INDIAN POWER MARKET

Journey so far and way forward

JUNE 2014

Prepared by:
MERCADOS ENERGY MARKET INDIA PVT. LTD.
(AF-MERCADOS EMI)

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ABBREVIATIONS

ATC	Available Transfer Capability
BSAS	Black Start Ancillary Services
BUs	Billion Units
CEA	Central Electricity Authority
CERC	Central Electricity Regulatory Commission
CPP	Captive Power Plants
CSS	Cross Subsidy Surcharge
DAM	Day Ahead Market
DHBVN	Dakshin Haryana Bijli Vitran Nigam
DISCOMs	Distribution Companies
EA	Electricity Act
FY	Financial Year
GWh	Gigawatt Hour
HT/LT	High Tension/Low Tension
IEGC	Indian Electricity Grid Code
IEX	Indian Energy Exchange Limited
IPP	Independent Power Producer
ISTS	Inter State Transmission System
JSEB	Jharkhand State Electricity Board
JSERC	Jharkhand State Electricity Regulatory Commission
kWh	Kilowatt Hour
LDCs	Load Dispatch Centres
LT	Long Term
MT	Medium Term
MAPE	Mean Absolute Percentage Error
MISO	Midwest Independent Transmission System Operator
MoP	Ministry of Power
MPP	Merchant Power Plants
MUs	Million Units
MW	Megawatt
MWh	Megawatt Hour
NOC	No Objection Certificate
NR	Northern Region
NRLDC	Northern Regional Load Dispatch Centre
NTSD	Non-Transferable Specific Delivery
NVVN	NTPC Vidyut Vyapar Nigam Limited
OTC	Over the Counter
PPA	Power Purchase Agreements
PPC	Power Purchase Cost
PSPCL	Punjab State Power Corporation Ltd
PX	Power Exchange
RE	Renewable Energy
REC	Renewable Energy Certificate
RLDC	Regional Load Dispatch Centre
ROI	Rest of India
RPO	Renewable Purchase Obligation
SC-OPF	Security Constrained Optimal Power Flow
SEB	State Electricity Board
SERC	State Electricity Regulatory Commission
SLDC	State Load Dispatch Centre
SOR	Statement of Objects and Reasons
SR	Southern Region
ST	Short Term
STU	State Transmission Utility
TANGEDCO	Tamil Nadu Generation and Distribution Company
TWh	Terawatt Hour
UI	Unscheduled Interchange
UMCV	Unconstrained Market Clearing Volume
VC	Variable Cost
VCAS	Voltage Control Ancillary Services
VRE	Variable Renewable Energy

EXECUTIVE SUMMARY

The enactment of the Electricity Act 2003 laid down provision for promoting competition in the Indian power market. Introduction of non-discriminatory open access in electricity sector provided further impetus for enhancing competition in the market. This is prodded by the positive regulatory moves to create a vibrant electricity market supported by the efforts of market operators and market makers in bringing out new products and solutions to benefit the consumers, suppliers and the sector as a whole.

The efficiency and liquidity of the power exchanges has improved since their inception in 2008. This is exhibited by decrease in number of price peaks, reduced volatility, and reflection of market information in prices. The size of power exchange based markets has grown to approximately 3% of the total electricity generated, since inception. With further tightening of the frequency band, and an expected zero-tolerance towards frequency deviation[1], the volumes are expected to move from the real time to day ahead or intraday electricity markets on the power exchanges. The cumulative percentage of electricity traded through UI and PXs today stands at approximately 6%.

The new market structure, which has evolved over the last five years, provides distribution utilities with avenues to optimise their power purchase portfolios and reduce their overall power purchase costs. The power purchase cost constitutes nearly 80% of the average tariff of the ultimate consumer. While base load power is usually procured by the States through long term contracts, the States rely on medium term or short term bilateral contracts/markets for meeting their intermediate load requirements. The peak load requirements and seasonally (or a day ahead) varying requirements are met through the power exchanges and bilateral trading mechanisms. Power Exchanges as envisioned, have helped unlock the potential of hitherto bottled up power through an auction mechanism that has low transaction costs and helped to narrow the gap between demand and supply. This is important, especially in a price sensitive market, where distribution utilities often prefer load shedding instead of buying costly power through a protracted administrative process. There are now several trading hours on the exchange during the day when supply exceeds demand. It is seen that if the States were to procure power instead of shedding demand, the combined cost to the distribution utilities will increase by ₹ 36,284 Crores[2], which is far less than the cost to the economy of not serving energy, which is ₹ 243,157 Crores[3]. There are several key regulatory, institutional, infrastructural and operational challenges that need to be overcome to allow unlocking of the potential of short term markets in India.

1 This would be imminent after the integration of the NEW and SR grids.

2 Source: Report by AF Mercados EMI on peak power pricing for gas based generating station.

3 Source: Report by AF Mercados EMI on peak power pricing for gas based generating station.

The short term power markets in India are still short of exploiting their true potential natural limits. Currently the exchange accounts for approximately 29%[4] of the total short term market. The National Electricity Policy, 2005 envisions that 15% of power from new capacities shall be contracted outside long term PPAs. It is expected that players in the electricity market will transact substantial part of this 15%[5] power through market mechanisms. An analysis done by AF Mercados indicates a buying potential of 15.35%[6] and a selling potential of 4.57%[7] across states for the short term market at the current levels of demand met. This potential is only on account of co-skewness of the demand met in each state. The actual potential is however higher and would be around 23% if load shedding in energy terms is assumed conservatively at 10%. The potential would further increase if all the states were to allow their large industrial customers (greater than 1 MW) to procure from short term markets.

Short term markets not only help in improving the reliability of the power systems, by reducing the demand supply gap, but also signal the 'type' of capacity required thereby economizing the usage of generation and transmission resources deployed by the electricity supply industry. Exchange based prices are closing in on the variable costs of generation of the power plants operating at the margins of the merit order stack up of generators. This results in Lerner[8] Index which is close to zero and is indicative of efficient competitive markets.

Need for Ancillary Services Market

With integration of the Southern Region, the national grid is fully integrated in January 2014. Reliable operation of such large power system requires robust primary, secondary and tertiary control of frequency, while the flows on inter- state tie lines must also be maintained at their scheduled levels. This operational requirement of large grid imposes responsibility on the regulators to create new market for ancillary services. Many of the states such as Tamil Nadu, Gujarat, and Rajasthan have huge variable renewable energy based generators, where the problem of maintaining frequency and tie line flows between limits, in the absence of adequate and economical in-state balancing resources may become unmanageable. This calls for development of ancillary services market and re-invigorating the intra-day market. Ancillary Services Market will facilitate procurement of real time active and reactive power to operate the system reliably. Power Exchanges can play a big role in development of these markets.

Need for Capacity Market

Prices close to variable costs of operation is good news for short term electricity market. In 2008 and 2009, when electricity prices were high and the wedge between variable costs and prices was substantial, considerable new investment in capacity took place. However, low prices in recent times have not only stymied new investments but also are not lucrative enough for many plants to operate. The situation is not typical of India alone. Low exchange prices in New York Independent System Operator (NYISO), Midwest Independent Transmission System Operator (MISO), and Electricity Reliability Council of Texas (ERCOT) etc. in the USA catalysed creation of capacity markets for getting investments in peaking capacities. This market is also being developed now in the UK. Therefore, while in 2008-2009, high power exchange prices induced new investments, low prices now signal policy intervention and need for creation of capacity market in India for getting peaking power plants. India currently has an overhang of base load power plants and needs investment in peaking power plants. In the implementation of capacity market, it will be important to recognise that:

(a) All distribution companies must be mandated to demonstrate capacity adequacy.

(b) Such markets are local i.e. constrained by the available transmission capability.

4 Source: IEX, 2013-14.

5 The number has been analysed through analysis of the load curves of states for their buying and selling potential.

6 AF Mercados EMI Analysis.

7 AF Mercados EMI Analysis.

8 Lerner Index measures a firm's level of market power by relating price to Marginal Costs.

Need for Financial Transmission Rights

For efficient operation of the existing Day Ahead Markets, and proposed Capacity and Ancillary Services Market allocation of scarce transmission resources is critical. However, the exchange based markets currently thrive on the residual transmission capability that is left over after being allocated to long, medium and bilateral short term electricity markets. Therefore in the present context, the ability of power exchanges to deliver efficiency for the sector and economy are constrained. Thus, allocation based on "value" that users attach to a scarce resource is perhaps the only fair way and definitely superior to a regulated mechanism – which is essentially first come first served basis. Financial Transmission Rights (FTRs) suitably modified for Indian set-up have been conceived for implementation for a reasonable and a just transmission allocation of transmission rights between the various consumers.

In light of the evolving nature of electricity markets, the power exchanges are expected to play a critical role in its further development. Transitioning from its role of being a platform providing price signal for investments, in future, the exchange would play a twin role of providing price signals as well as act as risk mitigation platform. Further, introduction of futures contracts in electricity would indeed facilitate the exchange in its role as a risk mitigation platform.

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CHAPTER 1

BACKGROUND AND OVERVIEW: POWER MARKETS IN INDIA

Transformation of power sector in the last decade was concomitantly supported by creation of institutions to enhance efficiency through markets via bilateral trading and later in 2008 through trading on power exchanges. The Electricity Act 2003 opened the power sector by laying down provisions for promoting competition in the power market. By identifying electricity trade as a distinct activity, Electricity Act 2003, along with pursuant regulations from the CERC, paved the way for a paradigm shift in the power sector. The Act envisages development of a competitive power market for promoting efficiency, economy and for mobilisation of new investments in the power sector. To this end, the open access regulations at both inter-state and intra-state level opened up avenues for more active participation from the private and state owned generators as well as industrial consumers, with contracted load equal to 1MW or above, in this vibrant market segment.

The Act is directed at institutional and regulatory initiatives to promote inter-state and intra-state power trading within India. In addition, the fundamentals of power trading – such as licensing electricity traders and ensuring open, non-discriminatory access to transmission services – have been put into place to allow for expansion of opportunities in all markets. As a result, there has been a paradigm shift in generation, transmission and distribution activities, which have facilitated power trading.

Long term power markets have historically dominated the power sector and expected to continue to do so. However, long term contracts could not meet the full requirements of the market participants as:

- Electricity cannot be stored.
- Hourly consumption over a long term without forecasting errors is difficult to predict.
- Long term contracts for peak load requirement are economically inefficient.

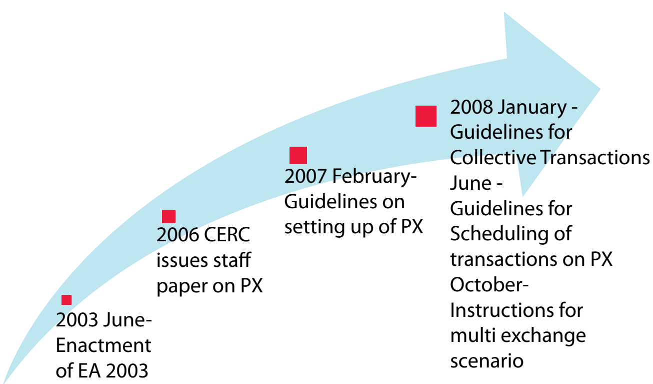
Thus, development of a short-term trading market is necessary to complement the long term trades that cater to the core demand in the power markets. By 2008, while the above-mentioned issues were partially addressed by traders operating in the bilateral short term markets, the following issues were still to be addressed:

- Absence of a mechanism permitting correction of positions taken by players in long term and short term markets close enough to real time and hence enable more efficient generation and demand management.
- Absence of a mechanism where multiple players could come together and interact to determine a market price that would be reflective of the collective conduct of all the players – because in real time all the players act simultaneously putting up their respective supply and demand – which is collectively reflected through system frequency.
- Limited participation by players in the trading activity.

- Non-standard and non-firm nature of contracts.
- Auctioning of surplus electricity resulting in discriminatory pricing.
- Arrangement of separate transmission access – explicit transmission auction.
- Insufficient price signals for investment growth.

Recognising the need to address the above identified gaps, the CERC, in the year 2006, initiated the process of organising the electricity market by establishing the power exchanges. Although the OTC mechanisms continue to serve an important function in the power markets, the exchanges provide a platform where standardised contracts could be entered into, the counterparty risk is taken care of, and a competitive and widely acceptable future electricity price is signaled.

Figure 1: Transition towards a competitive market structure



Source: AF Mercados EMI.

Setting up of trading platforms is the first instance of introducing sophisticated mechanisms in a market characterised by overall energy deficit conditions. In its 5 years of operation, the Indian Energy Exchange has emerged as a market leader with 92% market share in FY 2013-14, successfully providing a robust, competitive and efficient platform and playing a pioneering role in changing the landscape of the Indian power sector. With the growing market volume, fewer price peaks and declining price sensitivity, IEX has indeed helped to build liquidity and efficiency in the market. Clearly, what has been demonstrated to the world is that economies can be achieved through trades because deficits in supply are location and time variant. Improvement in payment security mechanisms could spur investment and reduce demand supply gap. The benefits that IEX provides to the consumers finally reflect in the benefits that accrue to the power sector and the nation. Some of the important tangible contributions that IEX has enabled being the market leader are mentioned in the following section.

CHAPTER 2

CONTRIBUTION OF POWER EXCHANGES (PX) TO THE INDIAN POWER SECTOR

The exchanges are designed with an idea to make electricity markets more transparent, efficient and competitive. The multi-buyer and seller environment along with equal access to transmission and distribution increases the responsiveness of demand and supply to price signals. The overarching objective of achieving higher efficiency in the market forms the basis of such a platform.

Successful development of exchanges is characterised by increase in volume traded, increase in liquidity and reduced price volatility over time. To assess the development of the short term markets in India, it is imperative to analyse the role of power exchanges with respect to the following questions:

- Has the participation and correspondingly the volumes increased in the short term markets?
- Have the PXs helped in improving market efficiencies?
- Are price movements giving out the right signals to the market?
- What can be inferred from the congestion experienced at PXs?

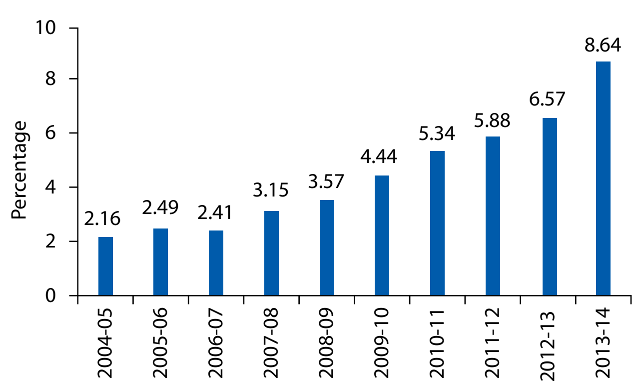
2.1. Increased Participation and Volume in Short-Term Market

During 2013-14, short-term volumes (OTC & PX) formed approximately 8.64%[9] of the total generation in the country. However, the trend indicates a CAGR of 22.86% in the last 5 years. The historical growth trend in volumes in the short-term market is shown in Figure 2 (in absolute terms and as a percentage of total electricity generation).

Volume of electricity transacted through OTC (inter-state trading licensees and bilaterally by states) has tripled during the period i.e. from 12 BUs in 2004-05 to 53 BUs in 2013-14 and the volumes traded on the power exchanges has increased from 7 BUs in 2009-10 to approximately 30 BUs in 2013-14. The maximum volume traded on the exchange is on the Day Ahead Market, which currently constitutes 97.5% of the total volumes traded at the exchange.

Markets have reached a juncture where the participation profile on the short term market is also diverse. Over the last five years, in addition to the state utilities, there has been an increased participation from retail customers, large IPPs and captive generators.

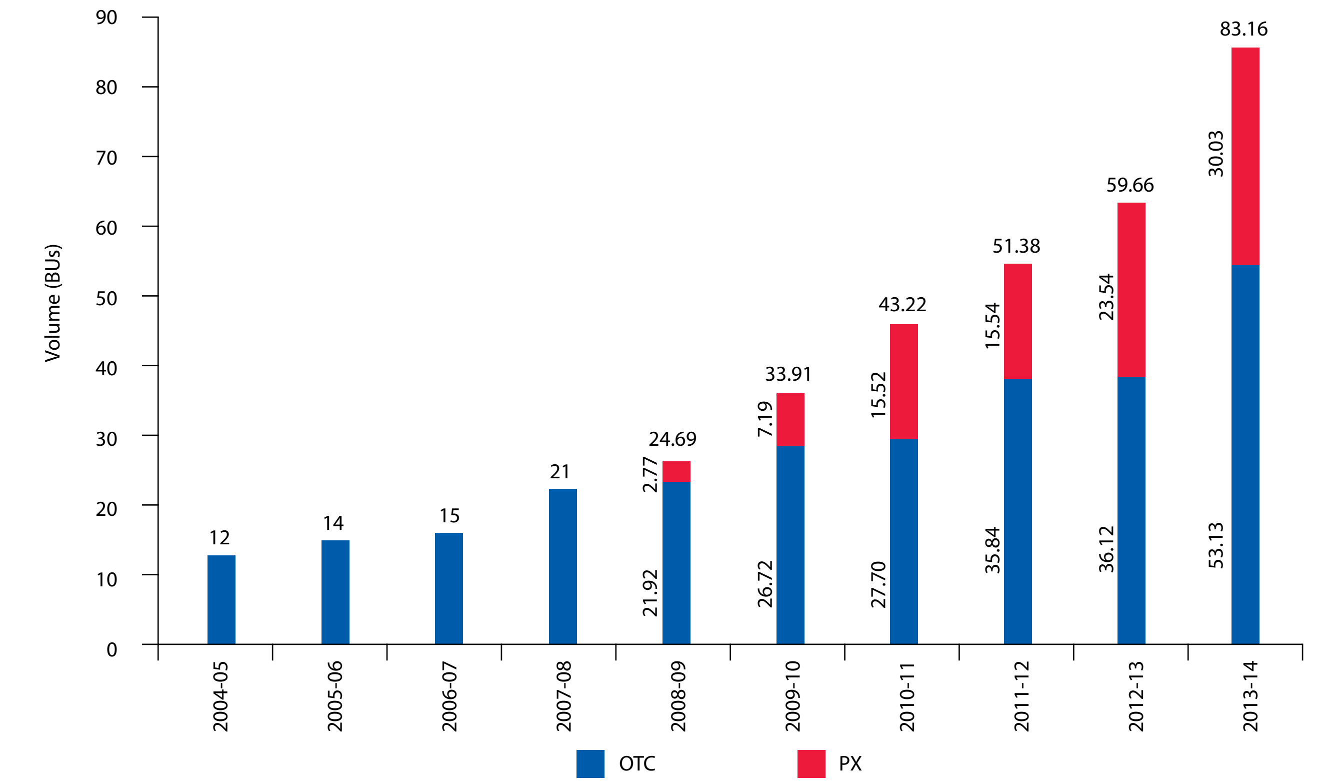
Figure 2: Volumes on short term markets (OTC & PX) (%)



Source: CERC Monthly Report on Short-Term Transactions of Electricity in India.

9 Source: CERC, Report of Short Term Market in India.

Figure 3: Volumes on short term markets (trading licensees and PX) (BU)

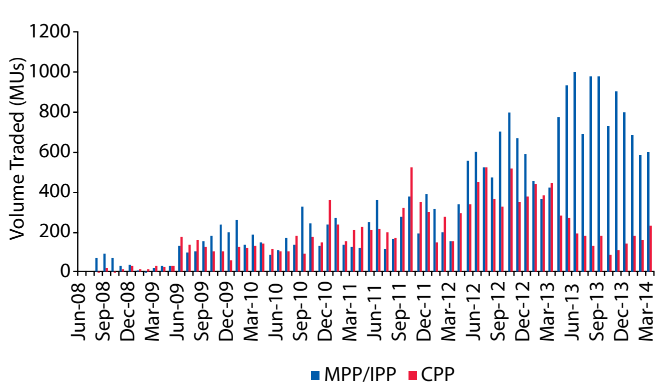


Source: CERC Market Monitoring Reports & AF-Mercados EMI Analysis.

2.2. Improvement in Market Efficiency

India has traditionally been a supply deficit nation, with a constant concern of security and reliability of supply. Creation of a national grid has been supported by commercial contracts wherein huge volumes of electricity are transferred across the country. The exchanges have aided in better utilisation of national resources, reduced unmet energy and consequent economic losses and improved energy security of the nation. Short term exchange based markets have been instrumental in incentivising mobilisation of resources in electricity generation – which India needs desperately to bridge its demand-supply gap. The exchanges have helped in bringing electricity from surplus to deficit regions, for example - it is not uncommon to observe power flows from bid areas A1 (Meghalaya, Tripura, Manipur, Mizoram and Nagaland), W3 (Chhattisgarh), W2 (Gujarat, Maharashtra) and E1 (West Bengal) to S1 (Andhra Pradesh and Karnataka) and S2 (Kerala, Tamil Nadu and Puducherry). The exchanges are not only providing a reliable platform for such trades but are also bringing in time and costs efficiencies in the market through their implicit auction mechanism. The implicit auction mechanism takes care of the price bids and the transmission capacities at the same time and avoids the higher transaction costs that are associated with the performing separate transactions for energy and transmission capacity under the explicit auction mechanism.

Figure 4: Volumes sold by IPP/MPP/CPP (MU)



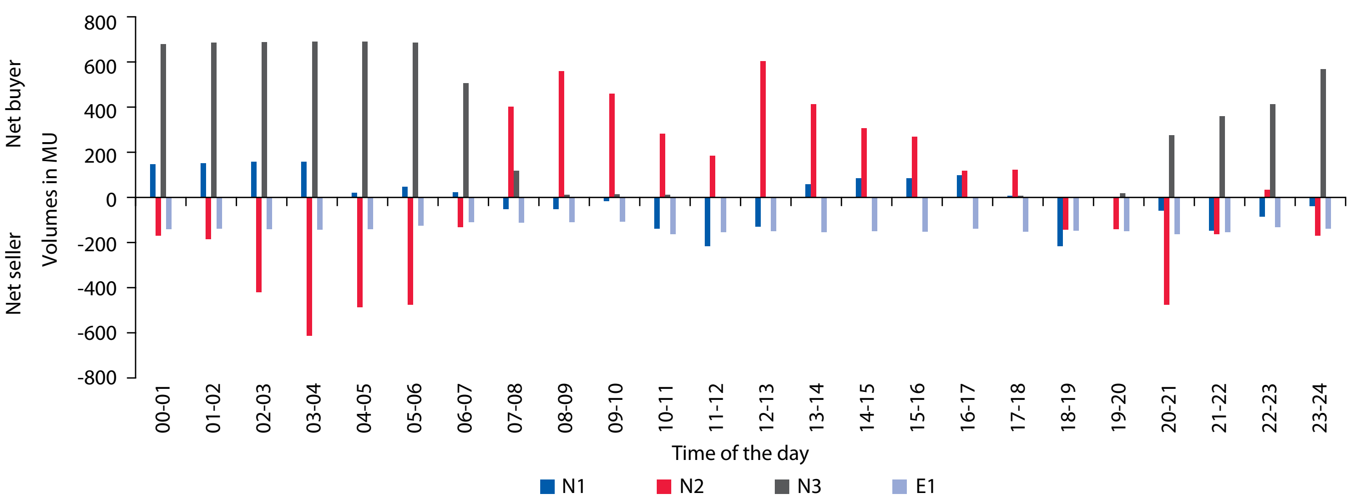
Source: IEX.

Congestion in the transmission network is observed normally along three corridors, viz., S1-S2, S1/S2-ROI, W3 - ROI and N3-ROI. While the power transfer between Rest of India and SR gets constrained mainly in winter season (although in recent times it is observed throughout the year), the ROI – N3 corridor gets congested during summer/ monsoon season. Such seasonal reversal of flows indicates the utilisation of electricity at locations where the electricity is valued the most. IEX, as a leading exchange, indeed facilitates the discovery of the highest marginal utility for each unit of electricity sold.

Apart from efficiencies related to time and cost savings, trading of power has also resulted in higher level of utilisation of generation plants across the country. Power plants, located in regions having off peak or seasonal surplus, no longer have to curtail generation since the power can be sold through the competitive power markets to meet available demand. Higher asset utilisation is indeed a positive effect of trading, resulting in higher efficiency of capital employed and overall economic savings for the nation.

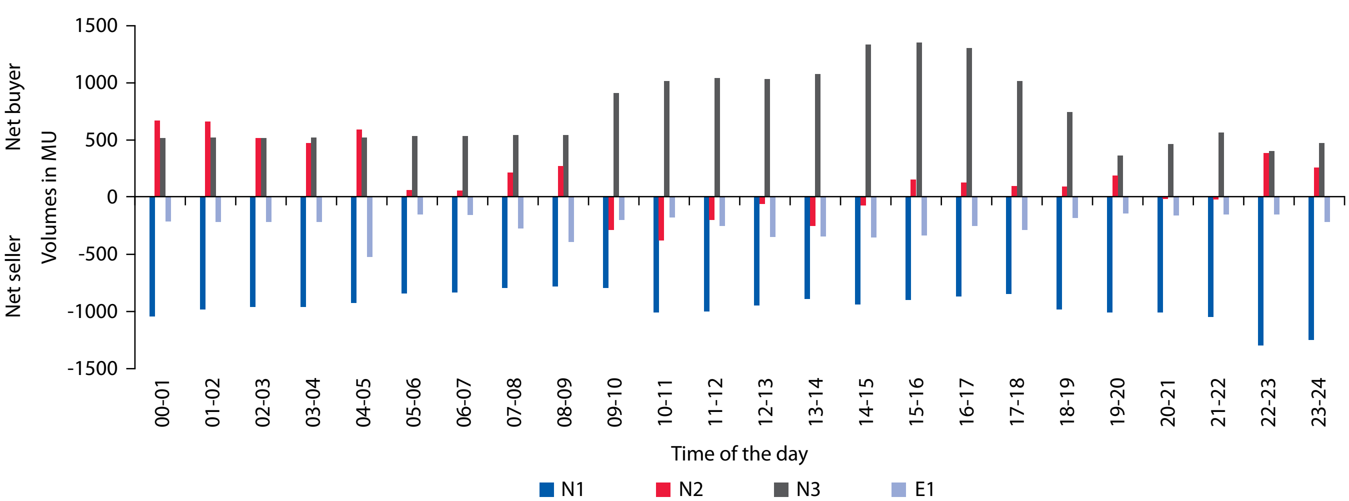
The above graphs provide a snapshot of trade on IEX for typical days at different time of the year. The

Figure 5: Profiles for volume transacted on the exchange on a typical day in December 2012



Source: AF- Mercados EMI Analysis.

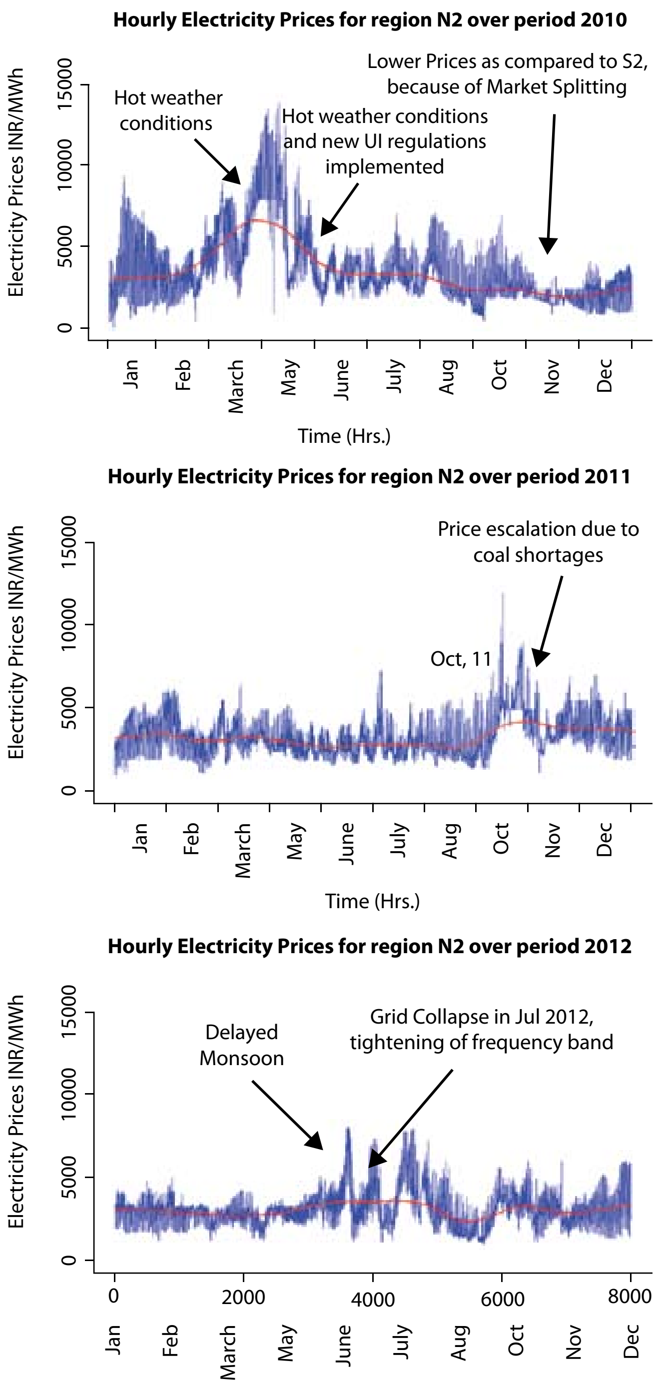
Figure 6: Profiles for volumes transacted on the exchange on a typical day in May 2013



Source: AF - Mercados EMI Analysis.

profiles evidently demonstrate that in summers, N1 is a net seller as generation from hydro assets is relatively higher. Ability to sell power on short term basis through exchange provides a ready platform for these generators to ramp up their production and thereby increasing the efficiency of the plants.

Figure 7: Price movement in N2 from 2010 through 2012



Source: AF Mercados Analysis.

Absence of an exchange would have led to loss in efficiency and overall loss in economic value for the society.

2.3. Signals through Price Movements

The initial period of exchange was marked by infrequent trading activity with high degree of price volatility. However, over a period of time with increased number of players and higher volumes being traded, the price volatility has reduced as captured by the graphs in Figure 7 (2010-2012).

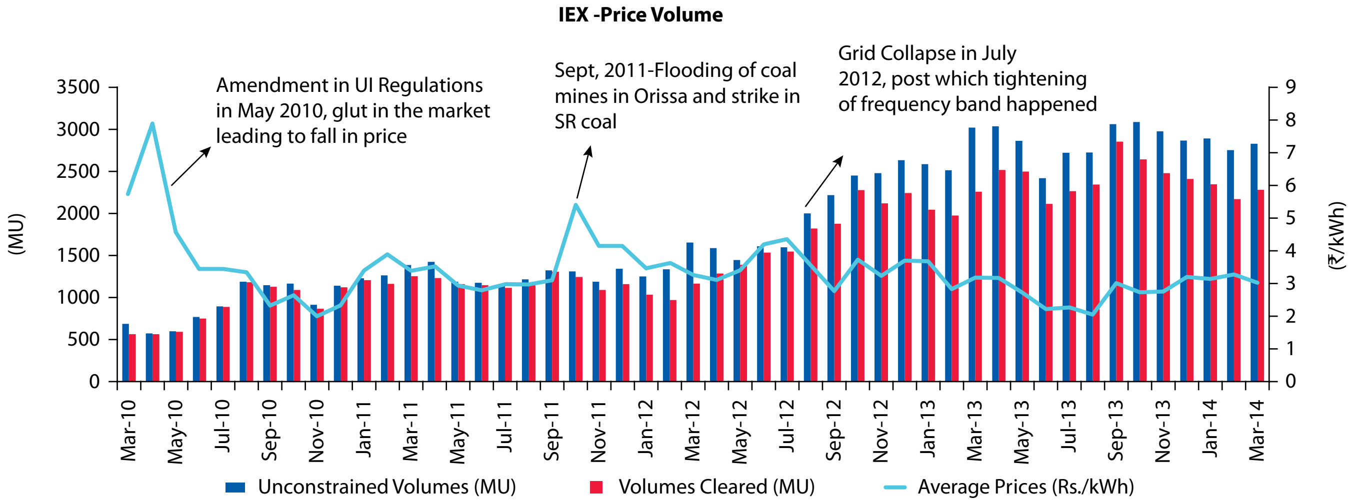
It can be observed from the above graphs that prices respond to various events. Over a period of time there has been a smoothening of price on the exchange. This can be attributed to factors such as, greater participation, and relative increase in the supply compared to the past. Further it can be seen, from the Figure 8 below, that change in the UI regulations in May 2010 led to substantial smoothening of prices. The monthly variation in prices has also reduced over a period of time. In the last one year the volumes have increased substantially due the tightening of grid security post the July 2012 grid collapse.

Price movements in response to market events like regulatory changes, fuel shortages, grid collapse, etc. as highlighted in the graph above support the efficient market hypothesis that prices reflect all publically relevant information and change instantly to reflect new public information.

While prices have internalised the regulatory and systemic changes, they have, at various times since inception of the exchanges, generated signals which were picked up by the investors and policy makers:

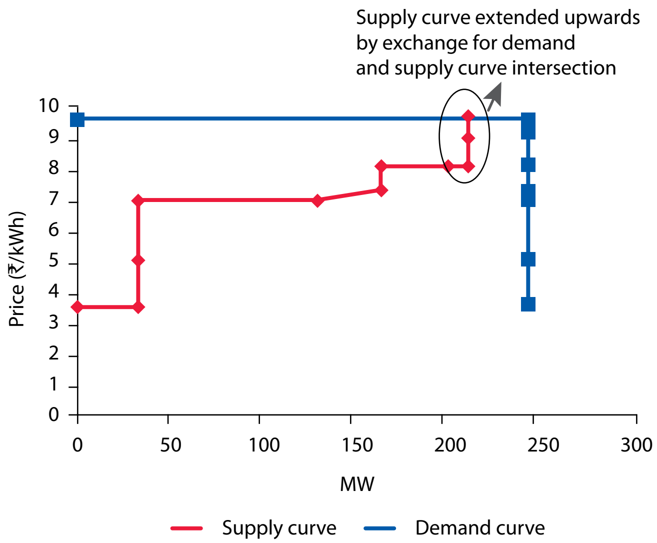
- In the year 2008 and the first half of the year 2009, when the participants presented in each hour were relatively less, high prices were discovered not due to monopolistic behaviour of suppliers but because of the inelasticity of demand. This is typical of economies where demand exceeds supply and supply curves need to be extended vertically to discover the market clearing price as shown in Figure 9.

Figure 8: Trends in prices and volumes on IEX from 2010 through 2014



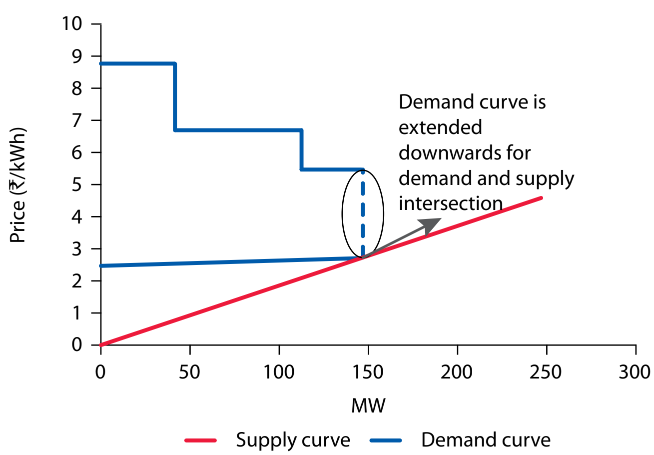
Source: IEX & AF Mercados Analysis.

Figure 9: Illustrative demand and supply curve at IEX during the initial period



Source: AF Mercados Analysis.

Figure 10: Illustrative demand and supply curve at IEX for periods when supply exceeded demand and the curves did not intersect



Source: AF Mercados Analysis.

Hence the prices were 'high' because of the inelasticity of demand and a strictly positive gap between the demand and supply. Though such high prices are not desirable from political and social considerations, from an economics perspective this indicates functioning of the market in accordance with the principles of social welfare maximisation as enunciated in the regulations governing the operation of IEX. However, as indicated by the price movements from 2010 onwards, the incidence of such phenomenon declined significantly. Thus fewer price peaks together with declining volatility is an indicator of short term markets achieving higher liquidity.

In the current market scenario, given the low prices on the exchange, the price is close to the marginal costs of generation thus reflecting any perceived lack of market abuse. Table 1 presents a comparison between the System Marginal Price based on AF Mercados internal models and IEX prices to illustrate lack of market abuse.

Table 1: Comparison between IEX prices and system marginal price as per AF - Mercados EMI Model

Months	System Marginal Prices* (₹/kWh) (2012-13)	IEX Prices (₹/kWh) (2012-13)
April	3.90	3.12
May	3.90	3.42
June	3.90	4.2
July	3.17	4.36
August	3.03	3.53
September	2.97	2.77
October	3.90	3.74
November	3.89	3.22
December**	12.78	3.68
January**	12.78	3.70
February	3.48	2.32

Source: AF Mercados Analysis & IEX.

* System Marginal Prices as computed by ORDENA Plus, a proprietary model of AF Mercados EMI.

** As per the model, system marginal price for December and January are high due to lack of availability of hydro generation and hence low total generation in the country. The actual realised prices are not high because of the inability of the states to purchase at System Marginal Costs.

2.4. Signals for Capacity Expansion

Prices on exchange have motivated independent power producers, captive power producers and merchant power producers to consider short term markets seriously in their portfolio construct. Prior to the commencement of power exchanges, bottled up power from these suppliers could be contracted only bilaterally – a process which involves price negotiations and is time consuming and mired in administrative processes. Exchanges have helped the power sector by allowing this power to flow to the customers in a transparent manner and without providing opportunity to any market player to seek rents.

IPPs have particularly been selling increasing volumes on IEX especially after June 2009 when high prices were discovered on the exchange. Further, depending on the states where they are located, IPPs and MPPs are required to sell a certain percentage of their generation to the state utilities, which in turn, in certain instances, have been selling on IEX. The revenues of the state utilities from sale in short term markets outside the states are ploughed back into more capacity development or are used to reduce the burden of electricity tariff on native state consumers.

Not only have the trading volumes seen an upward trend, the mix of participants on the exchange has also been evolving over time. Though the state utilities continue to be the most active players, there has been a growing trend of IPPs and CPPs selling power through exchange. Clearly, the short term markets, especially post establishment of exchange, are sending signals for investment in new generation and transmission assets.

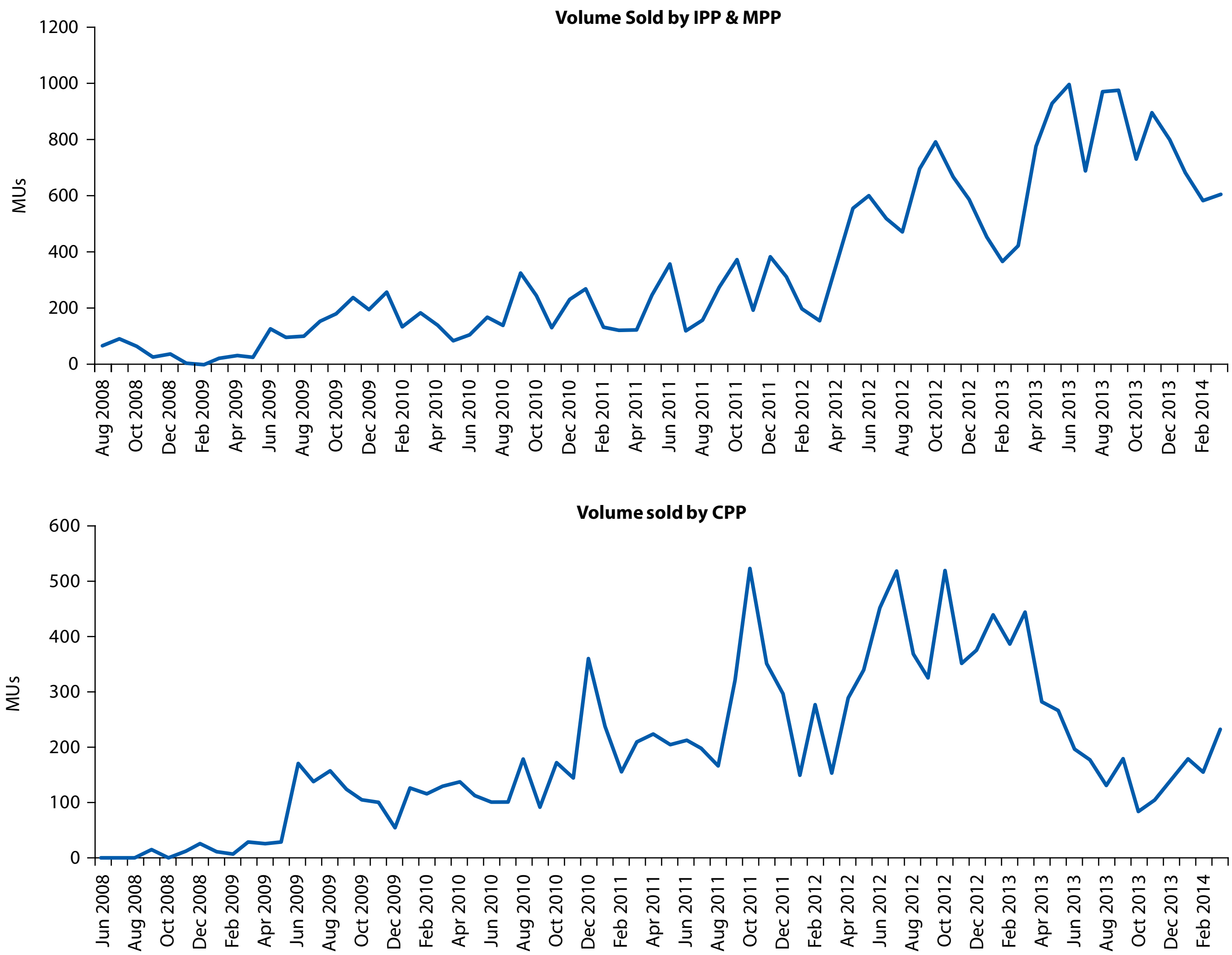
Figure 11 on next page captures the trading patterns of IPPs and CPPs over a time frame.

2.5. Signals for Investment in Transmission

In the last decade, India has transformed from five fragmented and relatively small grids into one large power system which is fully integrated in January 2014. The large grid size has allowed for big power stations, efficient power flows, trading of power and use of geographical diversity to its advantage in optimising power flows. However, the transmission system is marked by high congestion corridors and hence the power flows are constrained. Congestion is defined as a situation where the demand for transmission capacity exceeds the Available Transfer Capability[10]. Before the introduction of collective transactions through PXs in India the "real time" need of demand customers used to be met only through UI. With Day Ahead Market in PXs, volumes from UI shifted to the PXs. However, the transactions on the PXs need approval of the System Operator – RLDCs & SLDCs. It was only when the power system was dispatched and scheduled close to real time; patterns of congestion in the transmission network were transparently observed. Therefore, it was because of PX based transactions

10 Available Transfer Capability (ATC) means the transfer capability of the inter-control area transmission system available for scheduling commercial transactions (through long term access, medium term open access and short term open access) in a specific direction, taking into account the network security.

Figure 11: Volume sold by IPP, MPP & CPP on IEX



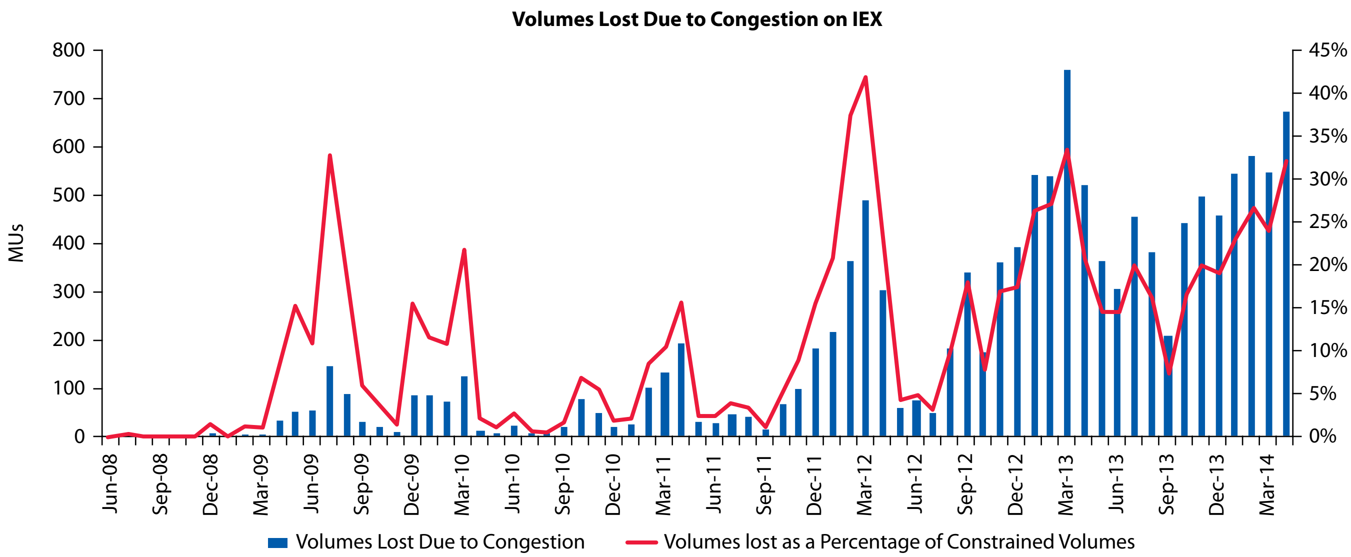
Source: IEX.

that economic impacts of congestion on state utility finances, quality of supply and retail tariffs began to be realised.

Congestion puts constraints on the volume of electricity transacted through power exchanges since they are at the bottom of the priority list of open access on the transmission system (after Long/ Medium/Short Term bilateral contracts). Congestion has a seasonal character. Monsoon and winter congestion tends to be more due to agricultural demand. Congestion and the consequent market splitting resulting in differences in market prices in different regions give rise to congestion charges. The total congestion amount accumulated over the years since inception of PXs is about ₹ 1500 Crores[11]. Even in the bilateral market, market players have been paying very high prices for getting access to transmission corridors (over and above the energy prices). Lack of adequate generation in South has increased congestion causing frequent market splitting between SR and the Rest of India (RoI). The realities of market operation and prices of "transmission" paid by the customers and high price of energy in SR (on the exchange) have generated signals for capacity enhancement in transmission, both at the inter-state and intra-state level. After grid disturbance of July 2012, the System Operator has clamped down

11 As per the CERC Advisory Note on 20th March 2013.

Figure 12: Total volumes lost due to congestion on IEX from 2008 through 2014



Source: AF- Mercados EMI Analysis & IEX.

on transmission capacity availability ostensibly for grid security, hugely increasing congestion.

Presently, a considerable percentage of the cleared volume after price matching is being lost on the exchanges due to congestion in the transmission network. In the last two quarters of FY14 (Oct, 2013 – March, 2014), the cumulative un-cleared volume at IEX was 3.07 BUs which is 17.64% of the total volumes cleared on the exchange in the same period.

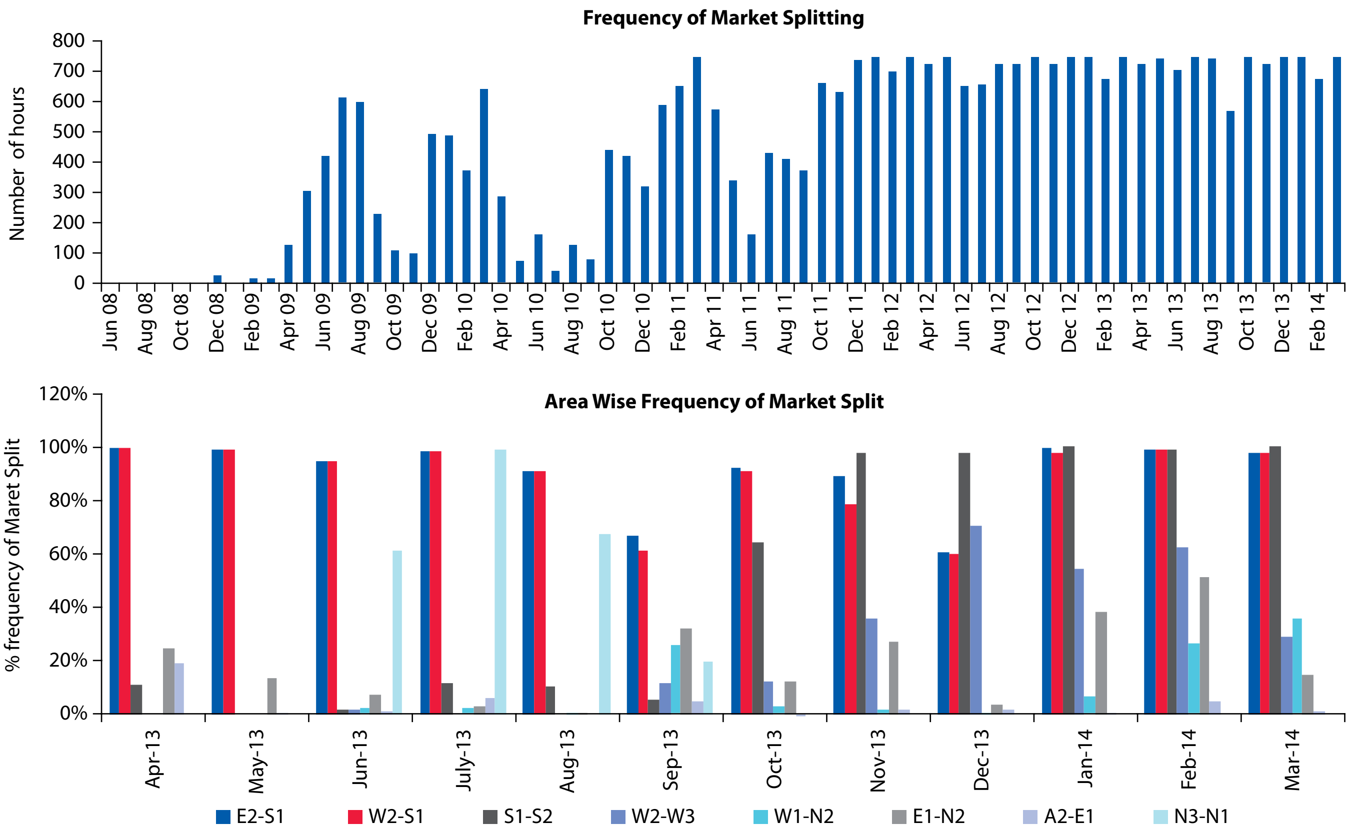
2.5.1. Market Splitting: Efficient Method for Congestion Management

Better congestion management through market splitting allows full utilisation of available transfer capability simultaneously maximizing the trade. The market splitting mechanism avoids e-bidding and makes it possible to integrate auctioning of transmission capacities within the bidding mechanism of the exchange hence acting as a powerful platform for integrating energy and transmission markets. Implicit auction of transmission capacity through market splitting reduces the procedural complexities related to managing price bids and transmission capacities concurrently. The complete bid process from accepting bids to collecting funds and issue of request to NLDC is completed within five hours. The fundamental premise is that exchange handles transmission capacity in a market-oriented way. With this, there is a neutral and fair day-ahead congestion management. The exchange system secures that the day-ahead plans send the commodity in the right direction i.e. from low-price areas towards the high price areas and transactions are netted out in one area.

Figure 12 above shows the increased number of hours in which market splitting was observed since the inception of the power exchanges in 2008, clearly indicating the need for investment in the transmission infrastructure. The southern region has consistently seen the highest percentage of market split among all the regions. Also, the region-wise split shows increased instances of congestion in the Eastern Region.

As discussed above, implicit auction is definitely better than explicit auction, however in the context of Indian Power Market design, small quantum is transacted through implicit auction (about 3% of total generation and around 29% of short term market) and rest 97% of generation, is either on long term, first-cum-first serve or on explicit auction basis. The large

Figure 13: Increased instances of market splitting



Source: IEX.

volume which is not participating in the implicit auction is in fact affecting price discovery under the implicit auction methodology. Therefore there is a need to take a holistic view of the situation and to bring equity between two sets of transactions.

2.6. Risk Mitigation for State Utilities and Open Access Consumers

2.6.1. Risk Mitigation for State Utilities

Open Access provides the flexibility that allows for multiple and diverse power supply contracts to take advantage of the load and time diversity across the geographic regions. Retail choice and open access has in fact been facilitated by the power exchanges, with IEX being the pioneer in operationalising it. Setting up of the exchange has had a positive impact on load serving ability of the utilities, which have traditionally been resorting to excessive load shedding due to inadequate optimisation capabilities. The exchanges have provided an alternative source of buying power in the short term markets close to real time. DISCOMs have also had the opportunity to hold an optimal mix of long term and short term contracts to hedge the risks. They can optimise their power purchase costs by replacing costlier procurement of power under the long term contracts with cheaper power available on the exchange for a certain volume of electricity.

To illustrate the savings that can accrue to utilities as a result of adopting price forecasting techniques for portfolio management, an analysis of the likely savings for Punjab State Power Corporation Ltd by forecasting hourly prices on the DAM on IEX, is presented below:

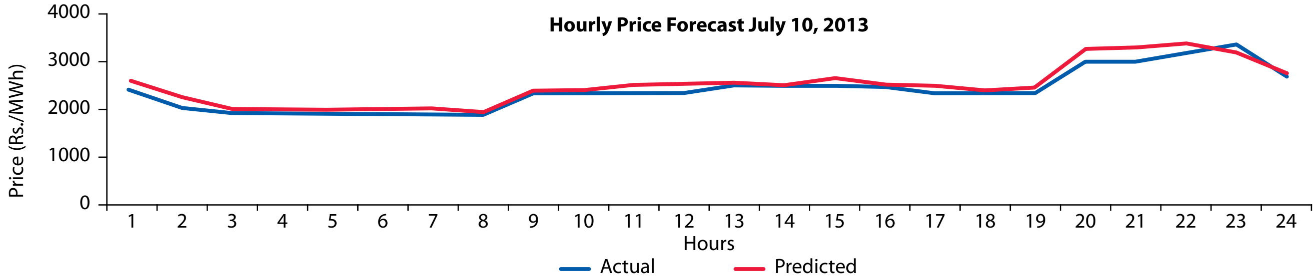
2.6.2. Risk Mitigation for Retail Consumers

One of the most important benefits sought from Open Access is that large number of retail consumers can now approach the exchange for procuring

CASE STUDY

PSPCL procures power from various sources to meet the state demand. If state utility, PSPCL in this case, adopts techniques to forecast the day-ahead prices on the exchange, they can optimise their power procurement costs by adjusting the schedules of some of the high cost generators.

For the purpose of the analysis the day-ahead exchange price forecast for July 10, 2013 have been obtained from the AF-Mercados short term price forecasting model. The Mean Absolute Percentage Error (MAPE) for the forecasts is close to 6%. Graph below depicts the comparison between actual and forecasted hourly prices for the day:

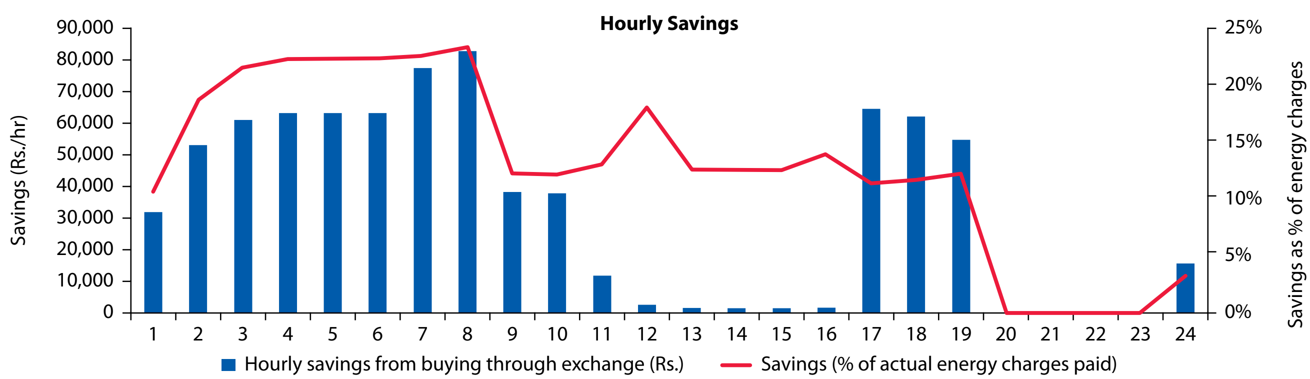


Source: AF- Mercados EMI- Short Term Price Forecasting Models.

The hourly withdrawal schedule of Punjab has been obtained from Northern Regional Load Despatch Centre. Based on the hourly withdrawal from various generating stations and their corresponding variable costs, it was found that adjusting the generation schedules of plants namely Anta Gas, Auraiya Gas, Dadri Gas, and Farakka could lead to monetary benefits for the utility. Table below presents the total daily drawl of each of these stations and corresponding variable costs:

Plants	VC (₹/kWh)	Drawl (MWh/day)
Auraiya (G/F)	2.83	728.64
Dadri Gas (G/F)	2.85	1046.14
Farakka (ER)	2.86	144.52
Anta (G/F)	2.77	571.69

The variable charges for the above plants were higher than the hourly prices on exchange for most part of the day barring the peak hours. Hence, it would be prudent for the utility to buy power from exchange rather than scheduling these plants. Given below is the graph for hourly savings:



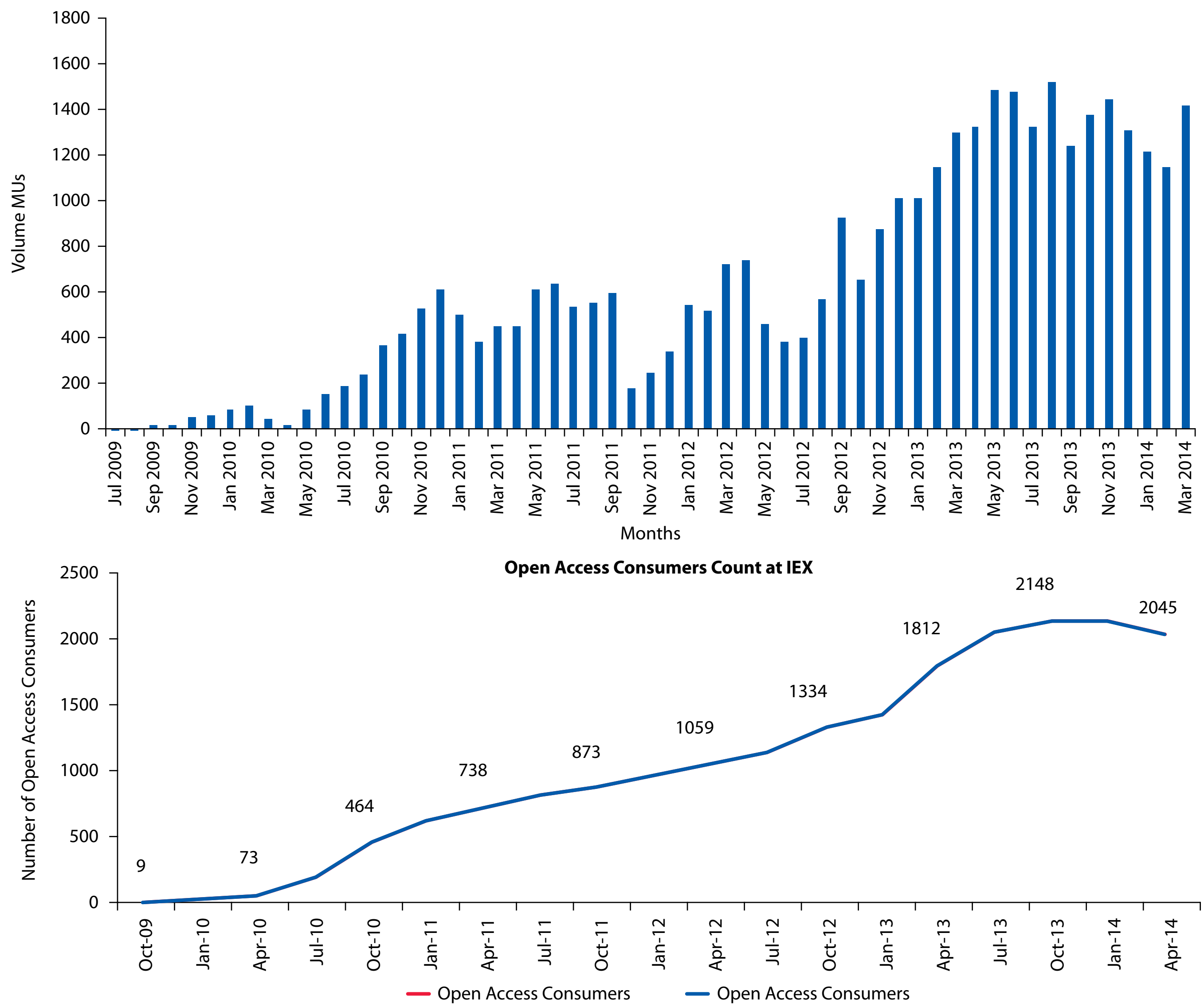
Source: AF- Mercados EMI analysis.

It was further analysed that even if the utility bids 10 paisa/kWh over the hourly forecasted price to ensure availability of supply of power, it would be able to procure power in almost all the hours during the day. The corresponding savings from buying power from exchange at the actual market clearing price would be ₹ 11.46 lakhs per day. Assuming similar savings throughout the month, the total reduction in power purchase cost would be close to ₹ 3.44 crores per month or approximately ₹ 42 crores per year.

uninterrupted power supply at a competitive tariff which was earlier curtailed during evening peak hours. Given the competitive and predictable day-ahead market prices, a large number of industrial customers have made forays into the day-ahead market utilising Open Access to supplement their off take from utilities and reduce their effective costs of purchase. This is expected to create immense value for these businesses.

Some of the states that are more actively participating on IEX are Tamil Nadu, Punjab, Andhra Pradesh, Rajasthan, Gujarat and Haryana where a large number of industrial consumers have accessed supplies from the power exchange. Over time the participation by Open Access customers has increased significantly. It is observed that currently as much as 40-45% of the overall trade on the day-ahead markets at IEX comes from direct customers availing Open Access. This constitutes close to 0.8% of the overall electricity supply in the country. While relatively low in overall terms, the volumes (annually about 6-7 BU) are significant. Figure 14 presents an approximate estimate of the power flows through open access on the exchange and the corresponding increase in the number of Open Access consumers.

Figure 14: Participation of Open Access consumers in IEX Day-Ahead Market

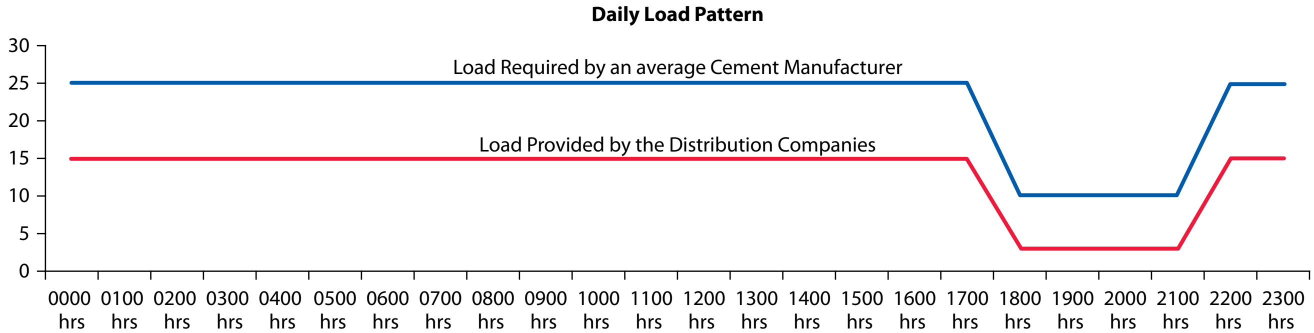


Source: IEX.

It may be indicated that there has been a significant growth in open access consumers on IEX in the last few years. Retail competition requires that the retail consumers should get an option to switch suppliers. IEX has provided a platform where the distribution companies can manage their risks and thereby allow unfettered movement of consumers across alternate sources of supply. The following Case Study highlights the point that IEX provides a cost effective alternative to the retail consumers through Open access.

CASE STUDY ON CEMENT INDUSTRY

For the Cement Industry, three Companies were selected in Andhra Pradesh. It was discovered that the cement manufacturers were badly hit due to the load shedding by the Distribution Companies. The power supplied by the Distribution Companies was only a fraction of what was actually needed by the manufacturers. The following figure shows the load required by an average manufacturer versus the load, which the Distribution Company of Andhra Pradesh is able to supply.

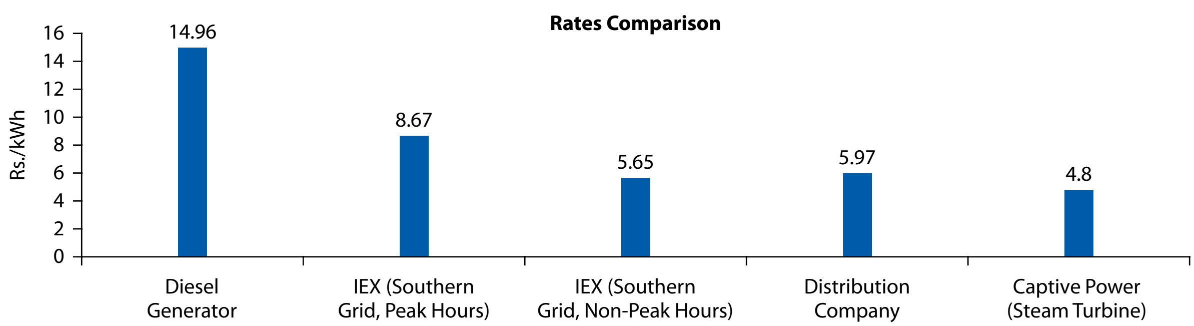


Faced with such a situation, the manufacturers have 3 options:

a. Cut down the production according to the power supplied by the Distribution Company - Total Revenue lost by manufacturer who has to reduce his production due to no power backup - ₹ 2.7 Crores per month.

b. Use a power backup or own source of electricity to generate the remaining power - In case the manufacturer chooses to generate his own power through diesel generator, he will have to pay an extra ₹ 1.32 crores monthly. If he chooses to set up a CPP, then he will have to bear an installation cost of ₹ 15 crores, apart from the risks of maintaining and running such a plant.

c. Buy power from IEX to fulfill requirements - given such a scenario, the best option for a Cement Manufacturer in Andhra Pradesh is to buy the electricity from IEX to meet the shortfall. A comparison of the electricity costs from different sources is shown in the chart below:



* IEX rates given above are calculated at Regional Periphery.

A quick look at the different rates shows that after the distribution company, the rates of IEX are the best option available to the manufacturer, given the high investments costs attached with setting up a Captive Power Plant.

2.7. Facilitating RE Generators to Participate in REC Market

India's renewable energy generation capacity addition has witnessed tremendous growth over the past two decades for both grid and off-grid applications. An REC, which represents 1 MW-hour of power produced from a renewable energy source, represents green attribute of the renewable power; is tradable on power exchanges. The states or utilities that are unable to fulfil their Renewable Energy Purchase Obligation (RPO) can buy these certificates to make up for shortfall in renewable power in their total energy mix. Users might prefer RECs, which are valid for 730 days, than buying renewable power from the market, as RECs do not involve inter-state scheduling and shield traders from the uncertainty surrounding renewable power. The concept of an REC was introduced with an objective to:

I. Address the mismatch between disposition of renewable energy sources within states and the requirement of obligated entities to meet their renewable purchase obligations in a cost effective manner.

II. Widen the base of the buyers and sellers of RE.

III. Obviate inter-state transmission needs in form of a certificate.

IV. Make procurement of green energy/attributes simpler.

REC mechanism aims at promoting additional investment in RE projects and to provide an alternative mode to the RE generators for recovery of their costs.

Experiences of REC transactions in the past two years have provided valuable insights into its operations. A total of 4414 MW of renewable energy generators have been accredited for REC out of which 4013 MW of capacity has been registered as on February 1, 2014.

After the introduction of REC mechanism on 14th January 2010, nearly 6,300 MW of RE capacity has been commissioned. Out of this, as of July 2012, 2,470 MW (~68%) of new capacity which got commissioned after 14th January 2010 was registered under the scheme as shown in the Table 2 below:

Also, in terms of volume, demand for RECs should largely have been from distribution companies. Only a few captive consumers are participating in the REC market. While most of the participating entities are Union Territories or privately owned DISCOMS; the state DISCOMS are not at all active in the market.

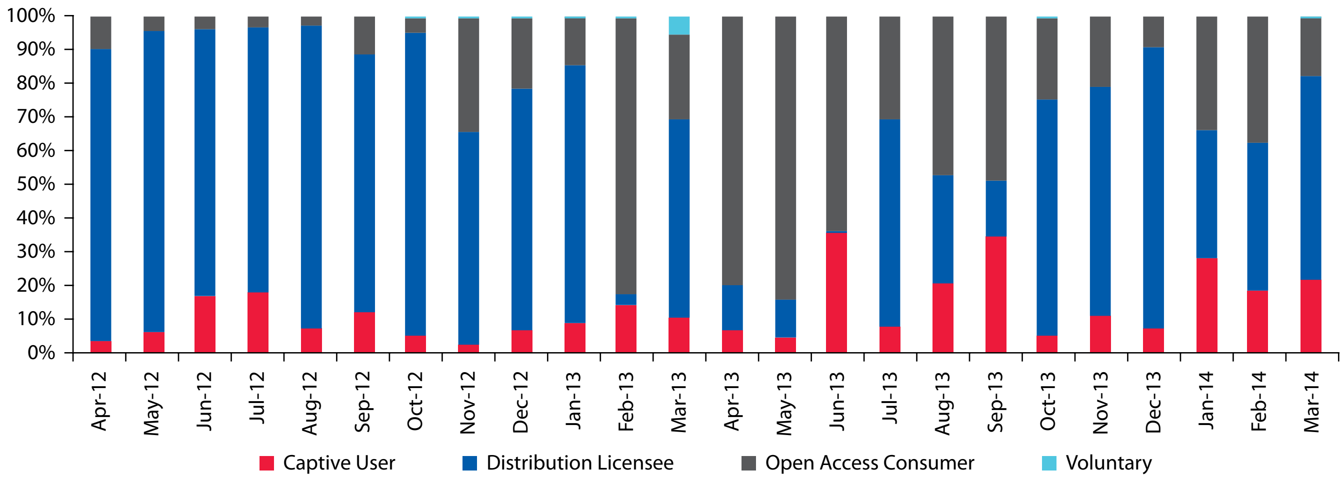
Along with trading of RECs, products like Intra-day Contracts and Day-Ahead Contingency Contracts can also facilitate inclusion of small and renewable based power generators in the Indian power markets. Forecasts for solar and wind based generation are more accurate and closer to the real time. By providing a

Table 2: Status of REC registered projects from January 2010 up till February 2014

S.No.	Energy Source	OLD (commissioned up to 14.01.2010)		NEW (commissioned after to 14.01.2010)		Total	
		No. of Projects Registered	Capacity (MW)	No. of Projects Registered	Capacity (MW)	No. of Projects Registered	Capacity (MW)
1	Wind	117	281.08	449	1893.1	566	2174.18
2	Bio-fuel cogeneration	46	532.68	35	205.39	81	738.07
3	Small Hydro	5	47.5	18	155.51	23	203.01
4	Biomass	29	293.6	39	356.86	68	650.46
5	Solar PV			164	368.88	164	368.88
6	Urban or Municipal Waste			1	8	1	8
7	Others			1	1.67	1	1.67
	Total	**197**	**1154.86**	**599**	**2659.05**	**904**	**4144.27**

Source: NLDC as on 31st March 2014.

Figure 15: Buyer Mix at IEX-REC market



Source: IEX.

window on a day ahead and term ahead (week ahead and intra-day/on the same day) basis, the exchanges can encourage growth in green power. Buying and selling of green power through the exchange will help the state utilities to plan their schedule better. For instance in the renewable rich states like Tamil Nadu, Rajasthan, Gujarat, etc., in case of unexpected increase in wind generation excess power can be sold on the exchange closer to real time. Also, if the demand is assessed anticipating wind generation and if the wind generation abruptly goes down, then the state discoms can purchase short term power on the exchange instead of resorting to heavy load shedding to maintain grid discipline.

SUMMARY: RELEVANCE OF PXS FOR INDIAN POWER MARKETS

To encapsulate, given the thrust on increase in competition in the market, Power Exchanges have evolved rapidly to compliment and supplement the needs of the wholesale power markets in a transparent and efficient manner. Trading on exchanges has matured despite initial low volumes and high prices. After six years of operation, markets are now more efficient, liquid and promote investment and better utilisation of national resources.

IEX, as the power exchange with maximum volume and largest participation, has played an important role in furthering the objectives of the Electricity Act 2003 by enhancing competition, implementing open access and through realisation of the impact of de-licensing of generation. Creation of national grid has been supported by commercial contracts wherein huge volumes of electricity have been transferred across India to improve the reliability and security of supply in both the surplus and deficit regions. The exchanges have aided in better utilisation of national resources, reduced unmet demand and consequently reduced economic losses and improved energy security of the nation. Huge bottled up captive generation has also been brought into the national market to facilitate its most productive use to the economy.

CHAPTER 3

ASSESSING MARKET POTENTIAL AND CHALLENGES HINDERING GROWTH

Introduction of power exchanges triggered market based reforms of institutions and led to development of processes to support creation of such markets. The increase in depth of short term markets is clearly reflected through increase in the share of volume traded in the short term as a percentage of total energy generated in the country. Further, in conjunction with the objectives of the Power Market Regulation, 2010, efficiency and liquidity in DAM has improved and is illustrated by growth in volumes, lesser price peaks, and prices that reflect adaptive and rational behaviour of market players. With an increasing market share being captured by short term markets over the years, it becomes important to analyse the potential growth capacity of such markets in lieu of changing market needs and existing barriers.

3.1. Current Potential Size of Short Term Markets

The natural limits to the short term markets are determined by:

(a) Nature of the load curves of various States and co-skewness between load curves of various States.

(b) Distribution of various sources of generation in the network, including renewable energy (more precisely VRE) generators.

(c) Flexibility of such generators.

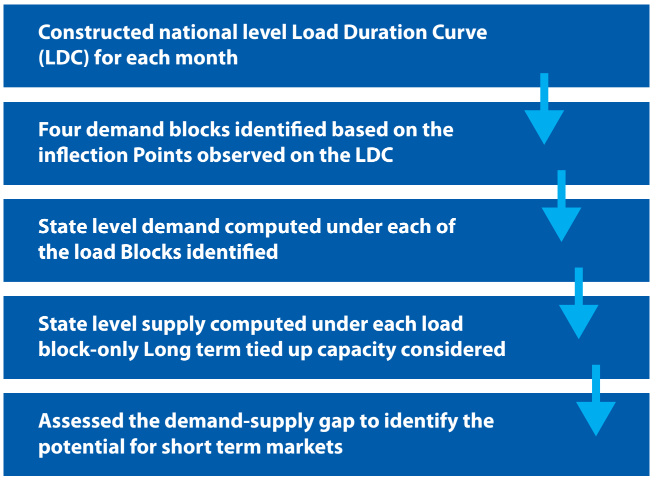
(d) Strength of the transmission network itself.

If the short term power markets in India are still short of exploiting these natural limits, it is imperative that the constraints be identified and next steps defined. In terms of the above description of the "natural limits" – while (a) can be exploited readily by the various DISCOMs, unlocking the potential through (b), (c) and (d) requires regulatory interventions. The National Electricity Policy, 2005 envisions that 85% of power from new capacity shall be contracted through long term PPAs. Such contracts would take care of debt coverage and financing obligations of the power players. It is expected that power players will transact substantial part of the remaining 15% power capacity through market mechanisms - a number which could be analysed through analysis of point (a) above.

To establish the natural limits of the volume of trades possible in short term market, the state/regional/national level load curves have been analysed to determine the potential of each state to participate in such markets under the current demand-supply scenario. Figure 16 presents a snapshot of the methodology adopted for computing these limits. Detailed assumptions and underlying methodology have been presented in Appendix 1.

Graphs in figure 17 depict the block wise demand-supply gap, considering only long term contracts by the state utilities, for representative months in the year. It is typically observed for all the states, as well as at the national level, that the long term supplies serve only the base load block. Shortfall, with respect to long

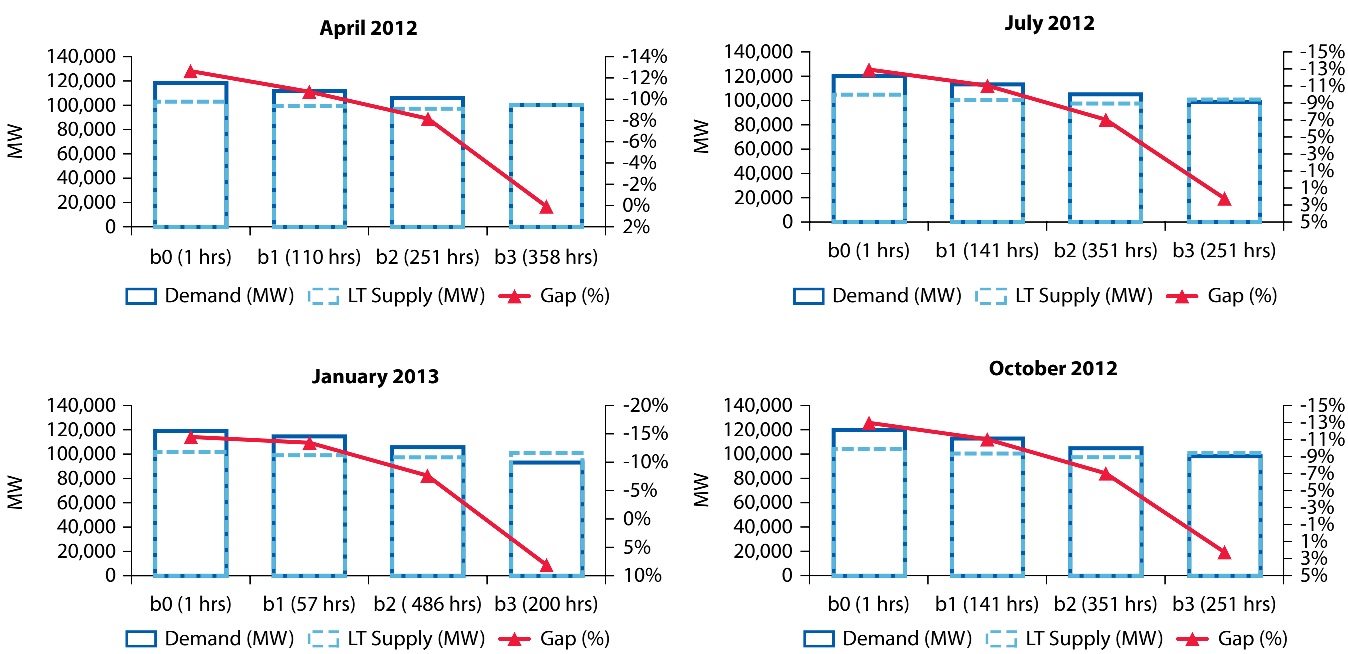
Figure 16: Methodology for establishing natural limits of short term markets



term supplies, in other blocks indicates the potential for short term markets. This potential is however subdued owing to approximately (conservatively) 10% load being shed.

The load curves of states not only differentiate from each other but also vary across seasons for a given state implying that a state might have a net buying potential in a month but might have a net selling potential in another month. Aggregation of total buying and selling potential across States in different blocks in energy terms (MWh) indicates buying potential of 15.35% and a selling potential of 4.57% across States for the short term market. This potential is only on account of co-skewness of the demand met in each State. The actual potential

Figure 17: National level block-wise demand and supply potential for sample months



Source: AF-Mercados EMI Analysis.

Table 3: National level block-wise demand and supply potential for 2012-13

Blocks	Buy Potential (MWh)	Sell Potential (MWh)
b0 (peak block)	339635	38230
b1 (Intermediate block-I)	30028372	4242540
b2 (Intermediate block –II)	77465238	16834202
b3 (Base Block)	40977338	23135706
Total	148,810,583	44,250,677

Source: AF-Mercados EMI Analysis

is however higher and would be 23.5% if load shedding in energy terms, assumed conservatively to be 10% is addressed.

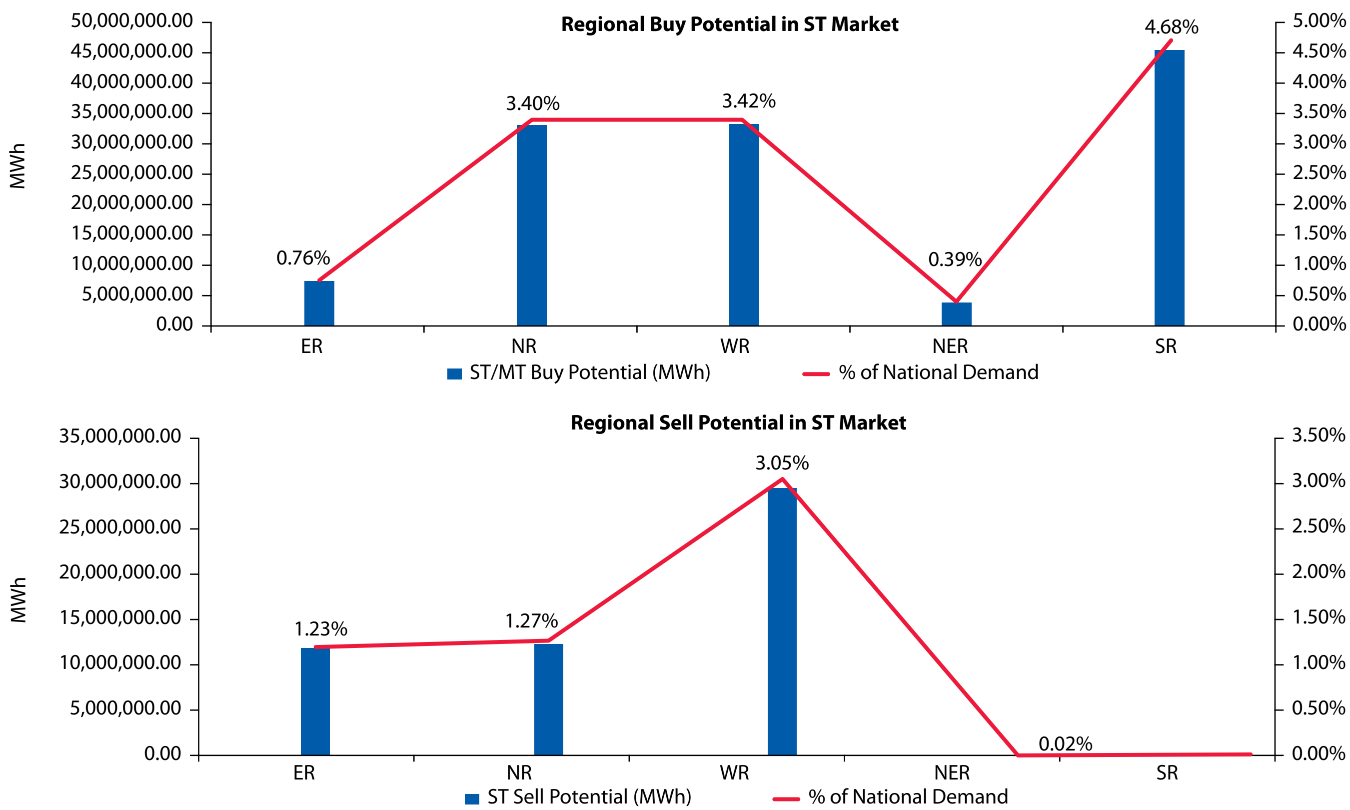
The potential would also increase if all the States were to allow their large industrial customers (greater than 1 MW) to procure from short term markets. The supply side potential is also high because (a) the private sector plants – e.g. Sterlite, Jindal, JSWL, etc. sell a fixed percentage of their output in short term markets, (b) the un-requisitioned capacity of central sector plants (which the Staff paper of CERC on Ancillary Services Market proposes to be used for providing Frequency Support Ancillary Services) is also available in short term markets.

Figure 18 illustrates the regional buy and sell potential limits at inter-state level due to co-skewness of the demand curves of various states, based on the data for 2012-13. The computation of the same has been carried out at state level and further aggregated to the regional level. State level buying and selling potential is presented in Appendix 2.

To reiterate, the natural limits derived above are subject to a certain degree of variability. Some of the aspects that might have an impact on these limits are mentioned below:

- State level demand reported is the constrained demand that does not take into account the latent demand or unserved demand that is not recorded in the CEA/Load Dispatch Centres (LDCs) recording systems.
- Demand currently reported does not capture demand of the large industrial and commercial open access consumers, which is met through captive diesel generating sets.
- The state level supply ignores the power that is sold on merchant basis. Only firm tied

Figure 18: Regional buying and selling potential limits at inter-state level due to co-skewness of the demand curves of various states (2012-2013)



Source: AF- Mercados EMI Analysis.

Table 4: State-wise buy and sell potential for sample months for the peak demand block

	April				July				December			
	BUY Potential		SELL Potential		BUY potential		SELL Potential		BUY Potential		SELL Potential	
	States	Volume	States	Volume	States	Volume	States	Volume	States	Volume	States	Volume
WR	Chhattisgarh	373	Gujarat	2766	MP	3100	Chhattisgarh	332	Chhattisgarh	459	Gujarat	1485
	Maharashtra	2317	Goa	94	Maharashtra	1225	Gujarat	2497	MP	5456	Goa	204
	MP	3927	Daman	2	DNH	35	Daman	13	Maharashtra	3348		
	DNH	5					Goa	75	DNH	14		
									Daman	14		
Total WR Region		**6623**		**2862**		**4361**		**2917**		**9291**		**1690**
ER	Jharkhand	38	Sikkim	58	Bihar	436	Sikkim	88	Bihar	685	Sikkim	17
	Odisha	650	DVC	1105	Jharkhand	41	DVC	671	Jharkhand	72	DVC	366
	WB	242			Odisha	1078			Odisha	445		
	Bihar	168			WB	1136			WB	435		
Total ER Region		**1097**		**1163**		**2692**		**759**		**1637**		**382**
NR	UP	1651	J&K	28	UP	3412	J&K	540	UK	850	Delhi	1101
	UK	594			UK	294	HP	469	Rajasthan	1106		
	Rajasthan	822			Rajasthan	1627			Punjab	203		
	Punjab	946			Punjab	1854			J&K	347		
	Haryana	293			Haryana	1769			HP	215		
	HP	135			Delhi	1056			Chandigarh	36		
	Chandigarh	43			Chandigarh	58			UP	525		
	Delhi	11							Haryana	51		
Total NR Region		**4495**				**10070**		**1009**		**3333**		**1101**
SR	AP	3832			AP	2969			AP	3774		
	Karnataka	2696			Karnataka	2775			Karnataka	2026		
	Tamil Nadu	5290			Tamil Nadu	3397			Tamil Nadu	4729		
	Kerala	1473			Kerala	1622			Kerala	1565		
Total SR Region		**13291**				**10763**				**12095**		
NER	Arunachal	63			Arunachal	23	Meghalaya	23	Arunachal	59		
	Assam	534			Assam	461			Assam	624		
	Manipur	21			Manipur	48			Manipur	73		
	Meghalaya	168			Mizo ram	23			Meghalaya	120		
	Mizoram	22			Nagaland	39			Mizo ram	17		
	Nagaland	24			Tripura	62			Nagaland	40		
	Tripura	16							Tripura	36		
Total NER Region		**848**				**656**				**970**		**0**
National Total	**51861**		**8078**		**56426**		**9392**		**53679**		**6347**	

Source: AF- Mercados EMI Analysis.

Table 5: State-wise buy and sell potential for sample months for the intermediate demand block

	April				July				December			
	BUY Potential		SELL Potential		BUY Potential		SELL Potential		BUY Potential		SELL Potential	
	States	Volume	States	Volume	States	Volume	States	Volume	States	Volume	States	Volume
WR	Chhattisgarh	34118	Gujarat	343531	MP	369497	Chhattisgarh	23848	Chhattisgarh	31810	Gujarat	123985
	Maharashtra	241569	Goa	10997	Maharshtra	113244	Gujarat	239211	MP	392642	Goa	16253
	MP	337070	Daman	1415	DNH	2784	Daman	1373	Maharashtra	257603		
			DNH	1311			Goa	12832	DNH	1344		
									Daman	625		
Total WR Region		**612756**		**357254**		**485525**		**277264**		**684024**		**140238**
ER	Jharkhand	9154	Sikkim	5571	Bihar	68332	Sikkim	9607	Bihar	47188	DVC	31589
	Odisha	81160	DVC	100449	Jharkhand	14920	DVC	50898	Odisha	52713		
	WB	44718			Odisha	91391			Jharkhand	1141		
	Bihar	25244			WB	117338			Sikkim	11		
									WB	27659		
Total ER Region		**160276**		**106020**		**291982**		**60505**		**101053**		**31589**
NR	UP	112839	Haryana	385	UP	301282	J&K	32765	UK	64142	Haryana	34346
	UK	62066	Rajasthan	33271	UK	36242	HP	50351	Rajasthan	101547		
	Delhi	283612			Rajasthan	144055			Punjab	8335		
	Punjab	48452			Punjab	174931			J&K	20946		
	J&K	22521			Haryana	1104			HP	15475		
	HP	13297			Delhi	375189			Delhi	181637		
	Chandigarh	2562			Chandigarh 5470				Chandigarh	2535		
	Rajasthan	33271							UP	44725		
Total NR Region		**705624**				**1330256**		**143622**		**495671**		**65935**
SR	AP	352270			AP	305316			AP	253094		
	Karnataka	267175			Karnataka	215232			Karnataka	129901		
	Tamil Nadu	467971			Tamil Nadu	340055			Tamil Nadu	356468		
	Kerala	134830			Kerala	169065			Kerala	108320		
Total SR Region		**869976**				**724352**				**594689**		
NER	Arunachal	6397			Arunachal	274			Arunachal	4702		
	Assam	48015			Assam	53698			Assam	42210		
	Manipur	3447			Manipur	4050			Manipur	6197		
	Meghalaya	16908			Meghalaya	1536			Meghalaya	10411		
	Mizoram	2746			Mizoram	2342			Mizoram	2642		
	Tripura	6789			Nagaland	4120			Nagaland	4476		
	Nagaland	2687			Tripura	7963			Tripura	7616		
Total NER Region	**86988**					**73984**				**78253**		
National Total		**5009518**		**960204**		**5751548**		**902276**		**4053551**		**443936**

Source: AF- Mercados EMI Analysis.

up capacity has been included. The selling potential is likely to increase by an equal extent, if that capacity is also accounted for. This would be close to an additional 100,000 MUs[12] of energy per annum.

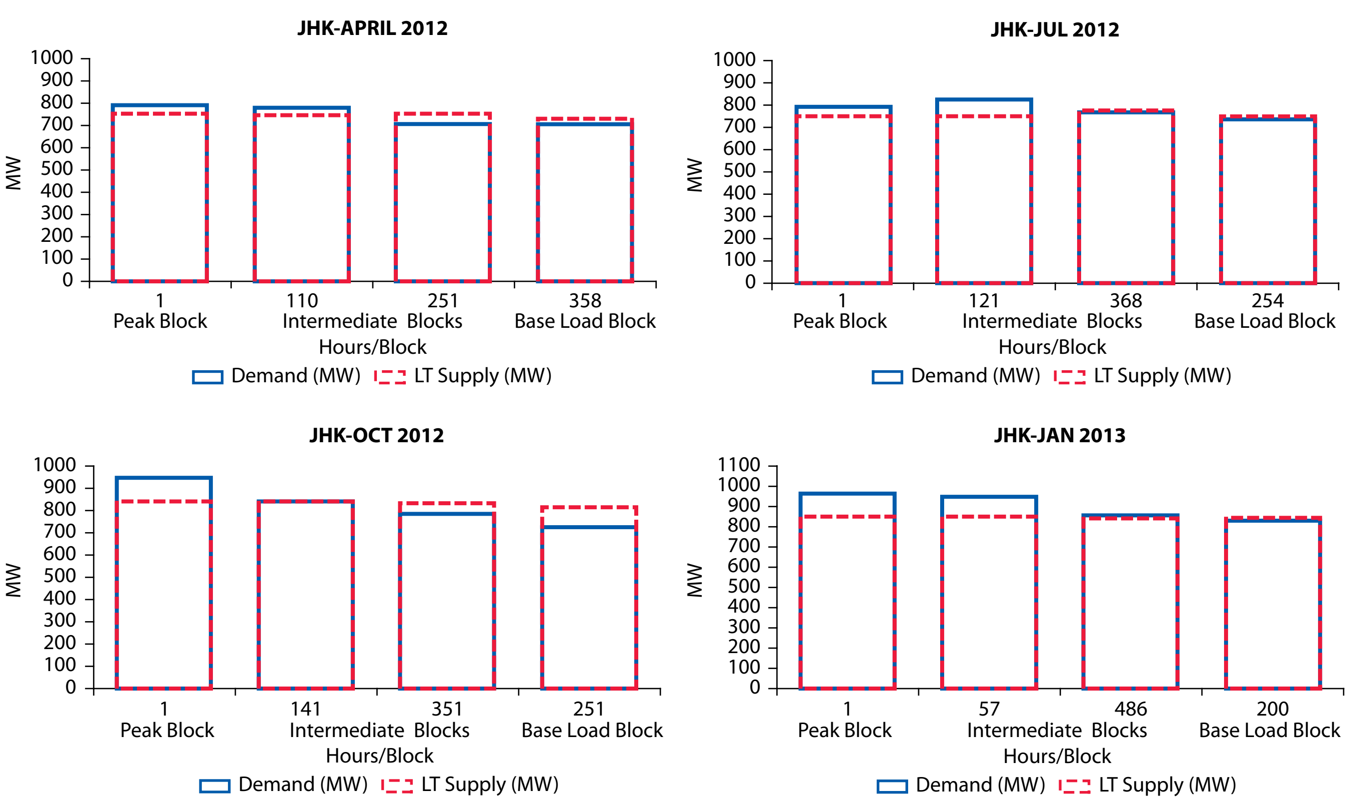
Trading in the short term markets is governed by the differences in the load curves of various trading utilities/entities in the country. It may not, however, always be possible to transmit power - from a region which has a peaking capacity, during other than peak periods - to another region where there is a peak requirement, due to transmission constraints. In these conditions the local distribution utility facing peaking conditions may need to tie up with a local peaking generator for short term. Therefore, short term planning is distinct from long term planning and involves consideration of both the local peaking resources and transmission from other regions for the reasons of economy.

Power distribution utilities optimally use forward positions and hence their requirements in the short term markets depend on forecasted usage, available transmission capacity, interrelations between local and system demand, and the co-skewness of local power demand with system-wide demand.

The tables and the graphs in figure 19 provide a snapshot of the seasonal co-skewness of states across different load blocks.

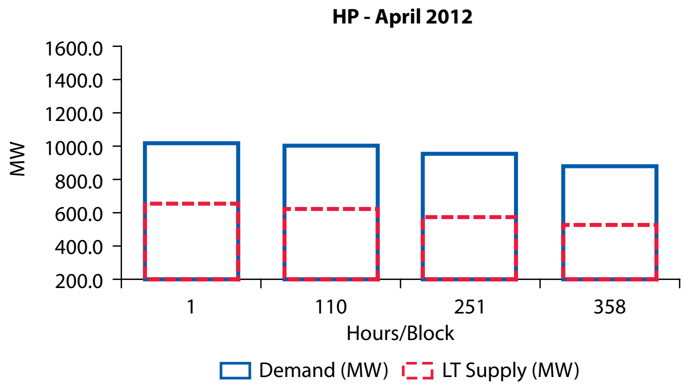
A comparison of the few sample states indicates that during April, Haryana seems to have surplus availability from long term sources in some blocks that could be traded, while other states have deficit and need to procure in the short term markets. A common observation across states is that in each month the procurement from LT sources is close to the requirement in the base blocks. In July, which is a monsoon month, Himachal Pradesh has surplus

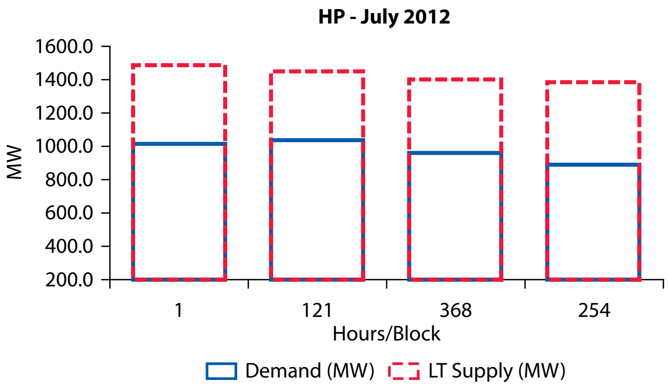
Figure 19: Block-wise buy and sell potential for sample states (the blocks in the following figures are sequentially b0 (peak block), b1 & b2 (intermediate blocks), b3 (base block))

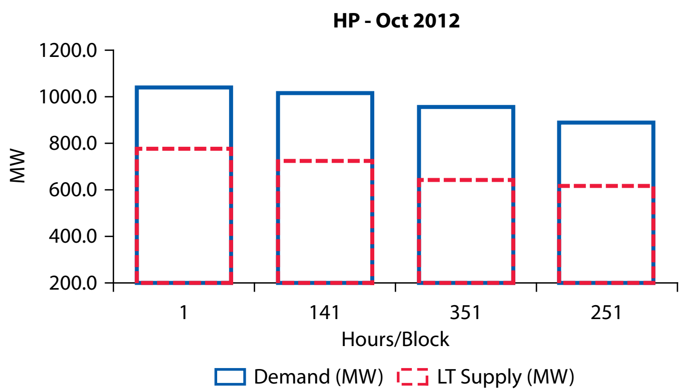


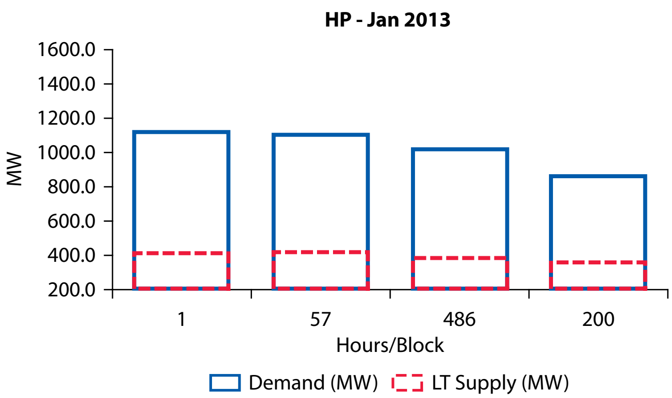
Source: AF- Mercados EMI Analysis.

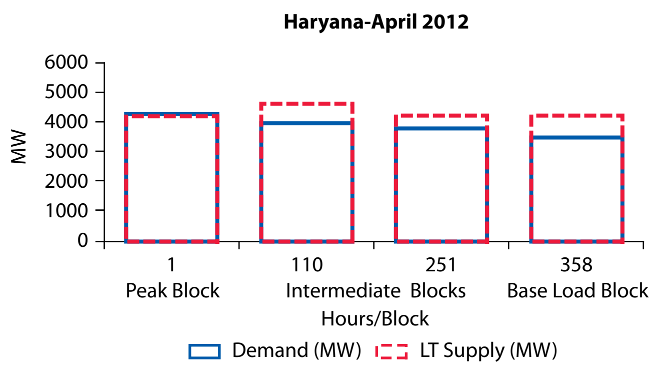
12 Based on AF Mercados Internal Databases.

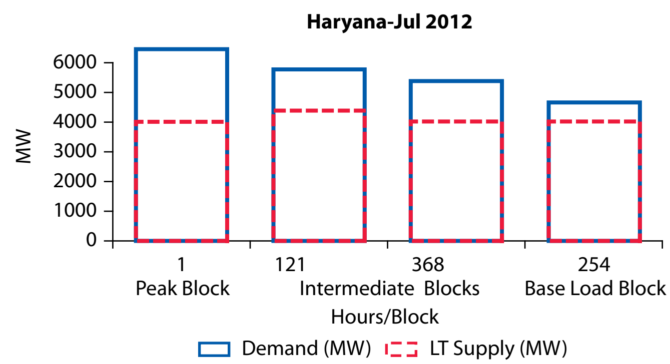


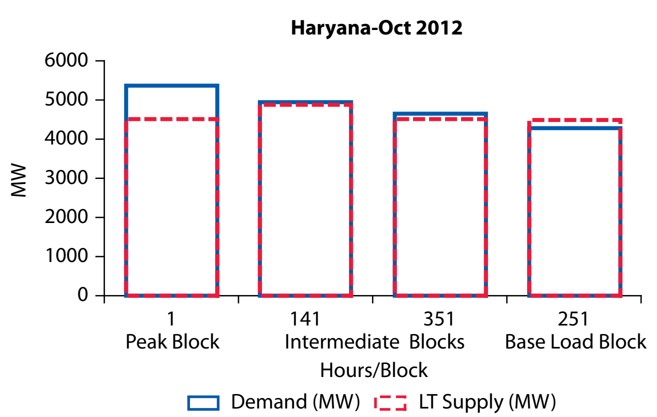


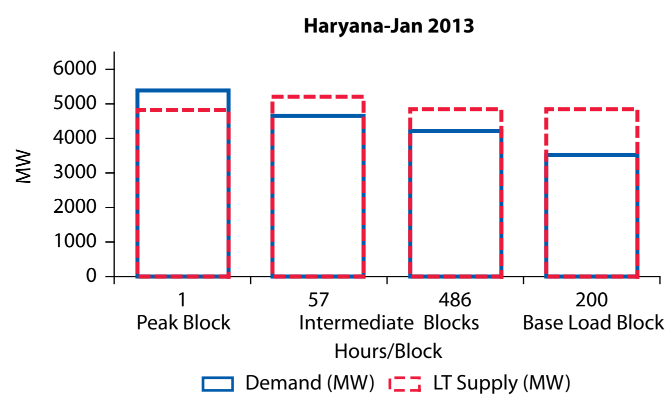












Source: AF- Mercados EMI Analysis.

ASSESSING MARKET POTENTIAL

To summarize, the short term market is still to achieve its full potential. Empirical analysis of the same illustrateds an annual buying potential of 15.35% and a selling potential of 4.57% at the national level for the year 2012-13. This potential is muted, as it does not take into consideration the extent of load shedding. If that is taken into consideration (assuming a 10% load shedding in the country), the potential size of the short term markets would be around 23.5%; thus highlighting the huge untapped potential and an opportunity of further development of the short term power markets in India.

Given the impact of integration of NEW and the SR Grids and the Central Electricity Regulatory Commission (Deviation Settlement Mechanism and related matters) Regulations, 2014 and Central Electricity Regulatory Commission (Indian Electricity Grid Code) (Second Amendment) Regulations, 2014, the size of the day ahead markets is only expected to increase over time.

Looking at the gap between demand and the supply from capacity tied up under long term contracts, clearly long term contracts of utilities will continue to be insufficient to serve the entire demand across various states. States will continue to depend on short term markets for meeting their power needs on real time basis. In this context, power exchanges would continue to play an important role going forward. Further, traction on the exchange would require introduction of new products like Ancillary Services Market to increase liquidity in the market and also address the regulatory actions taken for mitigating transmission congestion and strengthening grid security and stability.

capacity which could be traded. In January, Himachal Pradesh is deficit, because of its reliance on hydro generation while Haryana has surplus in all but the peak block, which it could make available for sale. This analysis shows the potential of short term markets due to co-skewness of demand across states.

While the country is currently short of exploiting the limits to these short term markets, it is expected that the ongoing trend of increase in volume of trade in the short term markets will continue.

3.2. Challenges Hindering Growth

The short term market has a considerable potential. Currently, there is a capacity overhang and there is surplus power which remains unsold on the exchange. The cost of procuring this energy and serving all the unmet energy in the system is approximately ₹ 36,248 Crores. The cost of not serving this energy could be in the range of ₹ 243,157 Crores (at a value of load of ₹ 34/kWh[13].

Further, Open Access facilitates competition in the market and is a supporting pillar for achieving the objectives of the Electricity Act 2003. However, there are several impediments in the successful implementation of Open Access and hence it becomes pertinent to identify some of these barriers that stifle the development of short term markets in India. In the following sections, these challenges have been analysed as:

- (a) Regulatory Challenges
- (b) Institutional Challenges
- (c) Infrastructural Challenges and
- (d) Operational Challenges

a) Regulatory

The various regulatory challenges faced by an Open Access consumer are given below.

- Differences in the interpretation of some sections of the Act Universal Service Obligations of Discom: As per the Ministry of Power letter dated November 30, 2011, if a consumer wants to avail the benefit of the option to buy power from competing sources, then the Discoms do not have an obligation to compulsorily supply power to such consumers. This puts the Open Access consumer in a quandary, in case the transmission network on which the power flows breaks down or if the generator, from where the Open Access consumer receives

13 NLDC estimates value of lost load to be between ₹ 34 per kWh to ₹ 112 per kWh. Source: Report by AF Mercados EMI on peak power pricing for gas based generating station.

electricity fails to generate power. Both the events are out of the control of the Open Access consumer and would typically fall under the force majeure category. Another judgement issued by Appellate Tribunal dated July 11, 2006 in Hindalco Vs. West Bengal Electricity Regulatory Commission matter, the judgement reads "*So long as an Open Access consumer abides by the subsisting terms and conditions as are applicable to identical industries the Discom is obliged to supply and the standby* energy has to be supplied subject to terms to be agreed between Discom and the OA consumers." A judgment dated December 21, 2012 between Tata Power and Maharashtra Electricity Regulatory Commission, the Commission directs Tata Power not to discriminate between various consumer categories while providing connections to new consumers, and ensure that the Universal Service Obligations are met.

Regulatory gaps

The Open Access Regulations have significant gaps as discussed below:

- There is no mechanism specified in the regulations for undertaking and monitoring the day ahead scheduling, real time dispatch, carrying of weekly meter reading instrument, preparation of UI account and monthly account etc.
- There is no methodology mentioned in the regulations regarding calculation of Additional Surcharge.
- The regulations do not specify any mechanism for computation of stand by charges.

b) Institutional

Resistance of licensee

The distribution licensee normally hesitates to implement Open Access for the fear of losing high paying industrial consumers who cross subsidise the agriculture and domestic consumers. The other reason cited by the distribution companies is that their demand and supply projections would go haywire if industrial consumers, who constitute almost 30% of the consumption migrate. This is feared to lead to chaos both in terms of demand projections and way to handle the long term capacity contracted to meet their needs.

There are some key issues that have appeared while consultation with discom officials. They are:

- Most of the HT consumers prefer to have partial Open Access, meaning meeting their base load through Open Access and peak load through licensee supply. As the peak power procured from the open market is costly the Discom feels that the Open Access consumer should be ready to bear the high cost.

STATE GOVERNMENTS ISSUING ORDERS UNDER DIFFERENT SECTIONS OF ELECTRICITY ACT

Section 11[14]: *Is being used as a shield against Open Access. As per this section the State Government has the right to issue directions to a generator in case of extraordinary circumstances.* This has basically meant **limiting Open Access to sale within the state** and the generator is not allowed to sell power outside the state:

- States like Tamil Nadu have been very active in invoking Section 11 to tide over the acute power deficit situation within the State by restricting export of power outside the State. Tamil Nadu has issued the intra-state Open Access Regulation 2011, where section 47 under force majeure gives the state right to take such decisions. In the past, states like Karnataka and Maharashtra have also invoked Section 11.

Section 37: Under this section the State Government issue directions to the RLDC or SLDC to take measures for maintaining smooth and stable supply:

- *Section 37 was misused in Rajasthan to give directions to Load Dispatch Centre to stop open access for power sale outside the State. Gujarat Flouro Chemicals (wind generator) appealed to CERC and CERC ruled that reasons provided by SLDC for disallowing open access are not correct and open access denial is unlawful.* Such misuse of powers under section 37 needs to be checked.

- If an Open Access consumer does not draw power exactly in the same pattern as scheduled then an imbalance is created. More number of Open Access consumers deviating from the grid even has potential to affect the entire grid.
- As part of future planning, Discoms have entered into long term PPAs with generating companies to source power at an optimal rate. Some of these PPAs are to start supply in next 2-3 years time. Any deviation in actual drawl of power due to migration of industrial consumers will cost the discoms as they will continue to pay the fixed costs of power contracted without drawing any power, as per the PPA terms and conditions. Alternatively they may have to cancel these agreements but this would be possible only after paying exorbitant liquidated damages. Any pass through of such costs will in turn affect the non-Open Access consumers.

Biased role of SLDC

Most of the States do not have Independent SLDC (State Load Dispatch Centre); they operate as a department under State Transmission Company (STU). Conflict of interest may arise between State Discom and SLDC or between SLDC and the Open Access consumer. SLDC usually act as a barrier to Open Access by delaying the applications, and in some cases even denying generators the right to sell power to a third party as on date.

An Open Access generator as well as consumer requires a *no-objection certificate* from the *State Load Despatch Centre* (SLDC). Under the Electricity Act 2003, the SLDC is the statutory body responsible for the technical integrity and the functioning of the grid. The SLDCs initially ignored the attempts of the Open Access consumers by not responding to their communications. In response to this, CERC issued an Order stating that the SLDC should reply within 3 days time or else it would be considered as approved, further, in an event of not granting the clearance, the reason for the same should be provided. Post this the SLDC continued to ignore the Open Access consumers by blocking Open Access citing technical reasons.

There are cases where SLDCs have not approved Open Access on technical grounds. For example in Odisha, Reliance Trading was denied Open Access by the SLDC however Odisha Power Transmission Company Limited was later allowed by the Commission.

c) Infrastructural

Absence of dedicated feeders

Open Access can be assured only if there are separate feeder lines. However, most of the present day network is meshed with embedded consumers (non-Open Access consumers). In the event of load shedding by distribution licensee for a feeder where both Open Access consumers and embedded consumers (non-Open Access consumers) are connected, Open Access rendered becomes infructuous. Forum of Regulator's Model Intra-State Open Access Regulations 2010 in chapter 3, clause 9(3), lay down following conditions before providing clearance:

- Independent Feeder- "Open access shall be permissible to the consumers seeking open access capacity up to which SERC has introduced open access and are connected through an independent feeder emanating from a substation of licensee or industrial feeder provided that all the consumers on such industrial feeder opt for open access and having simultaneous schedule of drawl under such open access".

It is to be noted here that only Punjab and Tamil Nadu have allowed open access on independent feeders, however any deviation in schedule has to be compensated through a penalty:

- Non Independent Feeder- "Such consumers will be provided open access subject to the condition that they agree to rostering restrictions imposed by utility on the feeders serving them; Provided further that, duties of the distribution licensee with respect to such open access consumers shall be of a common carrier providing non-discriminatory open access, as per section 42(3) of the Act".

In case of Tamil Nadu and Punjab, the State Regulator has exempted the condition of Open Access consumer having dedicated feeder. On commercial front, this is tackled by charging penalty for over drawl.

d) Operational

The various operational challenges faced by an Open Access consumer are given below.

Uncertainty with respect to dispatch

Most of the present day short term consumers of Open Access, who typically procure power from the DAM on the power exchange, face high level of uncertainty in terms of scheduling of power due to limited availability of transmission network, as the long term and medium term contracts have greater priority. Besides this, any deviation from the scheduled drawl or injection will have financial implications on the Open Access consumers, in terms of Unscheduled Interchange charges.

Unpredictability of charges

There exists irrationality with respect to Open Access charges. Some states like West Bengal and Tamil Nadu have cross subsidy surcharges that are too high. The Tariff Policy 2006 has provided a formula for the determination of cross subsidy surcharge, however in states mentioned before; State Commissions have either altered with the formula or put additional conditions for the computation of cross subsidy surcharge. Besides that there is no predictability about the level of future open access charges making consumers reluctant to avail this service. The Act calls for gradual reduction of Cross Subsidy Surcharge, but no such reduction trajectory is found in any of the states.

Standby arrangement and uncertainty with respect to high charges

Though the Act mandates the distribution licensee to arrange for standby supply of power to the Open Access consumer there are no proper guidelines in this respect.

- In case of Gujarat and Maharashtra standby arrangements are to be provided by the distribution licensee for a maximum period of 42 days in a year, subject to the load shedding, as is applicable to the embedded consumer of the licensee and the licensee shall be entitled to collect tariff under temporary rate of charge for that category of consumer in the prevailing rate schedule.
- In West Bengal, Supply of back-up power to an Open Access customer should occupy the last position in the despatch schedule so as to ensure that the demand of the embedded consumers is met first. The commission wants the demand charges for such back-up supply to be at least three times the demand charges levied on other consumers.

The charges and duration of such stand by supply is a concern for an Open Access consumer. Table 11 provides a snapshot of the key barriers that limit the open access activity in states. State specific issues have been discussed in detail in Table 12 on the next page.

Table 11: Barriers to Open Access

Parameters	Maharashtra	West Bengal	Haryana	Odisha	Jharkhand	Uttar Pradesh	Bihar	Punjab
High Open Access Charges	✓	✓	✓	✓	✓			✓
Regulatory Barriers			✓					✓
Operational Barriers						✓		
Infrastructure Barriers								
Poor Financial Health of Discoms	✓	✓	✓	✓	✓	✓	✓	✓

14 Electricity Act 2003, Section 11-"The Appropriate Government may specify that a generating company shall, in extraordinary circumstances operate and maintain any generating station in accordance with the directions of that Government". For the purposes of this section, the expression "extraordinary circumstances" means circumstances arising out of threat to security of the State, public order or a natural calamity or such other circumstances arising in the public interest.

High open access charges are a clearly a limiting factor for most States. This along with regulatory and operational barriers has restricted Open Access activity. Further details of the State level issues for open access are presented below:

Table 12: State level Open Access Issues

<table>
<tr><th>State</th><th>Issues with Open Access</th></tr>
<tr><td>Maharashtra</td><td>Maharashtra has increased the cross subsidy surcharge significantly in the latest tariff revision leading to higher costs for the Open Access consumers in the state as shown in the table below:
<table>
<tr><th>Licensees</th><th>Range for HT Consumers in 2012 (₹/Unit)</th><th>Range for HT Consumers (₹/Unit) in 2013</th></tr>
<tr><td>MSEDCL</td><td>0.21 to 0.61</td><td>a) 66 kV and above: 2.26 to 7.22
b) 33 kV: 1.82 to 6.77</td></tr>
</table>
Source: AF - Mercados EMI Analysis, State Tariff Orders.</td></tr>
<tr><td>West Bengal</td><td>West Bengal uses a modified formula for calculating the cross subsidy surcharge. As a result cross subsidy surcharge have gone up as high as ₹ 3.27/kWh, making it expensive for open access consumer to avail this route for procurement of power.</td></tr>
<tr><td>Haryana</td><td>As per the (Terms and Conditions for Grant of Connectivity and Open Access for Intra-State Transmission and Distribution System) (1st Amendment) Regulations, 2013, the conditions for grant of Open Access have been tightened, wherein an open access consumer has to prove a confirmed slot wise schedule of power a day in advance. The consumer is further required to manage its drawl from the licensee in case a reduced final schedule is accepted. However, in case of over drawl in any time-slot, penalties will be charged.

Further, in case the consumer exceeds its contracted demand by more than 5%, a heavy penalty in the form of demand surcharge of 25% will be levied on the SOP amount for that month.

The Regulation also restricts the incentive provided to an open access consumers due to reasons within its control. The consumer shall be compensated only to the extent of 10% of the entitled drawl in a time slot or up to 5% of the entitled drawl on aggregate basis for all the 96 time slots in a day.</td></tr>
<tr><td>Odisha</td><td>The latest cross subsidy surcharge in the state are as high as ₹ 2.76 per unit in addition to the relatively higher wheeling charges of ₹ 0.99 per unit which has significantly increased the cost for open access consumers.</td></tr>
<tr><td>Jharkhand</td><td>In 2010, Jharkhand State Electricity Board denied short term Open Access to Kohinoor Steel Pvt. Ltd. citing technical reasons that the synchronization at 33 KVA was for small power producer with a maximum limit of 10 MW and the latter's captive power plant was 17 MW. The case went to JSERC and the Commission in its verdict issued direction to the JSEB to allow Kohinoor Steel Pvt. Ltd. Short term Open Access.

Following the amendment to the Jharkhand Open Access Regulation 2010, open access consumer and open access generator is required to pay to the distribution licensee for reactive power drawl and injection @ 6 paisa/kVARH with an escalation of 0.25 paisa per annum. In case of drawl the payment is to be given when the voltage at the interface metering point is below 97% and in case of injection when the voltage at the interface metering is above 103%. This has further led to an increase in costs for the open access consumers in the state.

Post above information, there is no/limited information is available on open access in the State. Poor information on the reasons for limited open access indicates opacity in process. It is therefore for the state utility and the regulator to make open access information transparently available on the website of the State Load Dispatch Centre.</td></tr>
<tr><td>Uttar Pradesh</td><td>Uttar Pradesh has currently zero Cross Subsidy Surcharge its open access charges are low. But, the lack of Open Access consumers in the state is mainly due to infrastructural issues and lack of preparedness at the SLDC level. operationalisation of open access.</td></tr>
<tr><td>Punjab</td><td>As per the Open Access Regulations, the Regulator has restricted the demand of OA customers to the extent of peak load restrictions allowed, restricting the open access activity. Further, open access consumers are typically the cross subsidizing category for other consumer groups, reduction of power off-take by them from PSPCL power pool has adverse impact on the tariff of other categories.</td></tr>
<tr><td>Bihar</td><td>In Bihar, though the regulatory environment is conducive in the State, however the Open Access consumers participation is limited. Poor information on the reasons for limited open access indicates opacity in process. It is therefore for the State utility and the Regulator to make open access information transparently available on the website of the State Load Dispatch Centre.</td></tr>
</table>

SUMMARY

Even though the introduction of PX has changed the landscape of the markets to a certain extent, a large agenda is yet to be accomplished. The market design proposed at the time of establishment of the trading platform was in concert with the conditions of demand and supply prevailing then. These conditions have changed now with the evolution of the short term markets. There is scope for the short term market to deepen further if the current barriers can be appropriately dealt with. This can further be inferred by drawing a comparison with the international exchanges in the developed countries. The total volume traded on the Nord Pool Spot in 2012 was 432 TWh[15], which corresponds to 77% of the total Nordic/Baltic consumption.

CERC Power Market Regulations, 2010 further confer on PX to play a pivotal role in deepening the power markets in the country. The SOR of Power Market Regulation 2010 states.

The Commission would encourage market participants to develop price risk management tools to help power sector participants manage price risk arising from the volatility of prices. This would necessitate development of derivatives market as derivatives serve the purpose of price risk management, hedging and risk transfer between participants with different risk profiles.

It is expected that the role of Power Exchanges would transform with time. Initially the main purpose of exchanges was to act as price signal for investments, but over time it would have the twin role of providing price signal and act as risk transfer platform.

15 www.nordpoolspot.com

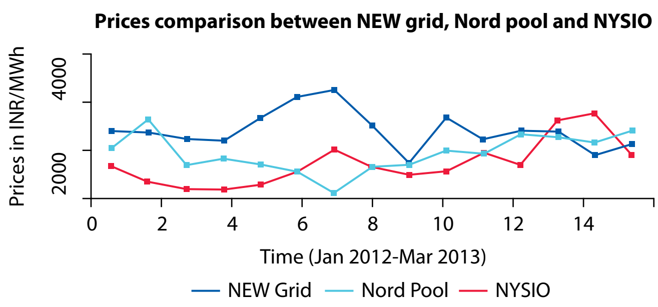
CHAPTER 4

WAY FORWARD

The prices and volumes on the power exchange provide useful signals for what trajectory markets should take in the future. Following are the key trends that have been seen on the Indian Energy Exchange (IEX) and provide signals for future needs:

1. Prices in the NEW grid have declined over time and average prices in the NEW grid have been low enough to barely compensate the generators for their variable costs.
2. There is surplus unsold power on the power exchange, when many states in India have scheduled load shedding. There is persistent congestion and hence market splitting between NEW grid and SR grid; market also splits within NEW grid.
3. The volume in Term Ahead Markets are very low.

Figure 21: Price trend in NEW Grid, Nord Pool, and NYISO (Jan 2010- Mar 2013)



Source: AF-Mercados EMI Analysis

4.1. Capacity Markets

Prices discovered in DAM in India are close to system marginal costs of generation and thus indicate efficiency of markets in maximizing social welfare. All power systems require an efficient mix of base load and peaking power plants. However in India, peak load power plants, typically gas based or diesel based – close to load centres are not induced to invest at these prices. This is expected to create substantial peak deficits. Prices close to system marginal cost in NYISO, PJM, and MISO etc. have led to creation of Capacity Markets. Capacity Markets allow for payment of capacity charges to these peaking generators thereby allowing them to invest.

Short term prices in India are normally close to the prices in similar international markets. Figure 21 shows price trend in NEW Grid, Nord Pool and NYISO over Jan 2012- March 2013 period.

These prices are close to variable costs of operation of power plants dispatched at the margin. However, when prices track marginal (variable) costs, investors do not recover their fixed costs and hence this may result in economic losses. This is defined as the problem of "missing money" in the US electricity markets. While operating in such markets, peak load power plants may find it difficult to get scheduled and yet recover their fixed costs. Therefore, a separate market for "capacity" has been conceived in PJM, NYISO, MISO, and even in the United Kingdom. Therefore, to encourage adequate peaking capacity in the country, the next logical step for Indian markets is also the development of capacity markets.

4.1.1. Pre-requisites for development of capacity markets in India

- Imposing Capacity Adequacy Requirement on the distribution companies.
- Forecast of future peak demand by distribution companies.
- Regulatory intervention that would bar states from shedding load; appropriate penalty mechanism would need to be designed for the same.
- Mechanism to pass through the additional costs resulting from establishment of such markets for system reliability.
- Clearly lay out policies regarding treatment of existing and newly constructed plants that would participate in the capacity markets. Ambiguity with respect to same can lead to disincentive for capacity creation.

Most of the electricity sold in DAM in India is from base load coal/combined cycle gas based power stations. These power plants could:

1. Be selling their electricity directly in these markets directly.
2. When their capacities are committed to DISCOMs (through Long Term/Medium Term Open Access agreements), the DISCOMs could be selling surplus electricity in certain blocks of time.

DISCOMs – constrained by their financial conditions and regulatory restrictions place their buy bids at relatively low levels in the DAM. When DISCOMs fail to get scheduled on the power exchange, they shed load. Thus, this can be achieved by imposing Capacity Adequacy Requirement on the DISCOMs. Each state regulator needs to explicitly direct, at least initially, that in no utility shall shed load more than X% of the energy requirement and Y% during peak hours. The appropriate regulatory commissions will need to design mechanisms to pass through such additional costs which enhance system reliability. This obligation on the state DISCOMs could be the key driver of capacity markets.

4.1.2. Market Design

In capacity market auctions the SLDCs/RLDCs solicit bids, on behalf of the power utilities operating in their respective control areas. These bids correspond to estimates of the level of resource commitment that will be needed to meet future peak demand on the system, and then provide market-based revenues to resources that can fulfil that commitment. The revenues take the form of a stream of capacity payments — at a price determined through a regional competitive auction, on the power exchanges.

Only those resources bidding at or under the market clearing price of the auction receive capacity commitments and payments for being available, and for measured and verified performance when called upon, during the expected system peak hours. This particular approach to planning and procurement in the power sector became generally referred to as a "forward capacity market."

4.1.2.1. Auction Lead Time

Initially a four year lead time may be chosen between the capacity auction and the year capacity is required to be available (the delivery year). This will ensure a contestable auction, and will allow relatively accurate forecasting of the level of capacity required.

A short lead time (e.g. one year) would enable more up to date and therefore accurate demand forecasts to be used to set the level of capacity to contract, but would preclude new investment from entering an auction (or at least force developers to take the risk of financially committing to a project well in advance of being able to bid into the capacity auction and getting the certainty of a capacity agreement).

4.1.2.2. Auction Format

Uniform Market Clearing Price auction may deliver the best long-term outcome for consumers by minimising opportunities for gaming and establishing a single fair price for capacity.

Capacity product is homogenous for each congestion zone (bidding areas as defined for the purposes of collective transactions). It, therefore, seems appropriate for all providers in a bidding zone (congestion zone) to receive the same payment (i.e. for new and existing plants to receive equal payment for providing the same service as they would in an energy market). This creates the efficient signal for new capacity to be created or existing capacity to be retired if unable to cover its forward looking costs.

4.1.2.3. Capacity Agreement Duration

Most existing plants should only have access to a one year price and obligation, it would be beneficial to allow new plants (and existing plants in need of a certain level of capacity payment, e.g. for refurbishment) to choose the most appropriate length of agreement for them, before the start of the auction.

This is because longer term capacity agreements are required to provide certainty of investment returns and reduce the cost of capital. Longer agreements should also reduce the potential for providers to front load cost, pushing up the price of capacity. Providers could choose a capacity agreement length of between one to around ten years.

4.1.2.4. Need for Secondary Auctions

The introduction of secondary capacity auctions to be held a year ahead of delivery is likely to offer a useful mechanism to purchase additional capacity if necessary. This is because the primary auction will be based on a forecast of demand four years ahead. A short lead time has the advantage of enabling estimates of the required volume of capacity to be made with greater accuracy.

4.1.2.5. Mechanisms for ensuring capacity availability

(I) Penalising

Capacity providers are obliged to deliver energy or reduce demand whenever needed to ensure security of supply, i.e. in real system stress situations. In the delivery year, they receive the payment for their capacity that was set in the capacity auction. When there is system stress, if they are not delivering energy or reducing demand up to the full level of capacity they offered in the auction, they face a financial penalty. This model could also include additional checking by the RLDCs/SLDCs.

(II) Incentivising

An agreement with the capacity provider puts him under an obligation to deliver energy (i.e. supplied electricity, or a reduction in demand) at a set price (the strike price) at times of scarcity. If market prices in a chosen reference market rise above the strike price in the option contract, providers of capacity effectively have to pay the difference between the price in the reference market and the strike price. This provides a strong incentive to deliver – because if they are not delivering energy, the capacity provider must still pay the difference between the strike price and the reference price, but will not recover the revenues to cover this from the energy market – leaving them at a loss.

4.1.2.6. Mechanisms for ensuring that the DISCOMs pay

A settlement agency, on the lines of the Settlement Guarantee Fund in the context of DAM or a separate entity, may need to be appointed for the purpose of Capacity Market. It is envisaged that the settlement agency would make back-to-back payments (i.e. within a day) between DISCOMs and capacity providers. This would be underpinned by collateral held by the settlement agency and mutualisation of any payment defaults by a DISCOM so that the settlement agency is always in a position to pay capacity providers.

4.1.3. Assessment of Capacity Market Potential in India

Implementation of Capacity Markets in India derives importance from the lack of peaking capacity and the localized nature of markets that is constrained by the available transmission capacity. Further, prices discovered in DAM in India are close to system marginal costs of generation and thus indicate efficiency of markets in maximizing social welfare. Peak load power plants, typically gas based or diesel based – close to load centres are not induced to invest at these prices thus creating serious peak deficits.

Capacity Market is also an important market based mechanism in the context of the proposed development of the ancillary services markets – where the load dispatch centres may be required to procure power in real time for maintaining system frequency.

Having established the need and benefits of introducing Capacity Market for system strengthening and better load serving ability of utilities, it is imperative to analyse the potential for such an instrument under the existing scenario.

Since capacity market is a localized market owing to the variability in the nature of load curves across States, analysis has been carried out to estimate the potential Capacity requirement for each of the states in India. Analysis is carried out for the year 2012-13. The methodology adopted is as follows:

Step 1: Block level Demand-Supply gap for each month of 2012-13 is computed in MW terms. The supply includes only the capacities that sell under the long term agreements.

Step 2: Average of the monthly deficits in block b0 and b1 is computed as the capacity requirement of each of the states. Deficits in block b2 & b3, if any, are not likely to be served through the Capacity Market route and would instead require medium/long term contracts to be signed as these deficits would need to be met on a perennial basis through base load capacities.

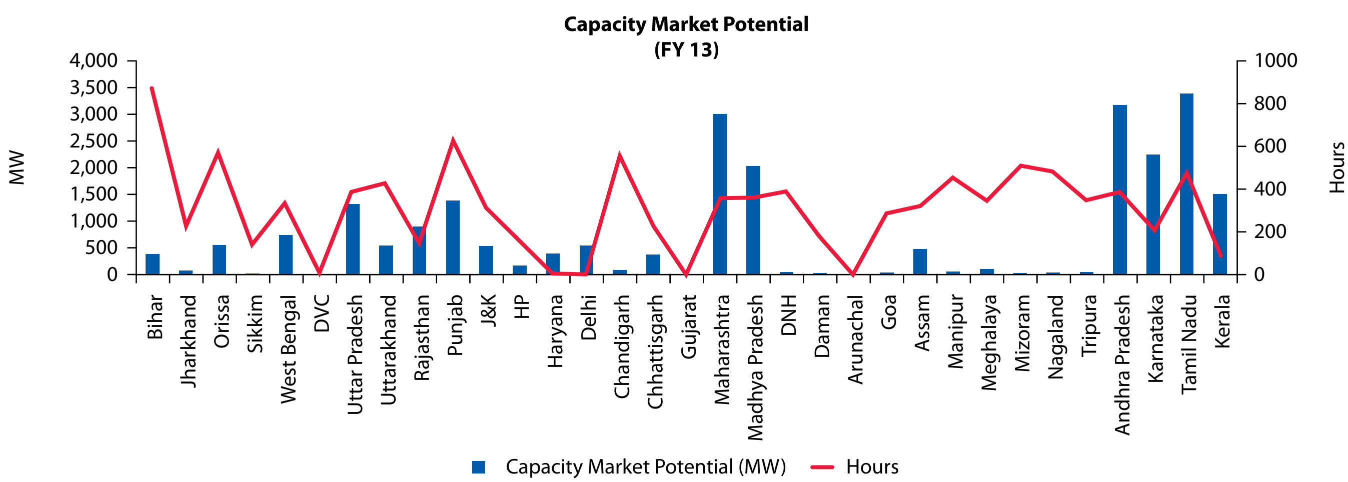
Step 3: Total number of hours that the capacity would be utilized is the sum of hours in the blocks b0 and b1 where the deficits are greater than or equal to the average deficits computed in Step 2 above.

Figure 22 presents the capacity market requirement for each state and corresponding duration for which such capacities can be utilized in a year.

It can be observed that Southern Region and States like Madhya Pradesh, Punjab, Uttar Pradesh, and Maharashtra have substantial peaking requirements. It may be noted that the Capacity Market potential computed above is based on the average peak deficit requirements across months. Actual peak deficits for certain months may be more than these average deficits, however for such requirements it would be more prudent for the utilities to procure power from the exchange on real time basis instead of entering into a capacity contracts.

Further, capacity requirements can also reduce to the extent of co-skewness of states on a regional level. For example, Hydro rich states like J&K and HP can serve part of the peak deficit requirements of states like Punjab in Summer/Monsoon months when hydro stations are running at high load factors.

Figure 22: Capacity market potential in india for FY 2013



Source: AF – Mercados EMI Analysis.

SUMMARY: CAPACITY MARKETS

In India, the shortage of electricity results in extreme inelasticity of demand in the time near to delivery. This results in both supplier market power and buyer's desperation to secure energy irrespective of cost. With this background, capacity markets could be considered in India for a variety of reasons:

- Since the capacity is procured ahead of time, the pressure on the utilities in the near term can be considerably reduced. As a corollary, commitment to capacity in forward markets puts a downward pressure on energy prices in short term markets and would also reduce volatility.
- A transparent national market for new generation capacity is created (even if actual prices can vary across regions on account of locational and transmission issues). This will help in ensuring adequate load – generation balance.
- On account of the counterparty risks being addressed through the market mechanisms, capacity markets provide revenue certainty to investors in generation, transmission and energy efficiency investments and hence mobilize resources.
- Capacity markets provide a mechanism for optimal development of power system by allowing the markets to choose the least cost mix of generation, transmission and energy efficiency resources. It provides a very powerful mechanism for the development of power system along with the National Transmission Expansion Plan by reducing uncertainty in determination of generation sources and drawal nodes.

4.2. Frequency Support Ancillary Services

In FY 2012-13 close to 42%[15] of the sell volume remained unsold on IEX. However, there were variations on monthly basis because of:

1. Offer price of such generation is greater that the market clearing price.
2. Congestion in the transmission corridor and resulting in market splitting.

Closer to real time, the demand becomes more inelastic and the willingness of the demand customer to pay for electricity at a higher rate increases. Recently, the Central Electricity Regulatory Commission, through the CERC (Deviation Settlement Mechanism and related matters) Regulations, 2014, tightened the operating frequency band between 49.70 Hz. – 50.05 Hz to ensure secure power system operation. This is imminent given the integration of the NEW grid with SR grid. Also, the regulations require that each control area operator shall operate the system in a manner such that the sign of area control error reverses every twelve time blocks. This provision in the regulations will require the SLDCs/RLDCs to procure power close to real time not only from outside their control areas but also from within their control areas with time intervals which could range from a few seconds (to enable primary and secondary control) to minutes and hours (tertiary control). Procurement from outside the control Area to meet sub-hourly needs is difficult because such revisions are implemented by the RLDCs after at least four time blocks. This requirement is expected to become critical especially for states like Tamil Nadu, Rajasthan and Gujarat which have heavy wind/solar based generation wherein a loss of 1000 MW of generation within a few time blocks is not uncommon. This is expected to not only spur better utilisation of the Intra-day markets, but require SLDCs/RLDCs to procure reserves. This would also require productive utilisation of unsold energy on the exchanges as well as creation and procurement of new capacity under ancillary services reserves.

This section delves into the Ancillary Services Market. *Indian Electricity Grid Code defines Ancillary Services in relation to power system (or grid) operation, as the services necessary to support the power system (or grid) operation in maintaining power quality, reliability and security of the grid, e.g. active power support for load following, reactive power support, black start, etc.*

The IEGC has strict provisions vis-à-vis the maintenance of frequency within a designated band. Under the Electricity Act, State Grid Codes need to be consistent with the standards specified in the Grid Code notified by CERC. The State Load

15 IEX website.

Dispatch Centres (SLDCs) are obliged to follow the directions of the Regional Load Dispatch Centres (RLDCs). In its Staff Paper on the subject notified in 2012, CERC conceives Ancillary Services Market in the context of Frequency Support Ancillary Services (Load Following), Voltage Control Ancillary Services (VCAS) and Black Start Ancillary Services (BSAS).

VCAS are critical for compensating generators who provide dynamic compensation by compromising on their real power output. Similarly BSAS are also critical and can be obtained through market based mechanisms. However, in the immediate term, Frequency Support Ancillary Service (FSAS) market needs to be developed in India, and is discussed in detail in the following sections.

4.2.1. Utilizing Unsold Energy on PXs for Frequency Support

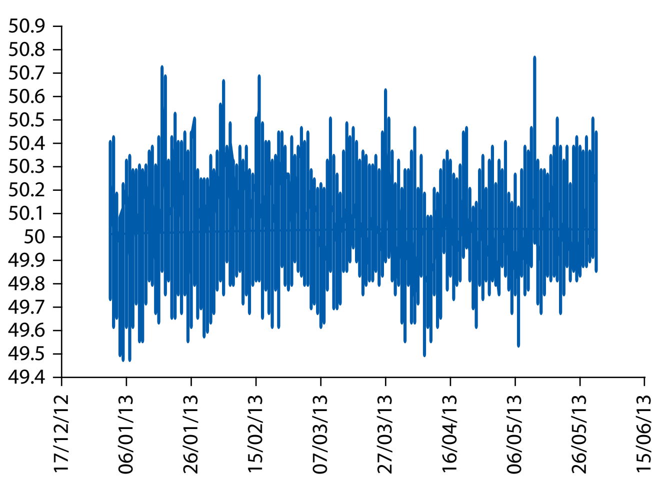
Maintaining the frequency at its target value requires that the active power produced and/or consumed be controlled to keep the load and generation in balance. A certain amount of active power, usually called frequency control reserve, needs to be kept available to perform this control. Three levels of controls are generally used to maintain this balance between load and generation – Primary Frequency Control, Secondary Frequency Control and Tertiary Frequency Control. The following sections analyse the provision of these three types of frequency support services in India.

The SLDCs in India are given the responsibility for optimum scheduling and despatch of electricity within a State, in accordance with the contracts entered into with the licensees or the generating companies operating in that State. For procuring electricity from outside the State, the schedule is provided to RLDCs a day in advance and the latter determines the feasible inter-state flows. The frequency deviation could happen because of any unscheduled drawl/injection by any of the licensees/generators/large customer in any State. Beyond the demand side measures, such as load shedding or supply measures such as overdrawl from the ISTS and curtailing excess wind/hydro generation, there could be two ways of handling this:

1. By allowing SLDCs to balance load with scheduled generation (scheduled both at the intra-state and inter-state level) within their control areas, so that there is no unscheduled flow on the inter-state lines in a region.
2. By allowing RLDCs to arrange for and provide Frequency Support Ancillary Services.

The Staff Paper on Ancillary Services market floated by CERC suggests that the Ancillary Services markets would kick in when the frequency breaches 49.5 Hz in two consecutive time blocks. This also means that a certain amount of Control Error is allowable at the state and the regional level.

- It may be observed from the frequency graph below (from January 1, 2013 to May 31, 2013) that frequency has breached 49.5 Hz only 2 times and was exactly equal to 49.5 Hz only twice. None of these instances were in two consecutive time blocks.
- The paper also specifies that if the frequency remains 0.05 Hz below the lower operating frequency range as specified in the IEGC (which is 49.90 Hz) for two consecutive time-blocks, the nodal agency to give instructions to the FSAS provider to despatch in the third time block for despatching generation from the fifth time block. This means that the generation would come on-line 45 minutes after the "event" of low frequency has happened.



Source: NRLDC Website.

It may be noted that this frequency profile was achieved due to considerable measures enforced by the RLDCs to discipline the states. The design of Ancillary Services Market should be such that it complements system reliability. In order to ensure operational reliability of grid in India, IEGC requires that *SLDC/SEB/distribution licensee and bulk consumer shall initiate action to restrict the drawal of its control area, from the grid, within the net drawal schedule whenever the system frequency falls to 49.90 Hz* and further requires that *the SLDC/SEB/distribution licensee and bulk consumer shall ensure that requisite load shedding is carried out in its control area so that there is no overdrawal when frequency is 49.9 Hz. or below.* While the states utilities and SLDCs are required to take the above mentioned measures to ensure that frequency is within this pre-decided band, IEGC also requires NLDC and RLDCs to take all possible measures to ensure that the grid frequency always remains within the 49.90 –50.05 Hz band.

Further, performance standards for such frequency support ancillary services would need to be defined in terms of the delay in response to the requisitioning by RLDCs and inability to help the system when required.

Given that, SLDCs/SEBs/State Utilities have taken measures within their control to contain frequency within the designated band, what measures can NLDC/RLDCs potentially take? Further, why does the IEGC require the states to take only demand side measures to contain frequency variations? While it is important to harness the un-cleared volumes on the power exchange, total reliance on the same would be contrary to the objective of the Ancillary Services Market – which is to ensure reliability of supply. This is because, the un-cleared volumes vary each day, and therefore, there is no guarantee of required ancillary services being available on any day. Further, the quality of ancillary services in terms of the ramp rate of capacities offering such services need to be specified.

Finally, the most efficient procurement mechanism for such services needs to be specified. In almost all deregulated energy markets the frequency regulation service is governed by the System Operator. The three fundamental questions faced by the Load Dispatch Centre (NLDC/RLDCs) are:

1. How to define the standards and specifications related to frequency regulation?
2. How much generation reserves are needed for frequency regulation?
3. How to procure the reserves from the market?

With the integration of the NEW and the SR grid in 2014, it has become imperative to have primary, secondary and tertiary frequency control reserves for reliable grid operation. Therefore it becomes critical to clearly answer the three questions raised above.

4.2.2. Suggested Market Design

For Frequency Support Ancillary Services, it is a pre-requisite that the standards and specifications related to frequency regulation be defined by either Central Electricity Authority or NLDC.

The standards and specifications would be in terms of:

a. Deployment start – The maximum amount of time that can elapse between a request from the RLDC/SLDC to the beginning of response from the service provider.

b. Full availability – The maximum time between the instant the service provider receives the request to the delivery of full response.

c. Deployment end – The maximum amount of time during which the service must be provided from the time of request.

d. Droop setting – The ratio of change in frequency to the change in load over the operating range of the generator.

e. Full deployment – The frequency deviation for which the entire primary frequency reserves are deployed.

f. Frequency characteristic – The ratio of total change in generation to the total change in frequency in a grid is called the frequency characteristic. It is expressed in MW/Hz and is representative of how big the synchronous grid is.

g. Controller Insensitivity – The frequency dead-band of the governor, or in other words the frequency band within which the generating unit governor does not change its output, is called controller insensitivity.

While the IEGC requires all governors to have a droop setting of between 3% and 6%, the same is not implemented completely. The recommended rate for changing the governor setting, i.e., supplementary control for increasing or decreasing the output (generation level) for all generating units, irrespective of their type and size, is required to be one (1.0) percent per minute or as per manufacturer's limits. However, if frequency falls below 49.9 Hz, all partly loaded generating units are required to pick up additional load at a faster rate, according to their capability. All these technical specifications are there in IEGC but need to be implemented. Further, beyond these measures, the regulations regarding "deployment times" as described above, need to be specified. Frequency characteristic of each control area needs to be computed regularly.

4.2.2.1. Quantification and Procurement of Reserve

Tertiary frequency control refers to manual changes in the dispatching and commitment of generating units. This control is used to restore the primary and secondary frequency control reserves, to manage congestions in the transmission network, and to bring the frequency and the interchanges back to their target value when the secondary control is unable to perform this last task. Some aspects of tertiary control relate to the trading of energy for balancing purposes.

4.2.2.2. Tertiary Control

The Staff paper contemplates that NLDC will procure tertiary reserves from the un-used capacity on the exchange. However, as pointed in the forgoing discussion, the quantity will vary daily and hence will lend no certainty and reliability to power system operation. The quantity required from tertiary ancillary service mechanism could be governed by:

a. Sum of the load forecasting error and the generation forced outages (Generation forced outage is based on a rolling 3-year average of forced outages that occurred on the scheduling day through the operating day), as in the PJM.

b. 150% of the largest committed generator in each hour.

Depending on whether a 10 minute service or a 30 minute service or a service with higher time period is being procured, the reserve requirement could be the contingency of the largest generator, or contingency of the largest generator followed by the second largest contingency.

Each RLDC/SLDC would need to evolve the tertiary control requirement.

While the un-used capacities on the power exchanges and un-requisitioned surplus of Central Sector power plants can offer to supply in this market, there needs to be certainty of capacity as discussed above. These services can again be procured on the power exchange and price formation can be through pay as bid mechanism.

4.2.2.3. Auction Mechanism

The markets for procurement of tertiary reserves of various kinds can be run on a day ahead and intraday basis on the power exchange. The providers of tertiary reserves will need to satisfy the standards and specifications as laid out by CEA/NLDC. The providers will be remunerated on 'Pay as Bid' basis. A bidder may offer in alternative products in Rs/kWh and ₹/MW/hour of availability. Remuneration of all providers can be adjusted for deviations from the performance standards.

4.3. Transmission Rights: Physical vs. Financial

Transmission across congested nodes in the grid is already being allocated based on e-bids conducted by RLDCs. The mechanism of e-bidding, as implemented, is a point-to-point mechanism which allows only trading partners in bilateral trades to participate. By design, the players operating in the Term Ahead Market and Day Ahead Market on the power exchanges cannot participate in these markets, even if they were allowed to. The sum of the energy charges and transmission charges discovered through e-bidding contests closely with the energy only charges discovered through PX in SR.

- *In April 2013, NVVN sold power from Sterlite to TANGEDCO @ ₹ 4.1 per kWh and paid ₹ 6.1 per kWh to obtain rights to the transmission corridor. Average energy prices in SR during the same period hovered around ₹ 11 per kWh.*

It has been observed that there are times when energy prices in SR are slightly higher than the sum of energy prices and transmission prices discovered through e-bidding. This points to inefficiency – the buyers in the Day Ahead Markets being willing to pay a price greater or equal to the price paid by the consumers operating in the bilateral market and located in SR, but the former may not get transmission corridor. There is a loss of efficiency because probably the true value of congestion between the NEW grid and SR is not being realized.

This inefficiency could be alleviated by allowing all the traders/market participants to contest for transmission rights between bidding zones on the PXs. Financial Transmission Rights, therefore offer a solution. There is another school of thought around physical transmission rights wherein the Power Exchanges could be made counter-party in the process. The following discussion briefly discusses this proposal and surmises that while this could be an immediate solution, the future rests in implementation of Financial Transmission Rights. The section concludes with the rationale behind Financial Transmission Rights.

4.3.1. Power Exchanges as counter-party in the e-bidding process

Participants desirous of procuring electricity from the power exchange may book transmission corridors in advance through the e-bidding mechanism by making power exchange as counterparty to the contract. The current procedure for e-bidding requires that both the buyer and seller be specified. Consider a case where a buyer in SR proposes to purchase electricity from ER. The counter party, power exchange in this case, would be the "deemed seller" based in ER and would be assumed to be supplying electricity at the regional boundary of an identified state in ER. However, for secure grid operations, RLDC will have to explicitly consider the exact point within ER where the power is being injected and also seek approvals from the SLDC concerned. But, since, power exchange is the counter party the exact source of injection cannot be identified at the time when allocation based on e-bidding takes place. This would require change in e-bidding processes. The current process grants approval for all transactions involved, i.e.

(a) The point of injection of a seller to the injecting State's periphery (control area boundary) as confirmed by the concerned SLDC.

(b) From the periphery (control area boundary) of injecting State up to the periphery (control area boundary) of the drawee state as confirmed by the concerned RLDCs.

(c) From the periphery (control area boundary) of the drawee State to the point of drawl of buyer as confirmed by the concerned SLDC.

If the said e-bidding takes place two months in advance, RLDC will be able to grant advance booking for the (b) transaction above, only when the seller state is indicated. E-bidding formulations would need to be evolved such that Power Exchange can be considered as a "deemed seller" located on ER periphery (without the need to identify a specific state). The buyer, however, runs the risk of not being selected in the Day Ahead Market. In this event, the buyer in SR loses the investment in procurement of transmission corridor through e-bidding. The purchased capacity gets transferred to other users on the power exchange, thereby giving this provision the nature of "physical" transmission rights.

4.3.2. Why Financial Transmission Rights work?

All generators and buyers are interested in the final outcome of electricity trade – the electricity is delivered from point of injection to point of withdrawal. The transmission rights can therefore be procured from the point of injection to the point of withdrawal (which are normally Financial Transmission Rights (FTRs)) or as a series of physical transmission rights over various "congested" transmission line elements or "flowgates"[16]. Financial Transmission Rights have been demonstrated to be superior as compared to Flow gate Rights. FTRs offer instruments for converting historical entitlements to firm transmission capacity into tradable contracts that keep the owners just as well-off as economically while enabling them to cash out when others can make more efficient use of the transmission capacity covered by these contracts.

All grid connected entities and traders (who have a firm supply/power purchase contract) may be allowed to purchase transmission rights in a yearly auction (or a three monthly auction initially). Each entity will be required to specify the point of injection and point of delivery. The auction will be held on the exchange and each bidder will quote their bids in (MW, ₹/MW, and duration of the contract). All the bids will be put through the simultaneous feasibility test – where the RLDC/SLDC examines the simultaneous feasibility of the transmission bids. The highest bidders are allocated capacity between the desired points of injection and withdrawal based on their price quotes – the highest price bidder gets the first preference. In return for the purchased transmission right, the bidder gets the difference between the DAM prices between the point of injection and point of withdrawal. Therefore, all such transmission rights get liquidated at the difference of DAM prices between the injection and withdrawal zones. This mechanism is essentially based on Financial Transmission Rights and does not allow the holder of the right to "withhold" transmission capacity.

4.4. Introduction of Forwards & Futures: International Experience

The current product portfolio on power exchanges focuses on short term demand of electricity in the country. As the market develops, there will be a need to expand the product portfolio.

Forwards and futures contracts are required to be introduced to enable higher liquidity and depth in the market. The short term market in India is currently dominated by bilateral contracts. Approximately 51%[17] of the short term volumes are traded through this route as against 29%[18] through the exchange. This clearly demonstrates the preference towards the longer duration contracts than currently available on the Exchange. Lack of contracts longer than a week on exchange restricts market growth as participants are not able to tie up supplies in the medium term. Introduction of such products on the exchange would ensure transparency in price discovery through a reliable neutral platform with lower transaction costs for such trades and also improve the overall liquidity in the market, making it more efficient.

It is suggested that forward delivery based contracts can be introduced on the exchanges. This would not only widen the portfolio on the power exchanges but also provide another window to the market players to tie up electricity in the not so short term.

The PXs can be an effective platform for providing hedging options to the players in the market. The existing products are all physical delivery linked

16 Common feature of both – Financial Transmission Rights and Flowgate rights is identification of the point of injection and the point of withdrawal. Both these transmission rights can be traded on the exchange. Flowgate transmission rights are however fraught with many problems – (i) the parties would have to procure a large number of flowgate rights, (ii) another complicating feature of flow -based trading on an electricity network is the potential for counterflows on certain elements. For example, a trade from one point on a power network to another may actually relieve congestion, by producing flows in the opposite direction, (iii) large number of flowgate rights for each point to point transaction would render the markets for such rights illiquid.

17 Report on Short Term Power Market in India 2013-14.

18 Report on Short Term Power Market in India 2013-14.

products. Going forward, as the market expands and gains more depth, players would also require hedging instruments to square off their positions. Currently, in case of cancelation of contracts before the delivery would impose penalties to the extent of paying up for overheads like transmission, scheduling & operating and other charges. In weekly market, in case of cancellation, the difference of contract value and spot price is charged to the defaulting party in addition to above mentioned charges. Though such measure reduces risk of speculative behaviour by market participants, it does not safeguard the buyer in case of a non-delivery. International markets like Nordpool, PJM etc can be a good reference for understanding the dynamics of financial markets for electricity.

International Experience- Nord Pool

Introduction of financial products has proved to be successful in developed markets such as Nord Pool. The Nordic financial market is closely related to the Nordic wholesale market. Financial instruments were introduced in the Nordic markets in 1995. A well developed financial market and the option of hedging strategy helps deepen the physical market. NASDAQ OMX Commodities Europe's financial market is the single financial energy market for (Nordic, German, Dutch and UK). It serves as a market place for futures, forwards and other derivatives for which electricity is the underlying commodity. Trading of financial instruments in the electricity markets is carried out primarily by companies that conduct electricity trading, mainly to hedge against price movements in the electricity market. Some of the key features of financial electricity market in Nord pool are:

- The power derivatives/financial instruments include base and peak load futures, forwards and other financial instruments.
- Reference price for the Nordic contracts is the system price of the total Nordic power market, EEX Phelix for German power, APX for Dutch power and N2EX for UK power.
- Maximum trading horizon is up to six years currently.
- There is no physical delivery of financial market power contracts.
- Cash settlement is made throughout the trading and/or delivery period starting at the due date of each contract.
- Financial contracts are entered into without regard to technical conditions, such as grid congestion, access to capacity, and other technical restrictions.

Futures Contracts

Futures contracts in the Nordic market were originally introduced as three year ahead contracts, however post 1997 the time period of these contracts was shortened from three years to 8-12 months. Post 2003, the structure of the contracts further underwent a change and were shortened to about 6 weeks ahead contracts. Markets preferred short term futures close to due date due to the higher liquidity attached to such products.

The futures contracts traded on the PXs include:

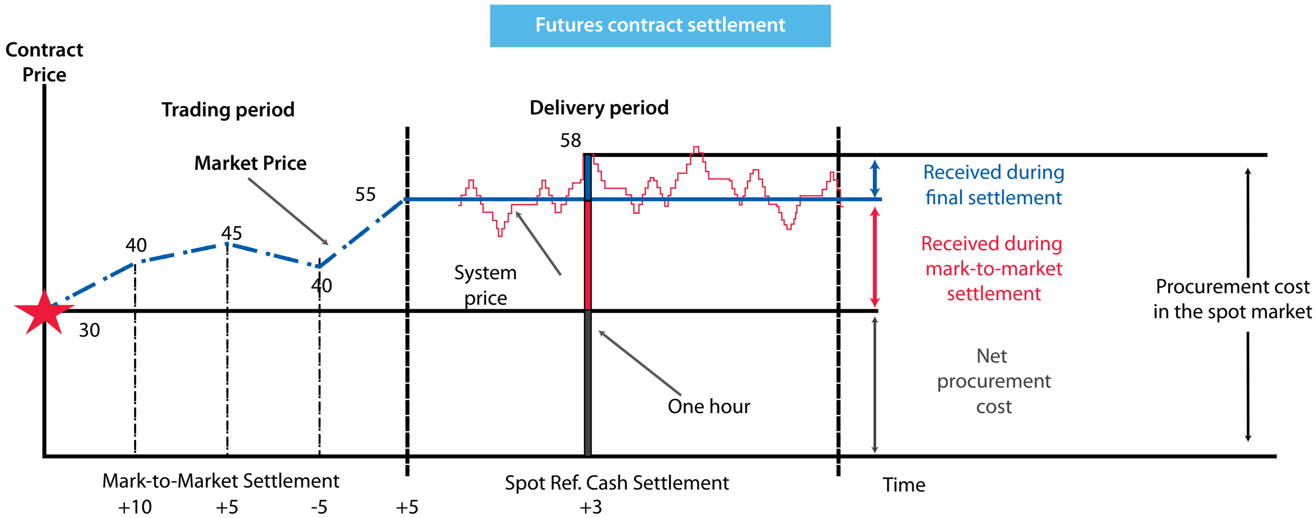
- Day Contracts, Base load
- Week Contracts, Base Load
- Peak Contracts

Settlement of the futures contracts involves a mark-to-market daily settlement and a final spot reference cash settlement, after the contract reaches its due date.

Mark-to-market settlement covers profit or loss from day-to-day changes in the daily closing price of each contract.

Final settlement, which begins at delivery, covers the difference between the final closing price of the futures contract and the system price in the delivery period. Throughout the final settlement period, which starts on the expiry date, the member is credited/ debited an amount equal to the difference between the spot market price and the futures contracts final closing price.

ILLUSTRATION



Source: Trade at NASDAQ OMX Commodities Europe's Financial Market.

As per the illustration above, an exchange member buys a futures contract at a price of EUR 30/MWh. During the trading period, from the date the contract was bought to the contract's due date, the market price for the contract increased to EUR 55/MWh.

The price EUR 55/MWh is the final closing price prior to delivery. Based on the daily mark-to-market settlement during the trading period, the member would gain a total gain of EUR 25/MWh (EUR 55-30). (The Exchange Member who sold the contract was debited EUR 25/MWh during the trading period).

Throughout the final settlement period, which starts on the due date, the member is credited/debited an amount equal to the difference between the spot market price and the futures contract's final closing price.

For the specific single hour indicated in the figure, the member has received EURO 25/MWh in daily mark-to-market settlement (during the contract's trading period) and a final settlement amount of EUR (58-55)/MWh = EUR 3/MWh for a total profit of EUR 28/MWh.

If the exchange member/clearing member in the above example chose to procure the power from the spot market rather than cash in the profit, his procurement cost in the spot market for the specific hour is EUR 58/MWh. However, he has already received a profit of EUR 28/MWh in the futures market. The total cost, with hedging in the futures market and physical procurement in the spot market, is thus equal to the hedging price EUR 30/MWh.

Forward Contracts

Forward contracts are not structured very differently than futures contracts. A key difference between forward and futures contracts is that the buyer or seller of a futures contract will suffer short term losses (or realize short-term gains) as the futures price changes. With a forward contract, profit and loss is realized only at maturity or when the position is reversed, but with a futures contract, profit and loss is settled daily.

The forward power contracts on the NASDAQ OMX Commodities are listed on monthly, quarterly, and yearly basis. The monthly contracts are listed on a six month continuous rolling basis. The quarterly and yearly contracts are split into monthly and quarterly contracts respectively.

Contracts for Difference (CfD)

A CfD is a forward contract that was introduced to hedge even when the markets are split into one or more price areas. For the Nordic market it was in reference to the difference between the area price and the Nord Pool Spot system price. The market price of a CfD during the trading period reflects the market's prediction of the price difference during the delivery period.

An area price differs from the system price when there are constraints in the transmission grid; CfDs allow exchange members/clearing members to hedge against this area price risk.

Contracts for Difference allow market participants to create a perfect hedge of a physical contract, even when the market is split into price areas, by following a three-step process:

- Hedge the required volume using a forward contract.
- Hedge for any price difference- for the same period and volume- through a CfDs.
- Accomplish physical procurement by trade in the spot market area where the member is located.

The illustration below shows how CfDs can be used for hedging area price differential.

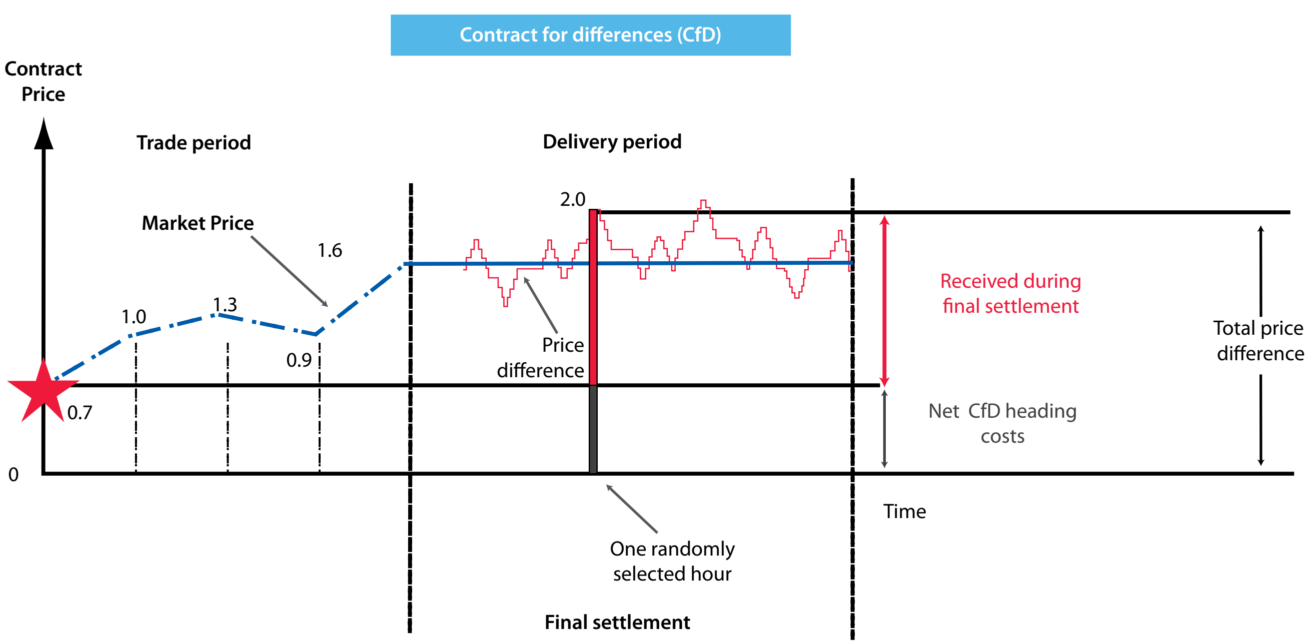
CfD will prove to be relevant in the Indian market context, given the increased instances of market splitting on the power exchange over a period of time.

Clearing of Financial Contracts

Nord Pool Clearing ASA clears financially settled electricity contracts traded on Nordic OTC and bilateral markets. The clearing house assumes complete counterparty responsibility for clearing and settling the contracts.

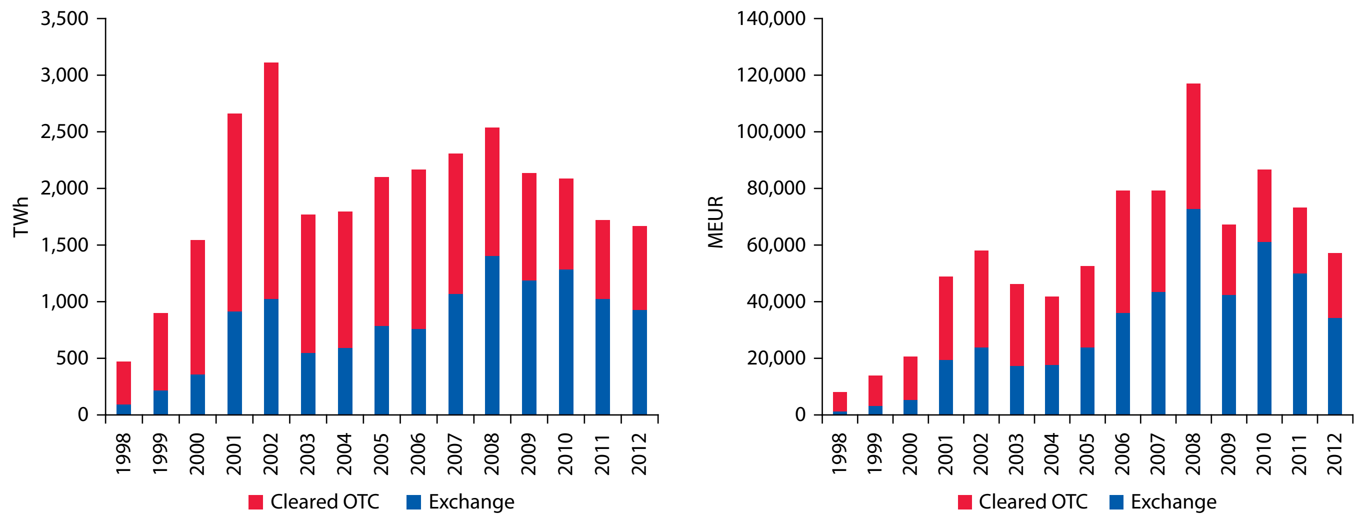
It has been observed in the Nordic markets that financial products lend volume and liquidity thrust to electricity market. The same can be observed for the Nordic Markets from the figure next page.

ILLUSTRATION



In this example, an exchange member/clearing member purchases a CfD at a price of EUR 0.7/MWh and no forward market hedge of the power volume was made. For the randomly selected hour during the delivery period shown in the illustration, the member receives EUR (2.0-0.7)/MWh = EUR 1.3/MWh. Spot market purchase cost over the system price for the specified hour is EUR 2.0/MWh. However, the member's net cost is equal to the hedging cost EUR 0.7/MWh.

Figure 23: Volume turnover in nordic financial electricity market 1998-2008



Source: Nordic Energy Regulator, Monthly Report.

There was an increasing trend in the turnover volumes from 1998-2008, with steep growth rates in the initial period till 2002 that can be attributed to the geographical expansion of the Nord Pool. The volumes traded through exchange as a percentage of total cleared volumes increased from 19% in 1998 to 56% in 2008. A downward trend in the overall volumes was observed post 2009 and is essentially attributed to the global financial crises. Although the markets have seen some decline, they are on account of exogenous factors, and the crucial role the financial market is crucial for functioning of the Nord Pool.

CHAPTER 5

CONCLUSIONS

Evolution of exchange based power markets has outperformed expectations since operation of such markets in a supply starved economy was viewed with scepticism. Volumes have grown almost 14 fold since inception and now the share of Power Exchange based market is 3%[19] of the total electricity generated in the country, and the short term markets including UI are approximately 11%.[20] This is expected to grow to approximately 15%[21] on the conservative side and 23.5%[22] if all the latent demand in India were to be met from short term markets. The prices on the exchange have fewer peaks, are transparent and rational – they can be explained in terms of the events in the market, regulatory changes, and special events like elections etc. The markets are sufficiently efficient and liquid and therefore should be enhanced further.

The potential of these markets can be further enhanced by suitably addressing regulatory and institutional barriers identified in the different sections of this report. Thrust needs to be given to develop new market products such as energy, capacity, ancillary services, forwards, futures and transmission rights.

Prices, close to variable costs of operation, especially in the NEW grid indicate the need for commencement of Capacity Markets – which will allow peak load power plants and other resources to be financially viable. With integration of the Northern, Eastern and Western States and the SR grid, the grid frequency will be maintained in a tight band necessitating requirement of frequency support ancillary services. There is a need to create market/mechanisms to operate primary and secondary frequency control reserves. However, tertiary control reserves can be procured on a day ahead and intra-day basis on the power exchanges. Generators are allowed to revise their schedules eight times in a day, tertiary frequency support markets will allow the SLDCs/RLDCs to procure theses services through the power exchange.

There is a need to create a market for transmission rights. Considerable capacity remains unsold on the exchange because of the want of transmission capacity between the point of injection and point of withdrawal. A market for Financial Transmission Rights (FTRs) will allow realization of the true value of transmission and also help alleviate congestion.

In a nutshell, the power exchanges have played a very critical role in transforming the overall power markets in India. It has now become imperative to deepen the short term markets by allowing new avenues to the power exchanges. With greater liquidity on account of new capacity addition, it is essential to serve consumer needs up to desired standards of supply, particularly when adequate power supply is available in the market. This would require developments that could cater to the exiting

19 CERC 'Report on Short Term Power Market July, 2013.

20 This number includes UI market also.

21 AF Mercados EMI analysis.

22 AF Mercados EMI analysis.

barriers for an even more efficient electricity system. Lack of contracts longer than a week on exchange restricts market growth as participants are not able to tie up supplies in the medium term. Introduction of forwards and future contracts on the exchange would ensure transparency in price discovery through a reliable neutral platform, allowing risk mitigation to participants, lowering the transaction costs and improving the overall liquidity in the market, thereby making it more efficient. Introduction of capacity markets would incentivize peaking generation to be set up in the country. Further establishment of ancillary services and trading of transmission rights would alleviate the grid frequency issues and disincentives/bottlenecks due to transmission barriers. Thus power exchange is likely to contribute significantly to the evolution of the sector and the economic development of the country.

APPENDIX 1

Demand Side Methodology/Assumptions

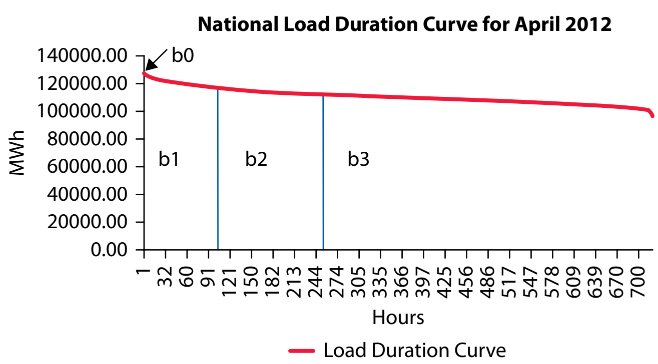
a. The actual FY 2012-13 daily demand data (energy requirement) at the State level has been obtained from different Regional Load Dispatch Centres'[23] (RLDCs). This data considers the energy consumption and the unmet energy/ shortages if any.

b. The hourly demand figures are derived from the daily demand data. An average hourly load profile for each State and every month is constructed from the Peak and Lean Day hourly consumption profile (available from RLDCs), for the particular State in that month. The hourly energy requirements obtained as a percentage of daily energy requirements on a typical day are multiplied with the demand on each day to generate the hourly load profile data for that month.

c. A horizontal summation of the hourly load profiles of all the States gives us the National hourly consumption profile.

d. The National hourly energy consumption (MWh) in a particular month is arranged in descending order to construct a Load Duration Curve.

e. Four demand blocks (b0, b1, b2 and b3) are identified based on the inflection points observed on Load Duration Curve. These are obtained by taking the area under the curve for the specific number of hours in those respective blocks. This is illustrated in the figure below:



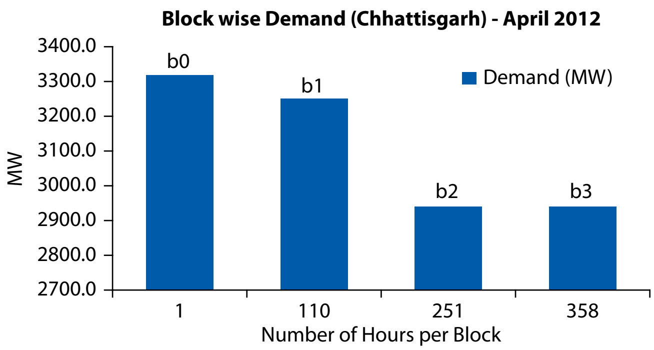
f. The first block (b0) captures the peak demand MW and the following three blocks represent the intermediate and the base load demand. This exercise is repeated for all the months.

g. Demand is spread over four blocks for each month in each year. Demand and duration of hours differ across blocks and months but not over years. For Example, the duration of hours obtained from the LDC for the month of April 2012 is given next page.

h. Once the Peak and Off-Peak hours are determined, the State level demand corresponding to the respective hours in each of the identified blocks is computed. The following figure shows the Demand for the State of Chhattisgarh in the month of April 2012, as observed in the National Peak and off- Peak hours.

23 Data as reported in RLDCs' Daily Power Supply Position.

Blocks	Hours	MW
IEEE Trans Neural Netw. 1997; 8(4): 835-46. **ANNSTLF-a neural-network-based electric load forecasting system.** Khotanzad A[1], Afkhami-Rohani R, Lu TL, Abaye A, Davis M, Maratukulam DJ. b0	1	127075
b1	110	120095
b2	251	112798
b3	358	106445



Supply Side Methodology/Assumptions

a. Existing long term capacity tied up with the state is identified for each of the states in India. Existing thermal, hydro, wind, solar, and biomass plants have been considered for the computation.

b. Share of Central sector plants have been allocated to respective states as per the current allocations provided by CEA. Share of state sector plants have been assigned to the home state unless specified elsewhere. Allocations from the private sector plants have been made according to the PPAs wherever available. Unallocated capacity from the private sector plants has not been included and is assumed to be available in the short term markets.

c. Total installed capacity of each state has been adjusted for by the monthly PLFs/Cufs for various types of plants. The data for the same has been obtained from CEA and other sources.

d. Total effective capacity for each state has been broken into four blocks using hourly profiles for various types of plants.

e. Thermal and Biomass plants have a flat hourly profile and have been assumed to supply equal amount in each block.

f. Regional hourly hydro profiles have been taken from respective regional load dispatch centres. The data for 2012-13 has been used. Regional profiles were available only for NR and SR region. For the rest of the regions, the data was not available and hence hourly profile for representative central sector hydro plants is used.

g. For solar and wind plants, CUF (Capacity Utilisation Factor) has been computed in the following manner:

- At the National level, the consumption is arranged in descending order for all the months X = 1, 2…, 12.
- Blocks b0, b1, b2 and b3 are constructed on the basis of the Load Duration Curve by visually inspecting the inflexion points.
- For solar and wind, frequencies are computed for the hours, i.e. the number of times i^{th} hour occurs in a block. This is done for all the blocks.
- The hourly generation of a representative day in a month is divided by the capacity to obtain CUF for each hour, CUFi.
- Given these CUFi's which have been calculated on an hourly basis, monthly block wise CUF is computed by the formula of weighted average.
- CUF for block bj = Σfij (CUFi)/Σfij, for each j = 0, 1, 2, 3.
  (Summed over all 'i', i = 1, 2…, 24)
  Where, fij = Frequency of i^{th} hour in j^{th} block.

Demand -Supply Gap

h. Demand- Supply gap in each block has been computed across states. The gap has been correspondingly multiplied with the number of hours in the corresponding blocks to obtain the buying/selling potential of states in energy terms.

i. Aggregated the buying and selling potential for each state for the whole year to arrive at the total national level limits for short term markets.

APPENDIX 2

State	Blocks	Buy Potential (MWh)	Sell Potential (MWh)
Bihar	b0 (Peak Block)	(5,476)	-
	b1 (Intermediate Block)	(556,941)	-
	b2 (Intermediate Block)	(1,499,626)	-
	b3 (Base Load Block)	(1,291,746)	-
	Total	**(3,353,790)**	**-**
Jharkhand	b0 (Peak Block)	(1,495)	-
	b1 (Intermediate Block)	(92,254)	-
	b2 (Intermediate Block)	(109,238)	40,033
	b3 (Base Load Block)	(103,438)	39,942
	Total	**(306,425)**	**79,975**
Odisha	b0 (Peak Block)	(8,775)	-
	b1 (Intermediate Block)	(790,592)	-
	b2 (Intermediate Block)	(2,237,408)	-
	b3 (Base Load Block)	(1,542,243)	-
	Total	**(4,579,018)**	**-**
Sikkim	b0 (Peak Block)	(59)	460
	b1 (Intermediate Block)	(2,455)	53,123
	b2 (Intermediate Block)	(3,529)	122,352
	b3 (Base Load Block)	(1,168)	115,297
	Total	**(7,211)**	**291,231**
West Bengal	b0 (Peak Block)	(13,625)	70
	b1 (Intermediate Block)	(1,021,489)	23,512
	b2 (Intermediate Block)	(1,040,352)	1,041,689
	b3 (Base Load Block)	(470,434)	1,384,354
	Total	**(2,545,901)**	**2,449,624**

State	Blocks	Buy Potential (MWh)	Sell Potential (MWh)
DVC	b0 (Peak Block)	-	4,220
	b1 (Intermediate Block)	-	492,019
	b2 (Intermediate Block)	-	2,152,246
	b3 (Base Load Block)	-	2,020,383
	Total	**-**	**4,668,867**
Uttar Pradesh	b0 (Peak Block)	(23,089)	-
	b1 (Intermediate Block)	(1,828,229)	-
	b2 (Intermediate Block)	(3,467,575)	60,612
	b3 (Base Load Block)	(1,422,369)	759,188
	Total	(6,741,261)	819,800
Uttarakhand	b0 (Peak Block)	(7,340)	-
	b1 (Intermediate Block)	(609,346)	-
	b2 (Intermediate Block)	(2,058,597)	-
	b3 (Base Load Block)	(1,466,557)	-
	Total	**(4,141,840)**	**-**
Rajasthan	b0 (Peak Block)	(15,387)	299
	b1 (Intermediate Block)	(1,007,015)	-
	b2 (Intermediate Block)	(2,123,912)	180,685
	b3 (Base Load Block)	(242,807)	797,227
	Total	**(3,389,120)**	**978,211**
Punjab	b0 (Peak Block)	(8,674)	-
	b1 (Intermediate Block)	(809,757)	20,709
	b2 (Intermediate Block)	(1,121,031)	154,128
	b3 (Base Load Block)	(93,784)	547,134
	Total	**(2,033,246)**	**721,971**
Jammu & Kashmir	b0 (Peak Block)	(1,350)	2,011
	b1 (Intermediate Block)	(129,448)	122,111
	b2 (Intermediate Block)	(405,940)	441,980
	b3 (Base Load Block)	(138,255)	448,502
	Total	**(674,992)**	**1,014,606**
Himachal Pradesh	b0 (Peak Block)	(1,536)	1,366
	b1 (Intermediate Block)	(115,435)	158,143
	b2 (Intermediate Block)	(277,672)	507,655
	b3 (Base Load Block)	(5,767)	461,067
	Total	**(400,410)**	**1,128,230**

State	Blocks	Buy Potential (MWh)	Sell Potential (MWh)
Haryana	b0 (Peak Block)	(7,398)	-
	b1 (Intermediate Block)	(39,629)	35,927
	b2 (Intermediate Block)	(124,193)	117,860
	b3 (Base Load Block)	(574)	191,080
	Total	**(171,794)**	**344,868**
Delhi	b0 (Peak Block)	(3,791)	4,633
	b1 (Intermediate Block)	(3,253,081)	-
	b2 (Intermediate Block)	(9,581,212)	-
	b3 (Base Load Block)	-	2,906,936
	Total	**(12,838,083)**	**2,911,569**
Chandigarh	b0 (Peak Block)	(473)	-
	b1 (Intermediate Block)	(37,648)	-
	b2 (Intermediate Block)	(68,609)	-
	b3 (Base Load Block)	(62)	-
	Total	**(106,792)**	**-**
Chhattisgarh	b0 (Peak Block)	(4,032)	405
	b1 (Intermediate Block)	(203,946)	34,465
	b2 (Intermediate Block)	(76,170)	592,129
	b3 (Base Load Block)	-	731,994
	Total	**(284,149)**	**1,358,993**
Gujarat	b0 (Peak Block)	-	23,452
	b1 (Intermediate Block)	-	3,114,641
	b2 (Intermediate Block)	-	10,246,698
	b3 (Base Load Block)	-	11,315,380
	Total	**-**	**24,700,171**
Madhya Pradesh	b0 (Peak Block)	(49,831)	-
	b1 (Intermediate Block)	(4,085,150)	-
	b2 (Intermediate Block)	(11,361,802)	-
	b3 (Base Load Block)	(6,008,615)	-
	Total	**(21,505,398)**	**-**
Maharashtra	b0 (Peak Block)	(29,927)	-
	b1 (Intermediate Block)	(2,372,047)	-
	b2 (Intermediate Block)	(4,380,789)	381,314
	b3 (Base Load Block)	(3,162,285)	530,848
	Total	**(9,945,047)**	**912,162**

State	Blocks	Buy Potential (MWh)	Sell Potential (MWh)
Dadra & Nagar Haveli	b0 (Peak Block)	(530)	33
	b1 (Intermediate Block)	(32,619)	13,261
	b2 (Intermediate Block)	(22,744)	86,826
	b3 (Base Load Block)	-	164,879
	Total	**(55,893)**	**264,999**
Daman & Diu	b0 (Peak Block)	(228)	32
	b1 (Intermediate Block)	(8,471)	6,967
	b2 (Intermediate Block)	(4,770)	62,736
	b3 (Base Load Block)	-	105,505
	Total	**(13,469)**	**175,240**
Goa	b0 (Peak Block)	-	1,083
	b1 (Intermediate Block)	-	137,573
	b2 (Intermediate Block)	-	589,012
	b3 (Base Load Block)	-	546,578
	Total	**-**	**1,274,247**
Arunachal Pradesh	b0 (Peak Block)	(461)	5
	b1 (Intermediate Block)	(34,069)	-
	b2 (Intermediate Block)	(98,559)	2,333
	b3 (Base Load Block)	(77,359)	7,107
	Total	**(210,449)**	**9,444**
Assam	b0 (Peak Block)	(6,335)	-
	b1 (Intermediate Block)	(526,790)	-
	b2 (Intermediate Block)	(1,098,218)	-
	b3 (Base Load Block)	(760,020)	-
	Total	**(2,391,362)**	**-**
Manipur	b0 (Peak Block)	(553)	138
	b1 (Intermediate Block)	(51,772)	25,234
	b2 (Intermediate Block)	(147,743)	39,861
	b3 (Base Load Block)	(71,681)	47,689
	Total	**(271,749)**	**112,922**
Meghalaya	b0 (Peak Block)	(1,243)	23
	b1 (Intermediate Block)	(88,816)	2,196
	b2 (Intermediate Block)	(320,868)	7,696
	b3 (Base Load Block)	(244,281)	6,605
	Total	**(655,209)**	**16,520**

State	Blocks	Buy Potential (MWh)	Sell Potential (MWh)
Mizoram	b0 (Peak Block)	(251)	-
	b1 (Intermediate Block)	(20,543)	1,473
	b2 (Intermediate Block)	(81,831)	3,722
	b3 (Base Load Block)	(48,696)	5,434
	Total	**(151,320)**	**10,629**
Nagaland	b0 (Peak Block)	(394)	-
	b1 (Intermediate Block)	(31,514)	1,185
	b2 (Intermediate Block)	(100,121)	2,635
	b3 (Base Load Block)	(68,840)	2,579
	Total	**(200,870)**	**6,399**
Tripura	b0 (Peak Block)	(790)	-
	b1 (Intermediate Block)	(72,038)	-
	b2 (Intermediate Block)	(187,184)	-
	b3 (Base Load Block)	(130,195)	-
	Total	**(390,206)**	**-**
Andhra Pradesh	b0 (Peak Block)	(42,981)	-
	b1 (Intermediate Block)	(3,951,643)	-
	b2 (Intermediate Block)	(13,471,836)	-
	b3 (Base Load Block)	(9,724,000)	-
	Total	**(27,190,459)**	**-**
Karnataka	b0 (Peak Block)	(37,107)	-
	b1 (Intermediate Block)	(2,640,683)	-
	b2 (Intermediate Block)	(7,301,934)	-
	b3 (Base Load Block)	(3,960,774)	-
	Total	**(13,940,498)**	**-**
Tamil Nadu	b0 (Peak Block)	(47,030)	-
	b1 (Intermediate Block)	(3,971,739)	-
	b2 (Intermediate Block)	(11,616,056)	-
	b3 (Base Load Block)	(8,297,320)	-
	Total	**(23,932,144)**	**-**
Kerala	b0 (Peak Block)	(19,475)	-
	b1 (Intermediate Block)	(1,643,215)	-
	b2 (Intermediate Block)	(3,075,717)	-
	b3 (Base Load Block)	(1,644,070)	-
	Total	**(6,382,477)**	**-**

APPENDIX 3: STATE-WISE BUYING AND SELLING POTENTIAL

State	Block	FY 14	
		Buy Potential (MWh)	Sell Potential (MWh)
Bihar	b0	(6,602)	-
	b1	(587,286)	-
	b2	(2,322,830)	-
	b3	(1,473,376)	-
Jharkhand	b0	(908)	303
	b1	(52,019)	33,194
	b2	(77,076)	464,266
	b3	(67,474)	302,960
Odisha	b0	(11,220)	-
	b1	(836,846)	-
	b2	(2,696,782)	-
	b3	(1,380,818)	-
Sikkim	b0	(40)	419
	b1	(3,199)	37,530
	b2	(6,921)	145,850
	b3	(2,121)	97,737
West Bengal	b0	(19,598)	-
	b1	(1,392,233)	-
	b2	(2,041,683)	499,954
	b3	(597,051)	784,067
DVC	b0	(297)	3,401
	b1	(4,509)	308,526
	b2	-	1,945,260
	b3	-	1,356,986
Uttar Pradesh	b0	(57,540)	-
	b1	(3,998,386)	-
	b2	(15,316,947)	-
	b3	(6,094,993)	-

State	Block	FY 14	
		Buy Potential (MWh)	Sell Potential (MWh)
Haryana	b0	(20,003)	-
	b1	(833,298)	93,421
	b2	(3,661,487)	450,759
	b3	(1,313,071)	932,398
Rajasthan	b0	(25,562)	-
	b1	(1,552,147)	-
	b2	(3,819,920)	-
	b3	(660,160)	296,609
Jammu & Kashmir	b0	(4,213)	1,097
	b1	(432,360)	32,968
	b2	(1,887,923)	280,373
	b3	(901,709)	273,954
Himachal Pradesh	b0	(4,481)	1,215
	b1	(364,752)	108,038
	b2	(1,574,885)	579,118
	b3	(733,551)	424,673
Delhi	b0	(4,076)	4,243
	b1	(2,671,605)	-
	b2	(11,613,825)	-
	b3	-	2,459,616
Punjab	b0	(23,538)	-
	b1	(1,628,207)	-
	b2	(5,749,931)	159,067
	b3	(2,672,006)	600,414
Uttarakhand	b0	(8,885)	-
	b1	(708,548)	-
	b2	(2,723,905)	-
	b3	(1,468,477)	-
Chandigarh	b0	(1,136)	-
	b1	(78,610)	-
	b2	(319,890)	-
	b3	(142,018)	-
Andhra Pradesh	b0	(14,581)	-
	b1	(1,041,236)	-
	b2	(4,976,567)	10,419
	b3	(1,469,967)	319,939

State	Block	FY 14	
		Buy Potential (MWh)	Sell Potential (MWh)
Karnataka	b0	(36,664)	-
	b1	(2,614,710)	-
	b2	(8,267,286)	-
	b3	(2,799,871)	13,064
Tamil Nadu	b0	(47,075)	-
	b1	(3,431,174)	-
	b2	(13,759,868)	-
	b3	(6,304,644)	-
Kerala	b0	(17,344)	-
	b1	(1,323,953)	-
	b2	(3,033,854)	-
	b3	(997,224)	-
Chhattisgarh	b0	(6,465)	-
	b1	(464,953)	-
	b2	(821,676)	458,631
	b3	(430,456)	430,140
Gujarat	b0	(14,362)	-
	b1	(938,368)	10,664
	b2	(2,250,555)	777,758
	b3	(667,874)	1,359,641
Madhya Pradesh	b0	(30,542)	-
	b1	(2,217,304)	-
	b2	(4,291,184)	712,241
	b3	(2,405,818)	686,515
Maharashtra	b0	(42,485)	-
	b1	(3,436,939)	-
	b2	(11,600,441)	-
	b3	(4,081,032)	217,428
Dadra & Nagar Haveli	b0	(1,005)	-
	b1	(71,635)	-
	b2	(299,274)	-
	b3	(129,996)	6,816
Daman & Diu	b0	(280)	37
	b1	(16,830)	2,280
	b2	(79,575)	1,130
	b3	(21,842)	48,066

State	Block	FY 14	
		Buy Potential (MWh)	Sell Potential (MWh)
Goa	b0	-	642
	b1	(1,090)	66,855
	b2	-	416,815
	b3	-	341,210
Assam	b0	(6,576)	-
	b1	(526,980)	-
	b2	(1,393,692)	-
	b3	(656,336)	-
Meghalaya	b0	(1,110)	2
	b1	(89,594)	1,010
	b2	(358,387)	8,781
	b3	(207,032)	4,906
Nagaland	b0	(484)	-
	b1	(36,090)	-
	b2	(114,231)	2,228
	b3	(45,904)	2,436
Arunachal Pradesh	b0	(467)	13
	b1	(34,998)	-
	b2	(100,908)	2,630
	b3	(55,250)	6,808
Mizoram	b0	(318)	-
	b1	(24,063)	27
	b2	(92,450)	4,335
	b3	(38,856)	4,332
Manipur	b0	(551)	124
	b1	(48,684)	6,767
	b2	(158,477)	61,516
	b3	(43,846)	42,399
Tripura	b0	(992)	-
	b1	(89,585)	-
	b2	(222,964)	-
	b3	(87,794)	-

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