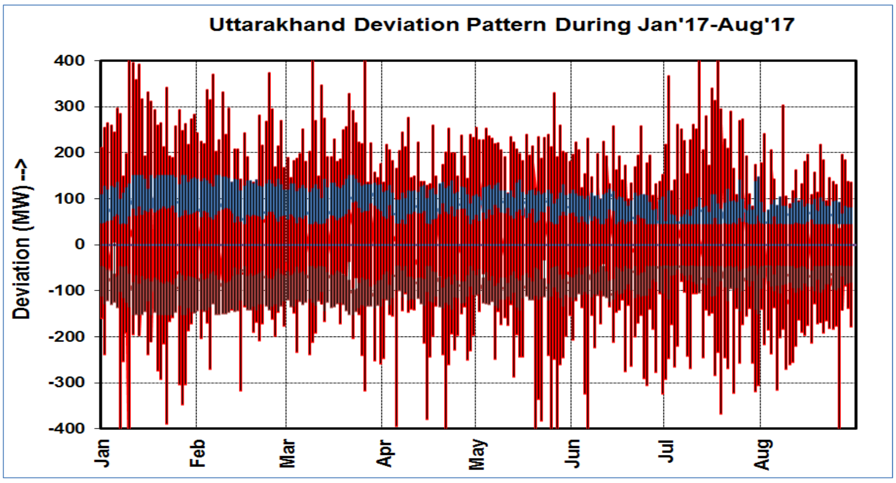
HEAD	MAX (in MW)	MIN (in MW)	AVG (in MW)
Schedule	8743	1613	5499
Actual	9496	427	5572
Deviation	1601	2102	-
Note: +Ve indicates O/d & –Ve indicates U/d			



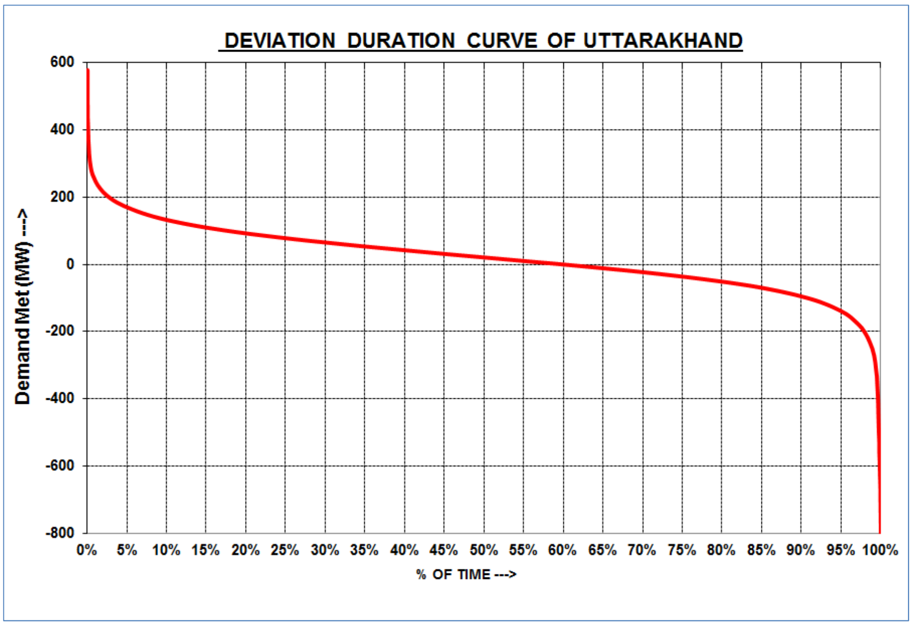


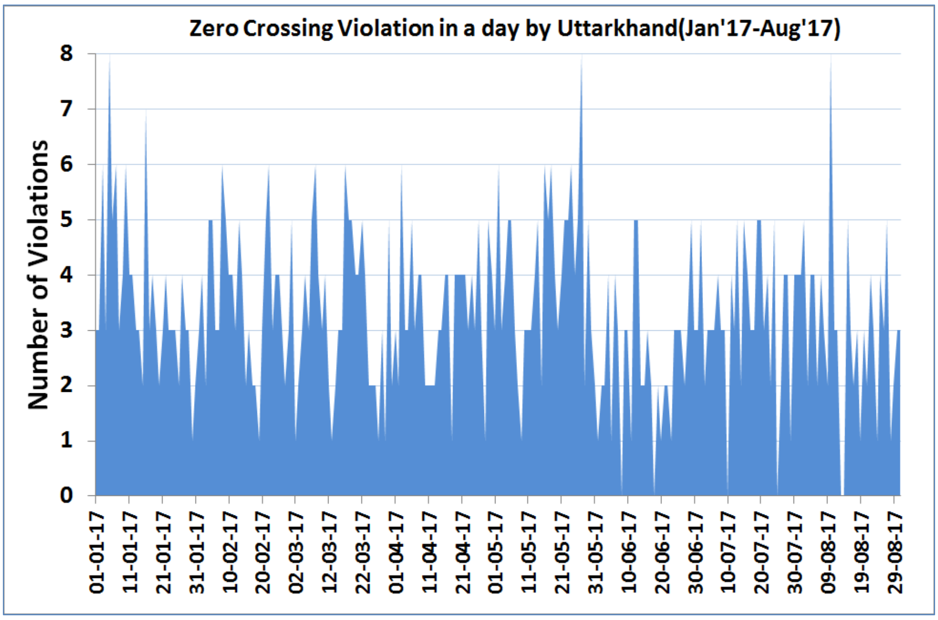
Uttar Pradesh Deviation



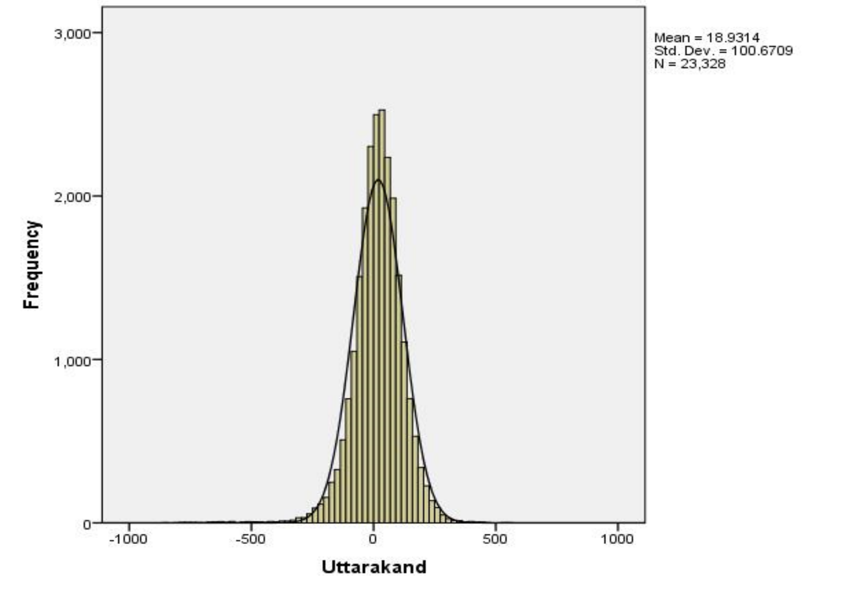


HEAD	MAX (in MW)	MIN (in MW)	AVG (in MW)
Schedule	1372	-27	704
Actual	1471	-112	723
Deviation	565	-857	-
Note: +Ve indicates O/d & –Ve indicates U/d			





Uttarakhand Deviation

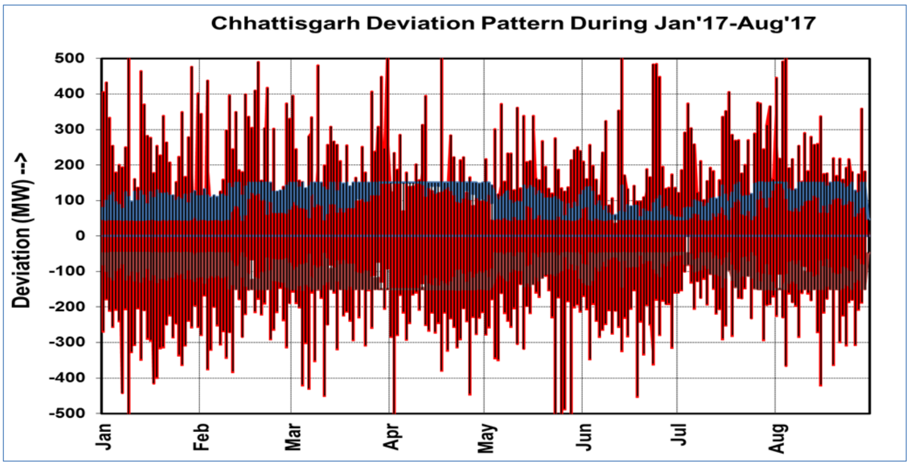


Deviation of States and Regional Entities: 15 minute time block wise

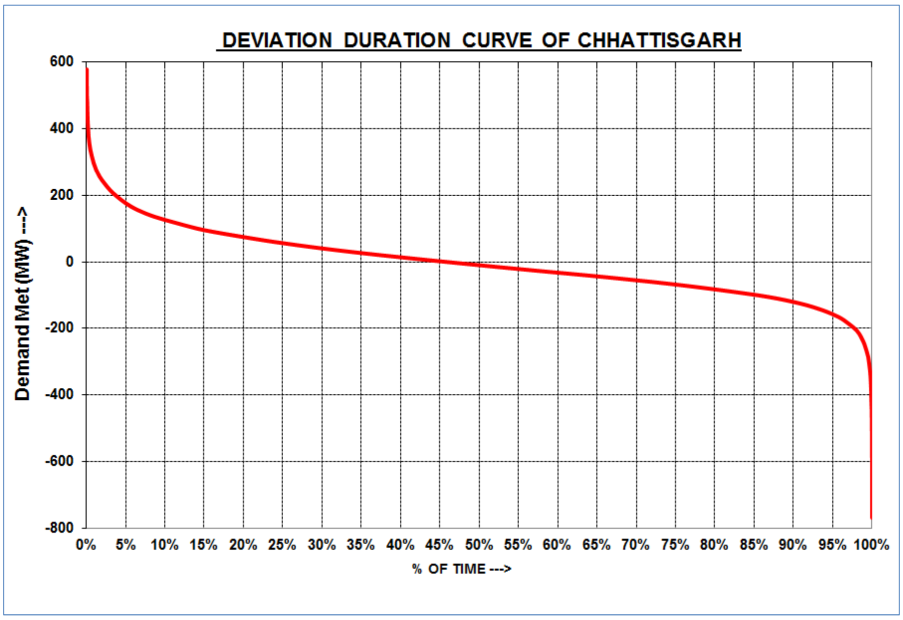
Period: January 2017- August 2017

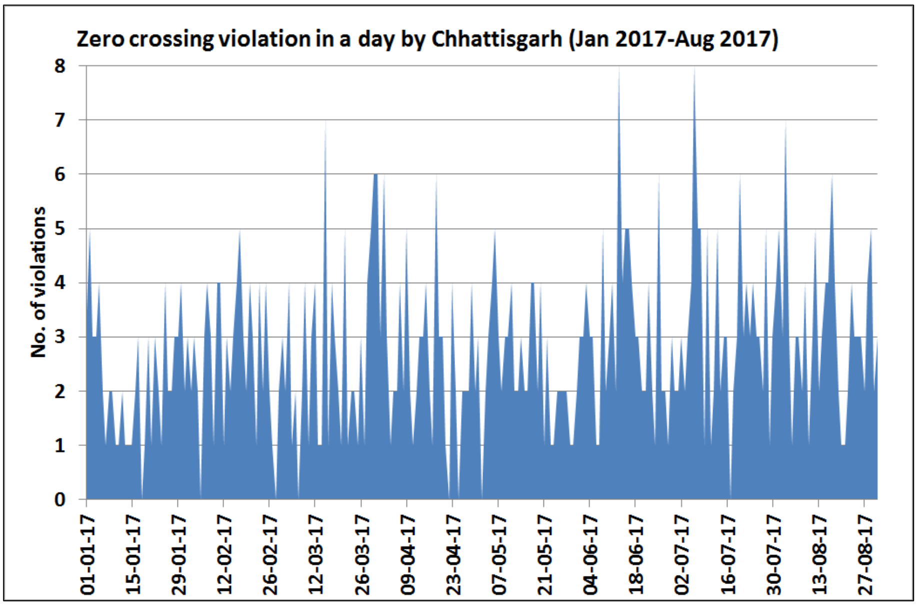
Western Region states

Period: January 2017- August 2017

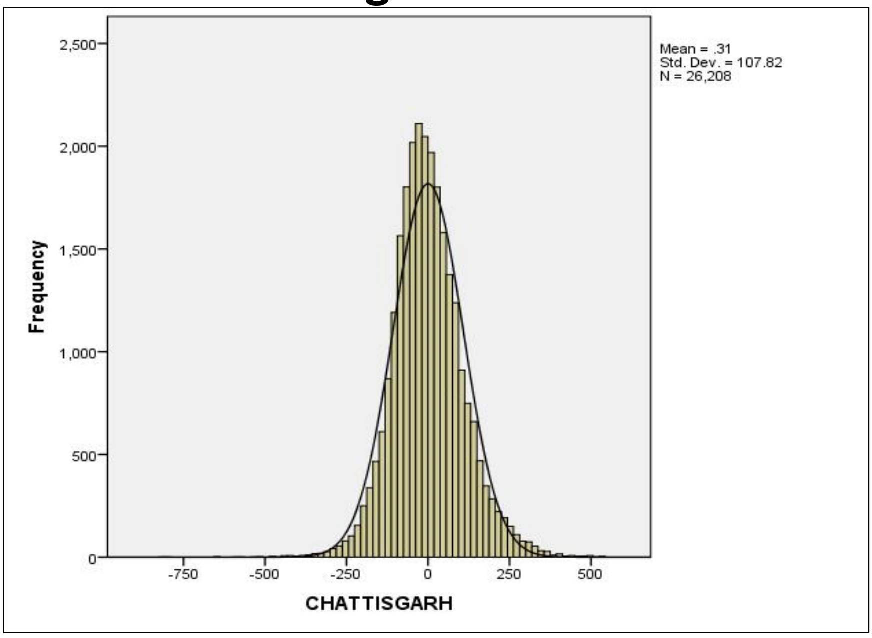


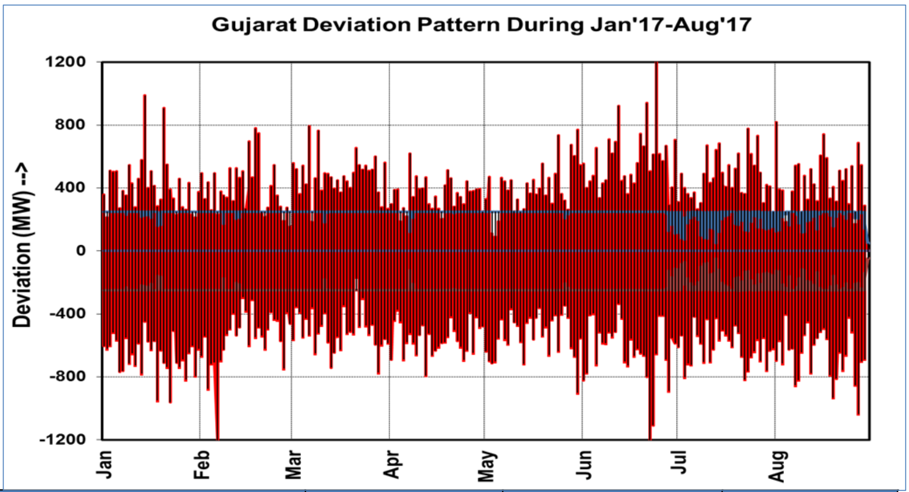
HEAD	MAX (in MW)	MIN (in MW)	AVG (in MW)
Schedule	2372	-179	853
Actual	2400	-523	850
Deviation	540	-807	-
Note: +Ve indicates O/d & –Ve indicates U/d			



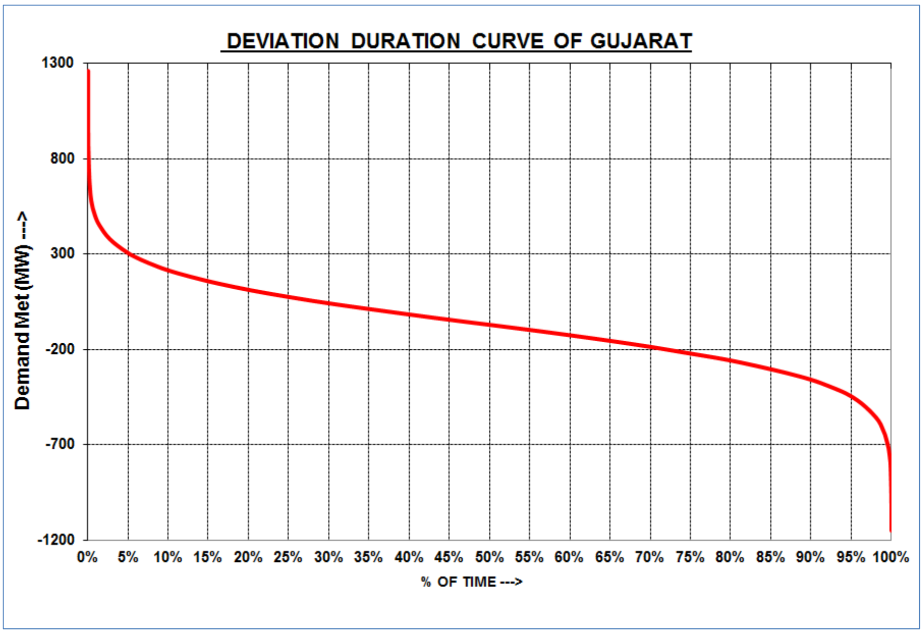


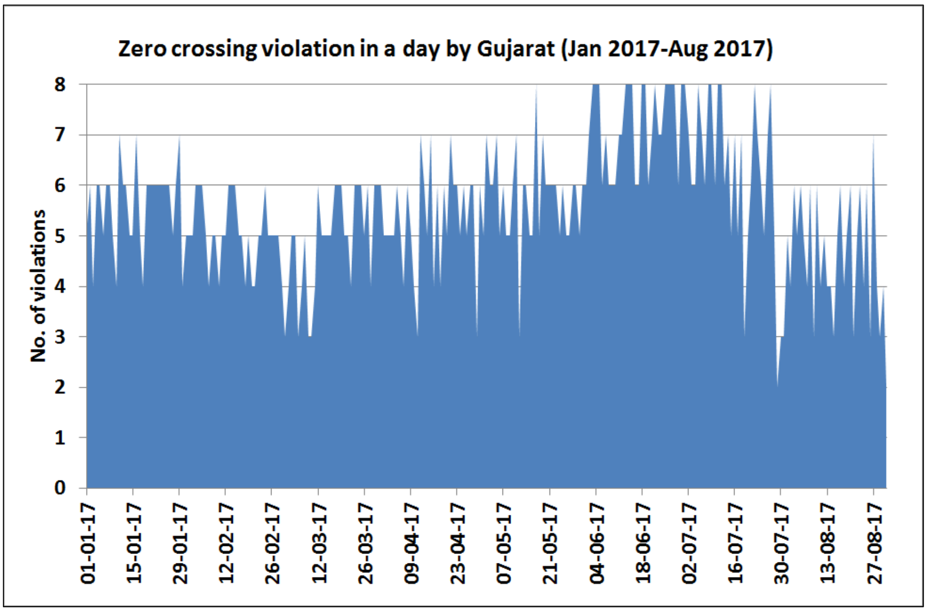
Chhattisgarh Deviation



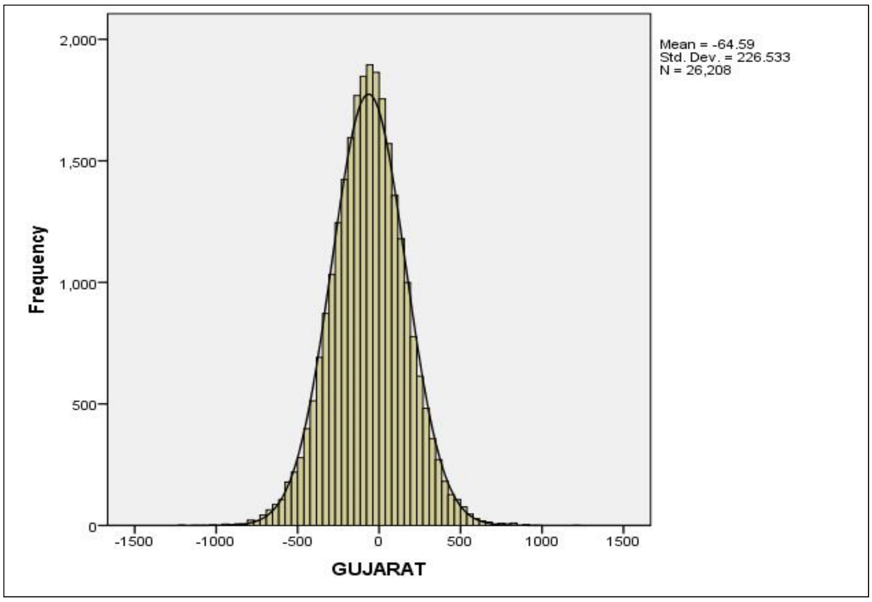


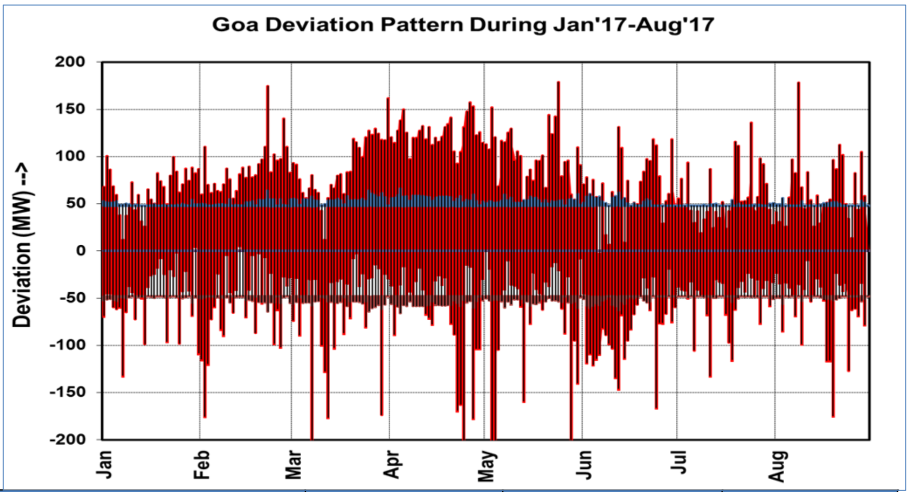
HEAD	MAX (in MW)	MIN (in MW)	AVG (in MW)
Schedule	6281	278	3264
Actual	6545	37	3194
Deviation	1208	-1211	-
Note: +Ve indicates O/d & –Ve indicates U/d			



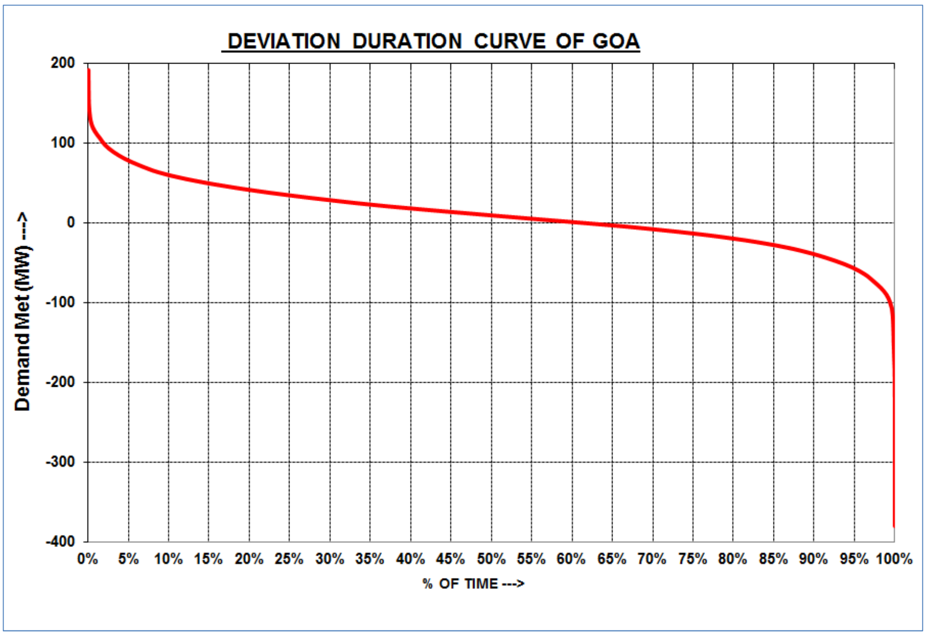


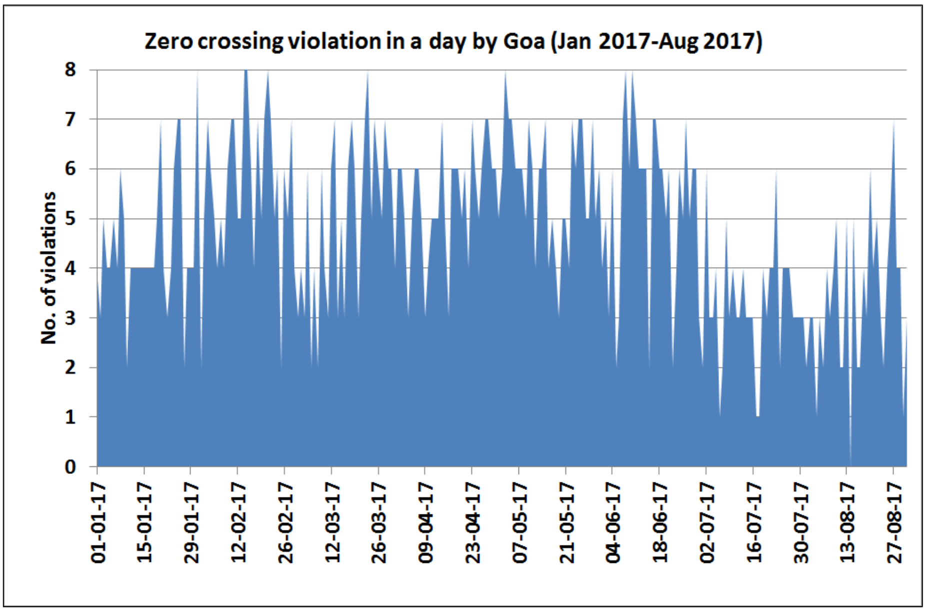
Gujarat Deviation



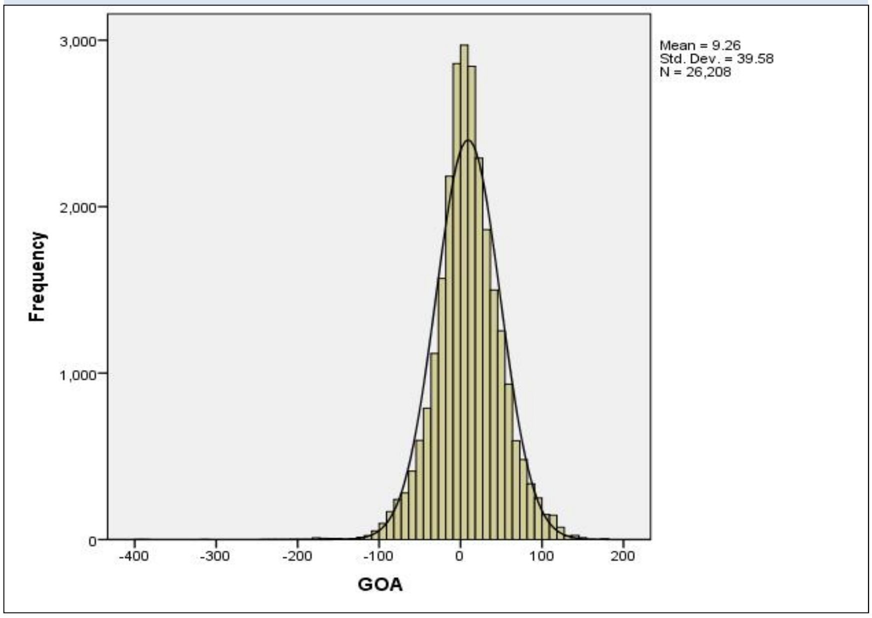


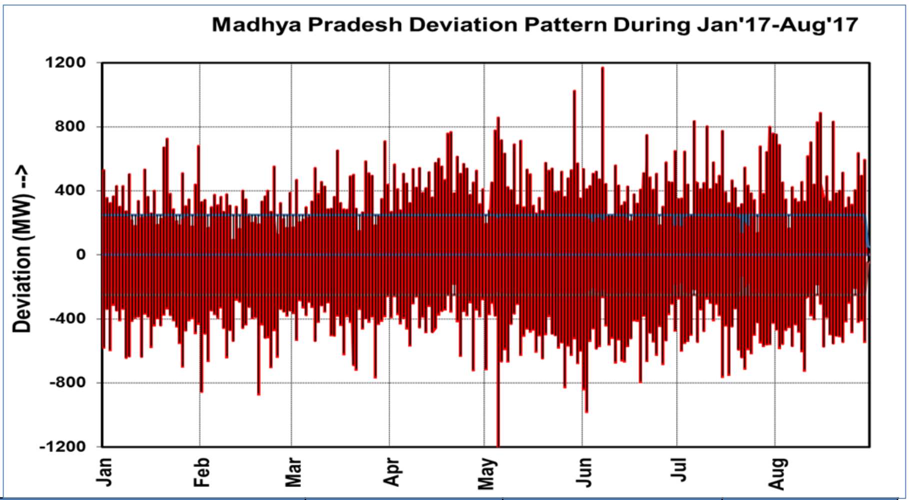
HEAD	MAX (in MW)	MIN (in MW)	AVG (in MW)
Schedule	550	193	357
Actual	557	24	368
Deviation	105	-219	-
Note: +Ve indicates O/d & –Ve indicates U/d			



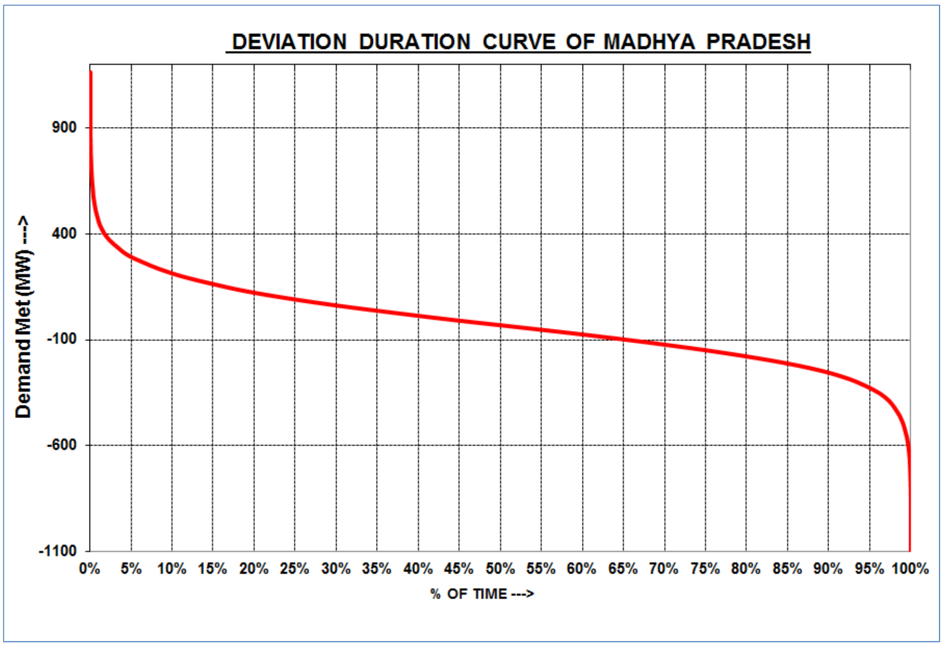


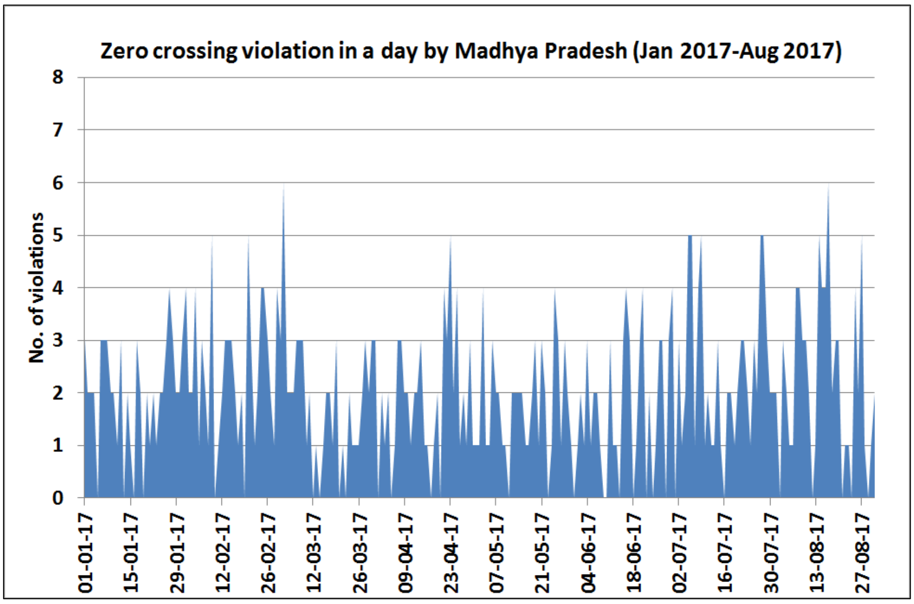
Goa Deviation



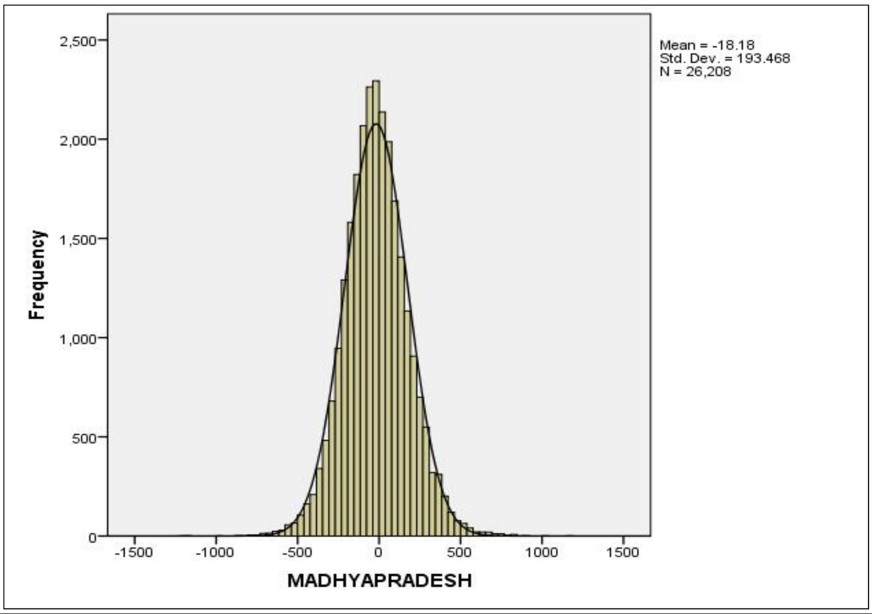


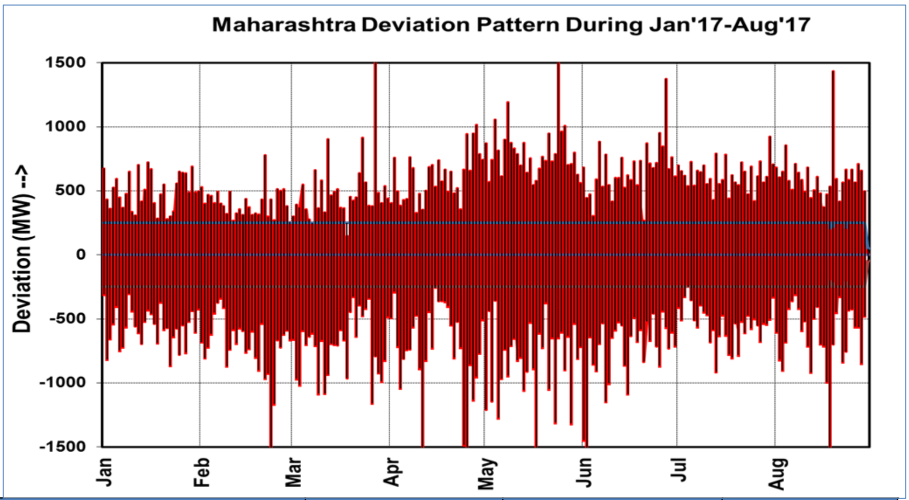
HEAD	MAX (in MW)	MIN (in MW)	AVG (in MW)
Schedule	6736	1177	4128
Actual	6669	1147	4101
Deviation	1168	-1207	-
Note: +Ve indicates O/d & –Ve indicates U/d			



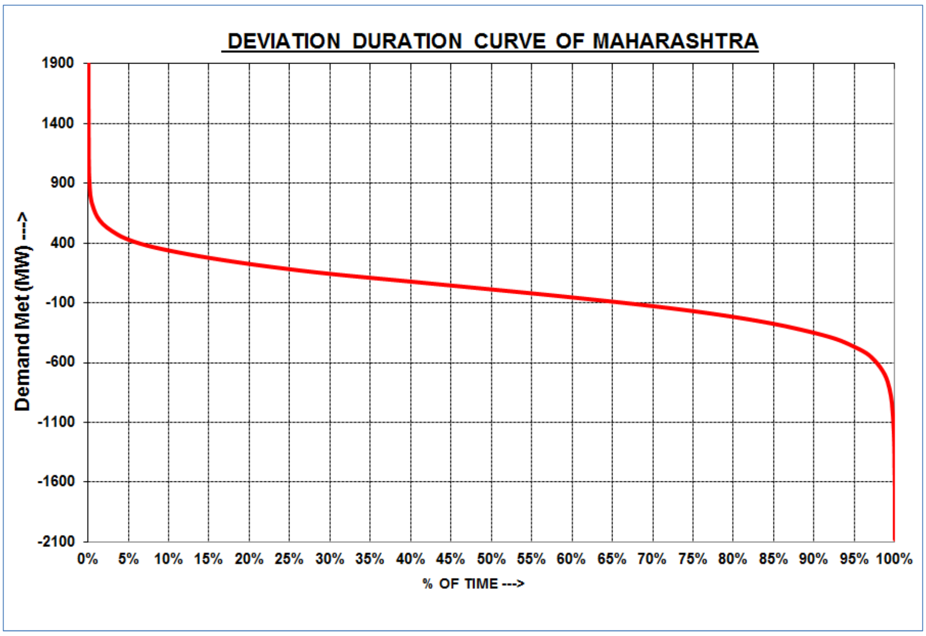


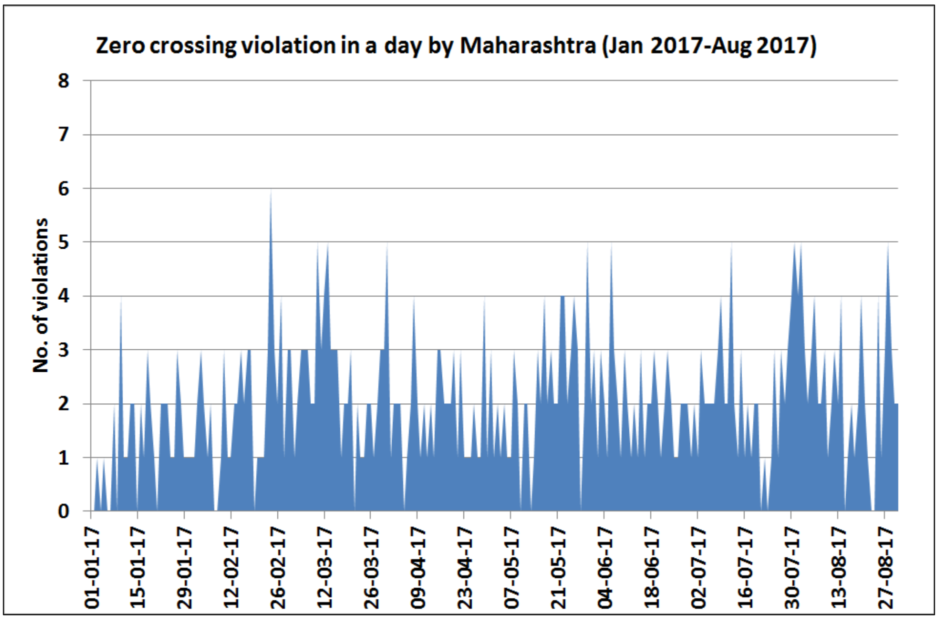
Madhya Pradesh Deviation



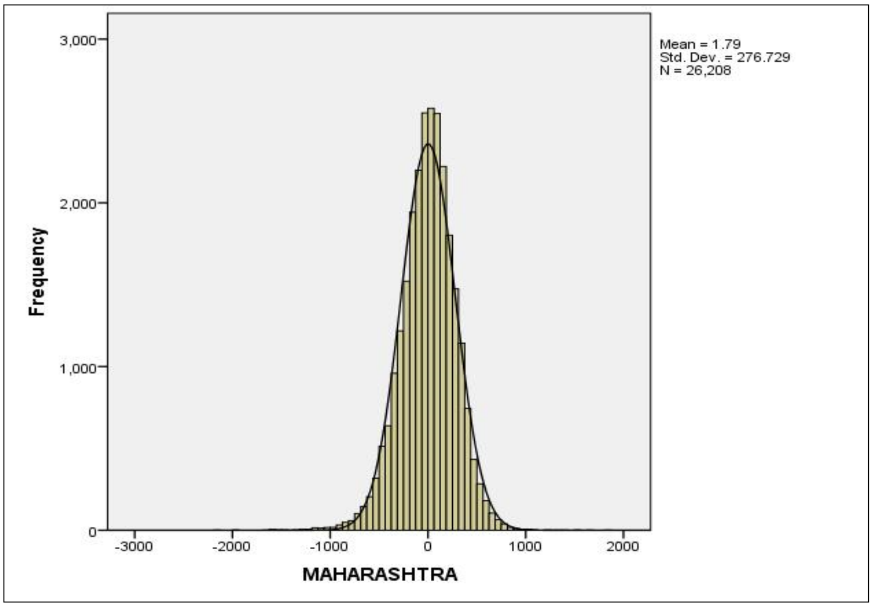


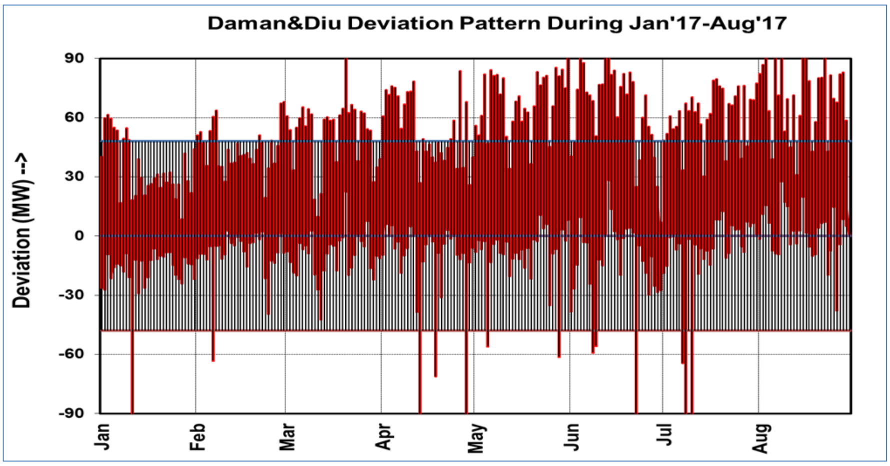
HEAD	MAX (in MW)	MIN (in MW)	AVG (in MW)
Schedule	8815	1706	5583
Actual	8844	1374	5582
Deviation	1852	-2185	-
Note: +Ve indicates O/d & –Ve indicates U/d			



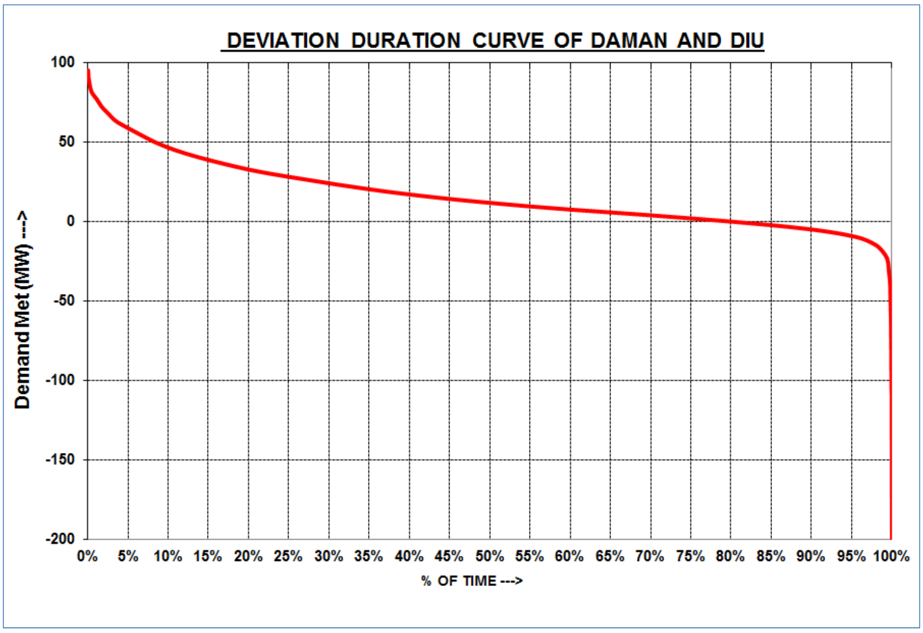


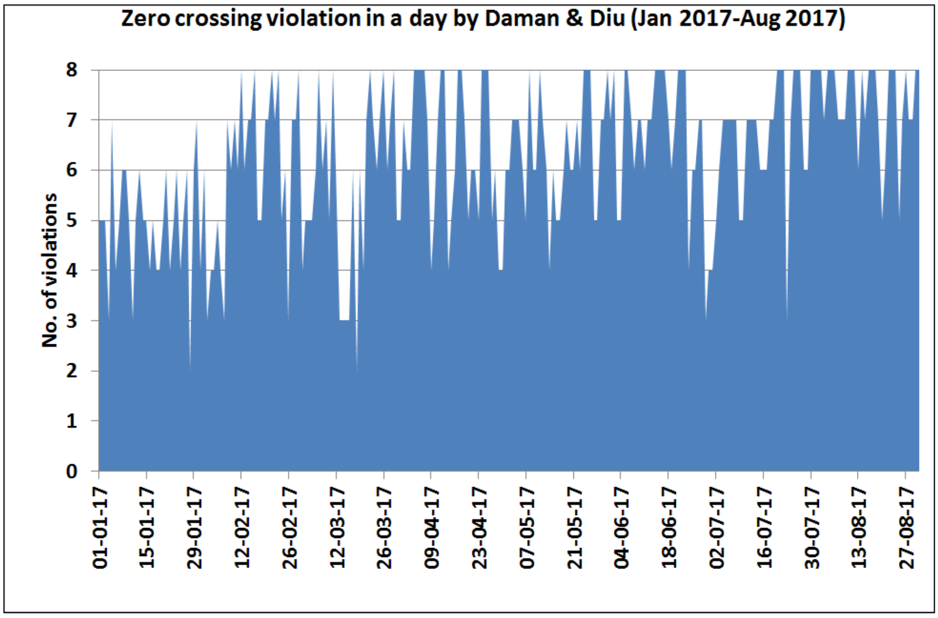
Maharashtra Deviation



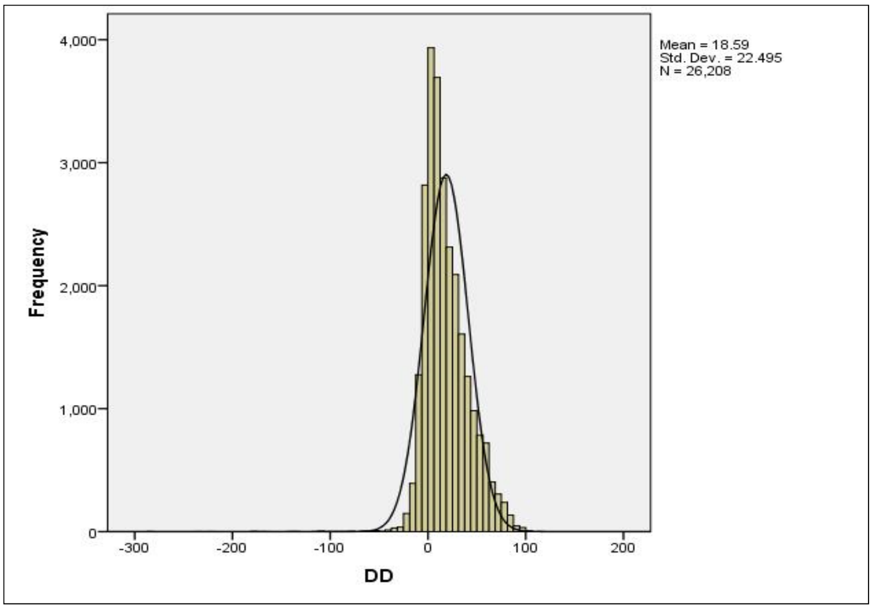


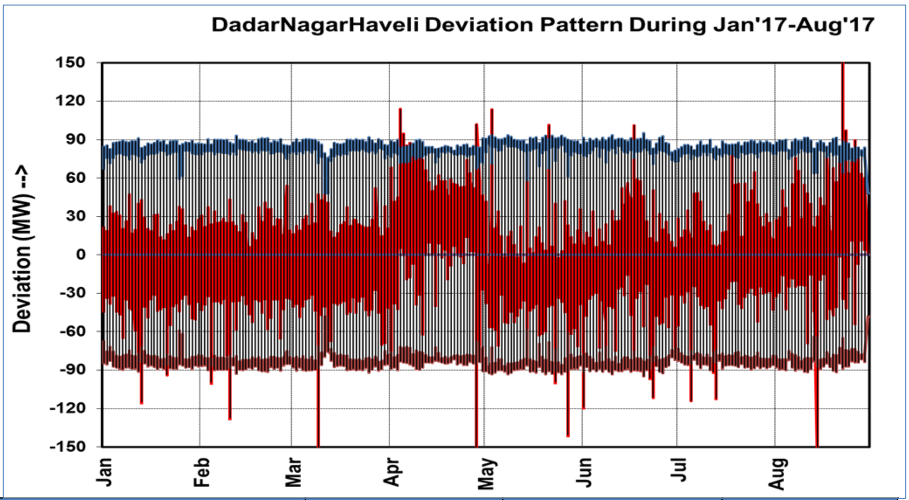
HEAD	MAX (in MW)	MIN (in MW)	AVG (in MW)
Schedule	321	99	266
Actual	338	69	282
Deviation	105	-286	-
Note: +Ve indicates O/d & –Ve indicates U/d			



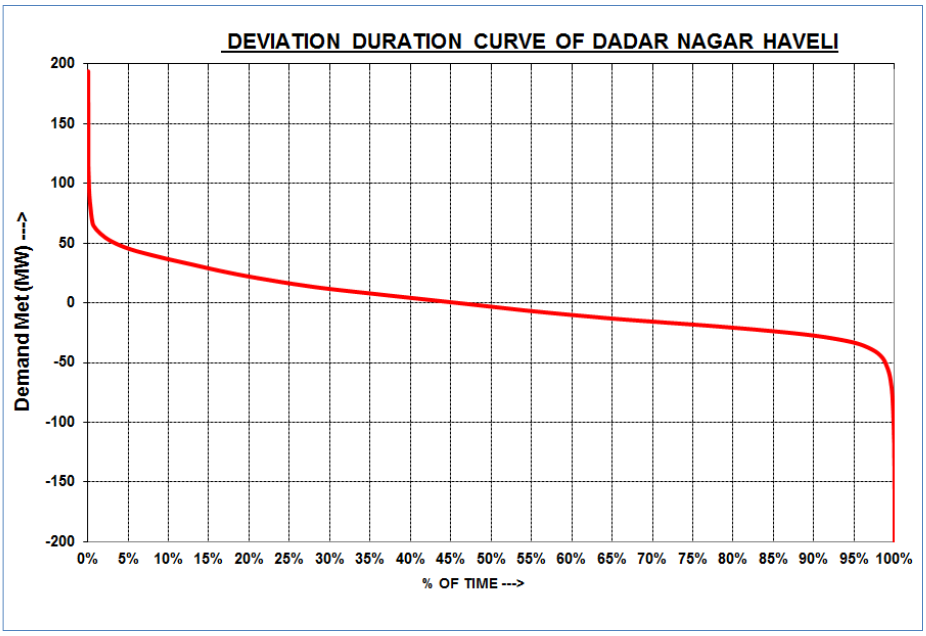


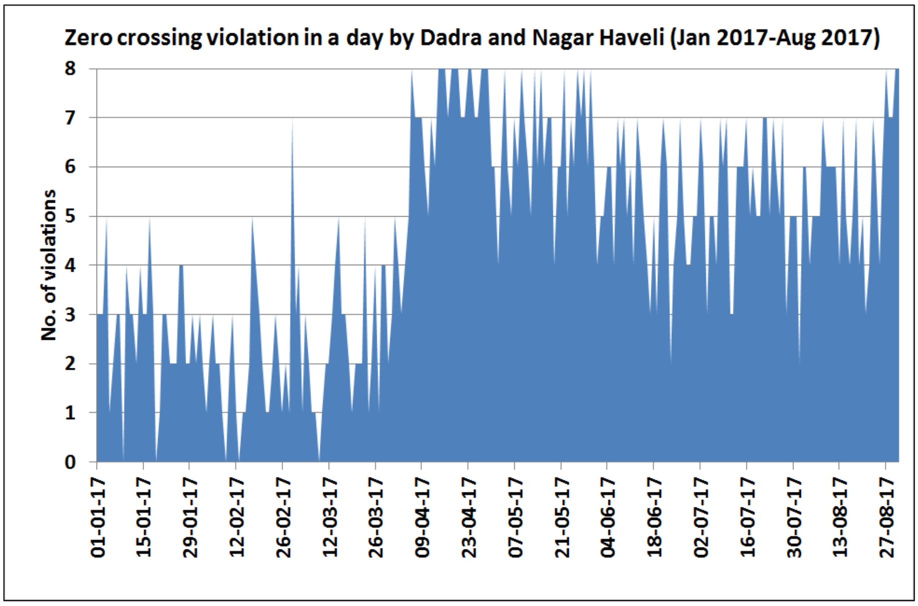
Daman & Diu Deviation



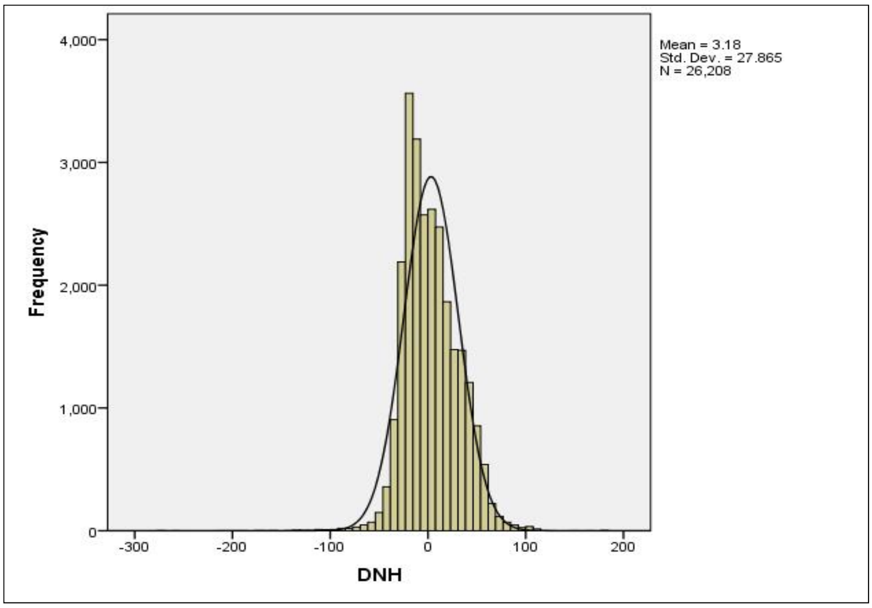


HEAD	MAX (in MW)	MIN (in MW)	AVG (in MW)
Schedule	791	347	689
Actual	781	351	689
Deviation	184	-254	-
Note: +Ve indicates O/d & –Ve indicates U/d			





Dadra and Nagar Haveli Deviation

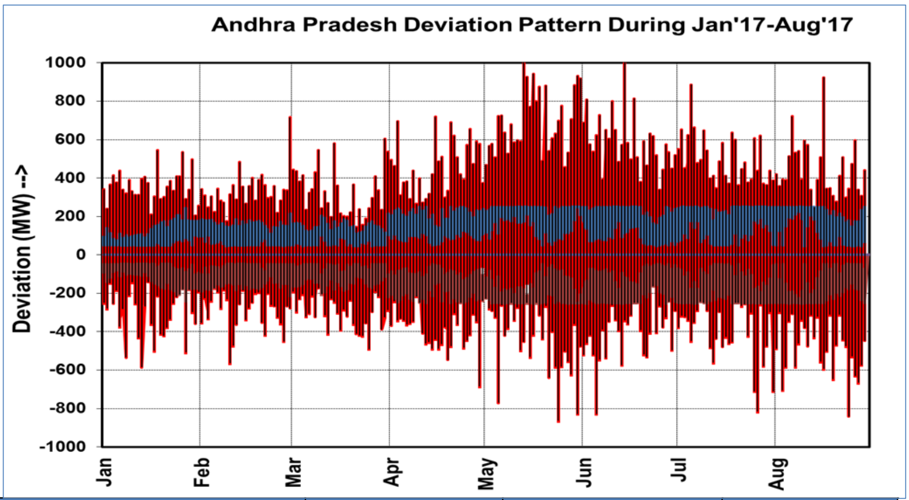


Deviation of States and Regional Entities: 15 minute time block wise

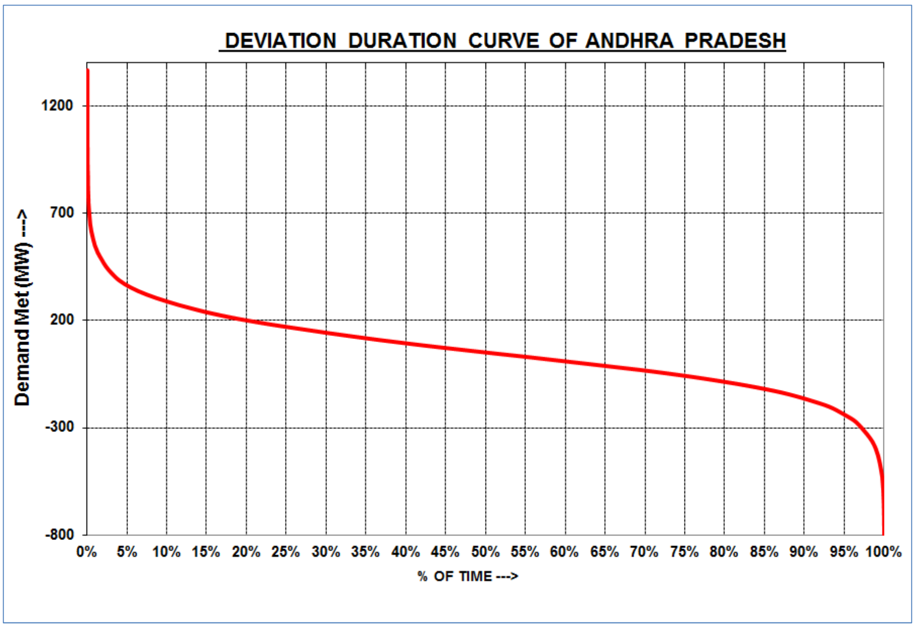
Period: January 2017- August 2017

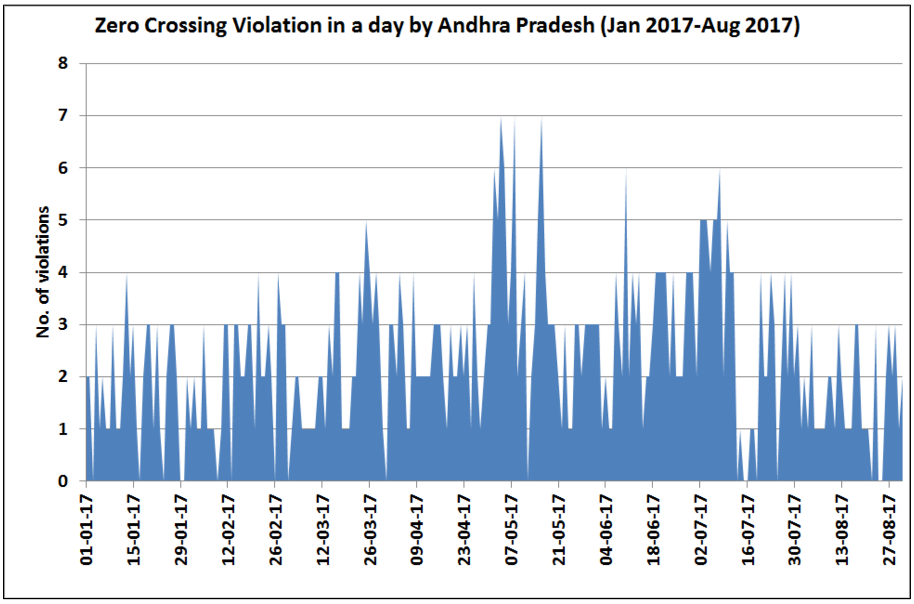
Southern Region states

Period: January 2017- August 2017

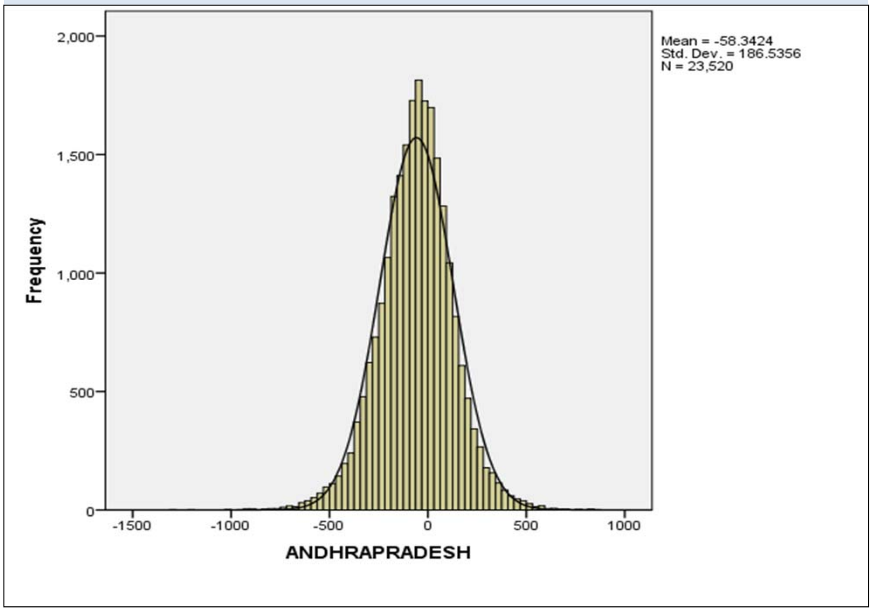


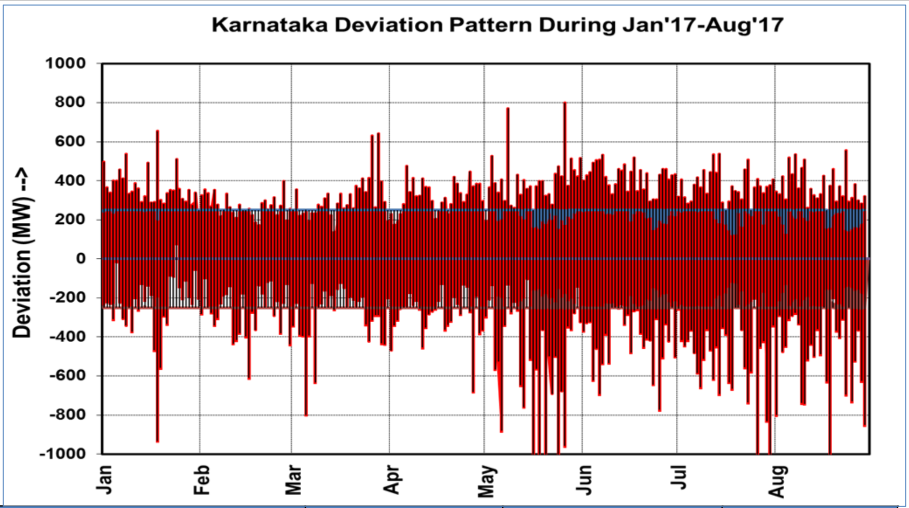
HEAD	MAX (in MW)	MIN (in MW)	AVG (in MW)
Schedule	3249	-483	1228
Actual	3471	-554	1286
Deviation	1306	-865	-
Note: +Ve indicates O/d & –Ve indicates U/d			



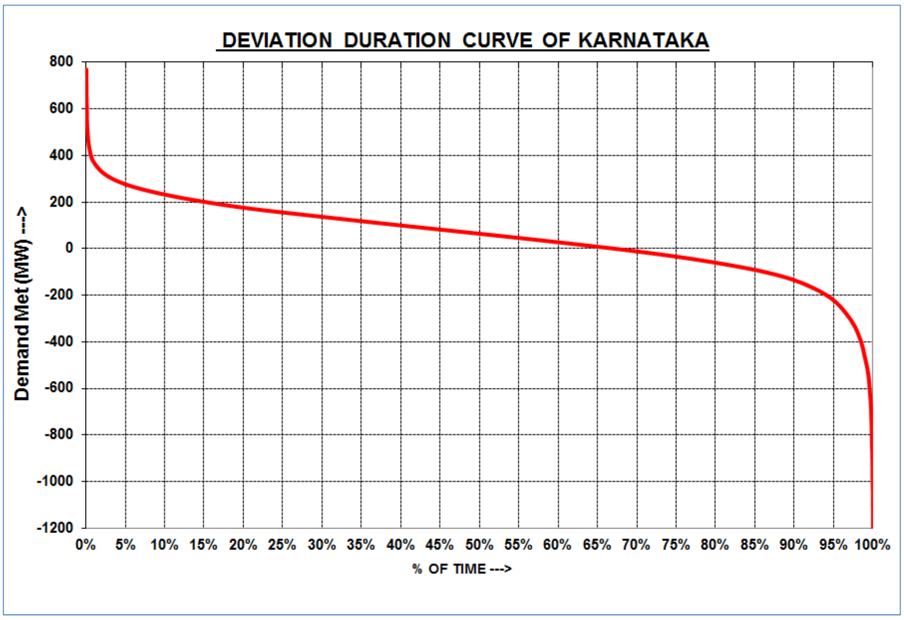


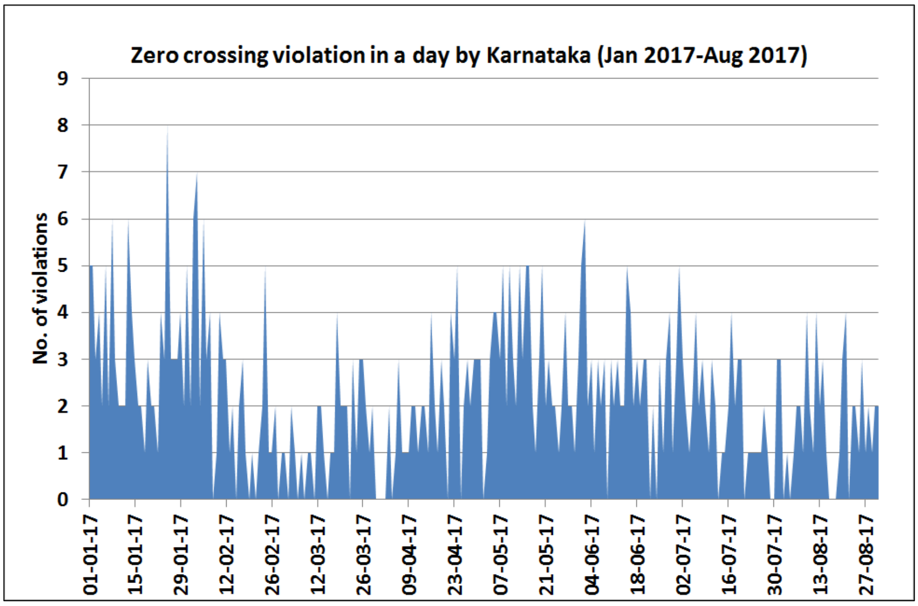
ANDHRA PRADESH Deviation



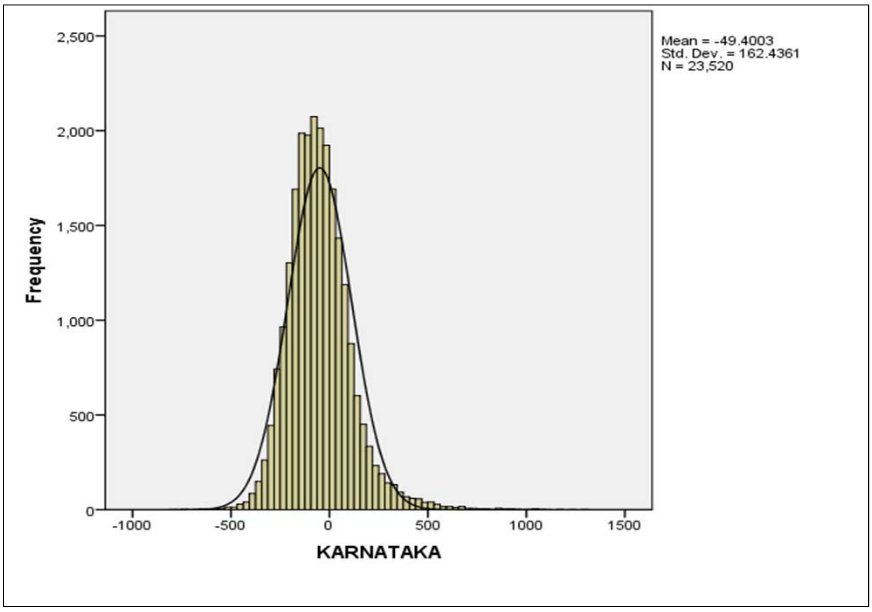


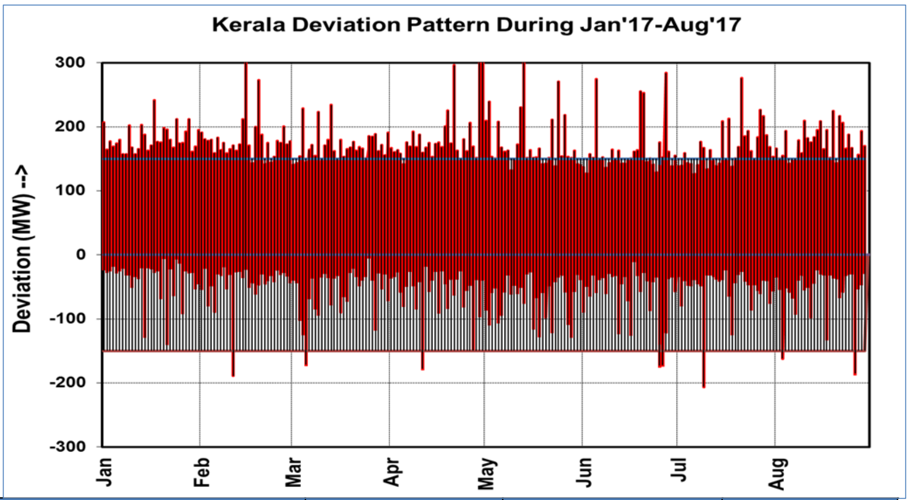
HEAD	MAX (in MW)	MIN (in MW)	AVG (in MW)
Schedule	5646	1061	2994
Actual	5039	317	3044
Deviation	799	-1299	-
Note: +Ve indicates O/d & –Ve indicates U/d			



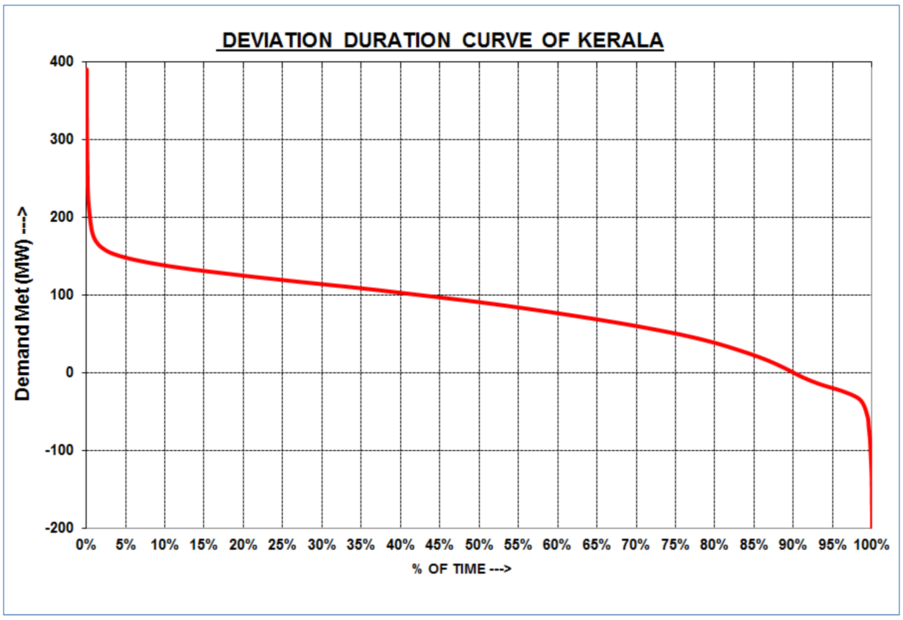


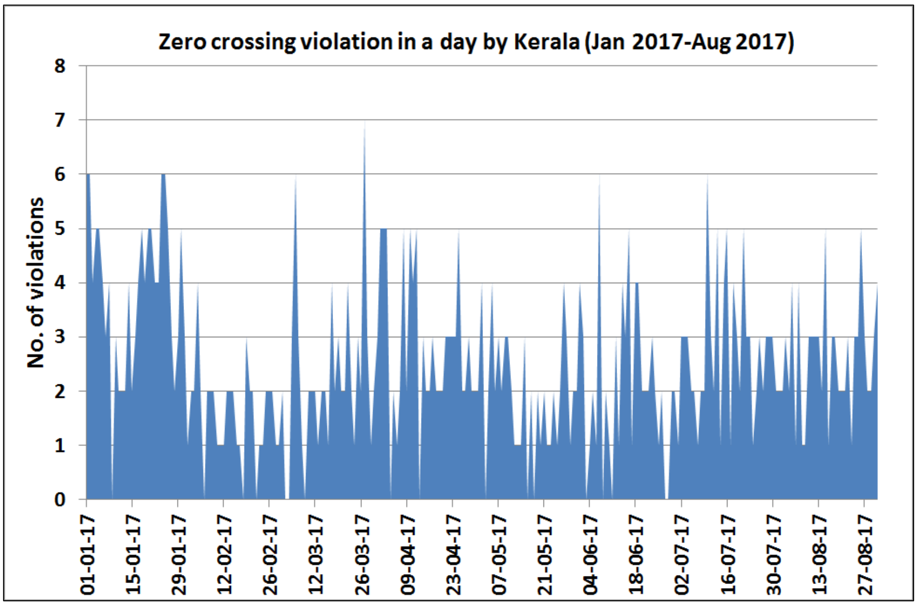
KARNATAKA Deviation



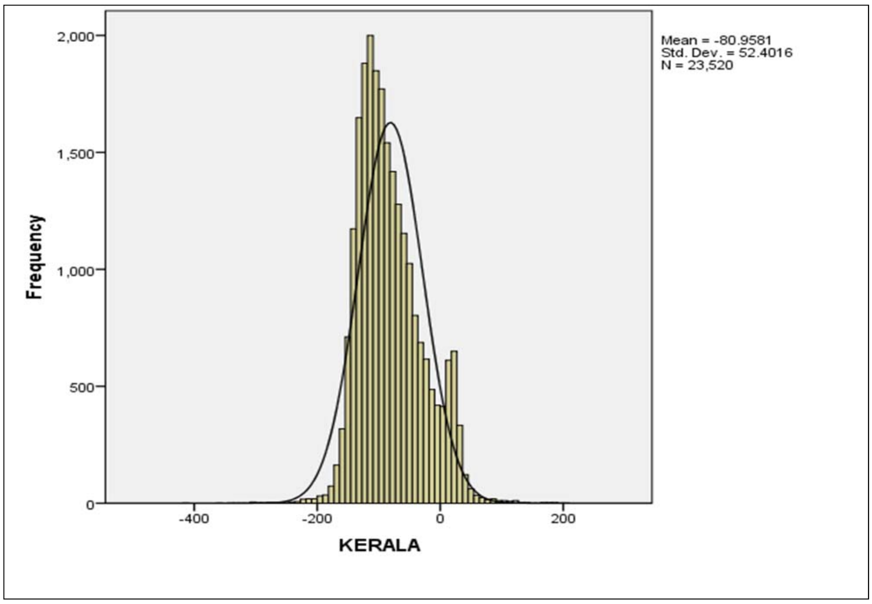


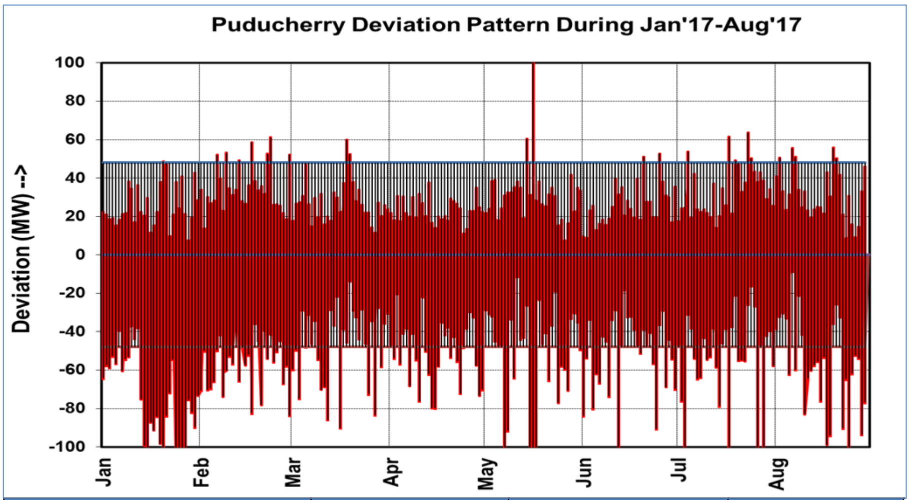
HEAD	MAX (in MW)	MIN (in MW)	AVG (in MW)
Schedule	2720	1181	2153
Actual	2851	1274	2234
Deviation	409	-206	-
Note: +Ve indicates O/d & –Ve indicates U/d			





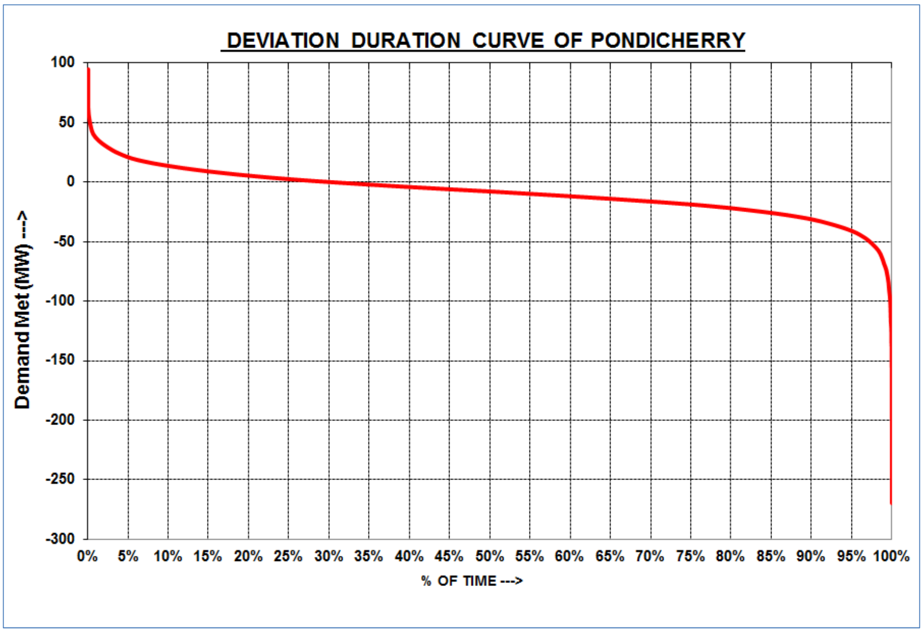
Kerala Deviation

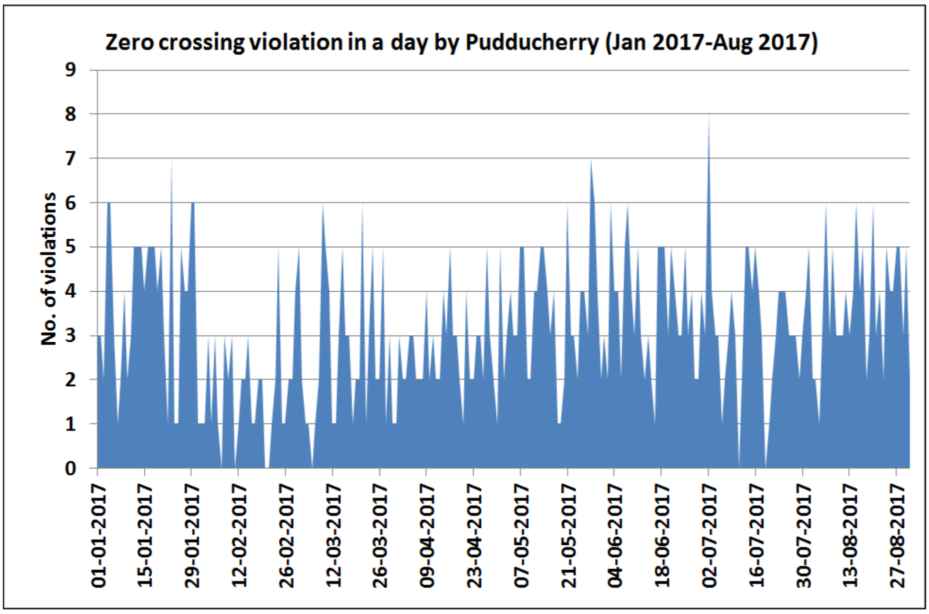




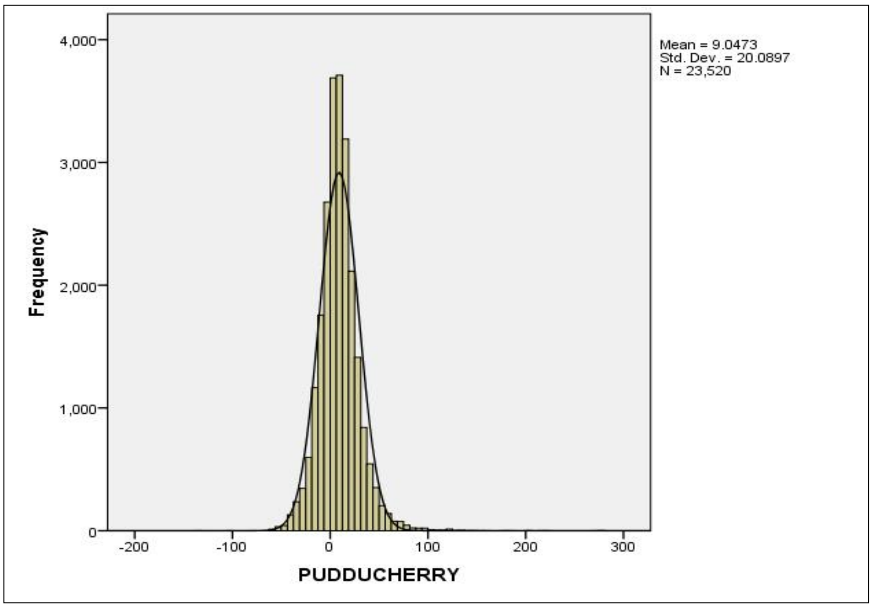
HEAD	MAX (in MW)	MIN (in MW)	AVG (in MW)
Schedule	392	109	303
Actual	378	81	294
Deviation	136	-279	-

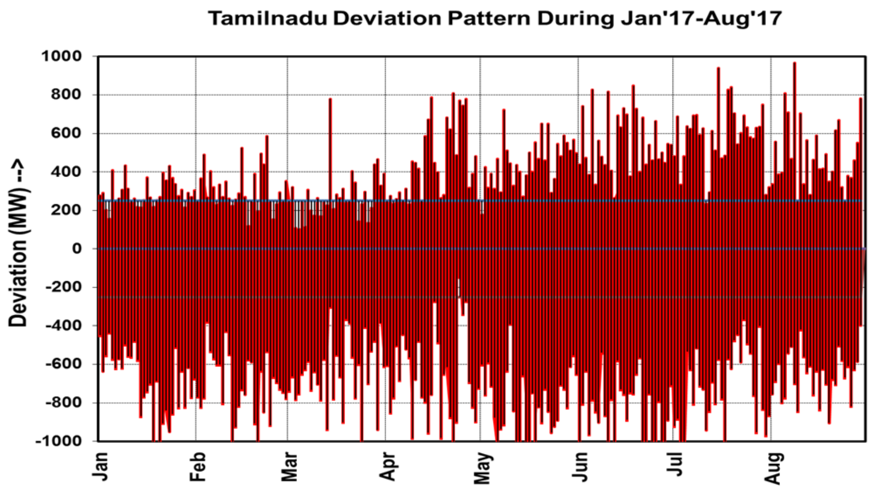
Note: +Ve indicates O/d & –Ve indicates U/d



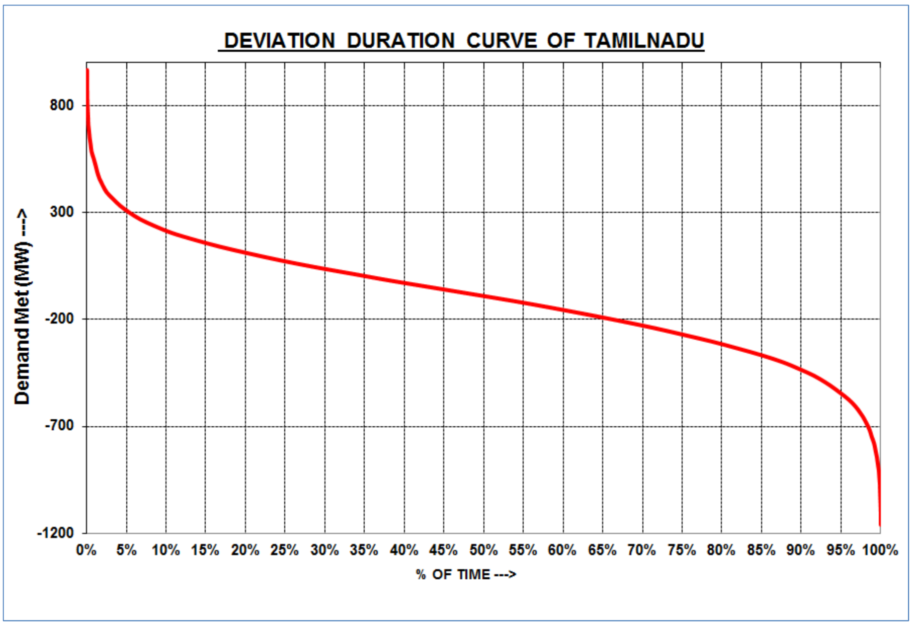


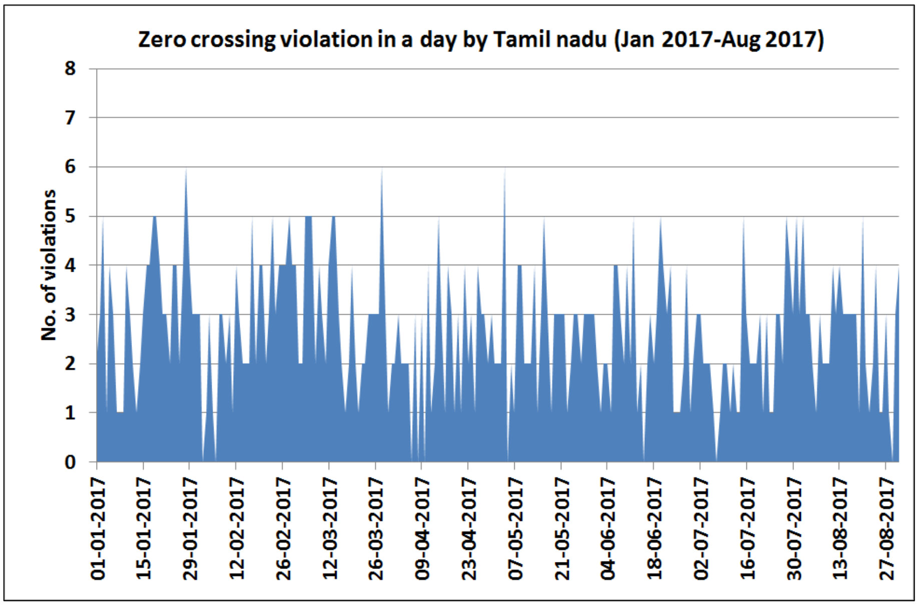
Pudducherry Deviation



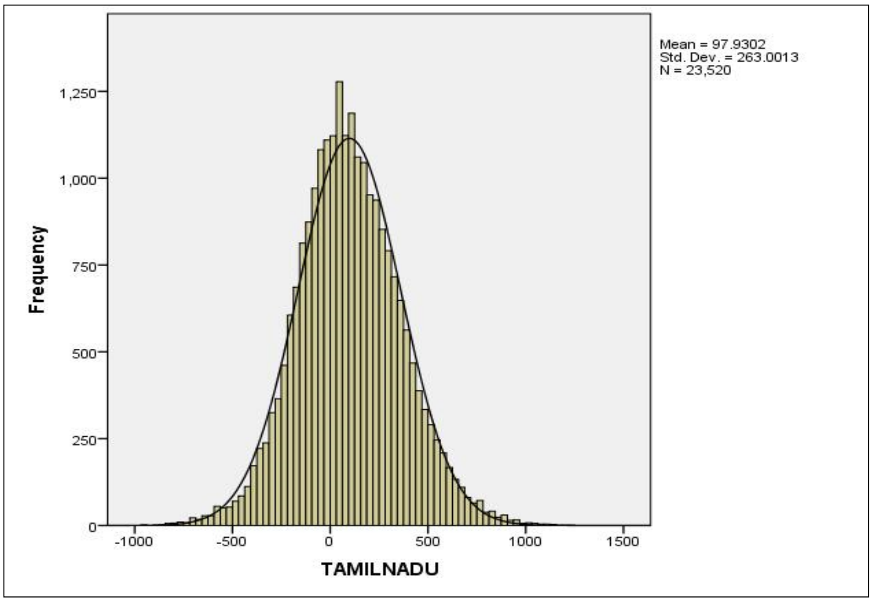


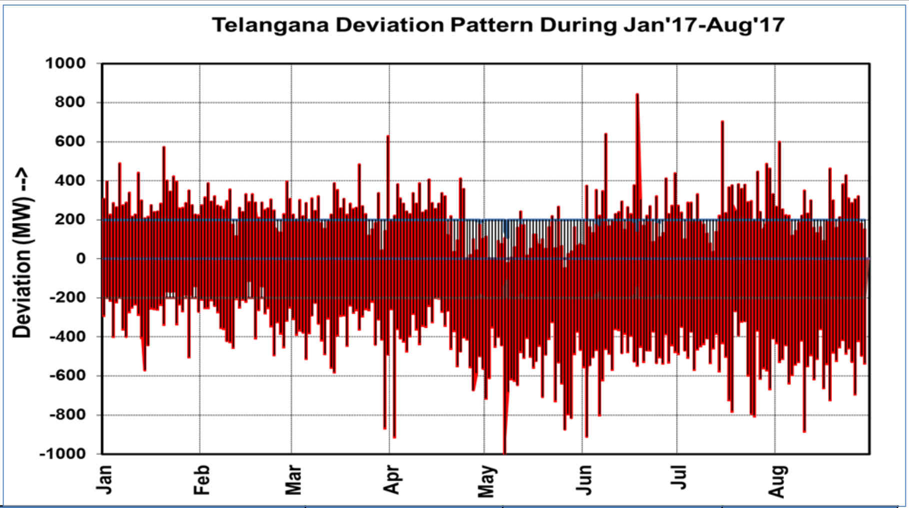
HEAD	MAX (in MW)	MIN (in MW)	AVG (in MW)
Schedule	9269	2307	5572
Actual	9062	1992	5472
Deviation	967	-1222	-
Note: +Ve indicates O/d & –Ve indicates U/d			



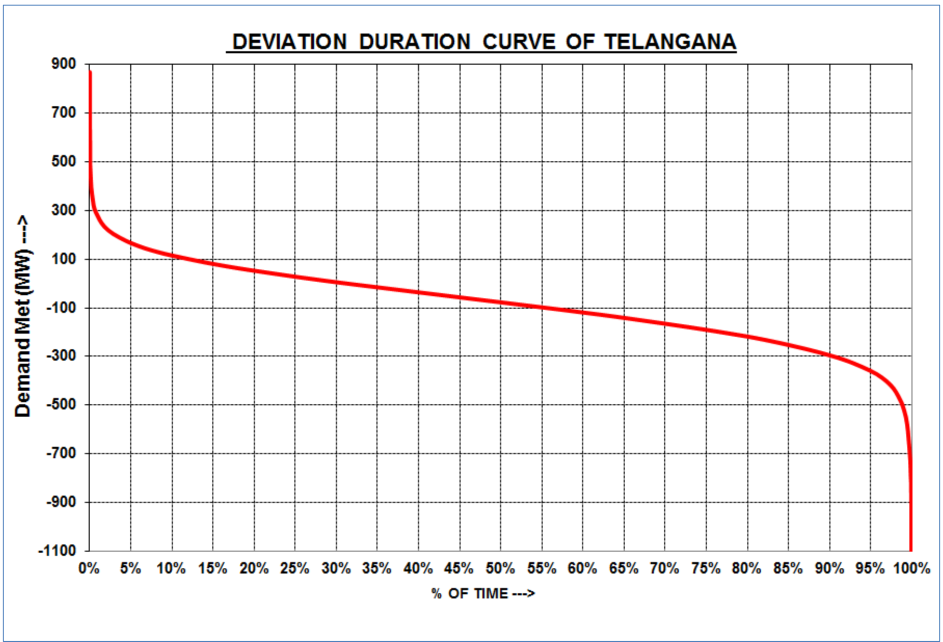


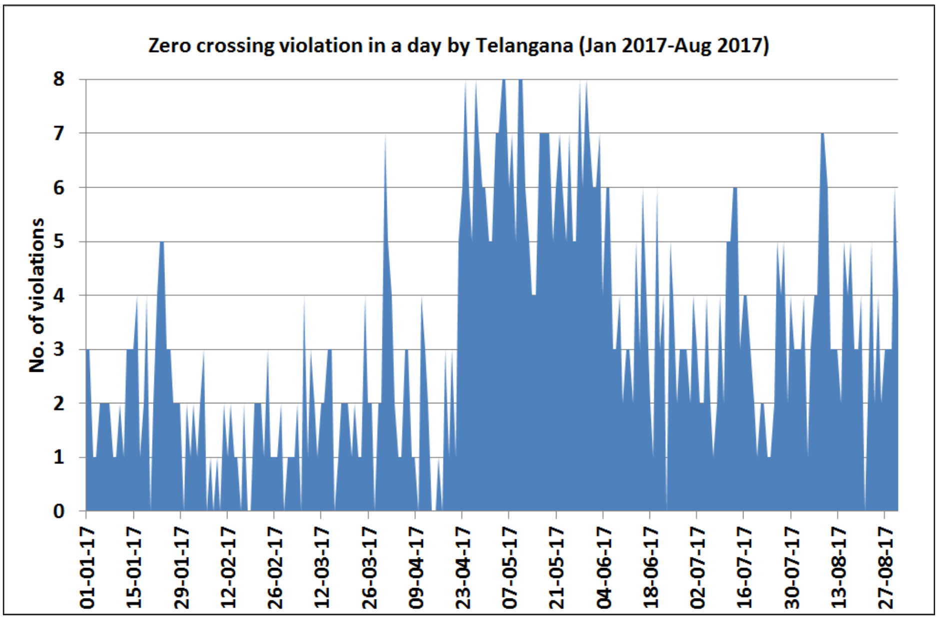
Tamil nadu Deviation



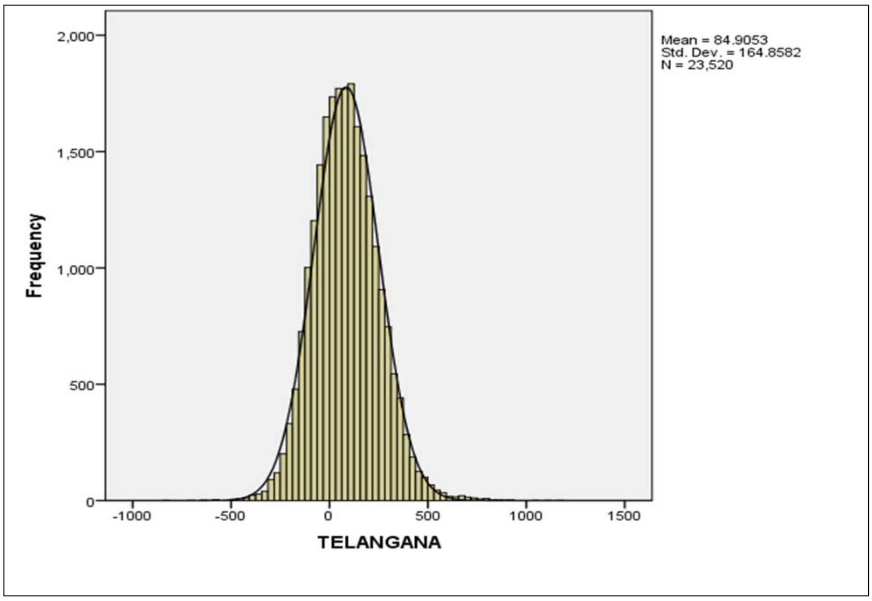


HEAD	MAX (in MW)	MIN (in MW)	AVG (in MW)
Schedule	6112	912	3182
Actual	5793	247	3098
Deviation	843	-1169	-
Note: +Ve indicates O/d & –Ve indicates U/d			





TELANGANA Deviation

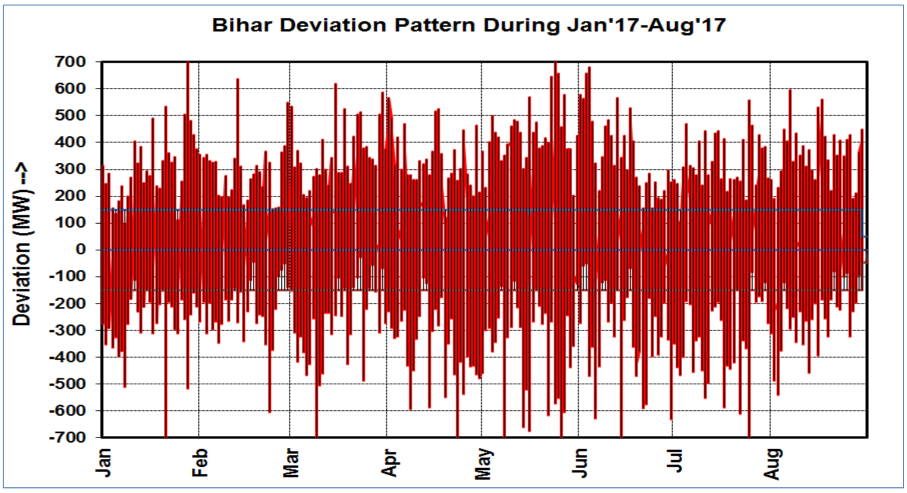


Deviation of States and Regional Entities: 15 minute time block wise

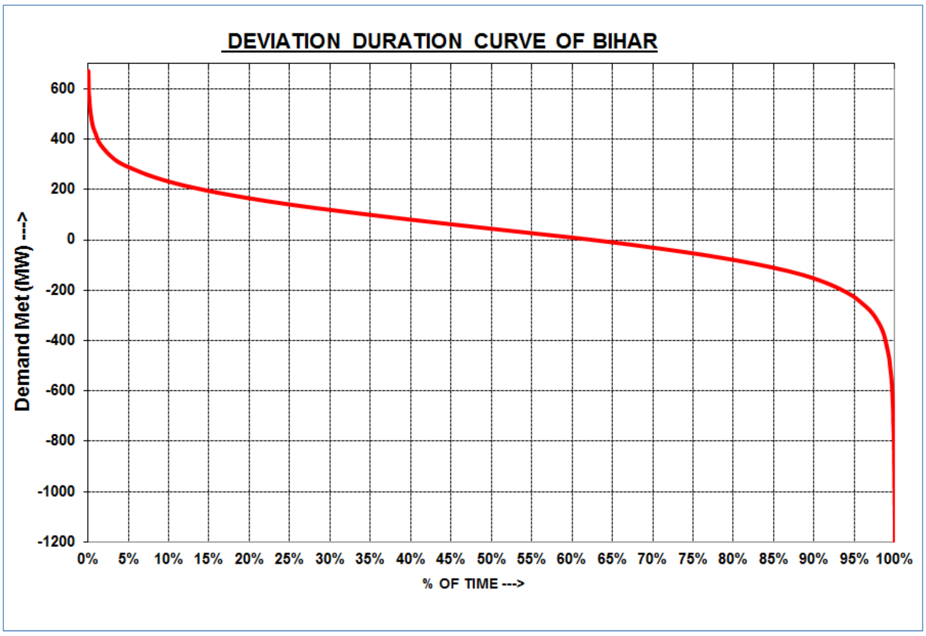
Period: January 2017- August 2017

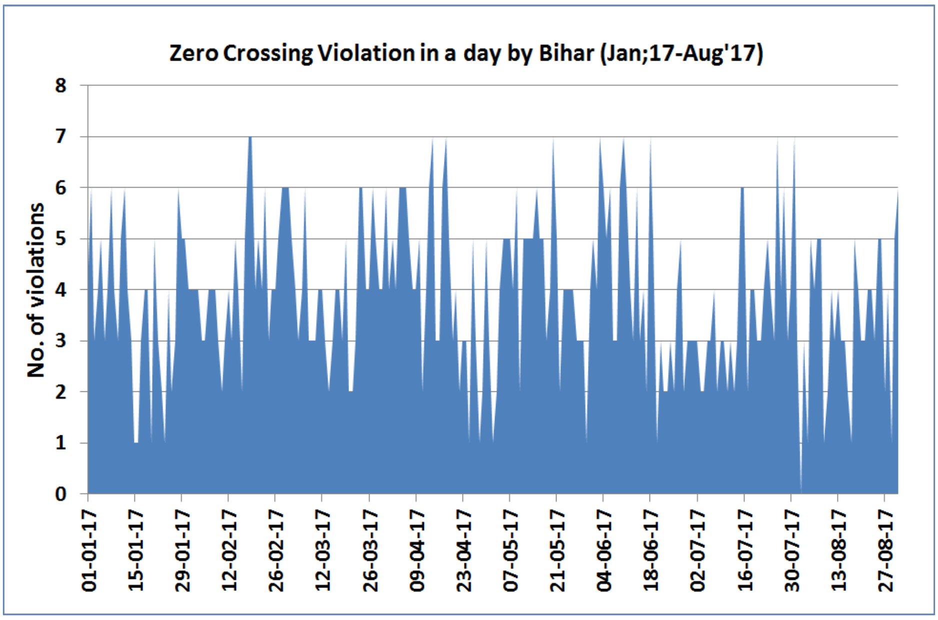
Eastern Region states

Period: January 2017- August 2017

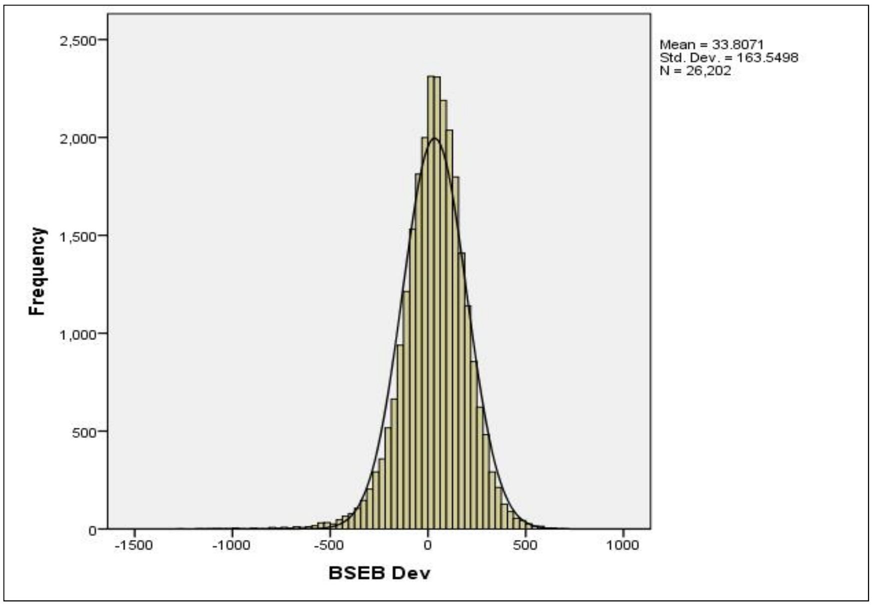


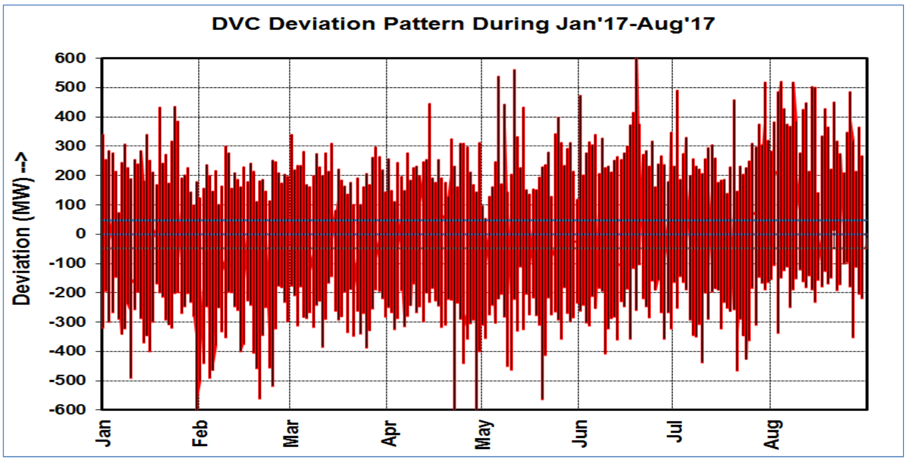
HEAD	MAX (in MW)	MIN (in MW)	AVG (in MW)
Schedule	4028	1138	2741
Actual	4102	481	2780
Deviation	710	-1266	-
Note: +Ve indicates O/d & –Ve indicates U/d			



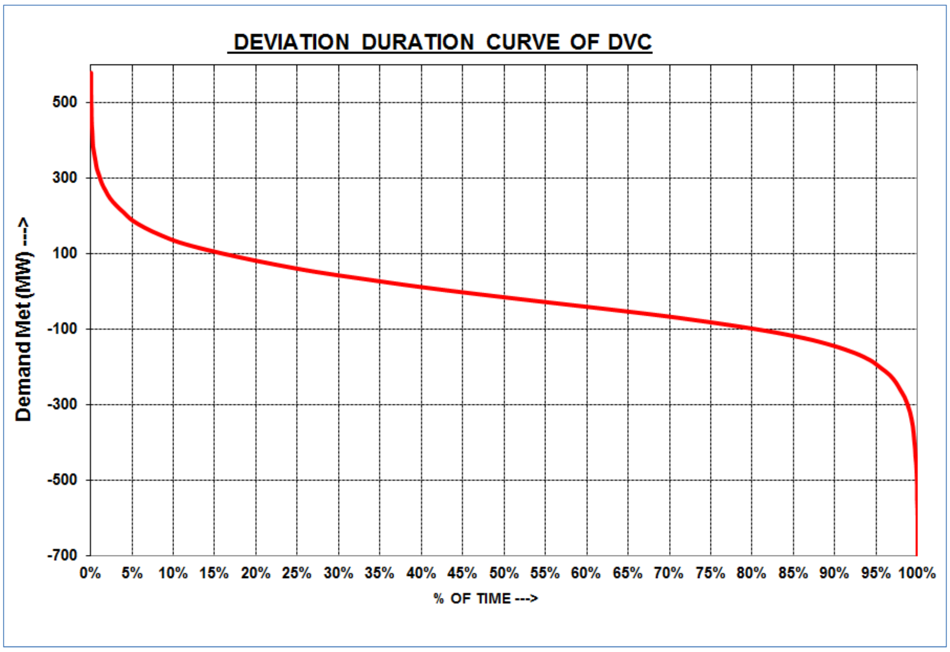


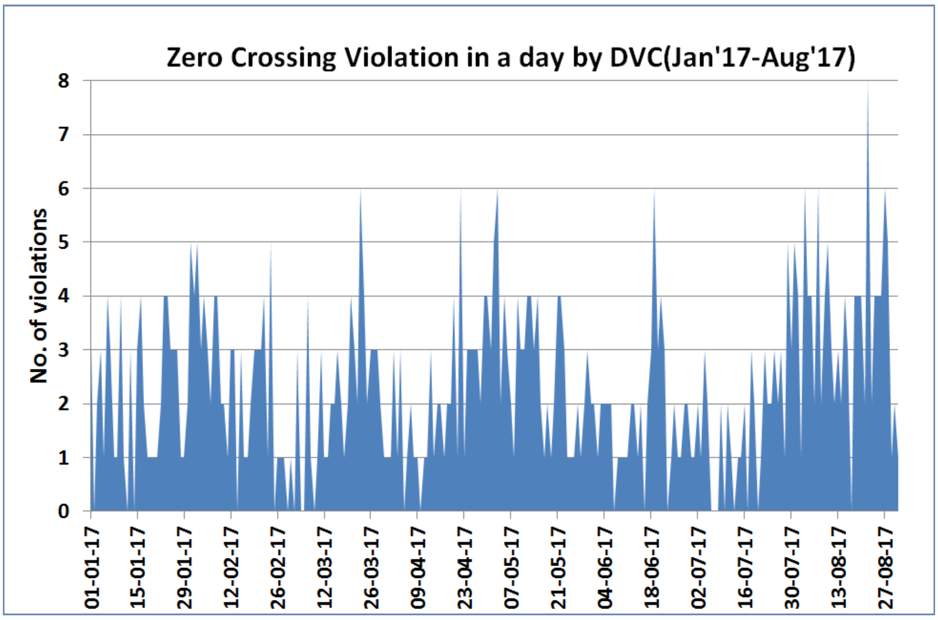
Bihar Deviation



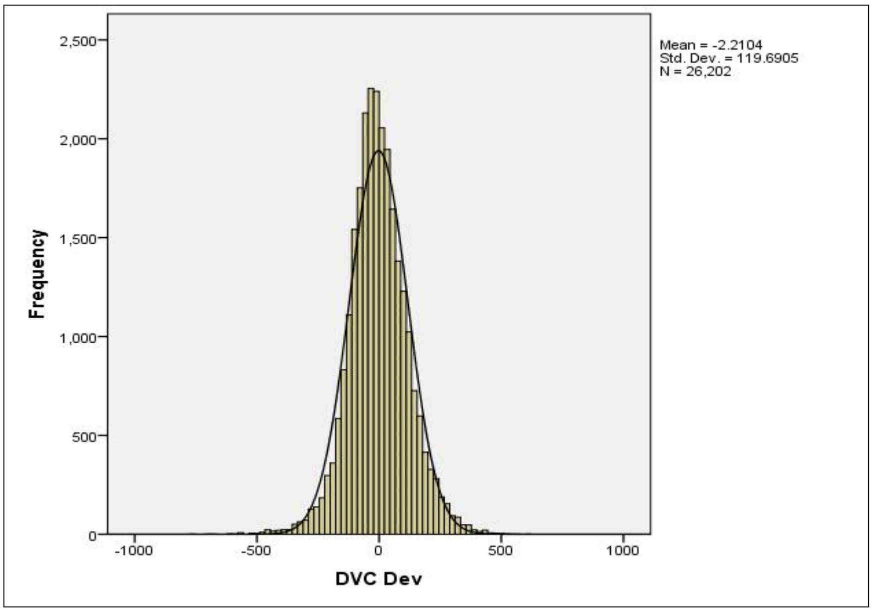


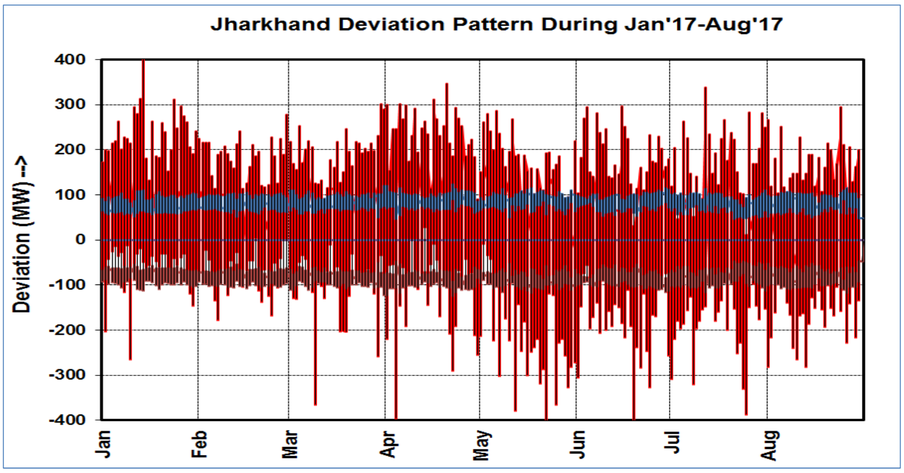
HEAD	MAX (in MW)	MIN (in MW)	AVG (in MW)
Schedule	-344	-2461	-1429
Actual	-301	-2617	-1439
Deviation	617	-764	-
Note: +Ve indicates O/d & –Ve indicates U/d			



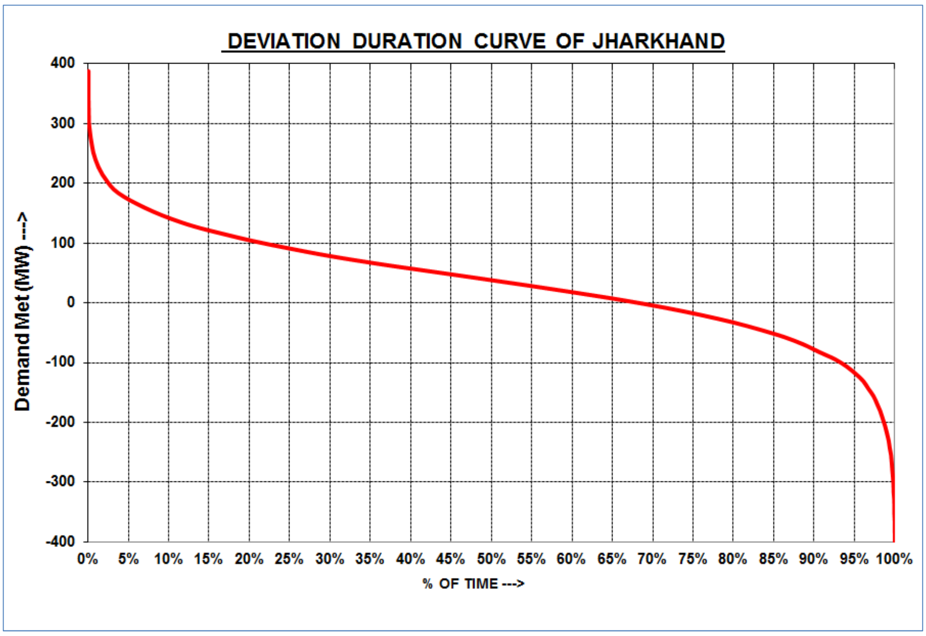


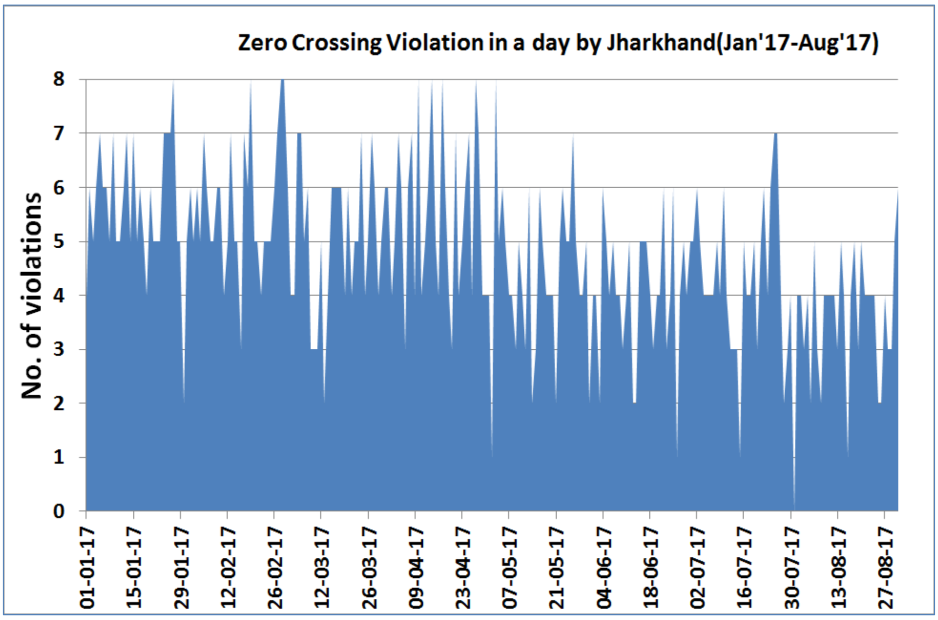
DVC Deviation



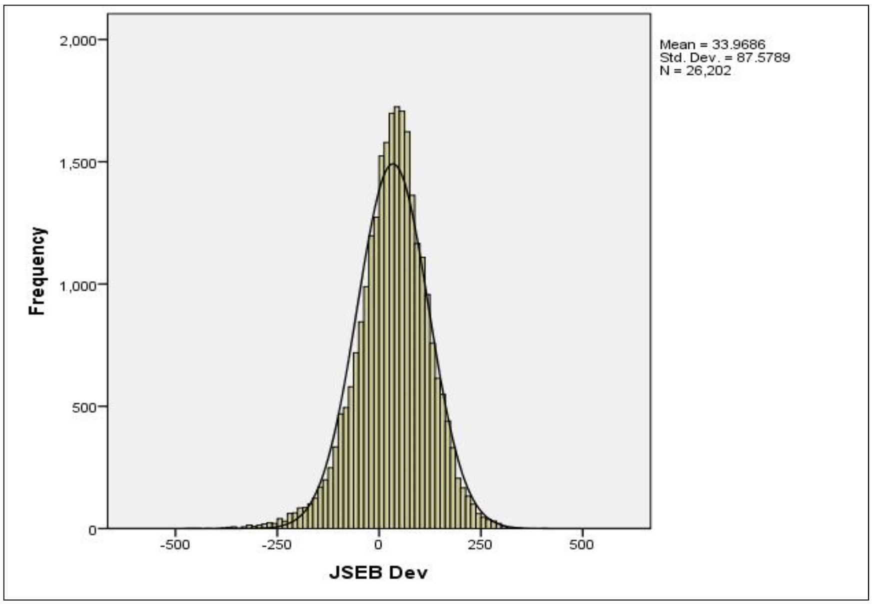


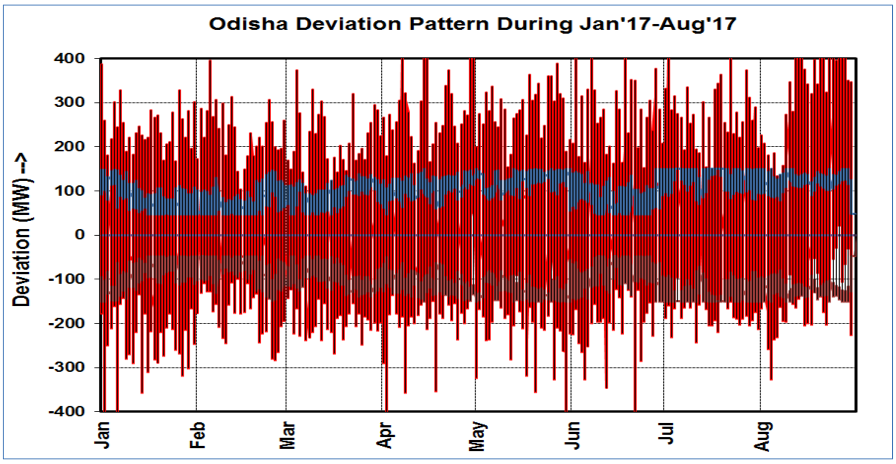
HEAD	MAX (in MW)	MIN (in MW)	AVG (in MW)
Schedule	1025	308	688
Actual	1125	60	722
Deviation	402	-466	-
Note: +Ve indicates O/d & –Ve indicates U/d			



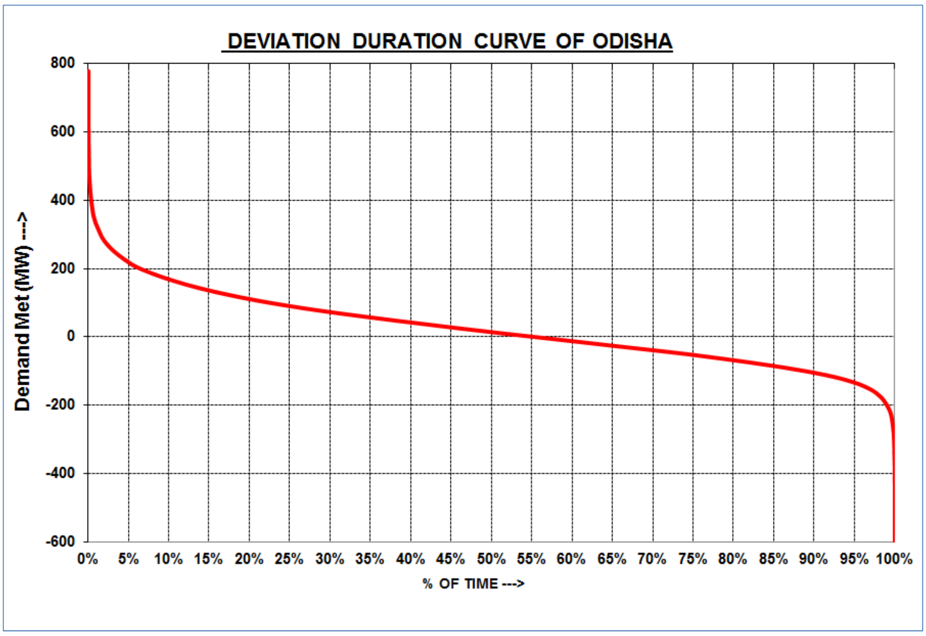


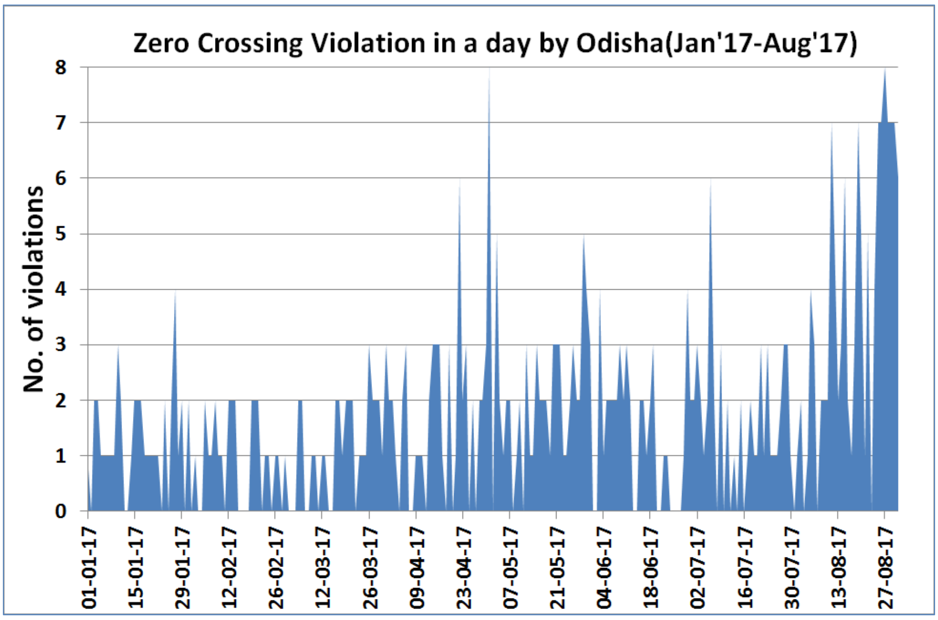
Jharkhand Deviation



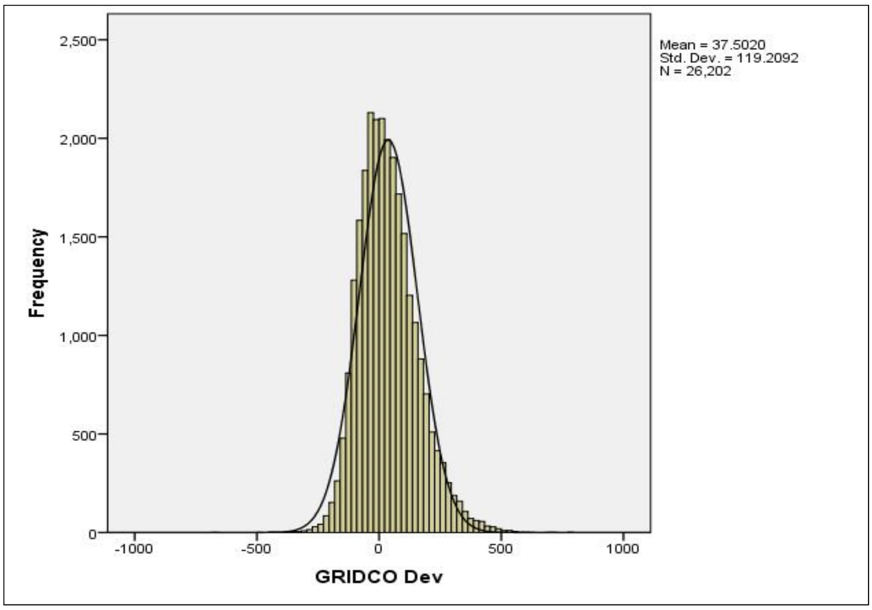


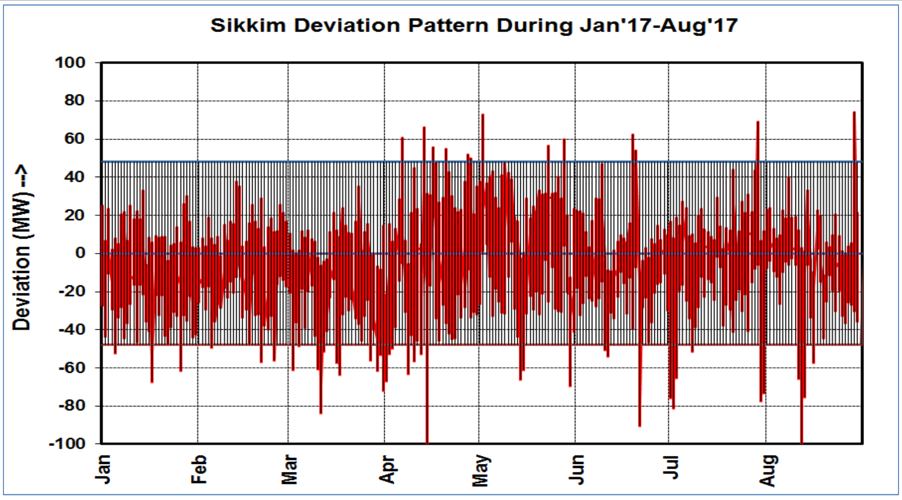
HEAD	MAX (in MW)	MIN (in MW)	AVG (in MW)
Schedule	2010	-35	878
Actual	2139	-112	903
Deviation	793	-673	-
Note: +Ve indicates O/d & –Ve indicates U/d			



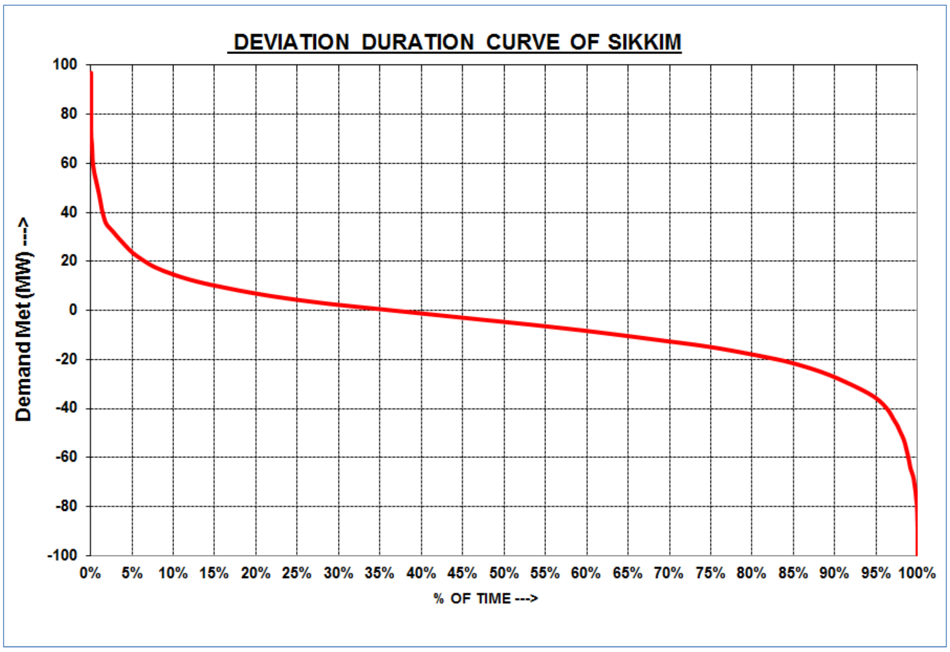


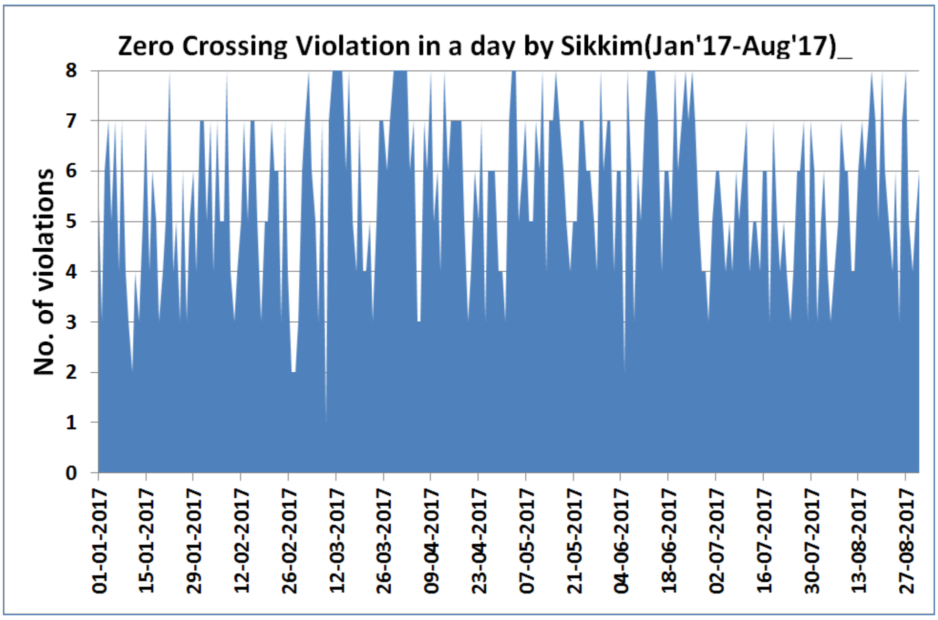
Odisha Deviation



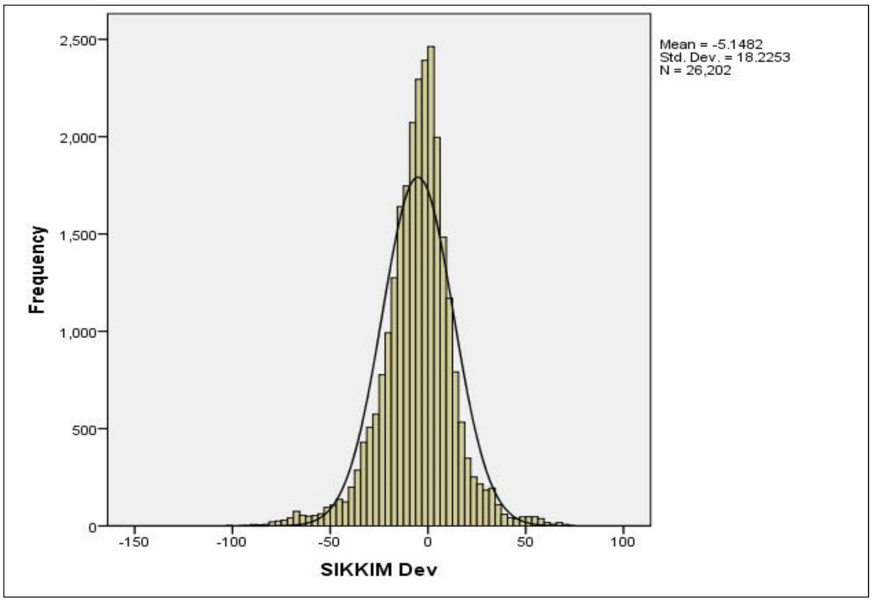


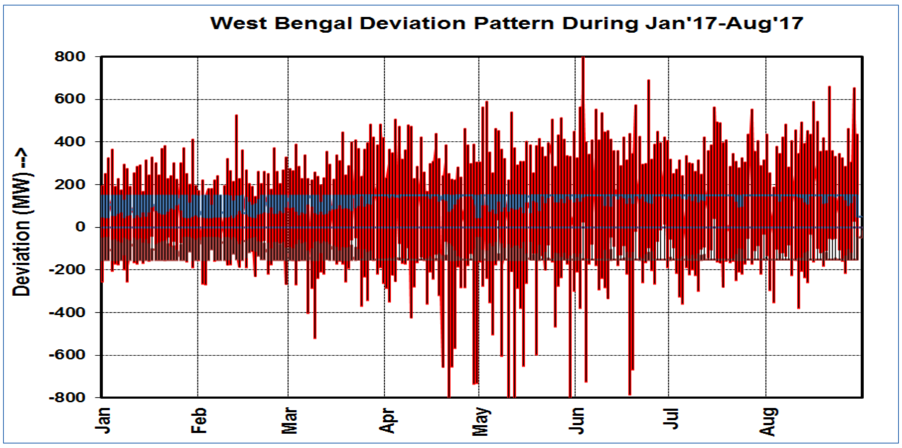
HEAD	MAX (in MW)	MIN (in MW)	AVG (in MW)
Schedule	157	-43	56
Actual	98	-3	51
Deviation	74	-102	-
Note: +Ve indicates O/d & –Ve indicates U/d			



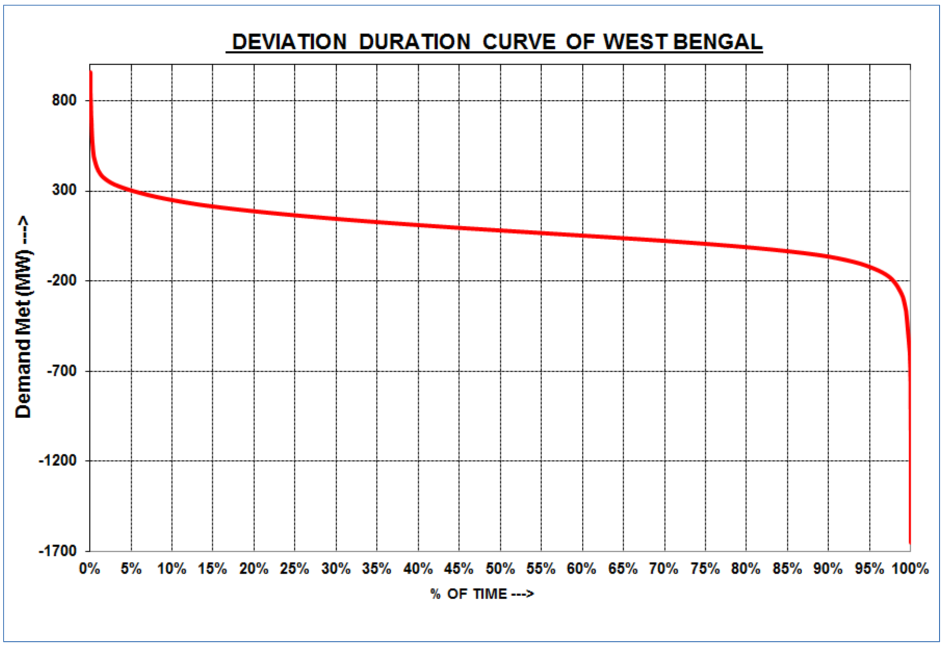


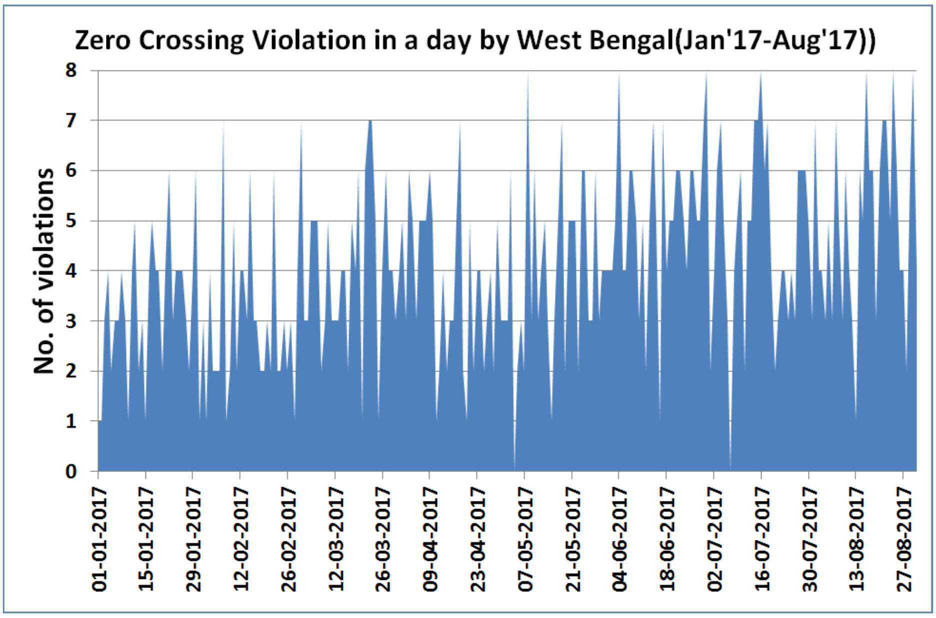
Sikkim Deviation



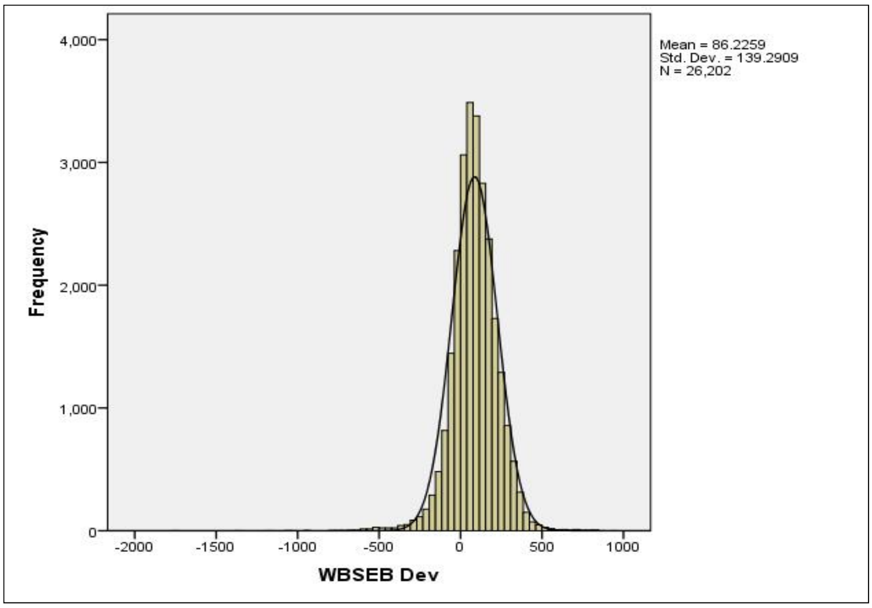


HEAD	MAX (in MW)	MIN (in MW)	AVG (in MW)
Schedule	3608	228	1580
Actual	3795	-88	1666
Deviation	931	-1740	-
Note: +Ve indicates O/d & –Ve indicates U/d			





West Bengal Deviation

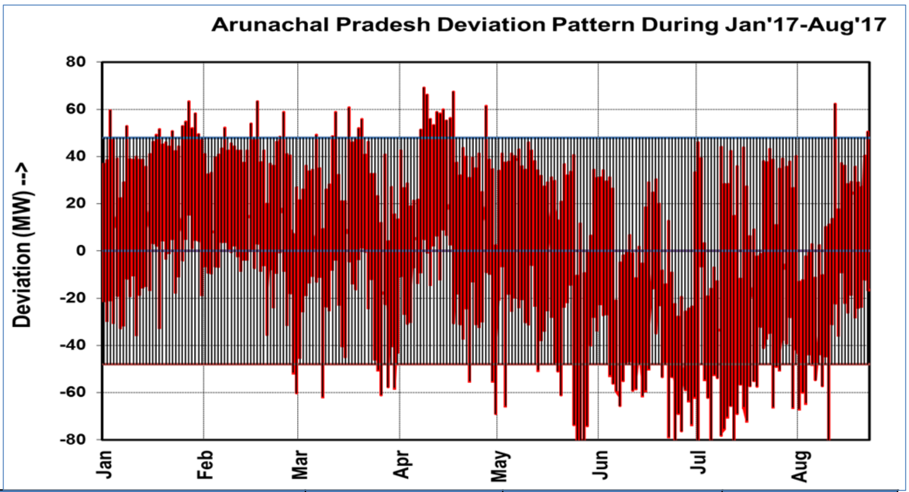


Deviation of States and Regional Entities: 15 minute time block wise

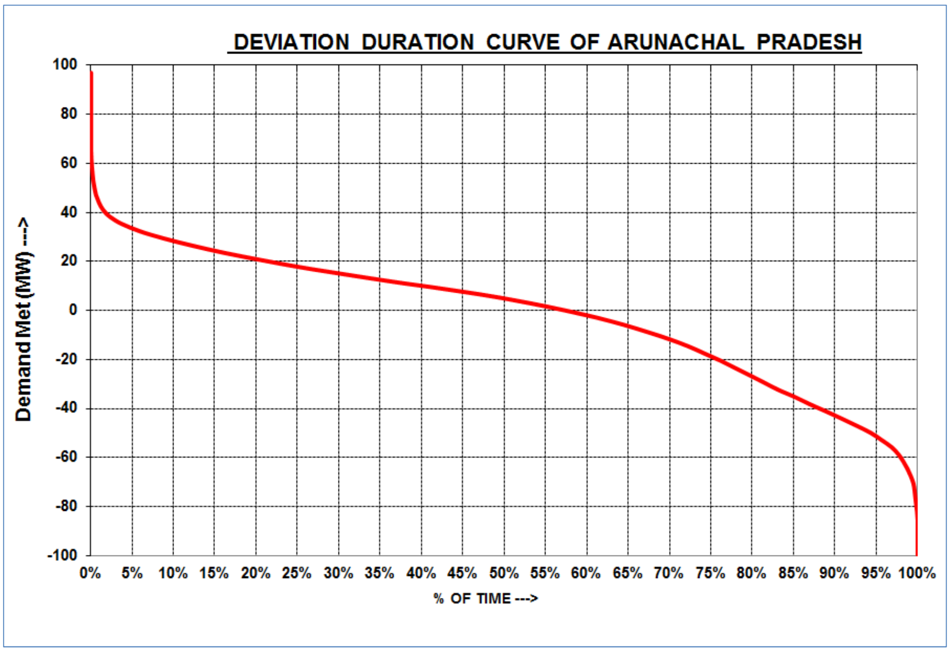
Period: January 2017- August 2017

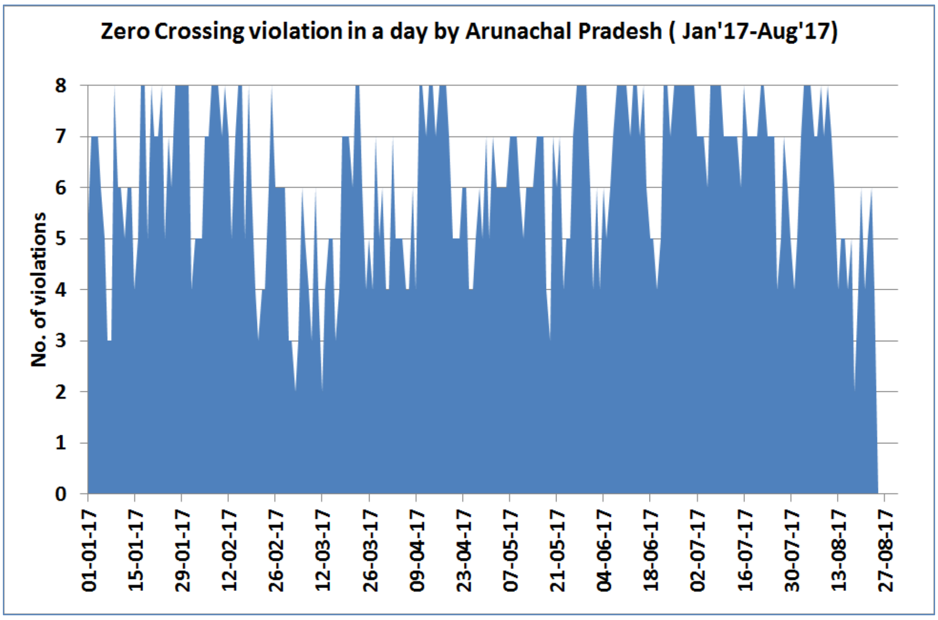
North Eastern Region states

Period: January 2017- August 2017

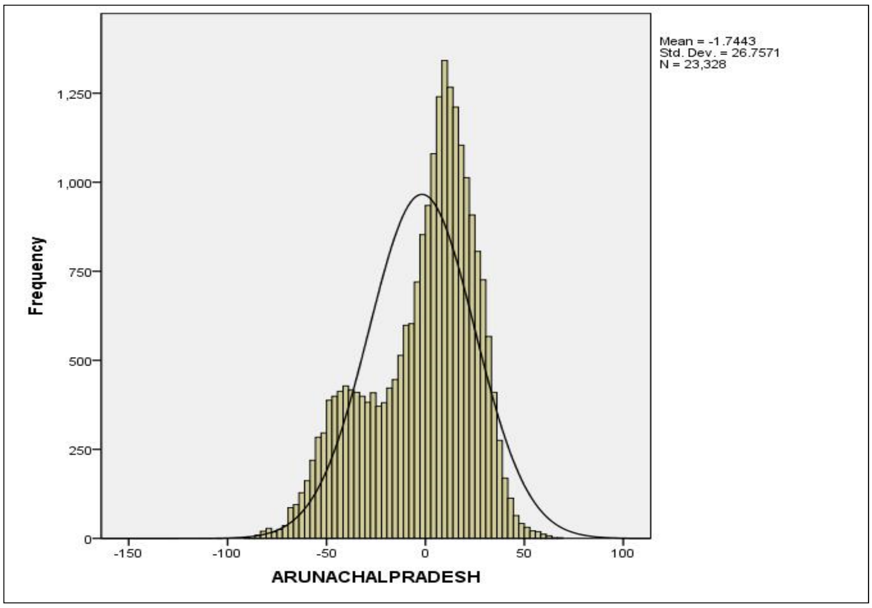


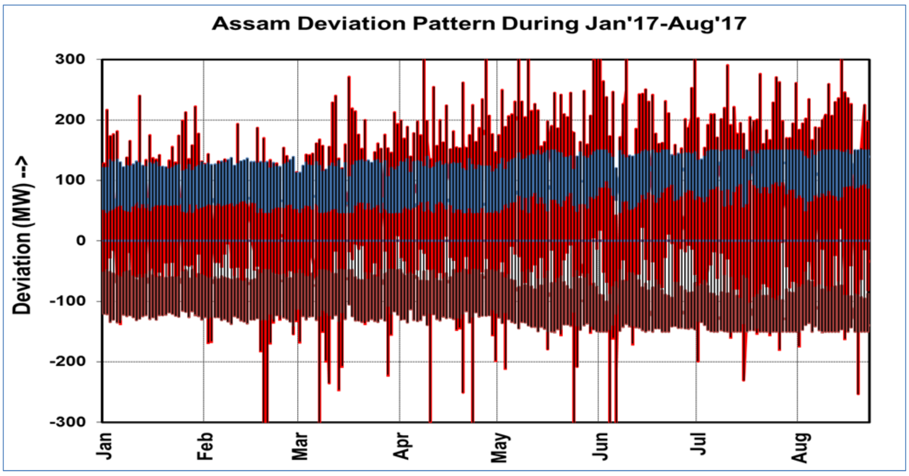
HEAD	MAX (in MW)	MIN (in MW)	AVG (in MW)
Schedule	158	32	88
Actual	143	15	86
Deviation	69	-105	-
Note: +Ve indicates O/d & –Ve indicates U/d			



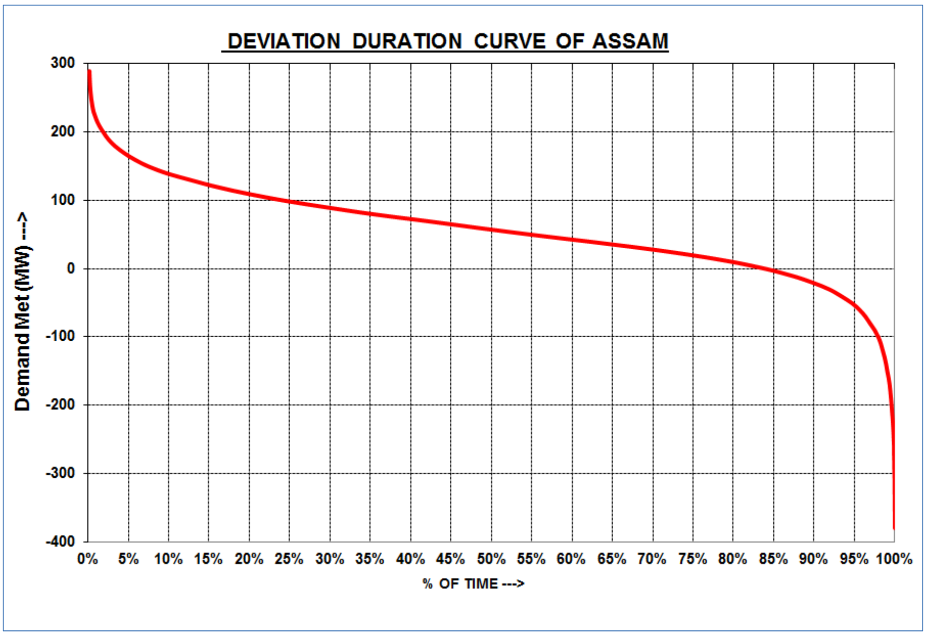


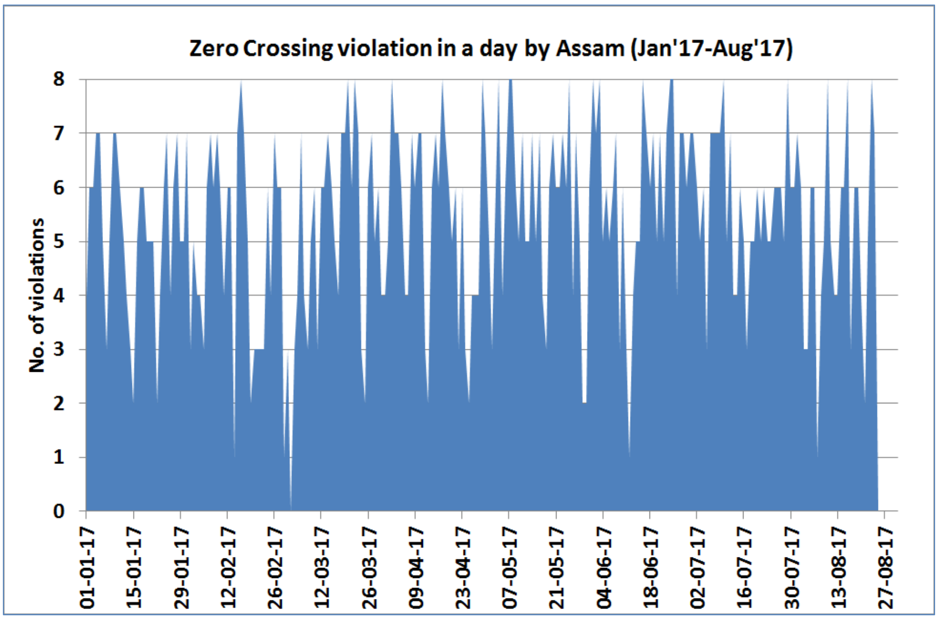
Arunachal Pradesh Deviation



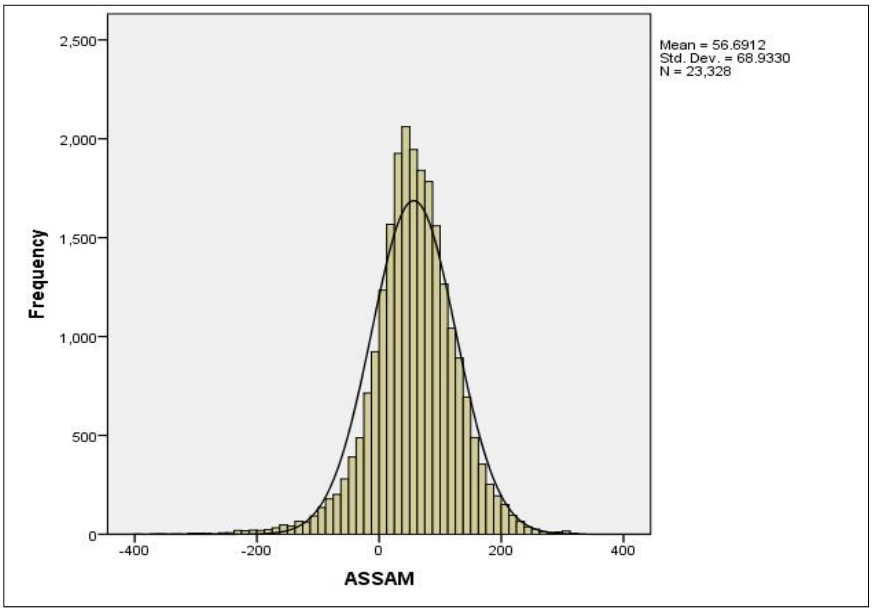


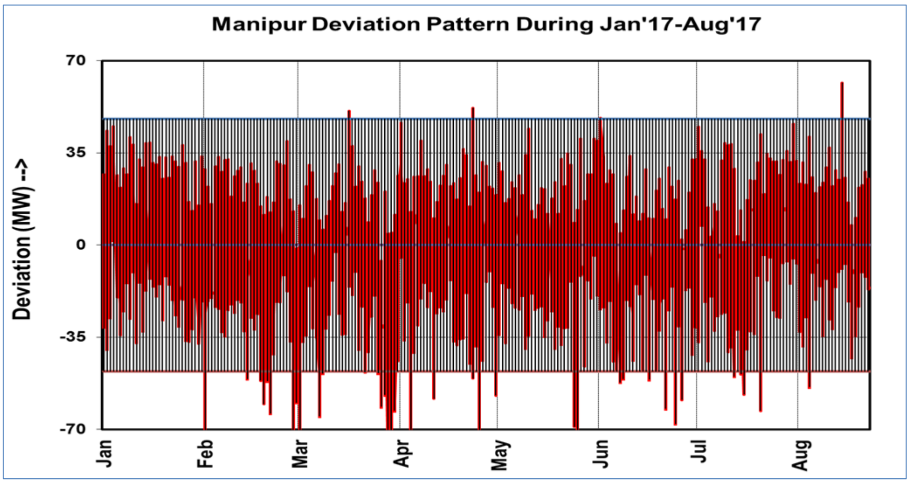
HEAD	MAX (in MW)	MIN (in MW)	AVG (in MW)
Schedule	1439	166	759
Actual	1488	161	816
Deviation	327	-395	-
Note: +Ve indicates O/d & –Ve indicates U/d			



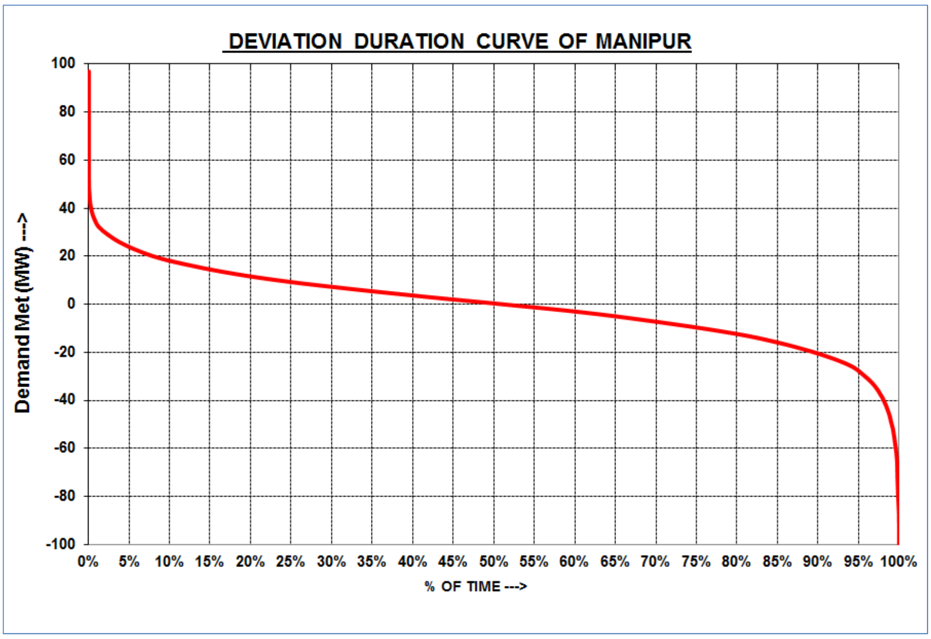


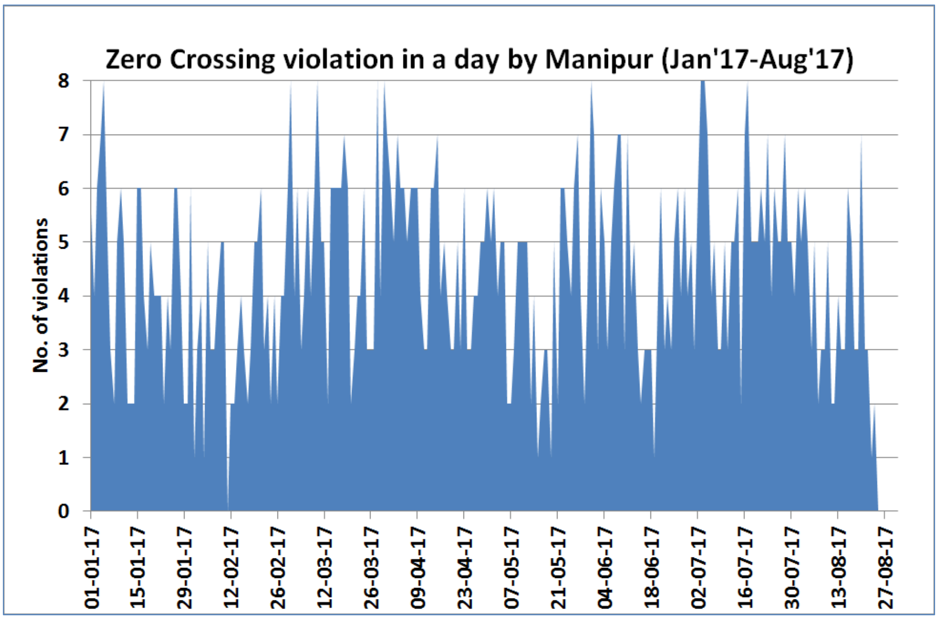
Assam Deviation



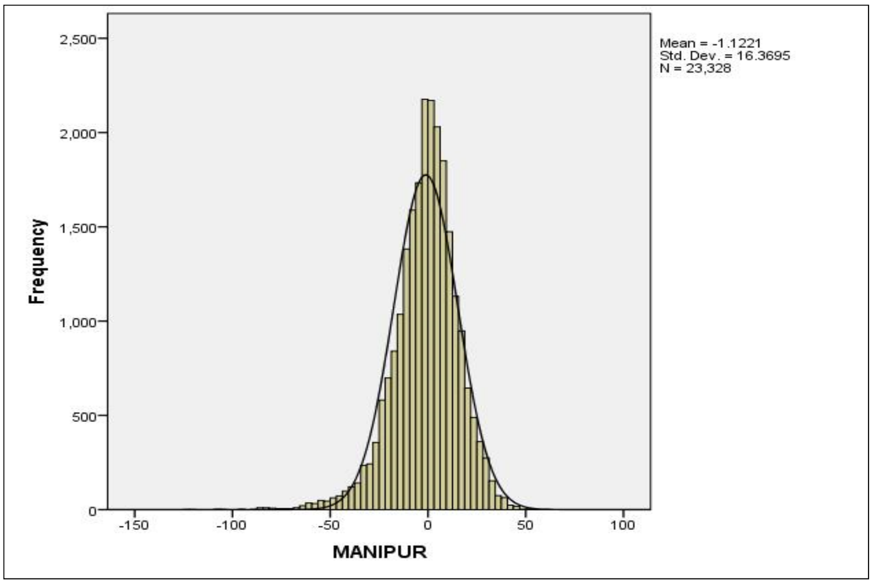


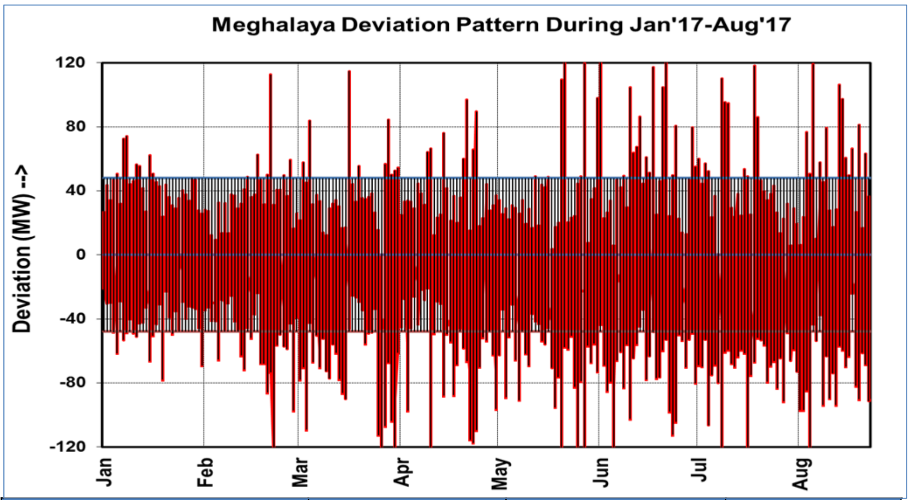
HEAD	MAX (in MW)	MIN (in MW)	AVG (in MW)
Schedule	182	-11	89
Actual	170	0	89
Deviation	62	-125	-
Note: +Ve indicates O/d & –Ve indicates U/d			



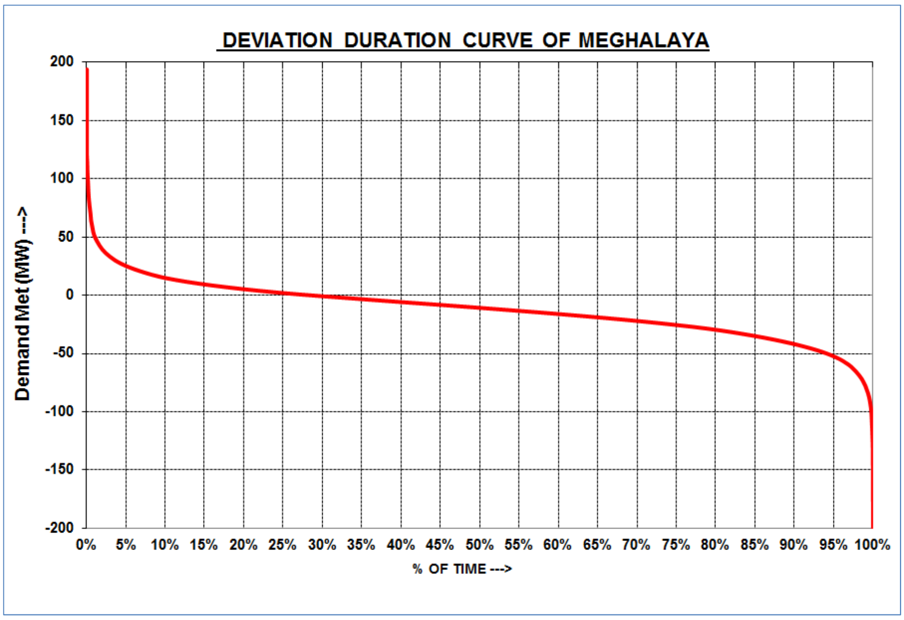


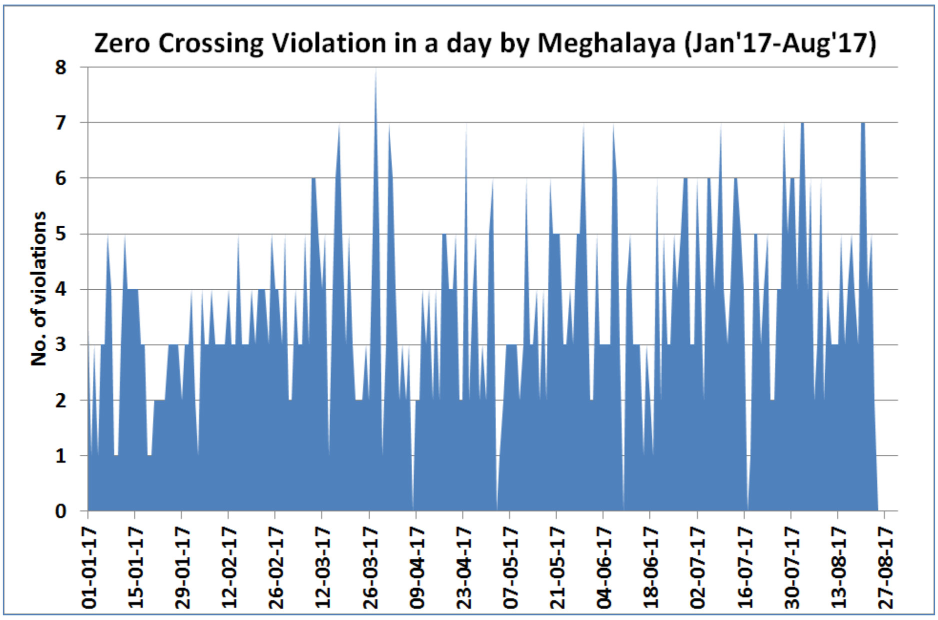
Manipur Deviation



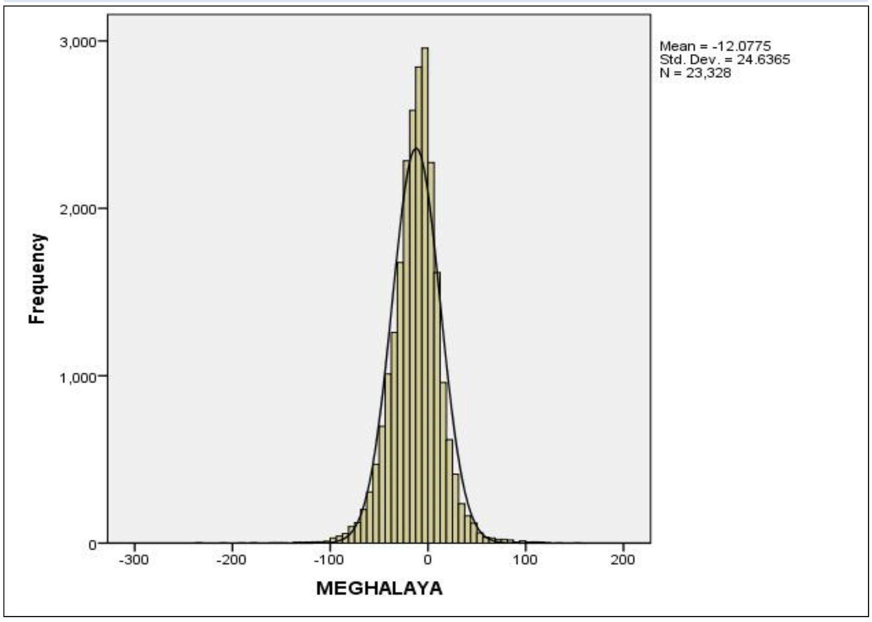


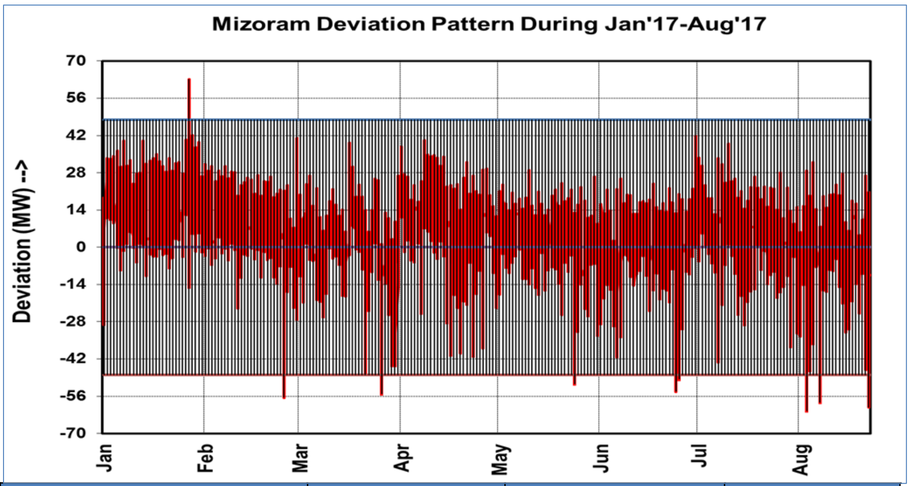
HEAD	MAX (in MW)	MIN (in MW)	AVG (in MW)
Schedule	286	-191	81
Actual	283	-150	69
Deviation	152	-234	-
Note: +Ve indicates O/d & –Ve indicates U/d			



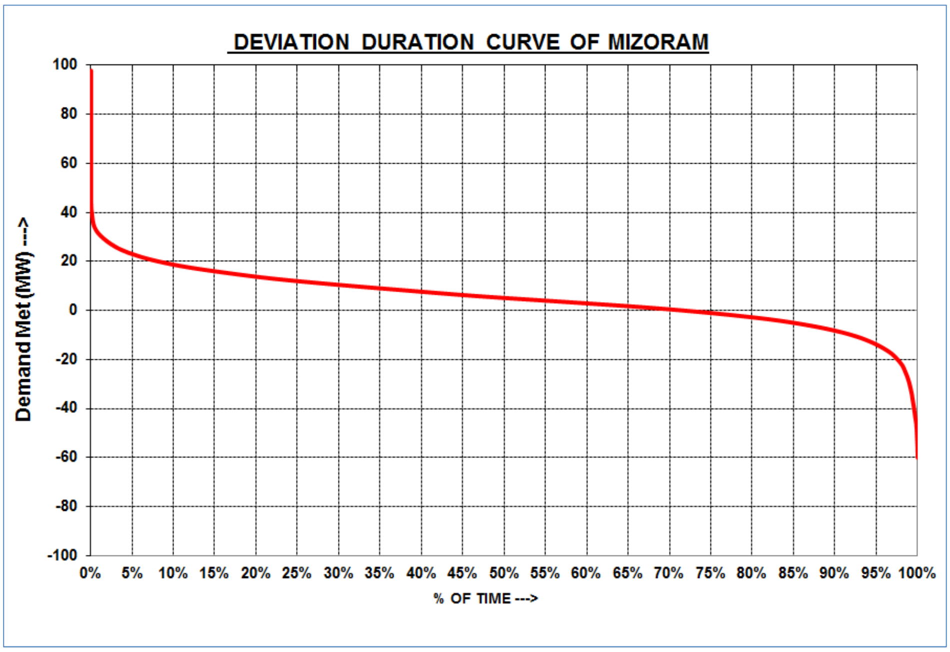


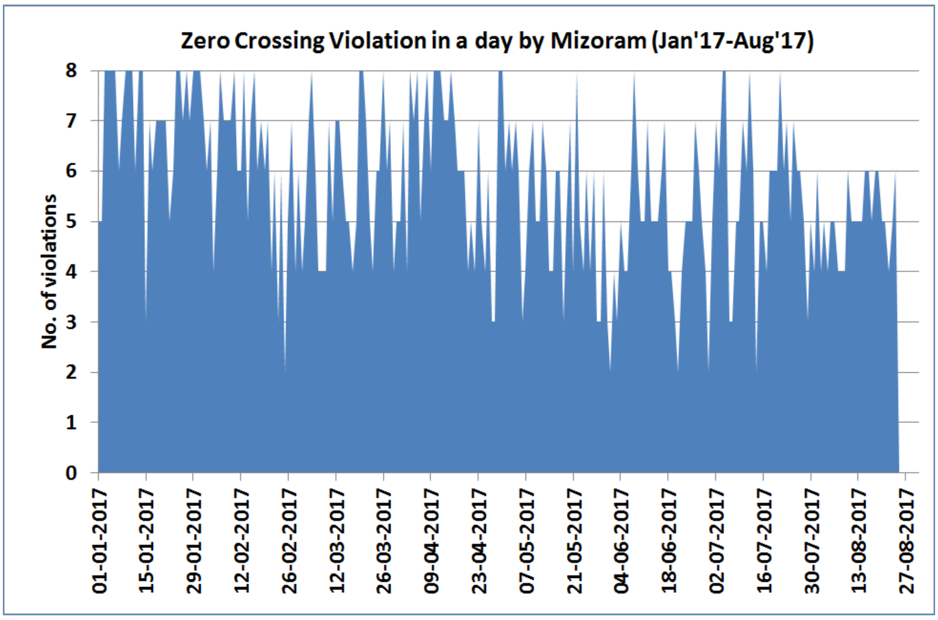
Meghalaya Deviation



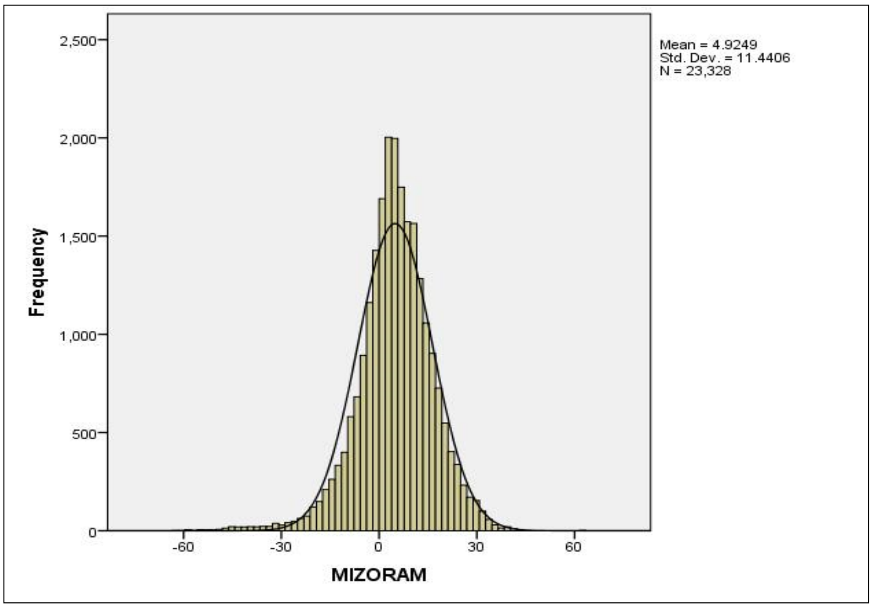


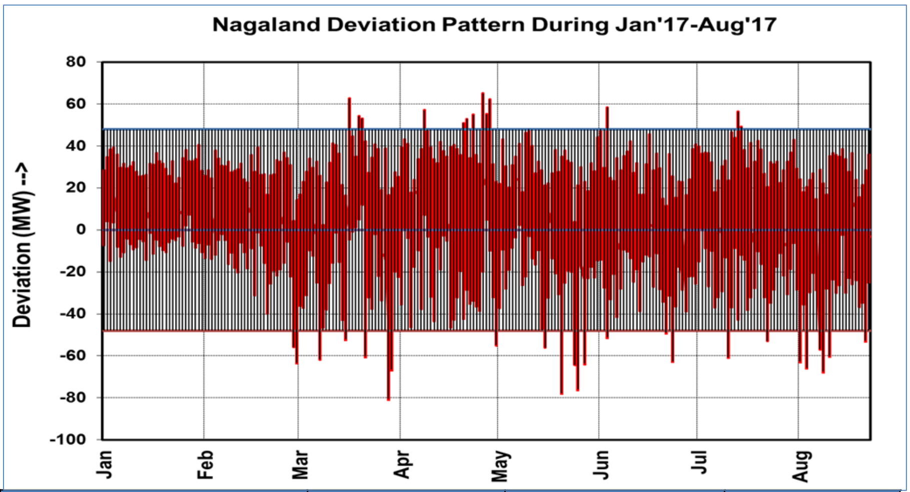
HEAD	MAX (in MW)	MIN (in MW)	AVG (in MW)
Schedule	93	0	48
Actual	100	0	53
Deviation	63	-62	-
Note: +Ve indicates O/d & –Ve indicates U/d			



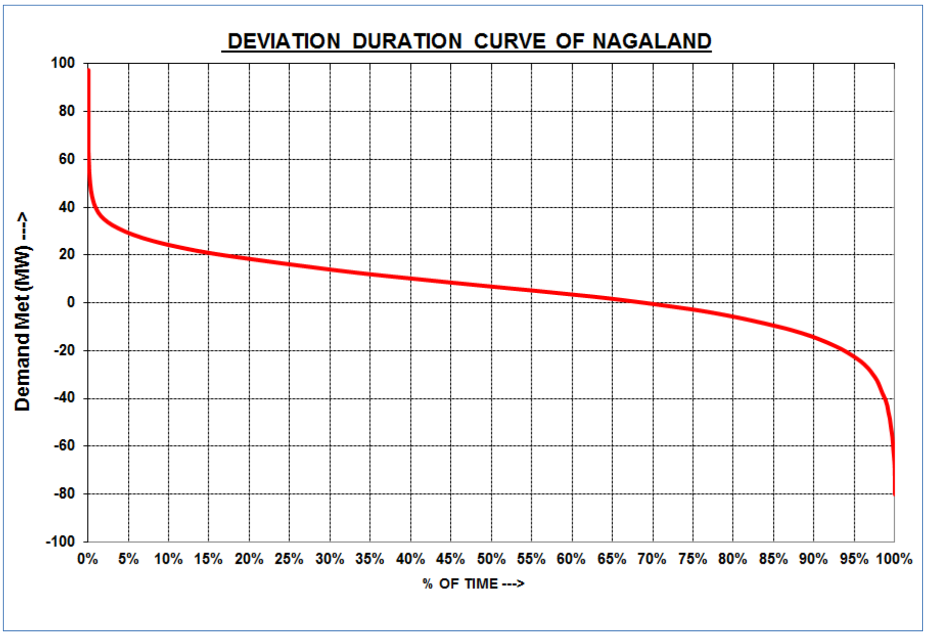


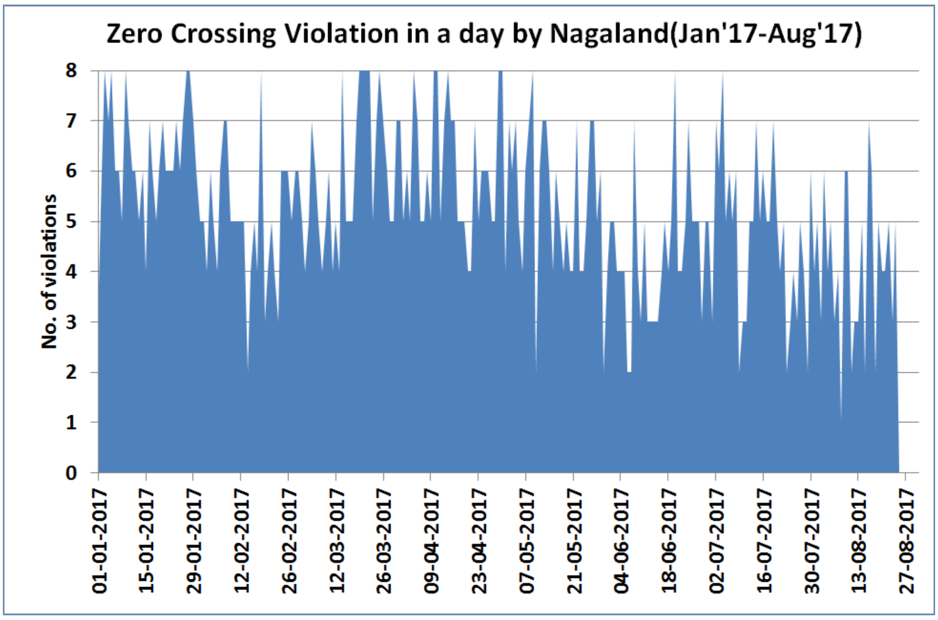
Mizoram Deviation



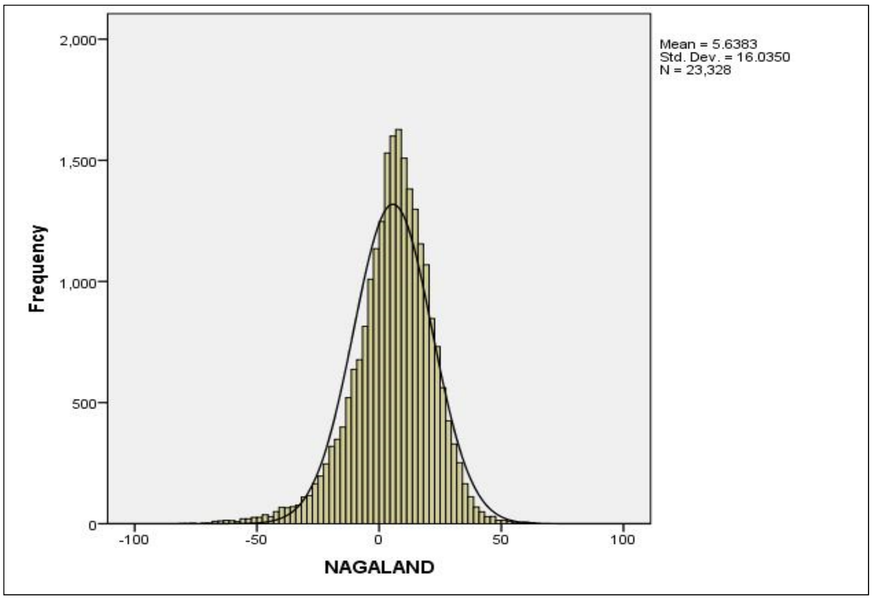


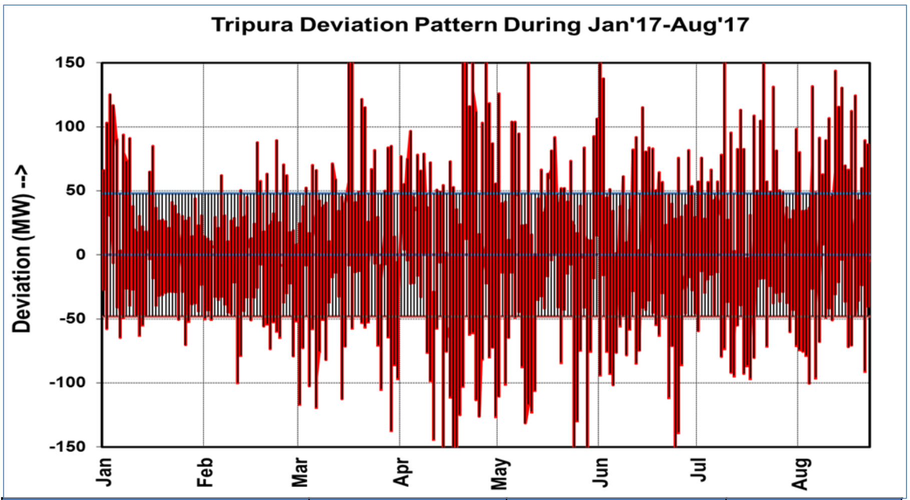
HEAD	MAX (in MW)	MIN (in MW)	AVG (in MW)
Schedule	133	28	77
Actual	150	-8	83
Deviation	65	-81	-
Note: +Ve indicates O/d & –Ve indicates U/d			



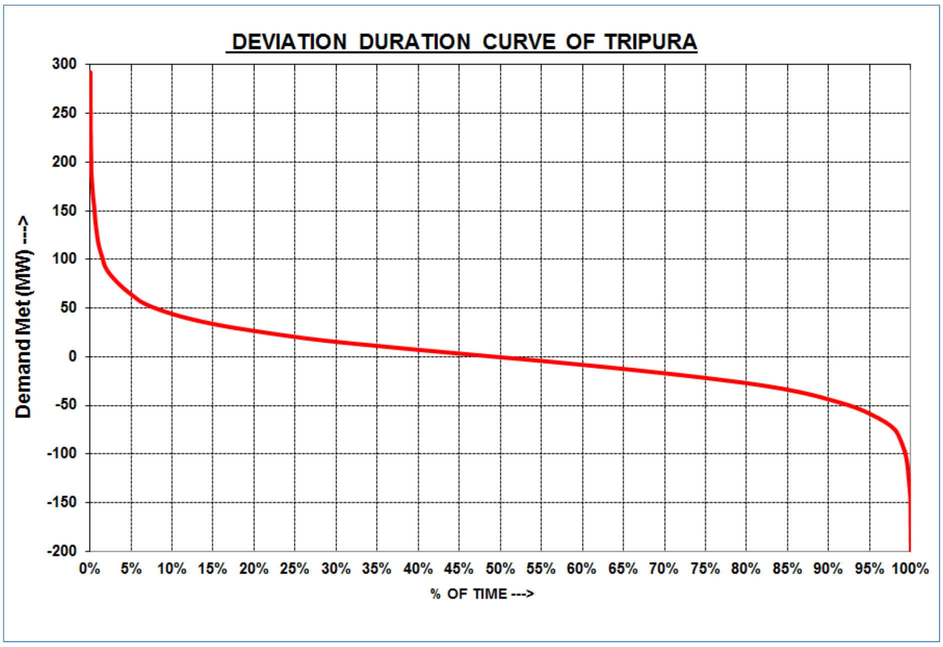


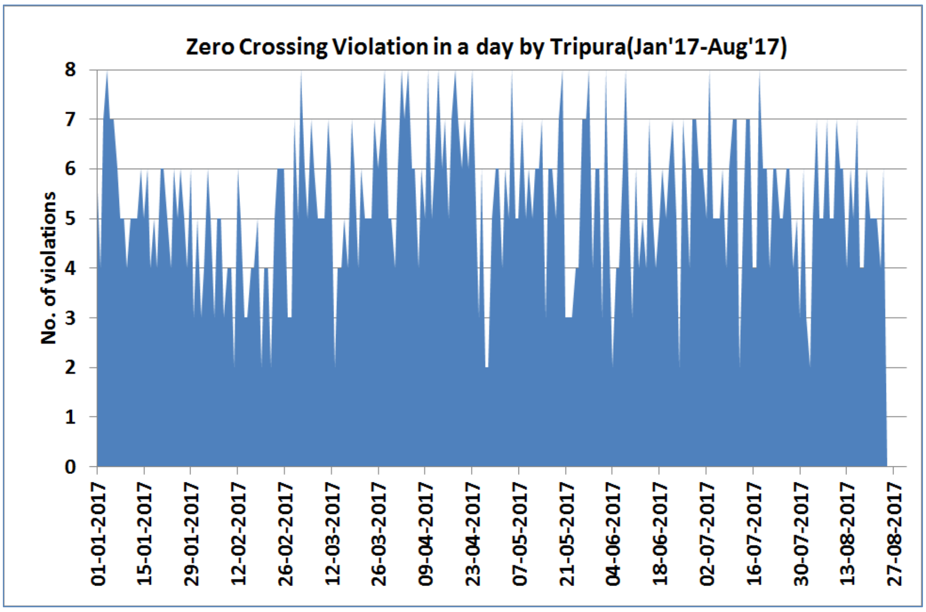
Nagaland Deviation



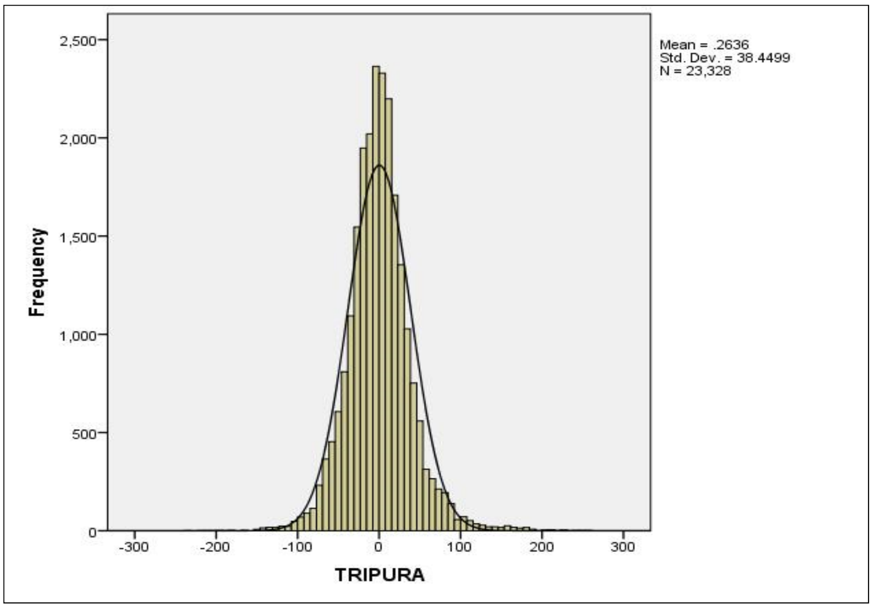


HEAD	MAX (in MW)	MIN (in MW)	AVG (in MW)
Schedule	305	-142	100
Actual	319	-99	101
Deviation	260	-236	-
Note: +Ve indicates O/d & –Ve indicates U/d			





Tripura Deviation



Annexure - IV

Discussion Paper

Transition towards a Market based DSM Price

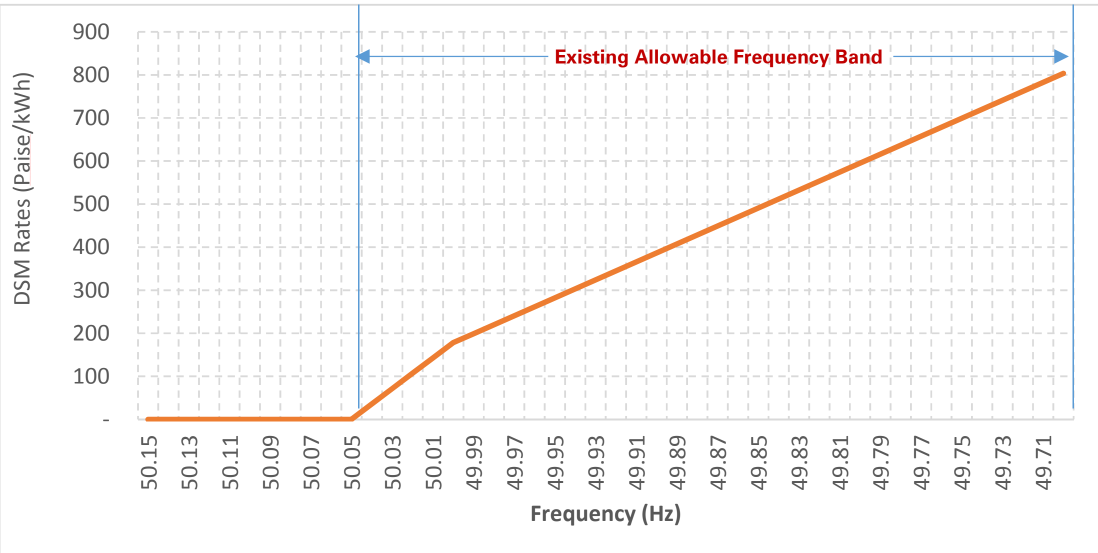
1. Background

The objective of Central Electricity Regulatory Commission (Deviation Settlement Mechanism and related matters) Regulations, 2014 is to maintain grid discipline and grid security as envisaged under the Grid Code through the commercial mechanism for Settlement of Deviations in case of scheduled drawal and injection of electricity by the users of the grid. In the context of system operation, observation by Niti-Aayog from the “Report of the Expert Group on 175 GW RE by 2022” that merits attention here is quoted below:

“Balancing in India is overseen by a state LDC, and is done by each state as a whole. Given that some states are very large indeed – comparable to many countries in scale – this is already a very significant task.”

The charges for the Deviations for all the time-blocks are payable for over drawal by the buyer and under-injection by the seller and receivable for under-drawal by the buyer and over-injection by the seller and are worked out on the average frequency of a 15-minute time blocks at the regulated rates. (Figure 1) The fact that frequency changes with the load-generation imbalance gives a good way to regulate the imbalance: use frequency (or frequency deviation) as a signal to alter generation or demand. A given power system has many generators and loads (all geographically dispersed), so system operators must balance load with total generation by appropriately regulating each generator and demand in response to frequency changes.

Figure 1: Existing DSM Price Vector with corresponding Frequency Bands



2. Evolution of Grid Operations in India

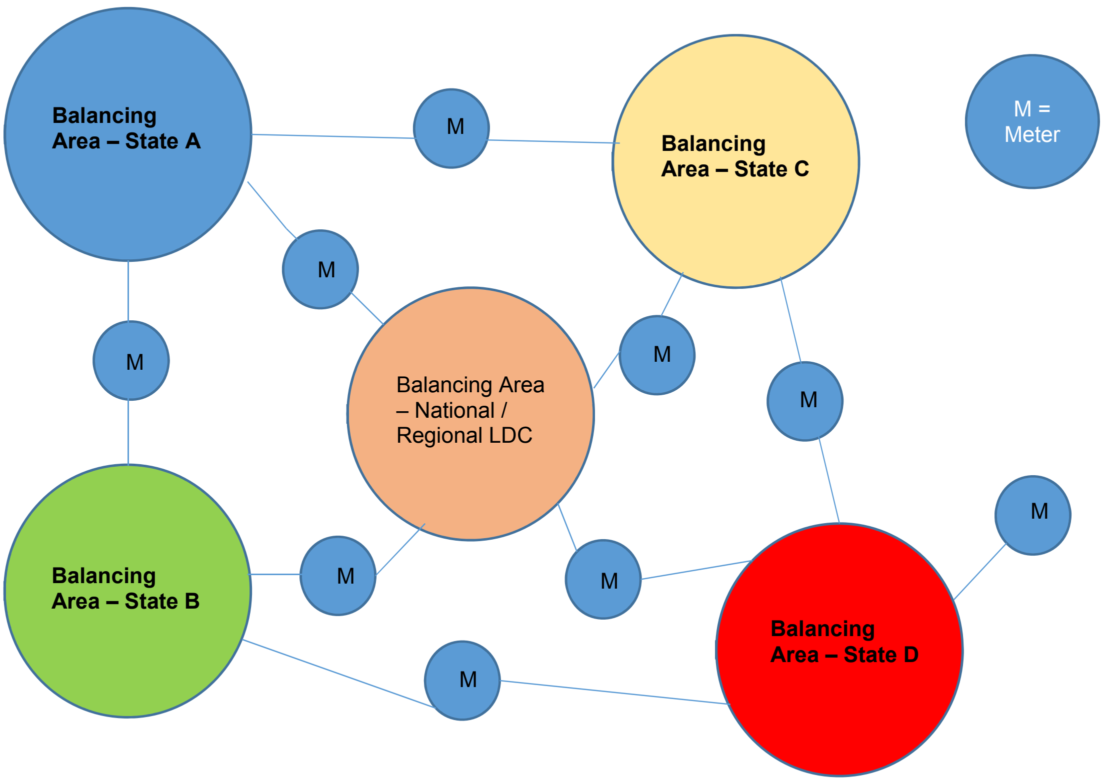
As a result of how the grid operations have evolved in India, the problem of maintaining a balance between inter-state flows, frequency and therefore load generation balance within a particular state is complex. Initially, each state and gradually each region grew as isolated interconnections, with each one having the problem of balancing its load with its generation.

Gradually, in order to enhance grid reliability, these state and regional grids interconnected to assist one another in emergency situations and with restructuring and deregulation of electricity markets post the Electricity Act, 2003 led to the full integration or coupling of the regional grids.

For instance, in 1980s, the grid was operated as separate asynchronous regional sub-grids, which meant that the generation and withdrawal had to be scheduled within each sub region. The emergence of Vindhyachal HVDC back-to-back station in 1989 dramatically increased the power exchange between WR-NR and consequently optimized the load generation balance. Subsequently, similar links and operations control were established between WR-SR (Bhadrawati), ER-SR (Gazuwaka) and ER-NR (Sasaram). In 1992, ER-NER was synchronously interconnected through 220kV Birpara-Salakati and subsequently by 400kV Bongaigaon-Malda transmission lines. WR was interconnected to ER-NER system synchronously through 400kV Rourkela-Raipur line in 2003 and thus the Central India sub system consisting of ER-NER-WR came into operation. In 2006, the NR also got interconnected to this system through 400kV Muzaffarpur-Gorakhpur line resulting in an upper grid system ('NEW' grid) having the NR-WR-ER-NER sub system. In 2014, the SR was also synchronised to the NEW grid through 765kV Raichur-Sholapur line resulting in the full integration or coupling of the regional sub grids.

Thus, the Indian grid today can be conceived of as a tightly coupled or integrated system as shown in the Figure 2 below.

Figure 2: Representation of India Power Systems



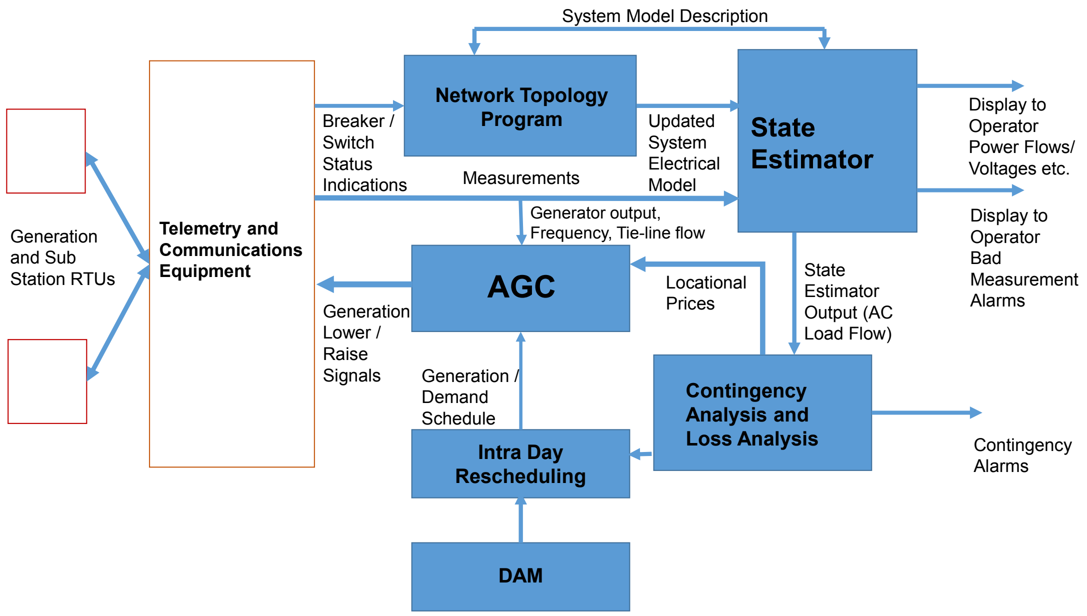
3. Understanding the Deviation Settlement Mechanism in the Indian Context

The problem of measuring frequency and net deviations on inter-state tie lines, and then re-dispatching generation or shedding demand to make appropriate corrections in frequency and net deviation is referred to as Automatic Generation Control (AGC). There are two main functions of AGC:

1. Load-frequency control (LFC). LFC must balance the load via two actions:
   a. Maintain system frequency
   b. Maintain scheduled exports (tie line flows)
2. Provide signals to generators for two reasons:
   a. Economic dispatch via the real-time market
   b. Security control via contingency analysis

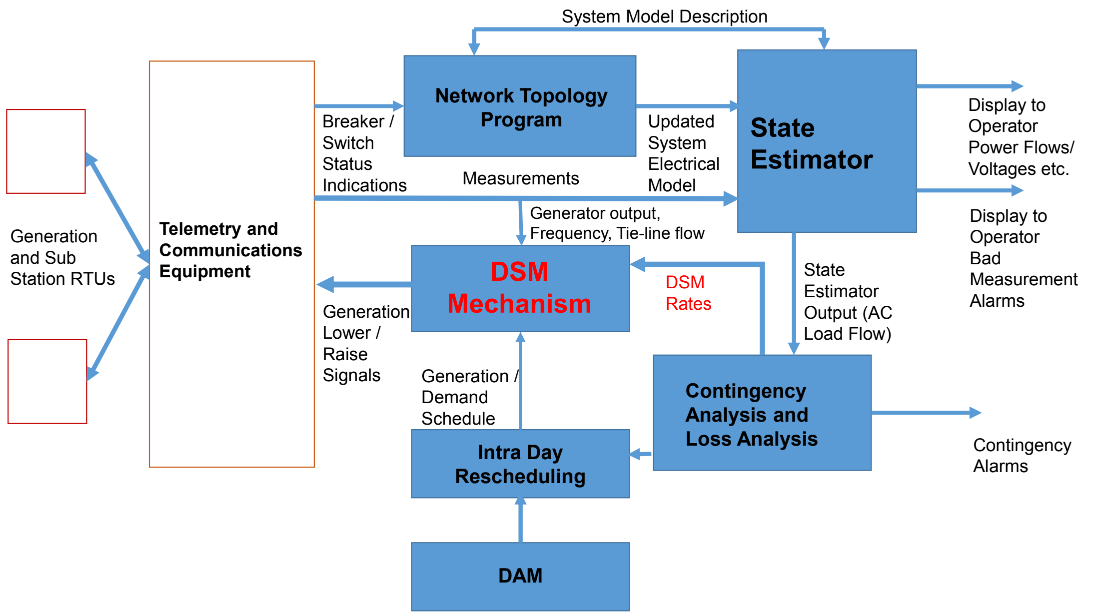
Figure 3 below describes the Energy Control Center (ECC) which includes SCADA, Telemetry, EMS (which includes AGC), Real Time and Day Ahead Markets. AGC is a control function that takes Generator set points (Schedules), tie-line set points (Schedules), nominal frequency, Actual Generation, actual tie-line flows, actual frequency and real time prices as inputs to provide signals (lower/raise outputs) to the generators. Each SLDC ideally needs to have AGC, which has become all the more important because of increasing penetration of RE generation.

Figure 3: Description of Energy Control Center (ECC) for an interconnected Grid System



However, given the absence of AGC in India, erstwhile Unscheduled Interchange (UI) mechanism and the present Deviation Settlement Mechanism (DSM) have been used to provide generation lower/raise signals and load shedding signals for load-generation interchange management. Further, instead of market determined "locational prices", regulated UI rates / DSM rates have been utilized to provide signals for effecting changes in generation and for load curtailment. Therefore, in the Indian context, the following description of ECC (Figure 4) may be a more accurate description of how system parameters are managed.

Figure 4: Description of Energy Control Center (ECC) in the Indian Context



The tight coupling between system and market operations, as shown in the figures above, implies that there are strong inter-relationships between system security management and market performance[1]. Typically, electricity is traded in a sequence of markets that are cleared at different frequencies and with different lead times. The clearing of Day Ahead Market (DAM) impacts the nature and the extent of the participants' responses to real-time conditions and therefore the real-time grid operations, which in turn impact system security. Several studies have quantitatively characterized the linkages between the real-time system security and the day-ahead markets. Further, several studies lead to the conclusion that the participation of financial entities leads to the convergence of the DAM and the associated real time market prices. Moreover, these studies also illustrate that such participation leads to improved forecasts of the real time system operations and consequently results in improving the assurance of system security[2].

Decisions to sell or purchase by each player (and state utilities) that participates in 15-minute DAM is based on the forecasts of the real time conditions for that 15-minute block of the next

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[1] T. Guler, G. Gross, E. Litvinov and R. Coutu, "On the Economics of Power System Security in Multi-Settlement Electricity Markets," IEEE Transactions on Power Systems, Volume: 25, Issue: 1, Feb. 2010

[2] X. Ma and D. Sun, "Key elements of a successful market design," Proc. of IEEE/PES Trans. Dist.: Asia and Pacific, Dalian, 2005.
NERC, Available: http://www.nerc.com/~filez/standards/Reliability_ Standards.html.
R. Kamat and S. S. Oren, "Multi-settlement systems for electricity markets: zonal aggregation under network uncertainty and market power," Proc. of 35th Hawaii Inter. Conf. Syst. Sci., pp. 739-748, Jan. 2002.
R. Kamat and S. S. Oren, "Two-settlement systems for electricity markets under network uncertainty and market power," Journal of Regulatory Economics, vol. 25, issue 2, pp. 5-37, Jan. 2004.
I. Arciniegas, C. Barrett and A. Marathe, "Assessing the efficiency of US electricity markets," Utilities Policy, vol. 11, pp. 75-86, Jan. 2003.
S. Borenstein, J. Bushnell, C. R. Knittel, and C. Wolfram, "Inefficiencies and market power in financial arbitrage: a study of California's electricity markets," Center for the Study of Energy Markets (CSEM), Working Paper - 138, Dec. 2004.

day. The 15-minute clearing influences the behaviour of players closer to real time in that 15-minute block. Ideally, the real time drawal / injection into the grid by each player determines the volume of deviations from the Schedule that was "fixed" for that player based on the outcomes of the organized markets.

Currently, in India, the real time prices (DSM charges) are regulated and change with frequency. There exists a difference between DAM prices and DSM prices, the latter being usually lower than DAM prices[3]. This is contrary to what is suggested by economic theory i.e. in real time electricity demand is inelastic and hence the prices should be higher. DSM prices are lower than DAM prices essentially because these are regulated and may therefore be leading to allocative and technical inefficiency in the market operations. Hence, this induces the players to treat DSM as a commercial mechanism in lieu of organized markets to the extent the same is within the limits prescribed by the DSM regulations. Ideally, the DSM mechanism is supposed to be used as a mechanism to "balance" the system – a function, which according to the figure above, is performed as "secondary" control by the AGC.

4. Proposed modifications to the DSM Price Vector

In order to nudge real time deviations in India towards a more market-like outcome, it is proposed that the DSM charges be linked to the Area Clearing Price (ACP) of the DAM market of the Power Exchanges. Though, the convergence between DAM prices and real time prices (DSM charges) and attendant efficiencies discussed in the foregoing paragraphs are results of dynamic interactions between conjectured day ahead and real time market processes. Therefore, in the absence of a real time market and AGC in India, it is considered appropriate to link the real time prices (DSM charges) to DAM prices exogenously. The behavioural outcomes of players in each settlement of multi-settlement markets are "different" and yet "linked". The "difference" is on account of the changes in expectations about the state of the power system at the time of actual delivery and the "linkage" is because each player attempts to maximize profits (generators) or minimize costs (distribution utilities) by selling / purchasing power in all these markets.

It is expected, as an approximation, that the "difference" between the expectations of players regarding the "state" of the power system between day ahead and near real time will not be large, expect of course, in systems with high RE penetration. Hence, it would be "more" efficient to link the real time "balancing" price of electricity to DAM prices rather than "regulated DSM charges" determined by the Commission. Such real time "balancing" prices (DSM charges) would have temporal and spatial variation.

5. Principles of pricing deviations from Schedule

DSM mechanism, conceptualized based on the principles of AGC should like AGC correct both tie line (inter-state transmission flow) deviations and frequency deviations. The tie line and frequency deviations are expected to be corrected by the DSM mechanism in such a way so that each control area compensates for its own load change.

To perform load-frequency control in a power system consisting of multiple balancing authorities i.e. the SLDCs, two things need to be measured:

- Steady-state frequency deviation: to determine whether there is a generation/load imbalance in the overall interconnected system. $\Delta f = f - 50$

[3] The average DAM prices in FY17 were 2.50 Rs/kWh as opposed to the average DSM price of 1.76 Rs/kWh

- Net deviation: to determine whether the actual exports are the same as the scheduled exports. $\Delta P_i = AP_i - SP_i$, When $\Delta P_i > 0$, it means that the actual export exceeds the scheduled export, and so the generation in area i should be reduced.

The measurements of these two things is typically combined in an overall signal called the area control error (ACE). ACE index reflects the control area power balance. ACE signal includes the interconnection frequency error and the interchange power error with Inter-state transmission system. ACE signal value is used as an input of AGC system. All SLDCs should ideally have their own AGC systems. An AGC system automatically controls generation units, which participate in regulation process. The regulation process is a real-time process and ACE is calculated every several seconds.

With AGC replaced by the DSM, operator's manual intervention in maintaining ACE within limits is required. Even with AGC, North American Electricity Reliability Council (NERC), has introduced Control Performance Standards (CPSs) to evaluate the quality of the balancing process. Under the extant DSM mechanism, there are DSM charges for:

(a) Deviation from schedule when frequency also deviates from its nominal value (steady state frequency deviation), and

(b) Deviation in net interchange with the Inter-State transmission system (Net Deviation) irrespective of frequency.

Though the extant regulations require that the direction of net deviation be reversed after every twelve time blocks, it is pertinent that non-adherence to the same should invite payment of additional charges.

6. Benefits of linking the DSM Charges with DAM market of Power Exchange

The key benefits of linking the DSM Charges with the ACP of the DAM market of Power Exchanges are discussed below:

1. **Nudging the market participants towards efficient Planning and Grid Operational practices:** The inability of states/utilities in India to develop a robust Day Ahead Power Procurement Planning and Operations with adequate reserve margins may partly be reflected in their excessive dependence on transactions through DSM. The un-cleared sell volumes on Power Exchanges provides sufficient evidence of the reliance states having supply shortages are putting on the DSM transactions as a means of meeting their demand.
2. **Scale up of Wind and Solar Capacity Additions:** The inherent characteristics i.e. variability and unpredictability of Wind and Solar generation is expected to contribute to the volatility of the grid frequency. Given the huge emphasis on wind and solar capacity additions, it is pertinent to improve grid reliability with also the tightening of frequency bands and de-incentivizing the DSM transactions. Further, the prices in real time should give signals for the type of capacity required for supporting large scale integration of wind and solar.
3. **Deviations should be priced as per the Market Value:** The market based discovery of real time prices is not currently available in the Indian Grid Systems, therefore linking the DSM Price Vector with the ACP of Power Exchanges would reasonably reflect the value of electricity in real time. This is likely since if all the potential deviations in schedule were to be converted to planned DAM transactions, the price would equivalently be represented by the ACP.

4. **Linking DSM Price Vector with the ACP of the Power Exchanges:** The ACP of Power Exchange represents the 'real time value[4] or the marginal price of electricity at which the buyers and sellers are willing to transact. Further, the size of DAM of PX is bigger than the DSM and linking the two comparable segments seems reasonable.

7. Key Design elements and Implementation Questions

The key design feature of the proposed DSM price vector are discussed below:

1. DSM charges will be linked to the weighted average price of all the power exchanges provided no power exchange has more than 90% market share in the DAM. In case an Exchange has more than 90% market share in DAM, DAM prices discovered on such an exchange will be adopted as DSM charges.
2. ACP discovered in the DAM of Power Exchange shall be taken as the DSM Charge at nominal frequency for each buyer and seller within the respective area. DSM charges will increase for a decline in frequency by 0.01 Hz and the DSM charges at 49.90 Hz. shall be twice the DSM charges at 50.00 Hz., subject to a cap determined by the variable cost of the costliest liquid fuel based power plant + 20% mark up. DSM charges shall decline as the frequency increases above 50.00 Hz and shall be zero at 50.05 Hz. The DSM Charges above 50.05 Hz shall further decrease by 0.20 for each 0.01 Hz decrement in frequency from 50.05 Hz.
3. The Figure 5 below shows the Index (multiplier) to be applied on the ACP of DAM for arriving at the DSM Charges. DSM price for any deviation at 50.00 Hz (INDEX = 1) will equal the ACP of the area in which the market participant is located. Price INDEX at 50.00 Hz will be decreased by 0.20 per 0.01 Hz for frequencies above 50.00Hz and increased by 0.10 per 0.01 Hz for frequencies below 50.00 Hz.
4. DSM Price for any block will be the product of ACP of that block / Average Daily ACP and the value of INDEX corresponding to the frequency prevailing in that block. The ceiling price will be equal to 8,032 Rs/MWh. If the derived prices in any time block are more than the ceiling price, then the DSM prices will be capped at the ceiling price.

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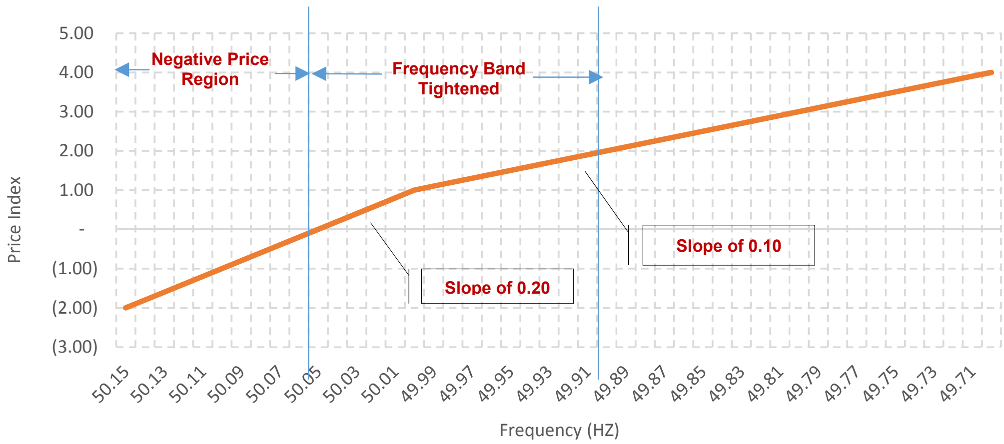
[4] Estimation of scarcity value requires computation of VOLL and LOLP, which in turn depends on the minimum contingency reserve requirement (as in ERCOT). However, in India, till these values are estimated reliably, deviation in frequency can be taken as a metric of "scarcity"

Figure 5: Proposed Index for DSM Charges



5. It is proposed that ACE should reverse in sign after every four time blocks instead of 12 at present and the charges for violation on non-overlapping four time blocks be 10% additional DSM charge for those four time blocks.
6. The other provisions in the DSM regulation such as volume limits and deviation limits for sellers and buyers, additional charges etc. are proposed to remain the same.

8. Key Implementation Questions

1. Should the DSM charges be linked to average daily ACP of the DAM or to the ACP in every block of 15 minutes? It is argued that the latter would lead to considerable volatility in the DSM charges. On the other hand, by linking DSM charges with 15 minute DAM prices, the differentiation in time value of electricity is retained. It is proposed that initially DSM charges will be linked to average daily DAM prices and based on the response of grid connected entities the same shall be brought for review before the Commission.
2. Should there be a difference between the buy charges and sell charges in the DSM mechanism?

9. Simulations for understanding Impact of DAM based DSM Price Vector

In order to understand the impact of proposed linking of DSM Price Vector with the ACP of DAM, three (3) days over the period of "01 Jan 2017 to 03 Sep 2017" were selected for carrying out the Price Vector simulations. The criteria used for selection was as under:

a) Day which observed the highest MCP **(25 Aug 2017)**

b) Day which observed the lowest MCP **(02 Jul 2017)**

c) Day which observed the median MCP from 1 Jan 2017 to 3 Sep 2017 **(17 Jan 2017)**

The Average ACP for each price region of Power Exchange (IEX) for the above days is summarised in the Table 1 below. IEX was selected since it formed more than 90% of the market clearing volumes for the selected days.

Table 1: Daily Average Area Clearing Price (ACP) of the selected days in IEX (Rs/MWh)

Date	A1	A2	E1	E2	N1	N2	N3	S1	S2	S3	W1	W2	W3	MCP
25-Aug-17	3,810	3,810	3,810	3,810	3,810	3,810	3,810	3,810	3,810	3,810	3,810	3,810	3,810	**3,810**
2-Jul-17	1,017	1,017	1,017	1,017	**1,023**	**1,023**	**1,023**	**1,991**	**1,991**	**1,991**	1,017	1,017	1,017	**1,115**
17-Jan-17	2,540	2,540	2,540	2,540	**2,870**	**2,870**	**2,870**	**2,939**	**2,939**	**2,939**	2,540	2,540	2,540	**2,665**

From the above table on ACP for the three selected days, it may be observed that there was market splitting on 02 July 2017 and 17 Jan 2017 indicating different ACP for Northern (N1, N2 and N3), Southern (S1, S2, S3) and Rest of India price areas.

The DSM Price Vectors were simulated using the actual block wise frequency data for all three days and for the following three alternatives.

a) Existing DSM based on the regulated DSM rates
b) Average Daily ACP of Power Exchanges
c) Block wise ACP of Power Exchanges

The summary of the results is shown in the Table 2 below:

Table 2: Summary of DSM Charges under Existing DSM Charges, Block wise ACP and Daily Average ACP approach for the selected days

Case (Date)	Metric	Region	DSM Price Discovery Mechanism (Rs/MWh)		
			Existing (Regulated)	Block wise ACP (Market based)	Average Daily ACP (Market based)
Highest MCP Day (26 Aug 2017)	Average	NR	1,902	3,719	3,835
		WR, ER & NER		3,719	3,835
		SR		3,719	3,835
	Max	NR	5,114	8,032	8,032
		WR, ER & NER		8,032	8,032
		SR		8,032	8,032
	Min	NR	-	-1,950	-2,286
		WR, ER & NER		-1,950	-2,286
		SR		-1,950	-2,286
Lowest MCP Day (02 Jul 2017)	Average	NR	1,480	927	741
		WR, ER & NER		922	738
		SR		1,623	1,444
	Max	NR	4,698	5,998	2,454
		WR, ER & NER		5,998	2,442
		SR		8,032	4,779
	Min	NR	-	-999	-2,045
		WR, ER & NER		-999	-2,035
		SR		-4,401	-3,982
Median MCP Day (17 Jan 2017)	Average	NR	1,922	2,941	2,885
		WR, ER & NER		2,635	2,553
		SR		3,031	2,954
	Max	NR	4,489	8,032	6,601
		WR, ER & NER		7,999	5,841
		SR		8,032	6,760
	Min	NR	-	-2,504	-2,296
		WR, ER & NER		-2,503	-2,032
		SR		-2,800	-2,351

From the above table, it is evident that linking DSM Charges to the ACP of DAM provides correct market signals for real time deviation settlements. This can be observed from the fact that the average and maximum DSM charges are higher for highest and median MCP day in case of ACP linked DSM Charges as compared to that of existing regulated DSM Charges. Similarly, the DSM charges for the Lowest MCP Day in case of ACP linked DSM Charges are observed to be lower for average and minimum cases as compared to regulated DSM Charges. The reasons for this may be attributed to the fact that the ACP / MCP in the DAM of Power Exchanges would be higher when the demand is higher and vice versa. Thus, linking DSM Charges with DAM of Power Exchange is expected to ensure better estimation of demand and accurate scheduling by the DISCOMS, which may result in improved grid discipline, avoid DSM being used as a trading route and provide the desired market signals for setting up of reserve and ancillary service based capacity.

Annexures

Table 3: Existing DSM Charges (regulated) and Market based DSM Charges

Frequency (Hz)	DSM Charges (Paise/kWh) (Regulated)	INDEX for DSM Charges (Market Based)
50.10	-	(1.00)
50.09	-	(0.80)
50.08	-	(0.60)
50.07	-	(0.40)
50.06	-	(0.20)
50.05	-	-
50.04	35.60	0.20
50.03	71.20	0.40
50.02	106.80	0.60
50.01	142.40	0.80
50.00	178.00	1.00
49.99	198.84	1.10
49.98	219.68	1.20
49.97	240.52	1.30
49.96	261.36	1.40
49.95	282.20	1.50
49.94	303.04	1.60
49.93	323.88	1.70
49.92	344.72	1.80
49.91	365.56	1.90
49.90	386.40	2.00
49.89	407.24	2.10
49.88	428.08	2.20
49.87	448.92	2.30
49.86	469.76	2.40
49.85	490.60	2.50
49.84	511.44	2.60
49.83	532.28	2.70
49.82	553.12	2.80
49.81	573.96	2.90
49.80	594.80	3.00
49.79	615.64	3.10
49.78	636.48	3.20
49.77	657.32	3.30
49.76	678.16	3.40
49.75	699.00	3.50
49.74	719.84	3.60
49.73	740.68	3.70
49.72	761.52	3.80
49.71	782.36	3.90
49.70	803.20	4.00

Figure 6: Highest MCP Day - 25 Aug 2017

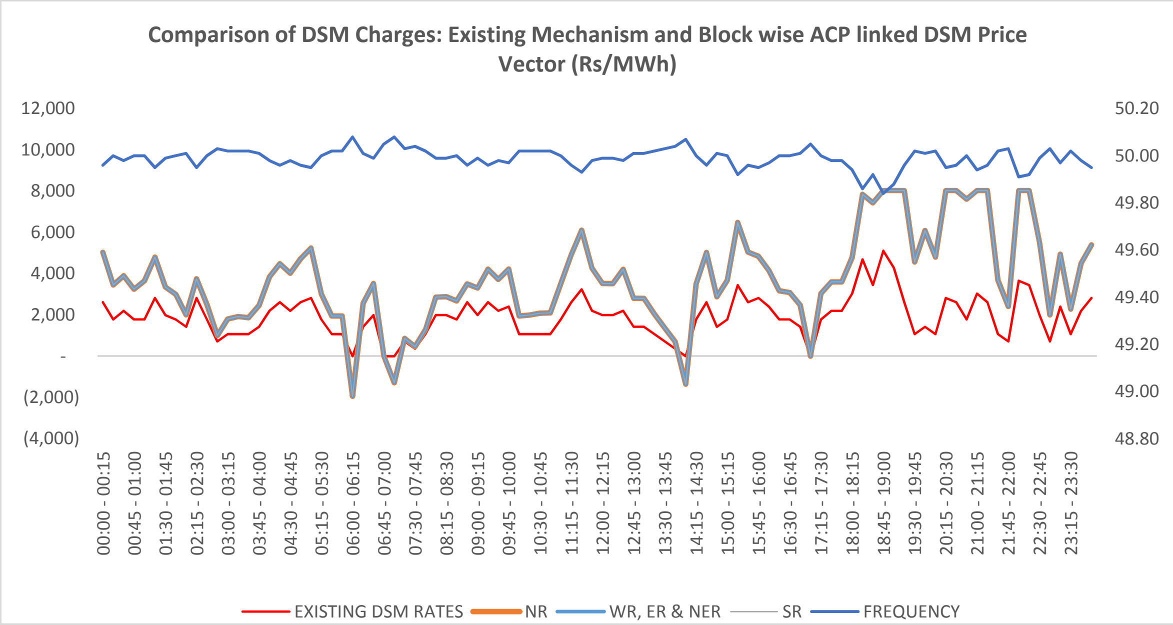


Figure 7: Lowest MCP Day - 02 Jul 2017

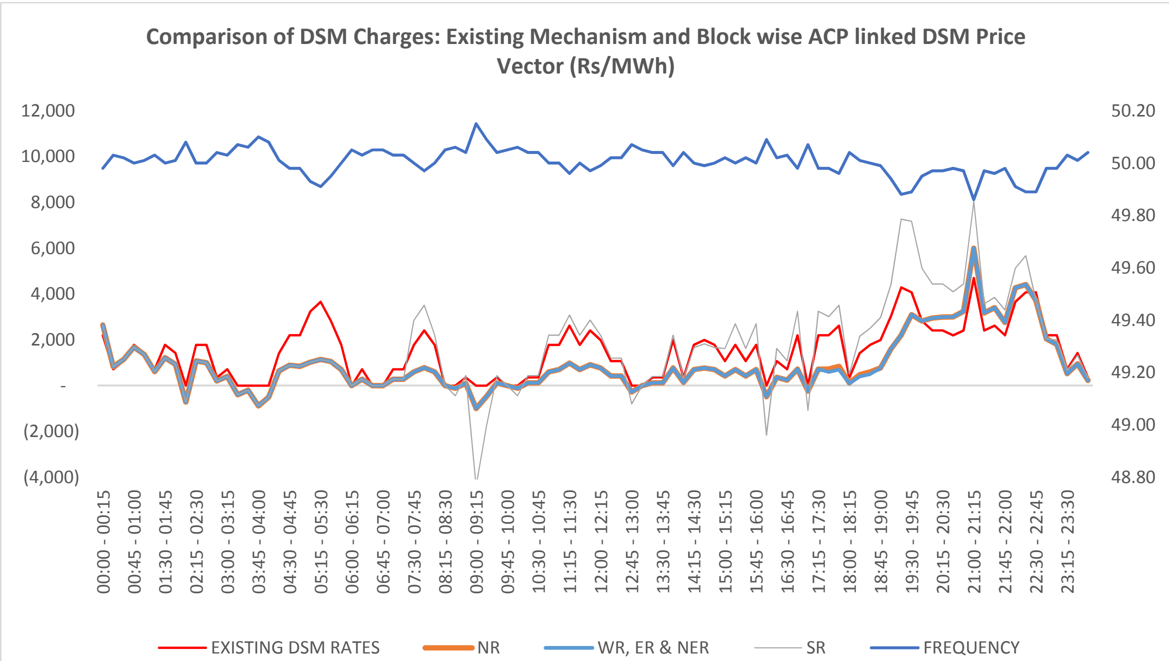


Figure 8: Median MCP Day - 17 Jan 2017