Discussion Paper

on

Market Based Economic Dispatch of Electricity: Re-designing of Day-ahead Market (DAM) in India

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Disclaimer

The issues presented in this discussion paper do not represent the views of the Central Electricity Regulatory Commission, its Chairman, or Individual Members, and are not binding on the Commission. The views are essentially of Staff of CERC and are circulated with prime aim of initiating discussions regarding Market Based Economic Dispatch of Electricity in India through redesigning day-ahead market in power exchanges and soliciting inputs of the stakeholders in this regard.

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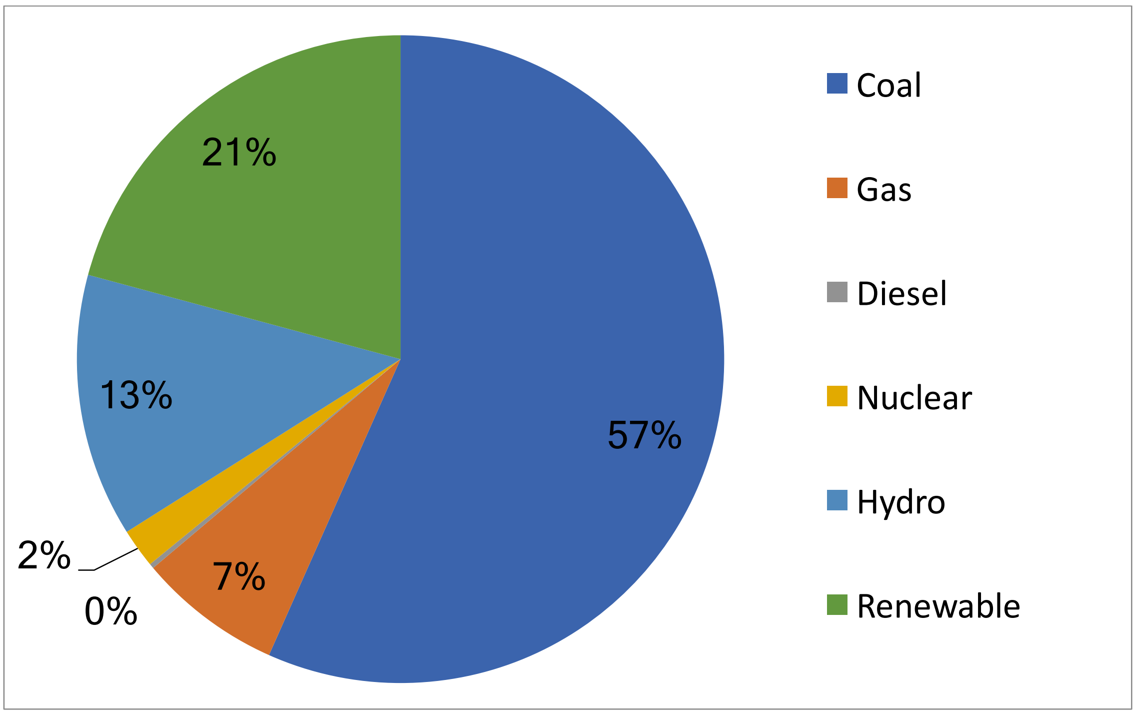
1. Introduction

1.1 Indian Power sector is characterized by multiplicity of players across all segments of the value chain viz., generation, transmission, trading and distribution. There are more than 600 generating stations, 30+ transmission licensees, 70 odd distribution licensees, 2 power exchanges, 40 odd trading licensees, load dispatchers at the center, in each of the five regions and in each of the 29 States. The total installed generation capacity is 346 GW (as on September 2018), out of which 57% is from Coal, about 13% Hydro, 21% Renewables, 7.2% Gas, and 2% Nuclear. (Figure 1)

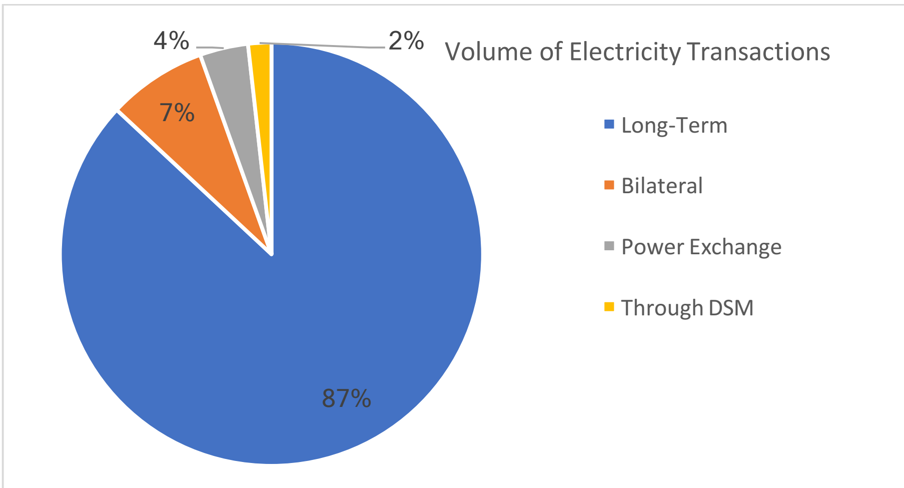
Figure 1. All India Installed Capacity (as on September 2018)



Source: http://www.cea.nic.in/reports/monthly/installedcapacity/2018/installed_capacity-09.pdf

1.2 Most of the generation capacities are tied up in long term power purchase agreements (of 25 years) with the distribution companies (discoms) and the rest in medium term contracts (up to 5 years) and short term contracts (up to 1 year). As depicted in Figure 2, at 87% long-term transactions dominate the share of total electricity transactions in the country. Discoms for meeting majority of their daily power need, self-schedule generation from the portfolio of these long-term contracts and the remaining is procured through bilateral transactions with other discoms, through power exchanges or traders. Self-scheduling refers to the practice followed by the discoms to requisition power from the generating stations with which they have contracts. While placing such request/ requisition, the discoms are not obligated to intimate to the system operator the variable cost of such contracted generator.

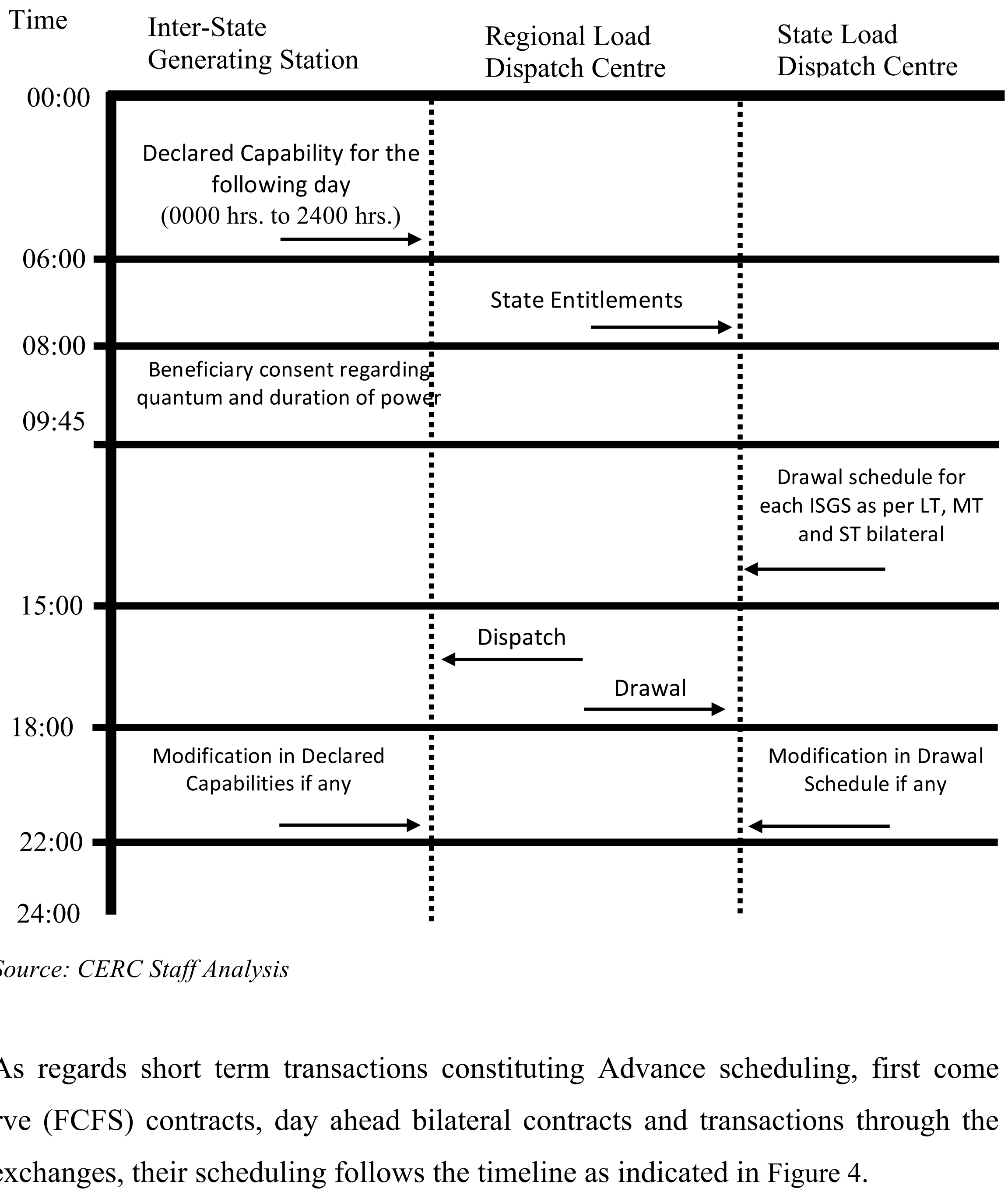
Figure 2. Volume of electricity Transactions in India



Source: Market Monitoring Report, August 2018

1.3 In case of the generating stations tied up in long term PPA, scheduling is done on day ahead time horizon based on the timeline as indicated in Figure 3. Every day by 6AM the Inter-State Generating Stations (ISGS) declare their capabilities for the next day and intimate to the concerned Regional Load Dispatch Center (RLDC). RLDC validates these capabilities and informs each state of its respective entitlements. Once the entitlements have been communicated, the State Load Dispatch Centers (SLDCs) request dispatch from the ISGS with respect to their share out of the declared capability for the following day. If the ISGS wants to sell power to the market, consent has to be obtained from its beneficiary first. The beneficiary has to communicate its consent by 9:45 AM. Thereafter, the SLDCs carry out reviews to calculate the State's power requirement from the ISGS, based on the forecasted load, State's own generating capability and the long-term, medium-term and short-term bilateral arrangements with the ISGS. This schedule is communicated to the RLDC by 3PM. The RLDC having all the required information computes the dispatch schedule for the ISGS and similarly the drawal schedule for the states by 6PM. The states as well the ISGS have the opportunity to make modifications to their drawal schedules and declared capabilities respectively by 10PM.

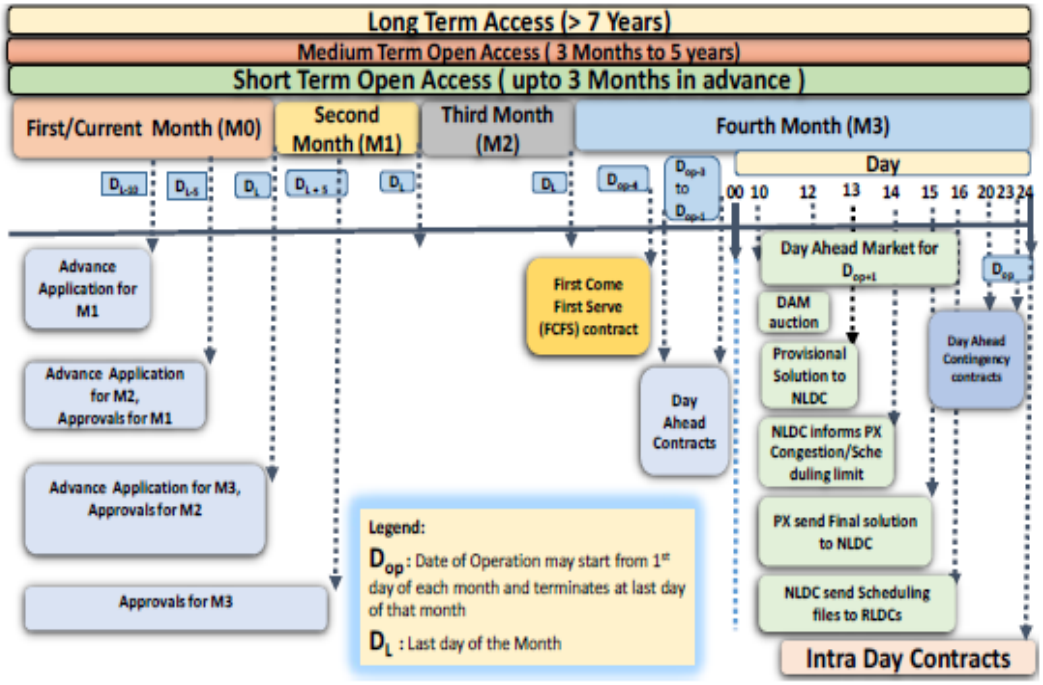
Figure 3. TimeLine for Day Ahead Scheduling of Long Term Transactions



Source: CERC Staff Analysis

1.4 As regards short term transactions constituting Advance scheduling, first come first serve (FCFS) contracts, day ahead bilateral contracts and transactions through the power exchanges, their scheduling follows the timeline as indicated in Figure 4.

Figure 4. Time-Line for Scheduling of Short Term Transactions



Source: Based on Regulations of CERC

The advance scheduling refers to scheduling up to 3 months in advance. Buyers have to make applications by the end of the first month for advance scheduling for the fourth month. Applications for advance scheduling in the third month must be made 5 days prior to the end of the first month and similarly applications for the second month must be made 10 days prior to the end of the first month.

1.5 After the advance scheduling deadlines, there is a provision for first-come-first serve (FCFS) contracts. The applications for FCFS need to be made four days prior to the day of operation and approval for the same is granted within three days. Finally, after the deadline of FCFS contracts, there is a provision for scheduling day ahead bilateral contracts the applications for which are made within 3 days prior to the day of scheduling and up to 3PM of the day preceding the date of operation. Applications made within this time period are processed together only after processing the collective transaction applications made during the same time period.

1.6 In so far as the transactions in the day-ahead market segment of the power exchanges are concerned, the bidding takes place from 10AM to 12 noon, a day prior to the day of operation. Provisional matching is sent to the NLDC for approval by 1PM and the NLDC reverts with congestion related information by 2PM. Based on the information, the power exchanges send the final scheduling request to the NLDC by 3PM. Once the NLDC confirms the scheduling request of the power exchange by 4PM, the power exchanges inform the SLDCs of the approved schedules by 5:30PM. The RLDCs and SLDCs incorporate all the collective transactions in their daily schedules.

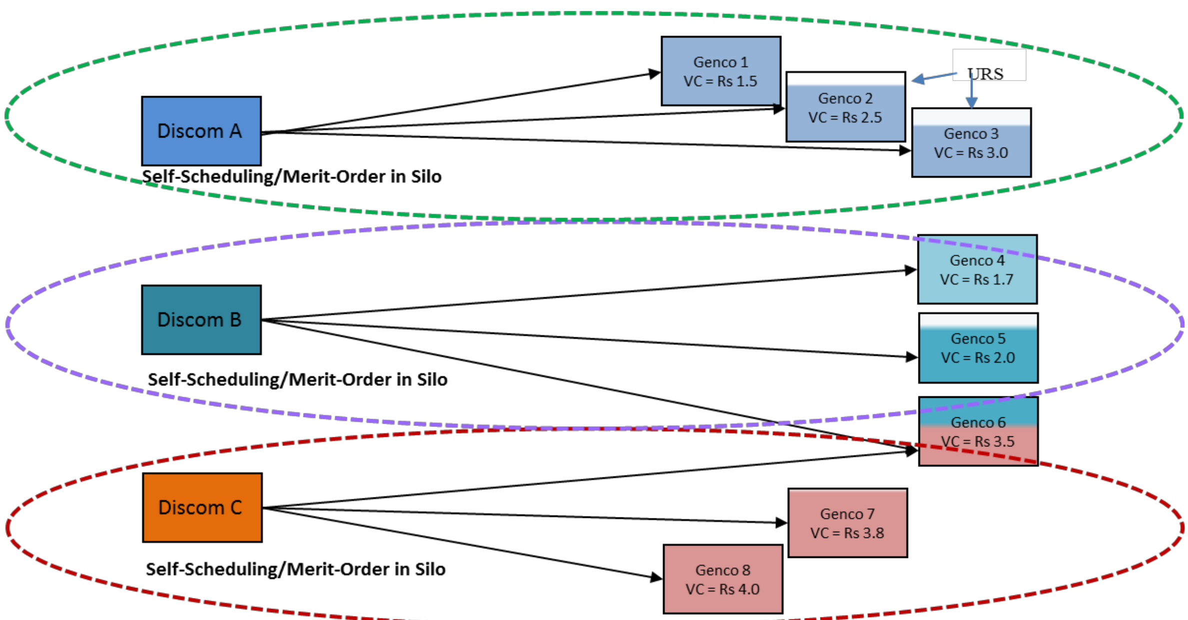
1.7 Day Ahead Markets are a part of a continuum involving the multi settlement markets. While a DISCOM contracts capacity in Long Term, it schedules the power mostly in day-ahead time horizon. Therefore, each of these markets – along the continuum, allows the DISCOM to "correct" its position by either buying more contracted quantity (if it perceives that the demand will increase) or selling (directly, being a deemed trader or through a separate trader) excess contracted quantity (if it perceives that the demand will decrease).

2. Issues in the current day ahead market design

2.1 At present, under the self-scheduling mechanism the discoms prepare their schedule from their portfolio of contracts to meet the expected load. These schedules are submitted to the load-dispatch centers as per the timelines discussed in section 1. This process does not mandate the discoms to declare the cost of their scheduled generation, more precisely, the variable cost.

2.2 There are consequential issues that arise due to self-scheduling. For instance, it leaves several low-cost generation capacities partially or sub-optimally utilized. This is because, the discoms do not have visibility of other cheaper options nor do they have the right to requisition/schedule power from the generating stations with which they do not have a contract. Figure 5 depicts how scheduling in individual silos by each discom can lead to sub-optimal utilization of lower cost generation while relatively expensive generation is used. Discoms do not have the opportunity to identify cheaper generation outside their portfolio due to the lack of visibility of such available capacity.

Figure 5. Self-Scheduling / Merit Order in silos

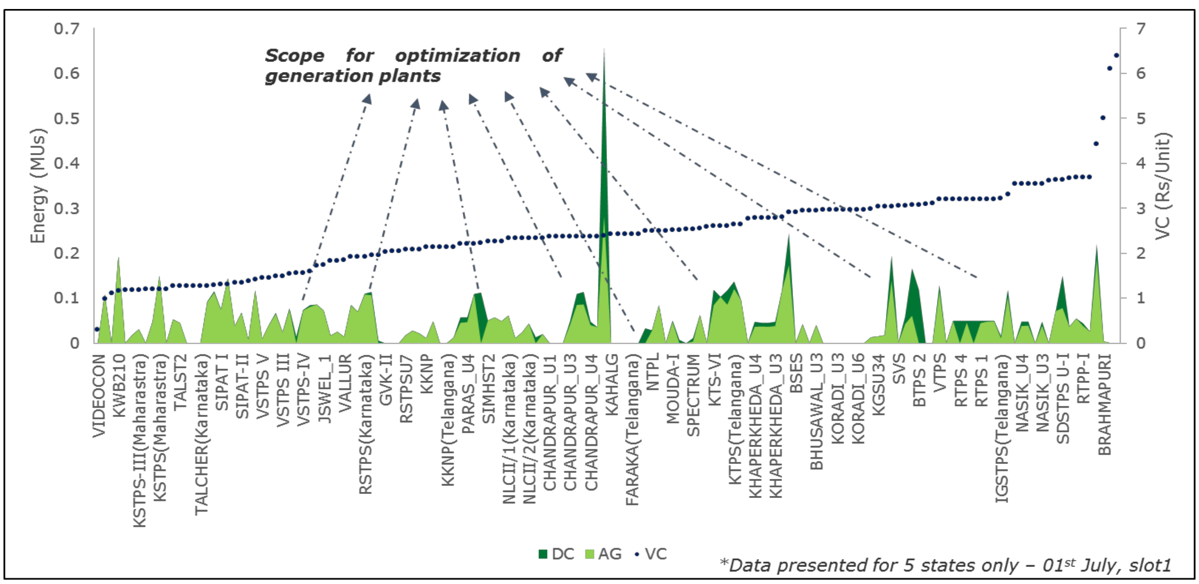


Source:- CERC Analysis

As depicted in Figure 5, under self-scheduling mechanism there remains a possibility of some cheaper generation capacities not getting scheduled fully (un-requisitioned surplus or URS) when some expensive generation resources are scheduled. This is because each discom operates in its own silo. In this example, URS at VC of Rs. 2.5 (Genco 2), and Rs. 3.0 (Genco 3) remain unutilized while higher cost generating stations (Gencos 6, 7 & 8) are scheduled. This is because Discom B or Discom C does not have contract with (Genco 2) or (Genco 3), and each one of them operates in its silos without the visibility of the other.

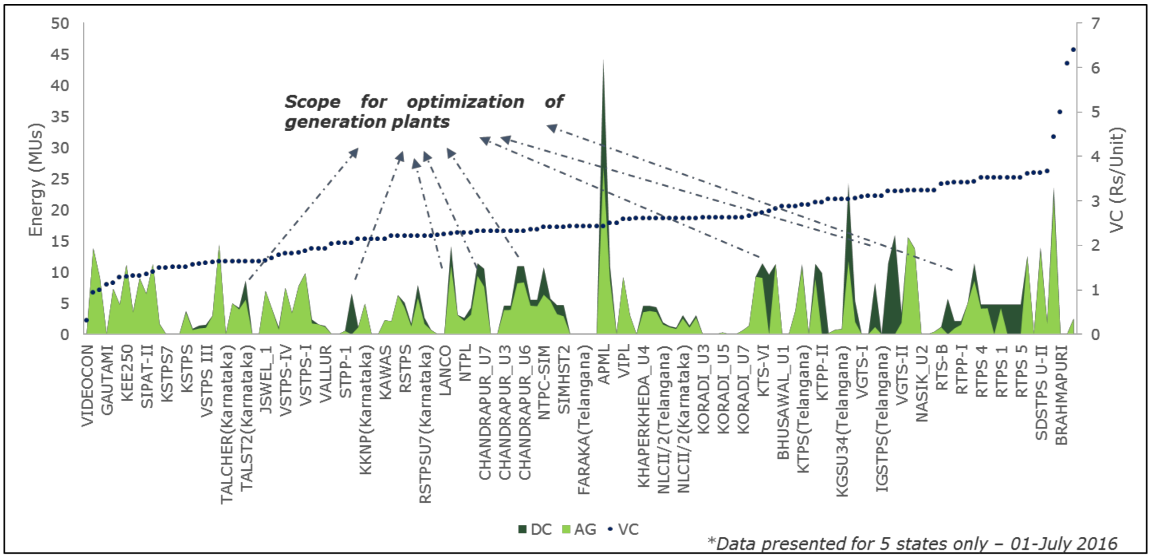
2.3 The Figure 6, theFigure 77 and the Figure 8 show the generation portfolio of five States viz. Andhra Pradesh, Karnataka, Telangana, Maharashtra, and Chhattisgarh (for which primary data have been collected) stacked in the order of their variable cost. The energy dispatched and declared capacity, respectively for one time block on a particular day; each time-block for a day and for all days of a month have been aggregated.

Figure 6. Actual and Max. Possible Generation for 5 States for one time block (Slot-1 of the 1st July, 2016



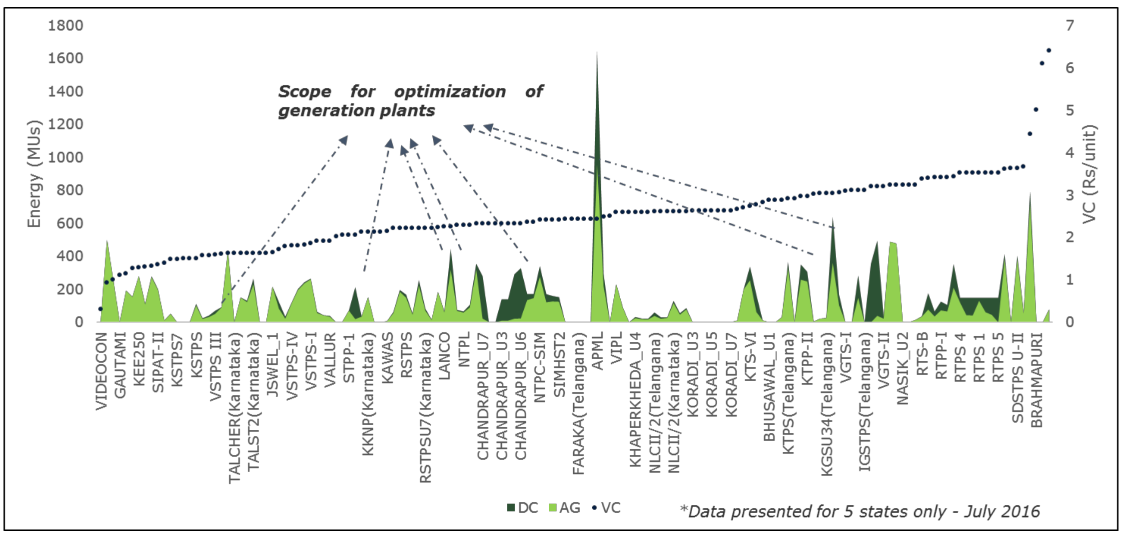
Source: CERC staff analysis

Figure 7. Actual and Max. Possible Generation for 5 States for a day (1st July,2016)



Source: CERC staff analysis

Figure 8. Actual and Max. Possible Generation for 5 States for the month of July, 2016



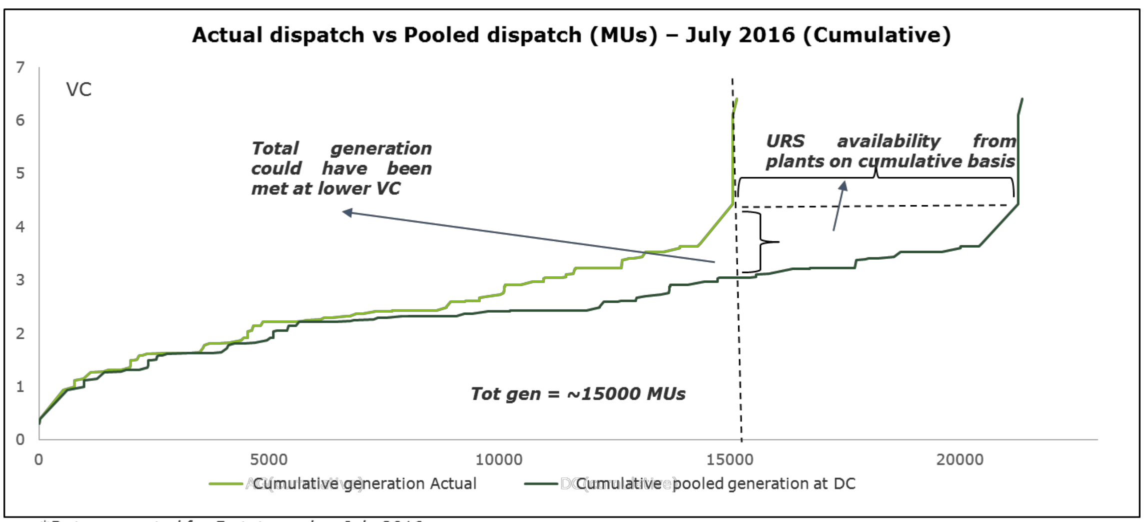
Source: CERC staff analysis

Note: For Five States (Andhra Pradesh, Karnataka, Telangana, Maharashtra, Chhattisgarh) maximum possible generation at Declared Capacity (DC) (in MUs) Vs. Actual Generation (in MUs) have been arranged in ascending order of variable cost of generators.

The two overlapping area graphs show the actual generation (AG) dispatched by these generators and their declared capacity (DC). It is observed that there are several low-cost generators (in a time block, a day as also in a month) with surplus DC remaining unused while relatively expensive generators were being dispatched. This implies, they were not dispatched completely by their state and in the absence of a platform where this low-cost capacity could be made visible to other buyers, the plants remain partially un-utilized. Self-scheduling adds a layer of opaqueness in the system and makes it difficult for the system operator to identify and dispatch the unused low-cost generation. The dark area in excess of the light area in the graph represents the scope for optimization in scheduling and dispatch. That area represents the surplus unused relatively low-cost generation.

2.4 The case for sub-optimal utilization of generation assets becomes all the more prominent when the actual generation of each state is combined together and is contrasted with the cumulative pooled generation of all the five states taken together, as depicted in Figure 9.

Figure 9. Actual Dispatch vs. Pooled Dispatch (MUs) July, 2016 (cumulative)



**Data presented for 5 states only - July 2016*

**VC-variable cost, AG: Actual generation, DC: Declared capacity*

Source: CERC Staff Analysis

The light green line indicates the cumulative actual generation of all the generators in the five States, where as the dark green line shows the cumulative pooled generation (equivalent to the declared capacity) of all the generators in the five States, stacked in merit order. It can be seen from the above figure that the system marginal cost in the actual dispatch scenario is much higher than that of the pooled dispatch. In other words, the available URS from plants with cheaper variable costs is not utilized, whereas the plants with higher variable costs are being dispatched.

2.5 There could definitely be some explanations for non-utilization of cheaper sources of generation. For instance, factors like transmission constraint, maintenance shut down, ramping constraints, technical minimum etc. could be responsible for such results. However, simulations have been done (as explained in later sections of this paper) by applying some of these constraints and the results of the constrained optimization still show definitive scope for optimization of generation resources.

2.6 The other challenges emanating from the practice of self-scheduling include lack of flexibility to meet seasonal and diurnal variation in demand. For example, a discom having contracts with hydro generators may not need to use this available capacity in monsoon period. In other cases, in order to meet peak demand in the evening, discoms are forced to keep running costlier generation capacity at its technical minimum in off peak period even at the cost of backing down of cheaper generation. De-centralized self-scheduling does not allow optimum utilization of cheaper generation capacity because of lack of visibility of demand from other discoms. The availability of un-requisitioned surplus (URS) from low cost generating stations also implies a potential for optimizing scheduling and dispatch in order to lower cost of power procurement for discoms.

2.7 The extant practice followed to provide day-ahead schedule (of the generation contracted under long-term agreements) often weakens physical and financial sanctity of transactions, as both the generator and the discom can revise schedule 4 time blocks ahead of dispatch without any financial liability. This makes system operation prone to a lot of uncertainties.

2.8 To summarise, the key challenges of the existing mechanism of self-scheduling are as under:-

i. Self-scheduling restricts visibility of low cost generation available with other discoms or generators;

ii. Costlier generation is used despite availability of cheaper generation – leading to inefficiency and increased system cost;

iii. Given that the discoms are not obligated to reveal the variable cost of the generation that they are scheduling, true system marginal cost is not known;

iv. Self-scheduling often constrains optimum utilization of renewable sources of energy. As the visibility of a discom is limited to its own territory, surplus renewable energy in the State is curtailed. Further, with increase in penetration of Distributed Energy Resources (DER) at Distribution Network (which SLDC and RLDC are not able to observe), DISCOMs would need to take into account generation from such sources, to ensure flexibility in the system while catering to 'net load (demand minus the generation from embedded RE resources)'. This is critical because such embedded sources of renewable generation need to be taken explicit cognizance of while scheduling other conventional sources.

2.9 The following section explores international experience in the context, especially on optimum utilisation of generation resources, before recommending a framework suitable for India.

3. International Experience

3.1 The independent system operators (ISOs), in the US have over the period adopted the centralized bid-based pool model as market design. In the process of designing and moving towards a centralized pool-based approach they have continued to accommodate self-schedules in a way that do not compromise their objective of least-cost grid operations. This has provided the ISOs room to gradually develop the market design to incentivize more and more participants to go through the energy market rather than submit self-schedules[1]. Currently, electricity transactions regardless of whether part of the day-ahead energy market or self-scheduled, all get settled financially at the market clearing price (MCP)[2]. Hence effectively, buyers who submit self-schedule become the price takers since they have to settle at prices cleared in the day-ahead market. Bilateral contracts do not generally relate to the dispatch of available resources but instead 'stipulate how economic rents from spot markets and the risks of lower than expected capacity factors will be allocated between parties.

PJM

3.2 The PJM's day-ahead market calculates the hourly clearing prices for the following operating day on the basis of all the generation offers, demand bids, increment offers, decrement offers as well as bilateral transaction schedules which are submitted[3]. All generators have to submit offers in the day-ahead market regardless of their operating status (e.g: maintenance or unplanned outages). Self-scheduled generators also have to submit their MW schedules to the day-ahead market. Buyers are required to submit their hourly demand bids for the following operating day as MW quantities at particular locations, which they are willing to purchase. (See Figure 1010)

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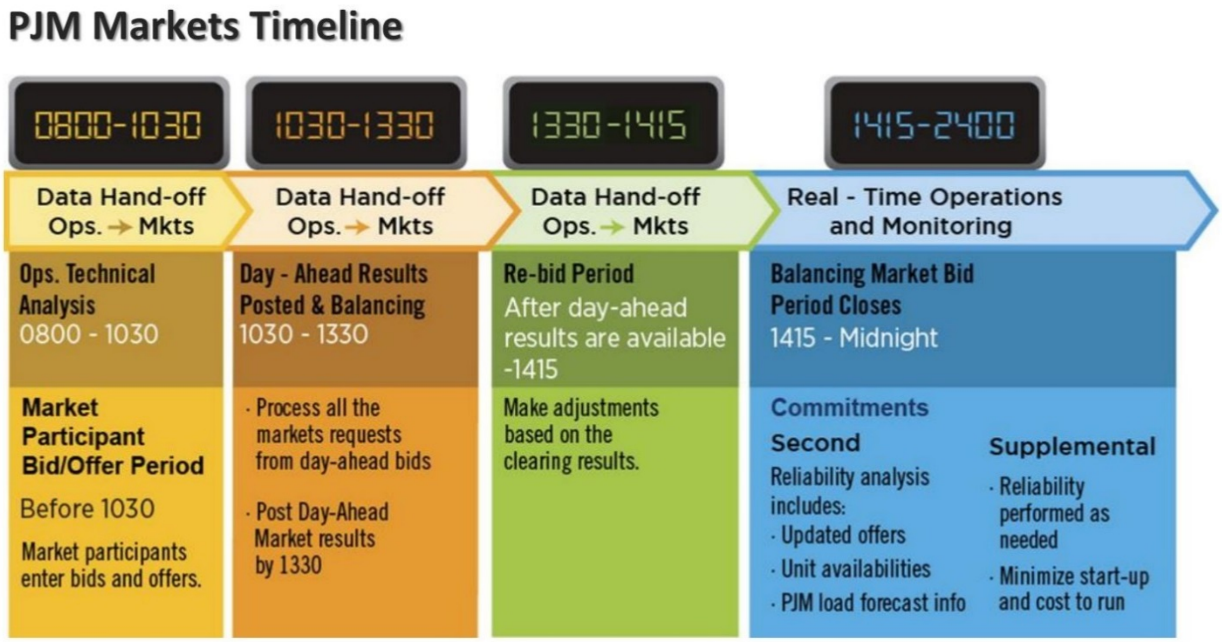
[1] Electricity Contracting in the United States (USAID Report 2018)
[2] Wholesale Market Design Initiatives in the United States (EPRI)
[3] PJM Manual 11, 26th July 2018

Figure 10. PJM Market Timeline



Source – PJM Manual 11: Energy and Ancillary Services Market Operations

3.3 The buyers can also submit price sensitive demand bids which include the price along with the MW quantity and location. After all the submissions are made, the prices are calculated on the basis of Locational Marginal Pricing (LMP) concept which considers three components; the system energy price, congestion price and loss price. The PJM scheduling philosophy for the day-ahead market is **"to schedule generation to meet the aggregate demand bids that results in the least-priced generation mix, while maintaining the reliability of the PJM RTO."** The day-ahead schedule is calculated based on least-cost, security constrained resource commitment and dispatch for each hour of the following operating day[4].

[4] PJM Manual 11, 26th July 2018

New York Independent System Operator (NYISO)

3.4 NYISO's markets are designed to ensure that bilateral contracts don't affect the ISOs objective of meeting the system load with least-cost and reliable electricity generation. A buyer is allowed to self-schedule its day-ahead demand with its contracted generators and communicate it to NYISO. However, all state generators (even if self-scheduled) are required to submit economic bids to the ISO comprising the quantum of electricity offer with a price for the following day. NYISO's day-ahead market closes the earliest amongst the different ISOs. Their bidding period starts seven days prior to the day of delivery and closes as early as 5AM the preceding day. (see Figure 11)

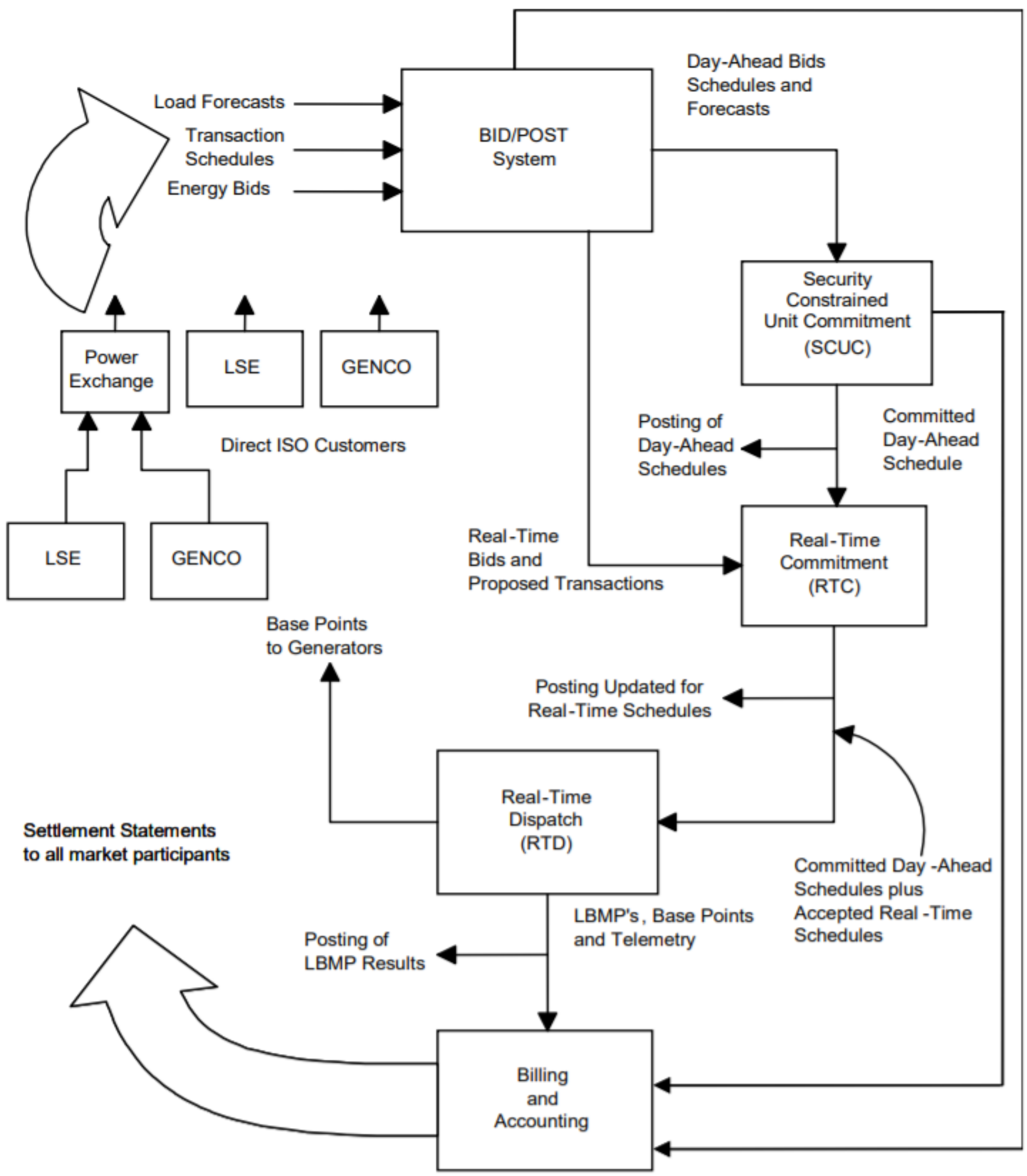
3.5 The ISO then combines all the generator offers which include generators offering electricity in the energy market as well as self-scheduled generators. The bids are processed and schedules are prepared by 11AM. Therefore, the schedule of the contracted generators does not impact the ISOs process of optimizing the available generation resources to ensure that the least-cost dispatch takes place in the system, effectively helping lower the system costs and costs to the buyer as well. The buyers who submit self-schedules have to be price takers since they do not bid a price into the day-ahead market. Bilateral contracts consist of 40% of the total electricity transactions and the rest 60% take place through NYISO's locational based marginal price (LBMP) market.

3.6 The following flow chart shows the NYISO's process right from bidding phase to financial settlement. All the bids from the power exchange as well as the self-schedule load and generation go through NYISO for centralized dispatch in merit order.

California ISO (CAISO)

3.7 California has been through a few phases of power market restructuring in the last three decades. Till 2009, CAISO's market design consisted of Load Serving Entities (LSEs) self-scheduling their day-ahead and hour ahead demand while the CAISO market only used economic bid-based dispatch of generation in the real time through economic bids. Therefore, self-scheduling was a major part of their day-ahead process and only the real-time energy transactions went through CAISO market. This bilateral day-ahead market design put the burden of optimizing the day-ahead schedule on the utilities. Optimizing their schedule was important since they had to meet the residual demand or supply through the CAISO market at the real-time prices.

Figure 11. NYISO Day-Ahead Market Process



Source: NYISO – Day-Ahead Scheduling Manual 11

3.8 In 2009, the market was redesigned on the lines of the PJM market. The CAISO markets require the participants to submit economic bids which include the quantity along with a price. Self-scheduled load or generation has to submit only their quantity and as mentioned earlier, they would be price takers in this scenario. So, locational marginal prices (LMPs) are discovered in both the day-ahead and real-time markets and all generation and load is settled at these prices. There have been a number of contracts that have developed to facilitate participation of buyers and sellers who are part of long-term bilateral contracts. Contracts for differences (CfD) being the most widely used as effective arrangement between the parties.

3.9 With increase in penetration of renewables into the grid, self-scheduling brings in major concerns. Self-scheduling makes it difficult for the CAISO to react to changes in the system. Renewable curtailment increases as significant amount of self-scheduled resources are online. Presently, CAISO is directing its efforts to reduce self-scheduling to ensure that RE curtailment is minimized as much as possible.

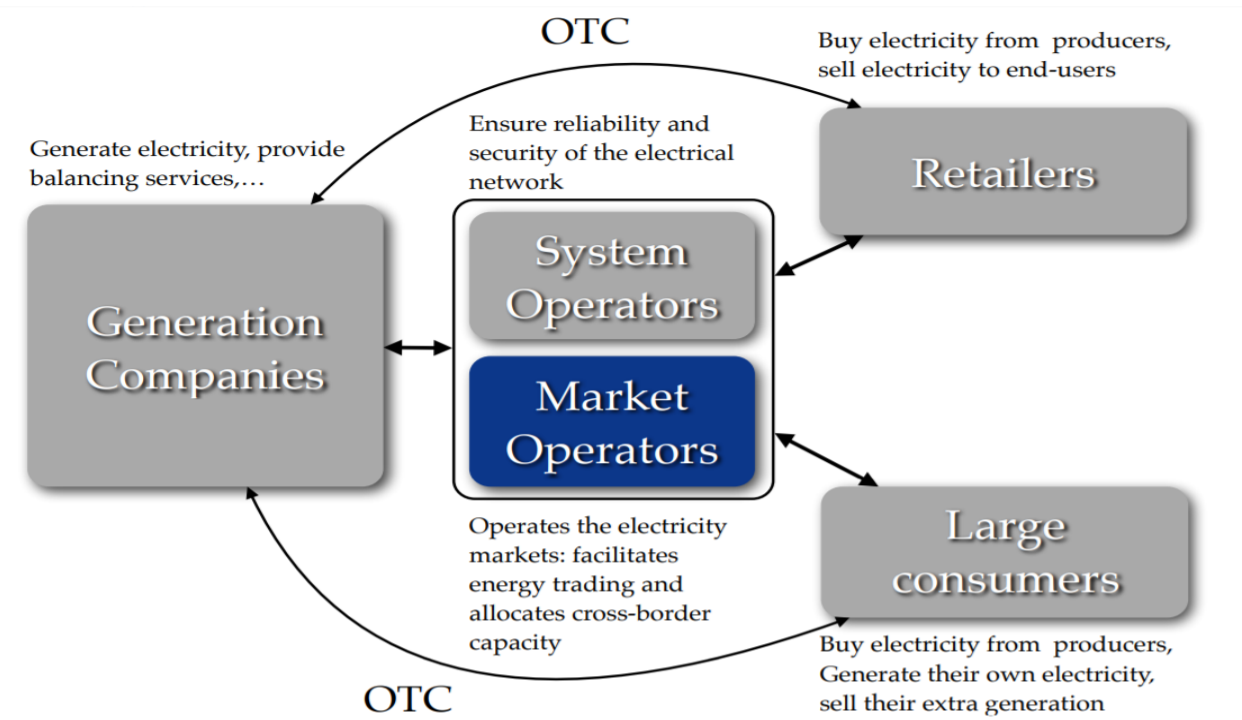
3.10 Production cost savings were examined in the Midwest ISO (MISO) region as the markets transition from a decentralized or less centralized dispatch operations (called as 'Day One') to a centralized market-driven unit commitment and dispatch process (called as 'Day Two')[5]. The analysis suggested as the market transitioned from a Day 0 (pre-RTO) to Day 1, production cost declined around 1.35% and transitioning to Day 2 operations yielded further reduction of 2.61%. Absolute savings across MISO in fuel and $S0_2$ from Day 0 to Day 2 amount to around $261 million a year, out of which $172 million are due to transition from Day 1 to Day 2. Implying that at a constant rate the savings would amount up to $1.72 billion in 10 years. Recently, MISO advertised that in 2017, "**its centralized dispatch system and modelling software resulted in a cost savings between $229 million and $259 million from improved unit commitment among the RTO's 30 balancing authorities**[6]."

[5] Generation Cost Savings from Day 1 and Day 2 RTO Market Designs, Brattle Group 2009
[6] RTO Insider, MISO touts $3 billion in 2017 savings

Integrated European Electricity Markets

3.11 Similar to India and contrary to the US, in European Union the system and market operators are distinct organizations which function independently. Figure 12 shows a simplified version of EU's day-ahead market design[7].

Figure 12. Organization of Electrical Power System in EU



Source: *How the European day-ahead electricity market works, Bertrand Cornélusse http://www.montefiore.ulg.ac.be/~cornelusse/material/CoursEM20170331.pdf*

Each region has its own system operator which is known as Transmission System Operator (TSO) and each region has its own power exchange which operates day-ahead markets, intra-day markets, balancing markets etc. Over several years EU has been trying to achieve their goal of an integrated European electricity market to increase transparency, efficiency, liquidity and most importantly social welfare[8]. Therefore, seven power exchanges; EPEX Spot, CME, Nord Pool, OMIE, OPCOM, OTE and TGE have

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[7] How the European day-ahead electricity market works, *Bertrand Cornélusse* - http://www.montefiore.ulg.ac.be/~cornelusse/material/CoursEM20170331.pdf

[8] PCR Project, *Price Coupling Region* - https://www.belpex.be/wp-content/uploads/PB102-7.6.1-PCR-Standard-Presentation_detailed_last_1.pdf

taken the initiative of integrating their markets and adopting price coupling mechanism to discover single electricity prices across regions[9].

3.12 Currently, these seven exchanges operate across 23 countries[10] and are working towards integrating more power exchanges. In the day ahead markets of these exchanges, price clearing takes place once a day for all the regions where it is possible to match the bids between different regions/power exchanges and utilize cross-border generating resources implicitly. Integrating more regions and implicitly allowing cross border trading can realize social welfare benefits to the tune of €16 - €43 billion by 2030.

3.13 Moreover, accommodating high levels of RE integration and balancing it over a wider region has allowed several geographic and technical diversities to be exploited which reduces the overall balancing volume[11]. Several other benefits of an integrated market based on market coupling principles have already been achieved. Figure 13 summarizes different benefits achieved and potential to achieve more. Integrated or larger markets in EU and US have delivered least cost electricity to consumers by efficiently optimizing the use of available generating resources while ensuring the security of the grid at the same time. Additionally, it also advances the climate and environment goals of clean energy transition by successfully accommodating high levels of intermittent RE sources.

3.14 Europe's primary initiative on integrating electricity markets has been the Target Electricity Model[12]. The model is based on two broad principles; Energy only regional markets and market coupling. The benefits to be realized upon successful integration as per the Target Electricity Model across Europe are around €2.5bn to €4bn per year. A 2013 report[13] stated "about 58%-66% of these benefits have already been achieved due to

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[9] PCR Project, *Price Coupling of Region* - https://www.belpex.be/wp-content/uploads/PB102-7.6.1-PCR-Standard-Presentation_detailed_last_1.pdf

[10] Austria, Belgium, Czech Republic, Denmark, Estonia, Finland, France, Germany, Hungary, Italy, Latvia, Lithuania, Luxembourg, the Netherlands, Norway, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden and UK.

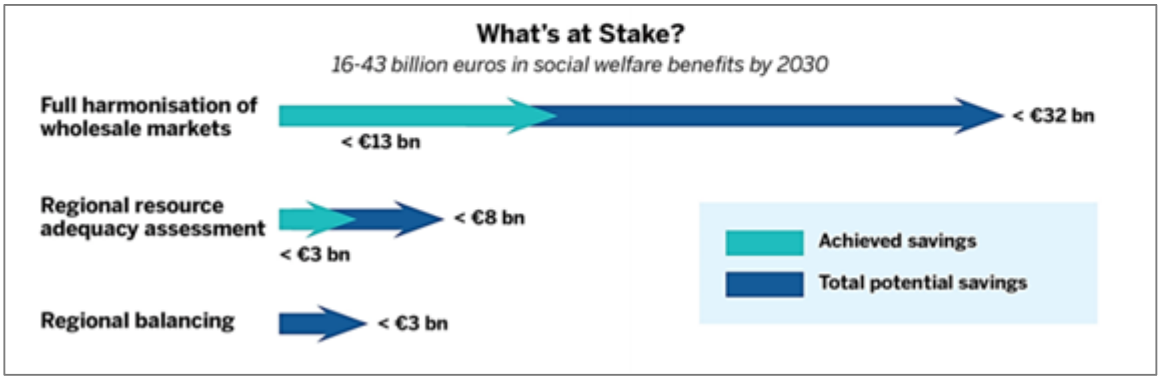
[11] Realizing the benefits of European market integration, *Regulatory Assistance Project,* May 2018

[12] *The EU "Target Model" for electricity market – fit for purpose?,* Oxford Institute for Energy Studies

[13] Report for Directorate-General Energy European Commission by Booz & Company, revised July 2013

the level of market coupling present in large electricity markets of north-western Europe and the Nordic region".

Figure 13. Benefits of an Integrated European Energy Market



Source: Based on Booz & Co. 2013. Benefits of an integrated European energy market and European Commission Staff working Document impact assessment, Part 3/5

Market coupling allows two or more electricity markets from different areas to integrate through implicit cross border allocation[14]. Integration has made it easier for EU member states to adopt high levels of RE penetration without substantial investments in transmission capacity upgrades.

Elspot: Nord Pool Spot's Day-ahead Auction Market

3.15 Elspot is the Nord Pool's Day-Ahead spot market where power is traded based on auction mechanism. All the participants must send their hourly buy and sale offers to Nord Pool Spot at the latest by noon the day before the actual power is transacted through the grid. The power purchase orders are aggregated to a demand curve and sale offers to the supply curve. The intersection of the two curves gives the market price for one specific hour. The Nord Pool then publishes the report to the participants the quantum of electricity bought and sold for each hour of the following day and to the Transmission System Operator (TSO). TSO later uses this information to calculate the balancing power for each participant during the real time transaction.

[14] Market Coupling, European Union Electricity Market Glossary

3.16 The system discovered price based on the supply and demand in a given region is theoretical in nature and applies only when there are no grid related bottlenecks. However, due to existing bottlenecks, the Elspot area is divided into a number of bidding areas. TSO decides the number of bidding area and its boundaries based on the transmission infrastructure in place for the particular region. Nord Pool spot exchange calculates a price for each bidding area for each hour of the following day.

3.17 Based on the available transmission corridor and capacity in the transmission grid, the Nord Pool spot market integrates the different bidding areas to maximize the overall social welfare in the combined market. In this manner, along with calculating the day-ahead prices, the Elspot market also carries out congestion management to bring out an efficient system through an implicit auction. The available transmission capacity is used to equalize the price differences as much as possible.

3.18 The surplus area is one where consumption is lower than the supply and hence lower clearing price as compared to deficit area with lower supply and higher consumption. This price difference between the two bidding area may be reduced based on the available transmission capacity as the export of power from the surplus to deficit area is reflected as an additional purchase for surplus area and additional sale for deficit area.

3.19 Nord Pool spot market carries out day-ahead congestion management both on external and internal transmission lines[15] among the bidding areas to maximize the overall efficiency of the system and optimize the generation cost of the system.

3.20 Given the concerns arising out of the self-scheduling process as highlighted in the preceding section and with due regard to the international experience of optimisation of resources in day ahead/ real time, the following section proposes a market design for India that optimizes dispatch and saves costs for consumers.

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[15] Nordic Electricity Exchange and Nordic Model – Nord Pool

4. Proposed Framework – Market Based Economic Dispatch on a Day Ahead basis.

4.1 The discussion in the preceding sections highlights the need for optimization of scheduling and dispatch of generation capacities through a suitable market design. The international experience offers alternative market designs in order to ensure optimum utilization of generation in different time horizons. It is in this backdrop that a **Market Based Economic Dispatch (MBED)** model is proposed in this section. This model would function on a day-ahead time horizon and schedule and dispatch all generation purely on economic principles, subject of course to technical constraints.

4.2 The objective of the MBED will be to meet the system load by dispatching the least-cost generation mix while ensuring that security of the grid is maintained. This will ensure that the total cost of generation i.e. system cost, to meet the system load in all time-blocks for a day is minimized. Given the current market framework in India, involving the system operator and the market operator separately, the proposed market design also envisages both these institutions to perform their respective functions as at present. The system operation will address the physical settlement of electricity, whereas the market operations will involve bid solicitation and all financial settlements. The market platform would discover the market clearing price in each time-block in a day that reflects the true value of the electricity dispatched.

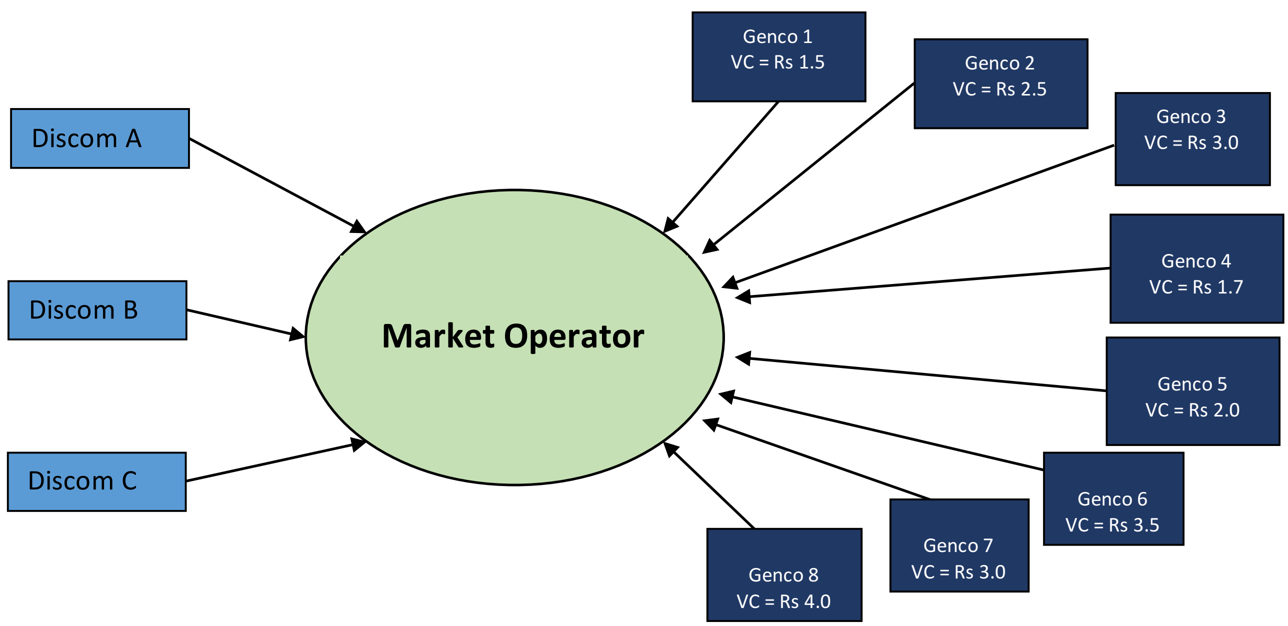
4.3 The MBED model involves primarily the following two aspects, viz., ‘Scheduling and Dispatch’ and ‘Settlement of Contracts’, which is being elaborated in the subsequent paragraphs.

MBED (First Aspect): Scheduling and Dispatch

4.4 In the MBED model, the sellers (central generators, state generators, independent power producers (IPPs)), traders and discoms as sellers) would be required to submit offers for all the time-blocks (which can be a single offer or block offer or multi-part offer) for the following day to the Power exchanges. These offers would reflect the quantum of electricity that the sellers are willing to supply at a particular price. Similarly, the buyers' bids would indicate the quantum of electricity they are willing to buy at a particular price.

4.5 Figure 14 depicts a simple schematic in which the discoms submit demand bids and the generators place supply offers.

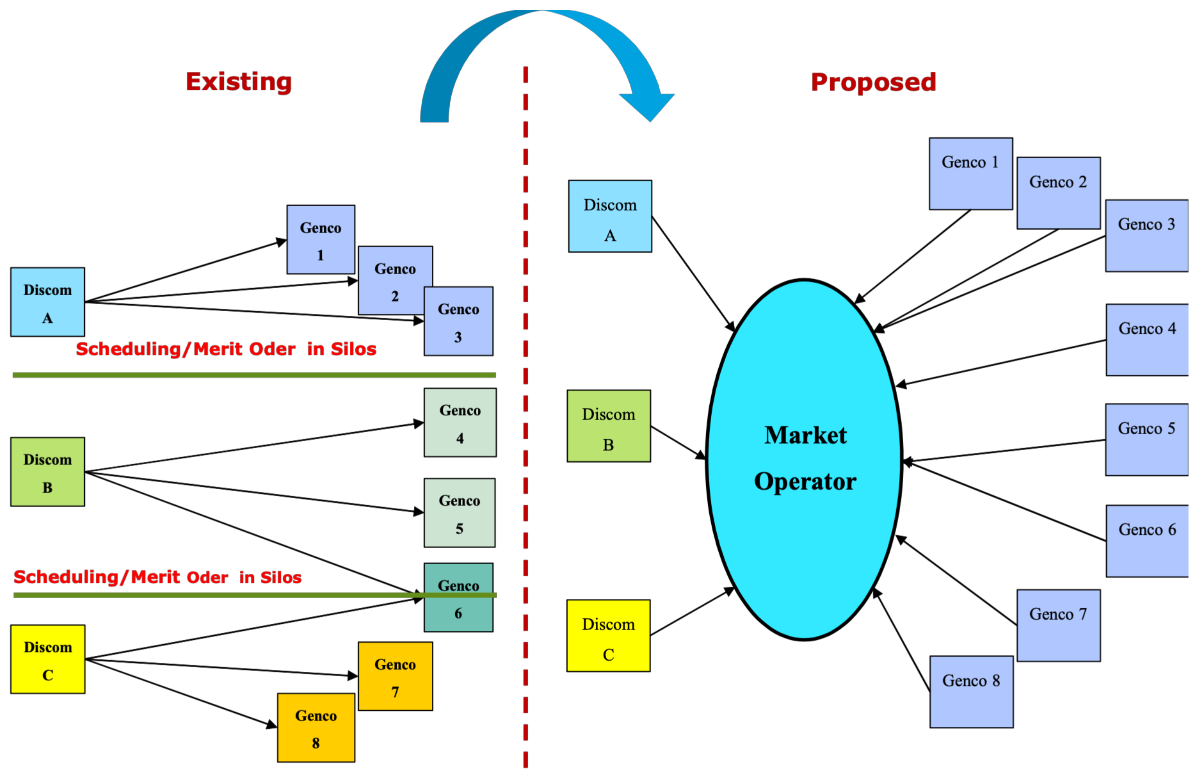
Figure 14. Market Based Economic Dispatch



Source: CERC Staff analysis

This could be appreciated by contrasting with the current framework of self-scheduling in silos by discoms as depicted in Figure 5 in the previous section. Unlike in the existing framework where the discoms requisition power specifically from their contracted generators, in the proposed MBED model the discoms would bid into the power exchange for procuring power and meeting their demand. (See Box-1)

Box-1: Existing Framework Vs Proposed Market Based Economic Dispatch

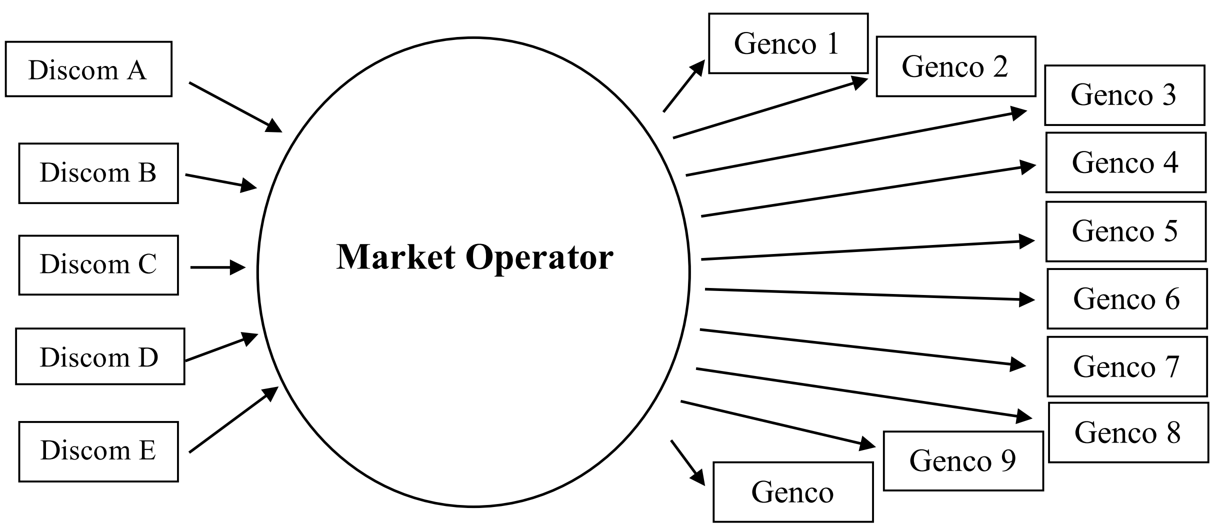


4.6 The generators are expected to bid based on their variable/marginal cost of generation. The existing bilateral contract holders will be paid the fixed cost separately outside the market and as such would also be induced to bid in the market based on their variable/marginal cost of generation. This is expected to ensure discovery of the true system marginal cost. Once the bids and offers are received, the market clearing engine will seek to optimize the dispatch of generation sources. The buyers will be supplied electricity as per their load and the generators will get dispatched in merit order up to the point where the total system load is met; and the contracts would be settled bilaterally.

MBED (Second Aspect): Settlement of Bilateral Contract (BCS)

4.7 The second important aspect of the proposed framework includes settlement of the electricity transacted. The market operator would discover the market clearing price (MCP) after the bid period closes. The MCP in each time-block would be the bid value of the last generator/sellers' offer matched to meet the demand offers which would reflect the marginal value of the electricity i.e. the cost of producing one more unit of electricity to meet an additional unit of demand. All the buyers will pay to the market operator at MCP for the day-ahead demand. Similarly, all the generators will be paid at the MCP according to execution of their selected bids. This uniform price settlement will take place for all the demand bids and the generator/sellers offers that are part of the day-ahead period. This has been represented in Figure 15.

Figure 15. Pay in / Pay out in the Market Based Economic Dispatch



Discom's Payment = Discom's load X MCP

Genco's Revenue = Genco's total scheduled generation X MCP

$$\sum Discom\ Payment = \sum Genco\ Revenue$$

Note: Under No Transmission Constraint

Source: CERS Staff Analysis

4.8 The Day Ahead Market follows uniform pricing principle. However, in case the Discoms and the Generators (tied in long term PPAs) were to participate, both would face the volatility of Day Ahead Market prices but because they are tied in bilateral contracts and have committed a price to each other, there would be a hedging arrangement (to be referred as Bilateral Contract Settlement or BCS) of refunding the difference between the market clearing price and the contracted price (the contracted price in this case would mean the variable cost as determined by the Appropriate Regulatory Commission, since the fixed cost would be paid separately based on availability as per the current practice).

4.9 Such an arrangement of bilateral contract settlement (or BCS) reduces exposure to variability of prices. If a generator and a Discom are exposed to the same Market (Area) Clearing Prices, then such an arrangement (BCS) removes their exposures to variation in that Market Clearing Price (MCP) for a given contract quantity over a given contract period.

4.10 The arrangement of BCS between the market clearing price and the contracted price, entails a payment by the generator to the discom equal to:

(Market Clearing Price – Contract Price) x Contracted Capacity scheduled under MBED summed over all blocks in a day

- The contract quantity is in MWh in each block, while the contract price is in INR/MWh.
- The MCP could, in principle, be either day-ahead or real-time
- This formula is applicable only when Discom and Generator are located in the same bidding zone and there is no congestion.

4.11 It is important to compute BCS payments by summing the {(contract quantity) × (MCP - (contract price))} over all time blocks in a day because some generators might put in block offers / linked offers and hence may get prices lower than the market clearing price in some blocks but their average per unit realization from the markets over all time blocks will be greater than or less than to the price offered by them for the entire block offer.

4.12 This proposed mechanism (Figure 16) ensures that the financial obligations of the existing contracts remain intact and the contracting parties' position is hedged against the MCP.

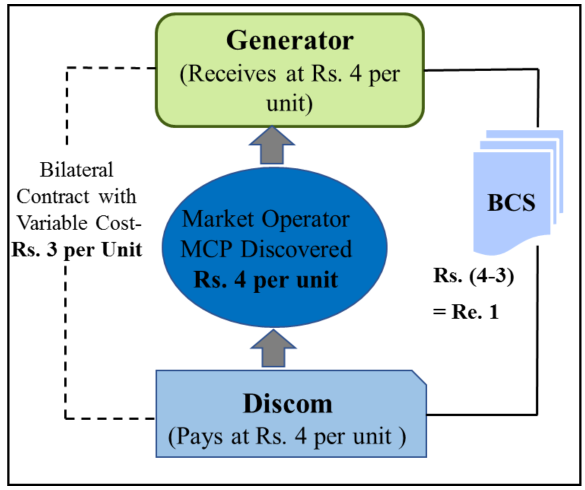
Figure 16. Arrangement for Bilateral Settlement - Simple Case

Consider a discom and a generator with a Contracted Price (VC) of Rs. 3 / kWh

If the Market Clearing Price (MCP) is Rs 4 / kWh,
- discom pays to pool/Market Operator (MO) Rs 4 / kWh
- Generator receives Rs 4/kWh from pool/MO
- Generator refunds discom 1 Re/kWh.

Discoms would be hedged against any increase in the market clearing price through BCS

For demand which is met out side of existing contracts, discoms would pay MCP.



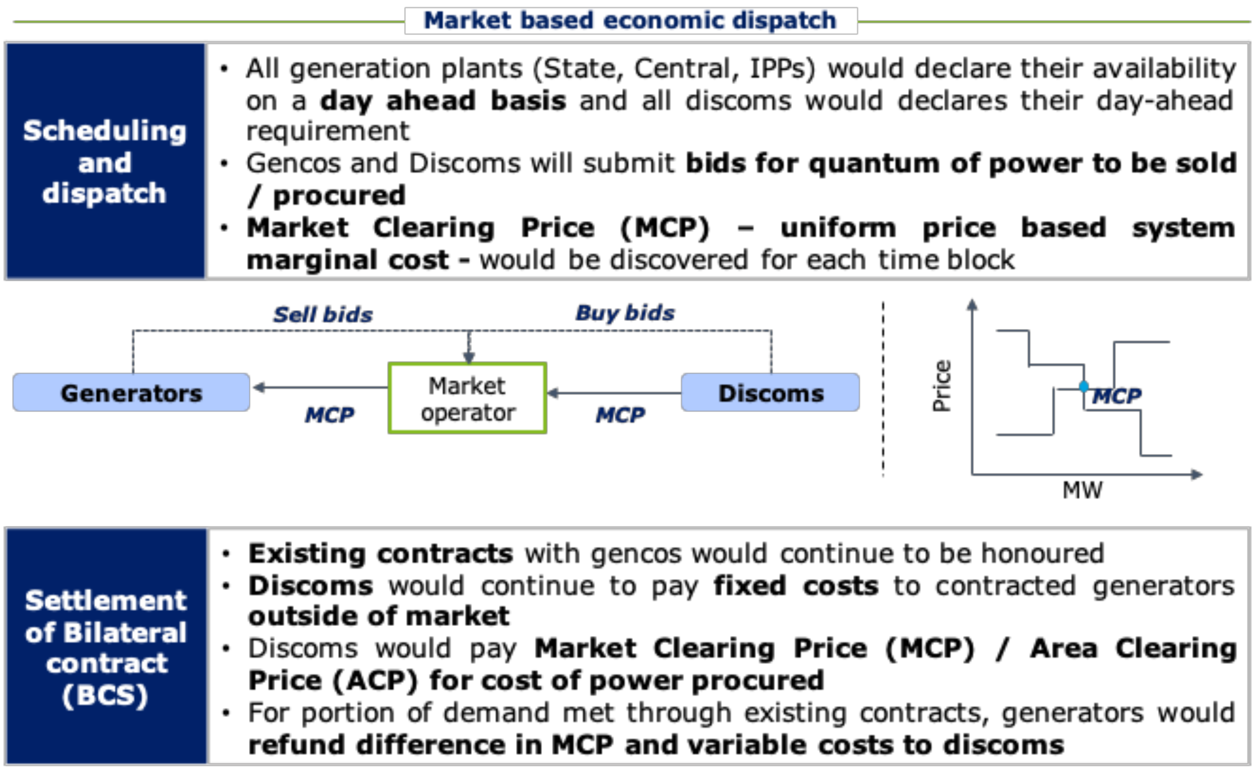
Source : CERC Staff Analysis

4.13 Here, the buyer shall receive an amount equivalent to the difference between the MCP and contract price times the quantum of contracted capacity scheduled from each of its contracted generators. If the MCP is less than the contract price, then it will mean that the discom contracted generator has not been dispatched and in that case there will not be any need for BCS. This would essentially act as a hedging mechanism for the buyer to ensure that they are covered against the risk of spot price volatility and their cost of procurement does not increase. The buyers would still continue to pay the fixed costs for the contracted capacity based on declared availability and regardless of whether the generator gets dispatched. This would ensure that the generators get paid for the capacity as per the existing contract.

4.14 BCS envisaged in the paper is a mechanism to provide hedging to both the parties against the price volatility in the market. It is reiterated that BCS is purely a non-tradable bilateral arrangement and is meant to grandfather the existing contracts (primarily the long-term physical contracts).

4.15 The Market Based economic dispatch mechanism as explained above (with the features of 'Scheduling and dispatch' and 'Settlement of Bilateral Contract Settlement' is summarised and depicted in Figure 17.

Figure 17. Proposed MBED Framework



Source: CERC Staff Analysis

4.16 Having explained the conceptual framework of the MBED mechanism, we will now deal with some specific implementation and operational aspects of the framework in subsequent sections.

5. Implementation and Operational Aspects of MBED Mechanism

BCS under congestion and market splitting

5.1 In the existing DAM at the power exchanges, market participants contest for supply and purchase of electricity in each time block to meet their demand on a day-ahead basis. There are occasions when the market splits owing to congestion. This results in buyers on the "downstream" of congestion paying a higher amount and the generators/suppliers on the "upstream" of congestion being paid – even for the electricity supplied to the downstream of congestion - a price equivalent to the upstream MCP which is lower than the downstream MCP. This leads to higher inflow than outflow of cash to the Power Exchanges. This "excess" amount is called "Congestion Amount" as per the provisions of the Power Market Regulations of CERC.

5.2 In the proposed MBED framework, under transmission constraints, Discoms and Generators located in different bid regions may face (apart from the 'temporal risk' being addressed through the BCS explained in the previous section) the 'Spatial Risk' due to difference in Area Clearing Prices (ACP) of bid areas. This risk can be addressed by allocating the "Congestion Amount" to the entities having bilateral contracts and paying the fixed charges for transmission.

5.3 Even under the existing system, the bilateral contract holders who pay the fixed charges for transmission have priority in terms of usage of the transmission network. Following the same principle, in the proposed MBED framework as well, it is important to ensure that such entities are not denied access unless the grid is faced with contingent conditions, as these users pay transmission charges. It is proposed that all transmission users with bilateral contracts, who are paying transmission charges shall specify the points of injection and points of withdrawal from the grid and the system operator shall certify that all these transactions, will simultaneously not violate grid security and reliability and hence will be technically feasible.

5.4 All such bilateral contract holders participating and getting cleared in the day-ahead market will then receive the “Congestion Amount” if the congestion occurs in the “direction” of the contract and will have an obligation to pay for congestion if the congestion occurs in the direction “opposite” to the direction of the contract.

5.5 Congestion Amount will be sufficient to pay out all the bilateral contract holders if the “bilateral contracted capacities” required to be transferred (by duly considering the direction) across the congested points do not exceed the network capacity.

5.6 The settlement procedure under market split and due to spatial price risk have been explained with an example as follows:

Consider Region –A and Region-B with demand bids and supply offers for an hour as shown in Table 1

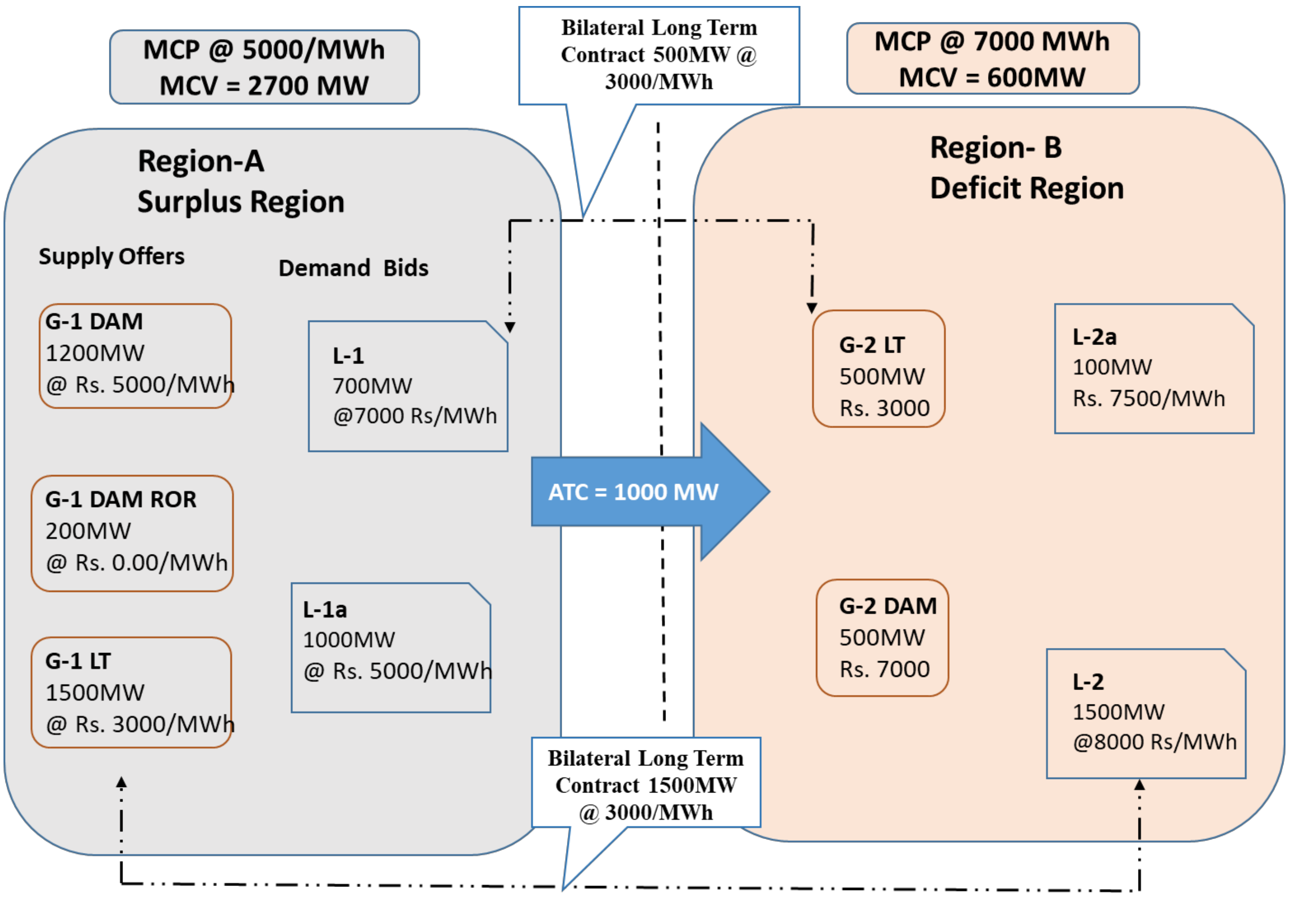
Table 1. Assumptions for Congestion settlement

Region -A		Quantity (MW)	Price (Rs/MWh)	Region -B		Quantity (MW)	Price (Rs/MWh)
Supply Offers				**Supply Offers**			
G1_DAM	Generator without any Contract	1200	5000	G2_LT	Generator with Long Term contract	500	3000
G1_DAM_RoR	Must Run Generator without price	200	0	G2_DAM	Generator without any Contract	500	7000
G1_LT	Generator with Long Term contract	1500	3000				
Demand Offers				**Demand Offers**			
L1	Discom-1	700	7000	L2	Discom-3	1500	8000
L1a	Discom-2	1000	5000	L2a	Discom-4	100	7500

Generator G1_LT in Region-A has bilateral contract for 1500 MW capacity with Discom L2 in Region-B at Rs. 3000/MWhr and Generator G2_LT in Region- B has a bilateral contract for 500 MW capacity with Discom L1 in Region-A. The Available Transmission Capacity (ATC) from Surplus Region (Region-A) to Deficit Region (Region-B) is upto

1000MW. These sets of offers and bids in Region-A and Region-B would result in Area Clearing Price (ACP) of Rs.5000/MWh and Rs.7000/MWh for Region–A and Region-B respectively as shown in Figure 18.

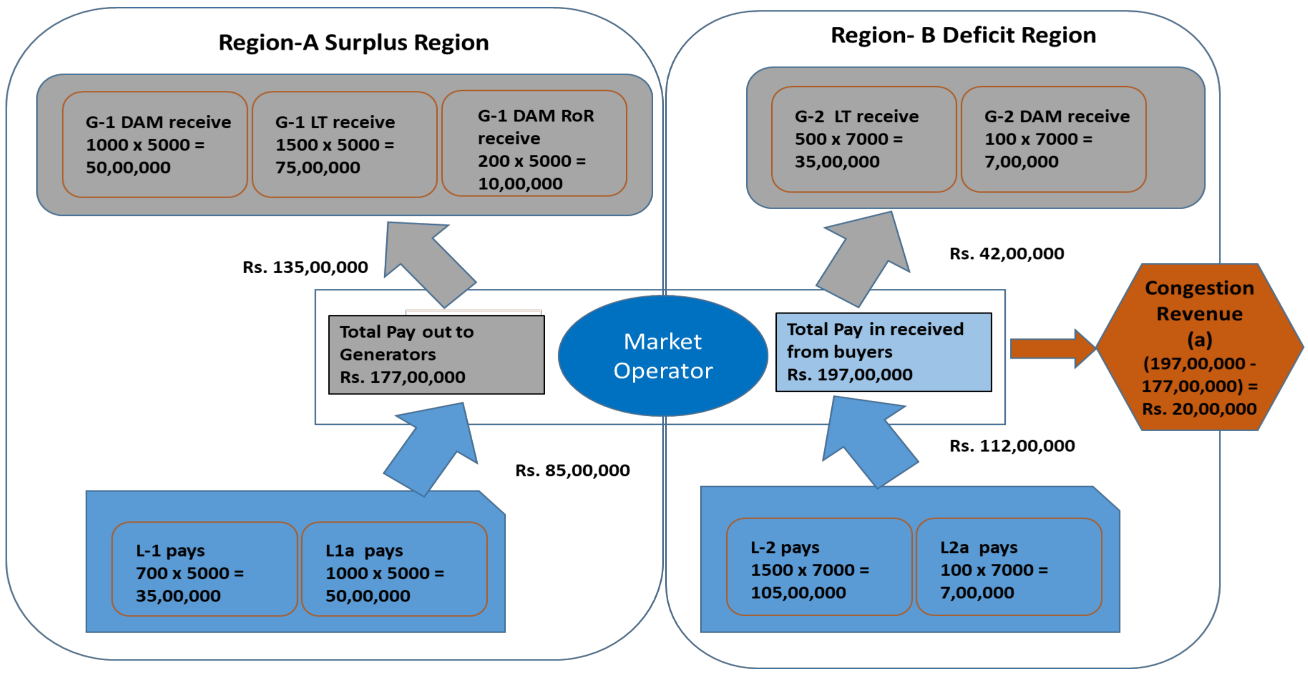
Figure 18. Sample case for settlement under 'Spatial Price Risk'



Source: CERC staff analysis

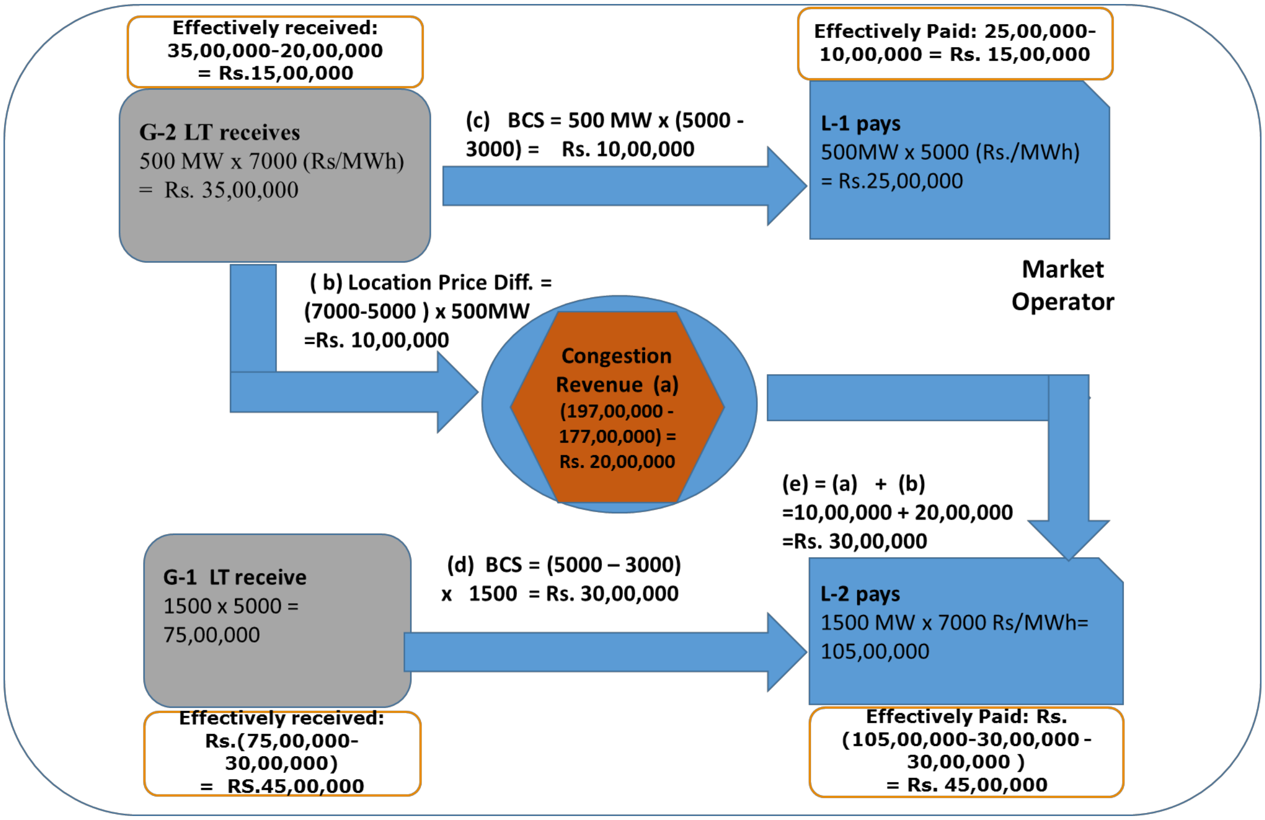
The congestion amount received by the Market Operator would be Rs. 20, 00,000 as shown in Figure 19. The payment settlement for Discoms, L1 and L2 having bilateral contracts of 500 MW and 1500 MW under BCS are explained in Figure 20 and Boxes 2A and 2B.

Figure 19. Settlement with Market Operator in Market Split



Source : CERC Staff Analysis

Figure 20. Final Settlement in Market Split with BCS and Congestion Amount



Source: CERC Staff Analysis

5.7 In the market splitting methodology, areas on either side of the congested corridor are identified separately and then the area which has the higher price, draws electricity from the area with the lower price just as much as the capacity of the congested line will allow. Under this scenario, it is important to ensure that available capacities are fully utilized and the sale- purchase balance requirement is satisfied in both areas.

5.8 Payment settlement with BCS would be done as follows:

	Box 2A: Payment and Settlement of bilateral contracts **Signatories to bilateral contracts are protected by BCS and are hedged for 'Locational risk"**		
	Payment Settlement for L1 and G2	**[(MW x Rs/ MWh) = Rs.]**	
(a)	Amount contractually obligated between L1 and G2	=Rs. (500 x3000)	=Rs.15,00,000
(b)	Payment by L1 to Marker Operator on account of bilateral contract of 500 MW	= Rs. (500 x 5000)	= Rs. 25,00,000
(c)	Payment to G2 by Market Operator	= Rs. (500 x 7000)	= Rs. 35,00,000
(d)	Excess Amount with G2 above contract revenue= [(a) - (c)]	= Rs. (35,00,000-15,00,000)	= Rs.20,00,000
(e)	Amount to be paid by G2 to L1 to cover 'Price Risk' of L1	= Rs.(500 x (5000-3000))	=Rs. 10,00,000
(f)	**Effective price for L1 after payment from G2 =[(b) - (e)]** **which is equal to its obligation to pay under bilateral contract = (a)**	**= Rs. (25,00,000 - 10,00,000)**	**=Rs. 15,00,000**
Note	G2 after having paid Rs.10,000,000 to L1 to cover Price Risk for L1, still left with an excess amount of Rs. 10,00,000. [i.e. (d) - (e)]. Hence G2 must pay back excess amount (Rs. 10, 00,000) that it got because of its "location" in congested zone to Market operator (MO)		
(g)	Amount to be paid to Market Operator by G2 to cover 'Location Risk' of L2 due to Congestion	=Rs.(500 x (5000-3000))	=Rs. 10,00,000
(h)	**Effective amount received by G2 for 500MW =[(c)-(e) - (g)]** **which is equal to its obligation to receive under bilateral contract = (a)**	**= (35,00,000-10,00,000-10,00,000)**	**=Rs. 15,00,000**

	Box 2B: Payment and Settlement of bilateral contracts		
	Payment Settlement for L2 and G1		
(h)	Amount contractually obligated between L2 & G-1	= Rs. (1500 x 3000)	= Rs. 45,00,000
(i)	Payment by L2 to Market Operator (MO) on account of bilateral contract of 1500 MW	= Rs. (1500 x 7000)	= Rs. 105,00,000
(j)	Payment to G1 by Market Operator (MO)	= Rs. (1500x 5000)	= Rs. 75,00,000
(k)	Excess amount with G1 above contract revenue = [(h)- (j)]	=Rs. (75,00,000- 45,00,000)	=Rs. 30,00,000
(l)	Amount to be paid to L2 by G1 on account of BCS which is equal to the excess amount with G1 = (k)	=Rs. (1500 x (5000- 3000))	=Rs. 30,00,000
(m)	Net pay out for L2 after BCS amount from G1= [(i) - (l)]	=Rs.(105,00,000 - 30,00,000)	=Rs.75,00,000
(n)	Excess amount L2 is still paying for contracted power	=Rs. (75,00,000 - 45,00,000)	=Rs.30,00,000
	Thus L2 faces Temporal Risk and Locational Risk because of congestion and its location. L2 under its long term contract with G1 has right to use transmission network and hence need to be protected for the Locational Risk and Temporal Risk. Hence, the Market Operator would pay differential amount from the amount paid by G2 under location risk and the congestion amount with Market Operator.		
(o)	Congestion Amount with Market Operator on account of price difference corresponding to ATC of 1000MW	=Rs. (1000x (7000- 5000)	=Rs. 20,00,000
(p)	Amount received by L2 from Market Operator = [(g) + (o)]	=Rs. (10,00,000+20,00,000)	=Rs.30,00,000
(q)	**Effective price for L2 after payment from G1 and Market Operator = [(i) - (l) - (o)] which is equal to its obligation to pay under bilateral contract = (h)**	**= Rs. (105,00,000 - 30,00,000-30,00,000)**	**=Rs. 45,00,000**

Voluntary vs. Mandatory participation in the MBED framework

5.9 The participation in the Market Based Economic Dispatch model in Day-Ahead Market (DAM) time horizon would initially be voluntary for the parties. Ideally all procurement by discoms should be done through DAM. However, the discoms may retain some generators on the self-schedule list and allow others, with whom they have long term PPAs to participate directly in the market. Maximum participation in the Market Based Economic dispatch would ensure multiple benefits to the system which include but not limited to overall reduction in the system marginal cost and the consequent reduction in the cost of power procurement at National level, better flexibility in the system to manage high penetration of intermittent resources in the system, better assessment of Ancillary Services etc.

5.10 The existing arrangement of self-scheduling of the long-term contracts described above should ideally hold good during the transition period (of say one year), after which all such generators as well as the discoms with whom they have contracts should also be mandated to participate in the day ahead Market Based Economic Dispatch system. This transition of one year is considered necessary to enable the discoms to accustom themselves to the market dynamics and prepare for participation in such market mechanism.

5.11 Both the Discoms and the Generators, under such an arrangement could opt for the following alternatives

Option 1: The Discoms could self-schedule the generators with whom they have bilateral contracts (LT/MT or ST) and access the Power Exchanges for the balance of their energy requirements. This is largely the current practice followed by most Discoms, except a few where they use power exchanges to replace their costlier contracts with cheaper options from the power exchanges.

Option2: Discoms and Generators will continue to hold long term / bilateral contracts. The Discoms will have the right to self-schedule but on the day ahead both the discoms and the self-scheduled generators will get scheduled/dispatched through the DAM. Discoms will approach the power exchanges with their demand bids and the self-scheduled generators will offer their capacities entirely on the exchange along with their price offers. The generators and the Discoms, who are locked in bilateral fixed price / regulated price contract, get paid / are paid by the Power Exchanges (Market Operator) at the market clearing price, and outside the market they can settle bilaterally the difference between the market clearing price and the contracted price by way of BCS as explained in the preceding section.

5.12 This proposition of the Day Ahead Market would allow National Level Merit Order Dispatch through a voluntary market mechanism. Option 1 should be available during the transition period of one year, post which Option 2 should be followed. This is expected to yield benefits in terms of meeting demand at reduced cost (explained in subsequent sections).

How Discoms and Generators would bid in the proposed mechanism?

5.13 **Discoms** may choose to submit 'Fixed Demand' in each Block, which is price inelastic and "has to be served". The quantum of such demand could be to the extent of capacity contracted bilaterally by the discom. In the existing system, the discom would have scheduled such demand (through self-scheduling) before bidding in the Day Ahead Market (DAM). Further, Flexible Demand by the discom, over and above the 'Fixed demand' in each block will be price sensitive similar to the existing practice of participation in the DAM. The sample format is presented in Table 2.

Table 2. Sample bidding format for Discom

Discom :	Name									
Date :	dd/mm/yyyy									
Forecasted Demand :										
Time	Fixed Bid	Price Cap -1		Price Cap - 2		Price Cap -3		Price Cap -4		Price Cap -5	
	MW	MW	Rs/ MW	MW	Rs/ MW	MW	Rs/ MW	MW	Rs/ MW	MW	Rs/ MW
00:00:-00:15											
00:15 - 00:30											
00:30 - 00:45											
00:45 - 01:00											
01:00 - 01:15											
01:15 - 01:30											
01:30 - 01:45											

Source: CERC Staff Analysis

5.14 **Generators** having bilateral contracts would recover their fixed charges bilaterally "outside" the market as per the existing practice. Therefore, it is envisaged that these generators would offer the quantum (in MW) at their variable costs (or regulated variable charges). The generators will normally offer at such prices to maximize their probability of getting dispatched and yet remain profitable.

5.15 It is important from the system operation point of view to have all the necessary information to ensure that economic dispatch takes place while the security of the grid is not compromised.

5.16 Hence, with the inclusion of larger set of generators, the system needs to ascertain transmission constraints in greater detail (as compared to the current practice) along with technical details from the supply bids (capabilities) of participating generators (which would include but not limited to ramp-up/down constraints, minimum up/down time, Technical Minimum, start-up/shut down costs).

5.17 The generators can be provided with options to either supply the technical information and costs separately or subsume the costs in their price offers. The latter, however, as per global experience might lend physical operations uneconomical under certain conditions. Therefore, as the markets mature and more generators and DISCOMs opt for MBED, they may themselves prefer to offer supplies with multi-part offers. This will also help co-optimize procurement of Day Ahead Energy and Ancillary Service (AS).

5.18 As mentioned in the discussion Paper on 'Re-designing Ancillary Services Mechanism in India' by the Staff of the Commission, the Day Ahead Markets will co-optimize procurement of Energy and Ancillary Services for each block of time on the subsequent day. This would require the suppliers to specify their availability in each time block along with the maximum amount of AS services they would wish to offer. The demand for Ancillary Service (AS) will be dynamically specified by the system operator in accordance with the set of rules approved by the Commission.

Figure 21. Bidding by Discoms and Generators in MBED

DISCOM Bids

- Fixed Demand in each Block, which is price inelastic and "has to be served" –
  - The quantum of such demand will be to the extent of capacity contracted bilaterally
  - In the extant system, DISCOMs would have scheduled such demand before bidding in existing DAM
- Flexible, Price Sensitive Demand
  - Over and Above the "Fixed Demand" in each time Block, DISCOMs will bid price sensitive demand in each time block
  - This is similar to the existing process by which DISCOMs bid in the exchange
- DISCOMs can combine the above two processes and place the same in a "composite" manner.

GENCO Offers

- GENCOs, with bilateral contracts, recover their fixed charges bilaterally "outside" the Market
- These GENCOs, therefore, offer the quantum (in MW) at their variable costs (or regulated variable charges)
- The GENCOs will normally offer at such prices to maximize their probability of getting dispatched and yet remain profitable

Source: CERC Staff Analysis

TimeLine of Scheduling and Dispatch under the Proposed Framework:

<u>During Transition</u>

5.19 Provision for self-scheduling: Self- scheduling will continue to operate as in the existing framework for long term contracts. In other words, as depicted in Figure 3, the generator tied up under long term PPA will continue to declare their availability and the discoms through their SLDCs will have the right to requisition/ schedule these generators. However, if part of the contracted capacities in any generating station remains un-requisitioned after 9.45 a.m., such un-requisitioned surplus (URS) capacities will have the right to participate in the day ahead market of the power exchange starting from 10.00 a.m. For such URS, the discoms shall not have the right to recall, but the net revenue earned by these capacities (URS) by participating in the DAM or RTM shall be shared in the ratio of 50:50.

5.20 Market Based Economic Dispatch (MBED) through power exchanges: From 10.00 a.m. to 12.00 noon, MBED model will operate where the un-requisitioned capacities of the Long Term/ Medium Term/ Short Term PPA and other generators not tied up in any contract can participate. The discoms to the extent of the requirements for power over and above their long term/ medium term contracts will participate in this market.

Beyond Transition

5.21 After the transition period, the Discoms will still have the right to self-schedule until 9.45 am. But as the day ahead market commences at 10 am, both the discoms and the self-scheduled generators will bid in the DAM – the discoms with their demand bids and the self-scheduled generators with their capacities along with their price offers.

5.22 The day ahead bilateral and the power exchange based contingency market will continue to operate with the same timeline as indicated in Figure 4.

5.23 While the above timelines relate to day ahead scheduling and dispatch, the real time market will start from 00.00 hrs of the day of the operation.

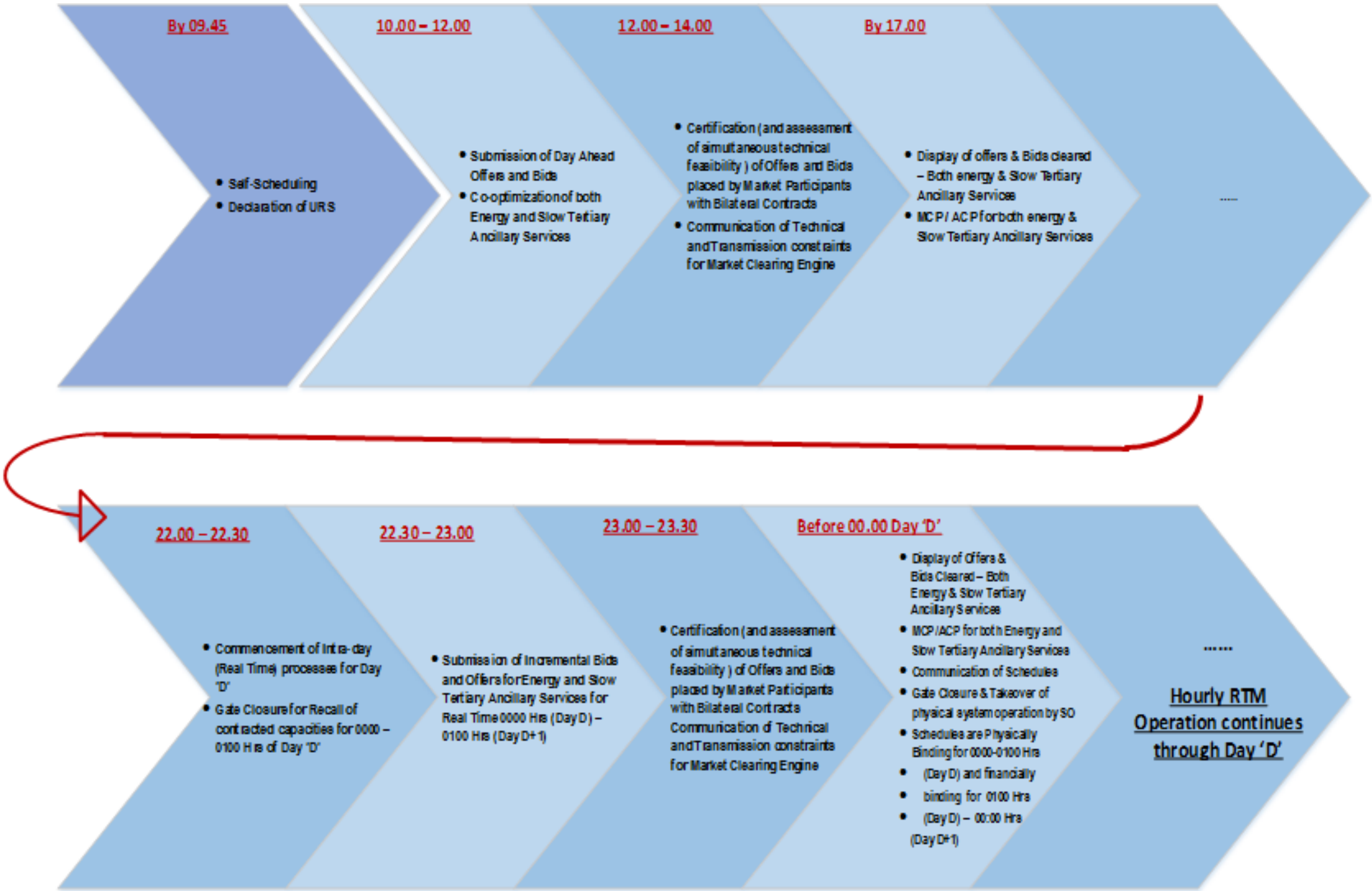
Inter-linkage between Day Ahead and Real Time Energy Market

5.24 In order to facilitate coordination between contracting of power (through Long Term / other types of contracts, as highlighted in previous section), scheduling and availability of least cost power, the staff of the Commission has come out with a series of papers on Real Time Markets, Ancillary Services Markets and now the present paper on Day Ahead Markets. These markets are interlinked since the final payments happen based on the "contract" (which could happen in advance), schedule of electricity (which happens on a Day Ahead Basis and after Real Time Markets) and actual flow of electrical energy (which happens ex-post the transactions have actually materialized). The timeline through the day ahead to the real time has been depicted in Figure 22.

5.25 Day ahead transactions are financially binding and physically feasible (unit commitment), and the changes in day ahead commitments (as a consequence of unit tripping or contingencies for generators, and due to load variation for discoms) can be corrected by participating in the real-time market. However, the Day-Ahead as well as the Real-time schedules shall be financially settled separately at their respective MCPs. While the position in terms of day-ahead commitment can be corrected (for reasons as stated above) in the real-time "energy market", any change/deviation in the real-time schedule will be settled through deviation settlement mechanism/ancillary services mechanism.

5.26 The issue of right to recall has already been explained in detail in the Staff Paper on Real Time Market. However, to put the discussion in perspective, it is clarified that so long as the provision of right to recall prior to the gate closure in real time exists, the generators tied up in long-term contract – in the event of their having sold the un-requisitioned surplus in the day ahead or any other time horizon – will have to buy back from the real-time market to meet their contractual obligation, if the discoms exercise the right to recall.

Figure 22. Timeline between Day Ahead and Real Time Energy Market



Source: CERC Staff Analysis

6. Benefits of Market Based Economic Dispatch

System Cost Savings

6.1 The MBED is expected to lead to cost savings for the system as a whole. This is explained by a sample illustration as follows. Let's consider a discom - Discom A having a demand of 2000MW for a time block of 15 minutes. Discom A has contracts with four generators Genco 1 to Genco 4 with variable costs ranging from Re. 1 per kWh to Rs. 4 per kWh respectively as shown in the Table 3.

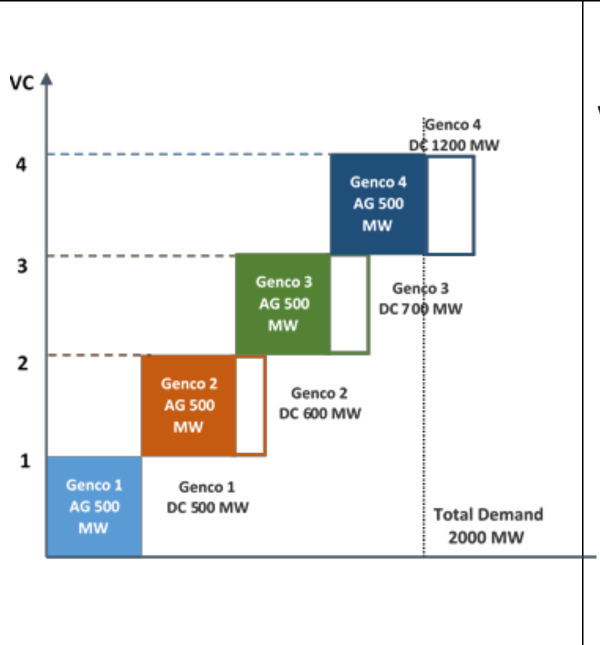
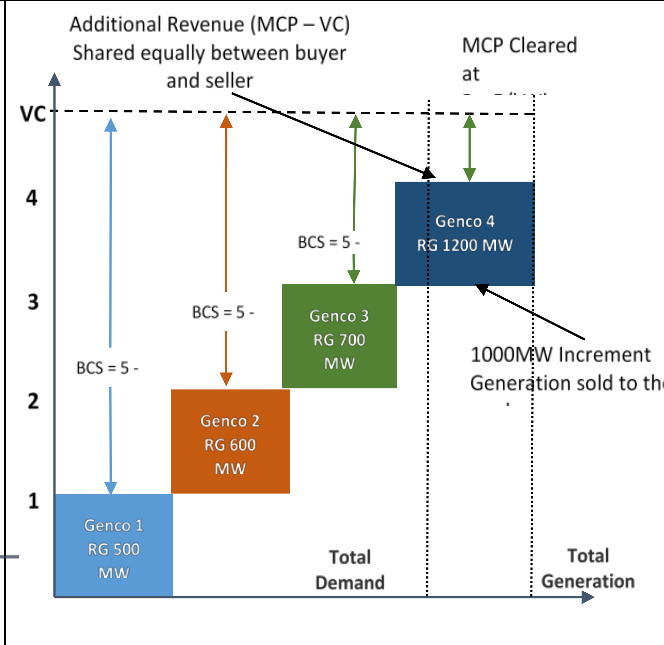
Table 3. Available URS for Discom-A in the existing system

Discom- A with Demand of 2000 MW for a time block				
	Declared Capacity on Day Ahead (DC)	Variable Cost - under contract	Available Generation (AG) to Meet the Demand of 2000MW	Un - requisitioned Surplus (URS)
	(MW)	(Rs./Unit)	(MW)	(MW)
Genco-1	500	1	500	0
Genco-2	600	2	500	100
Genco-3	700	3	500	200
Genco-4	1200	4	500	700

6.2 Discom-A is not able to utilize its URS available with cheaper generation (i.e. URS of Genco-2 and Genco-3) because it is obligated to keep its the last generator (Genco-4) at its technical minimum (assumed in this case as 500MW). Now, in this case, the cost of procurement for Discom-A to meet 2000 MW would be Rs. 12.5 Lakhs.

6.3 In the MBED mechanism, since the dispatch of generation is based on aggregated merit order, the URS of Genco-2 and Genco-3 would be utilized and would replace some of the more expensive plants in the system. Assuming the market clearing price (MCP) at Rs. 5.00 per kWh for the same block, the payment for the Discom- A would be Rs. 25 lakhs (i.e. 2000 MW x Rs. 5 / kWh x (1000/4)). But Discom-A would at the same time get a refund of Rs. 13.50 Lakh through BCS as shown in Figure 23. Thus, the net pay out for discom is Rs. 11.50 Lakh (Rs. 25 Lakh – Rs. 13.50 Lakh), thereby yielding a net saving of Rs.1.00 Lakh (Rs. 12.50 Lakh – Rs 11.50 Lakh).

Figure 23. Procurement Cost in Present Design and Proposed MBED Design (MCP (Rs. 5/kWh)>Contracted Price (Rs. 4/kWh))

<table>
<tr><th>Discom A : Present Cost of Power</th><th>Discom A : Cost of Power in MBED</th></tr>
<tr><td>
</td><td>
</td></tr>
<tr><td>Cost of power (AG)=
(500*1 + 500*2 + 500*3 + 500*4) * 250
= Rs 12.50 lakhs

Note: Multiplication by (1000/4) =250 to take into account 15 Minute Time block</td><td>Cost of power (RG) = a – b
a) Payment at MCP: 2000 *5* 250 = Rs 25 lakhs
b) BCS = [500*(5 - 1) + 600*(5 - 2) + 700*(5 - 3) + 200*(5-4)] * 250 = Rs 13.50 lakhs
Cost of power (a – b) = Rs. 11.50 lakh
Net Savings = (12.50 – 11.50) = Rs. 1.00 lakhs</td></tr>
</table>

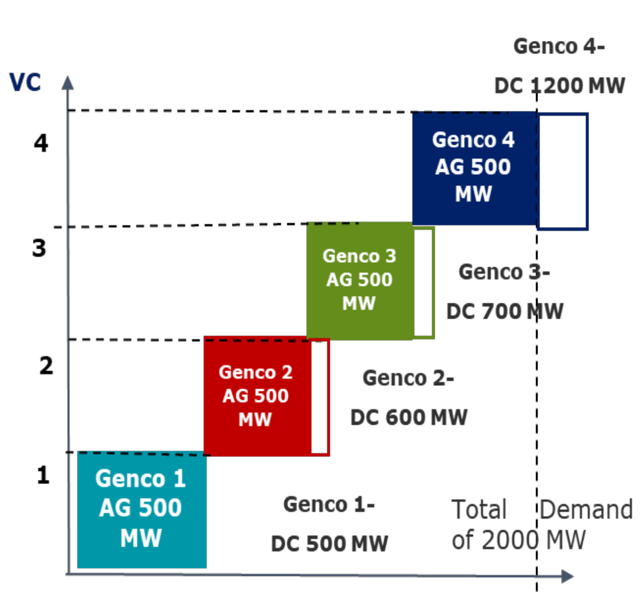
Source: CERC Staff Analysis

In addition to the net savings of Discom A in the proposed MBED scenario vis-à-vis existing cost of power procurement as shown above, the Discom will earn additional revenue on the basis of 50:50 revenue sharing mechanisms from the sale of URS to the market. The net settlement shall be carried out at the end of the day of actual dispatch as shown in **Annexure IV**.

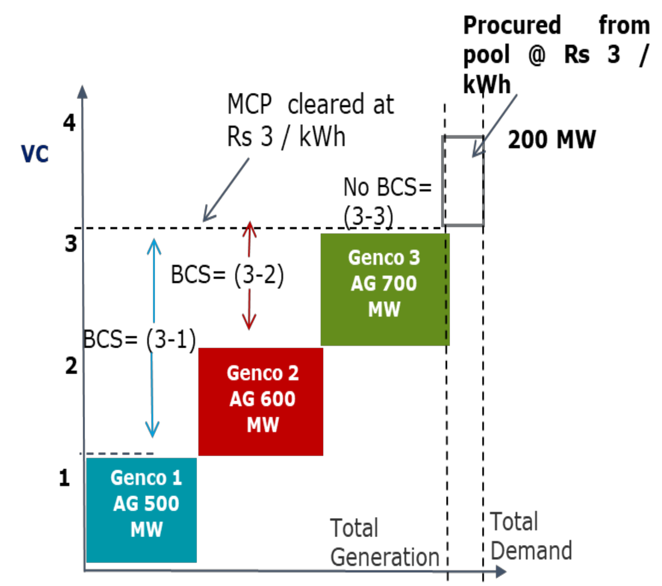
6.4 Another scenario when the MCP is less than the contacted price has been represented in Figure 24.

Figure 24. Procurement Cost in Present Design and Proposed MBED Design (MCP (Rs. 3/kWh<Contracted Price (Rs. 4/kWh))

<table>
<tr><th>Discom A : Present Cost of Power</th><th>Discom A : Cost of Power in MBED</th></tr>
<tr><td>



</td><td>

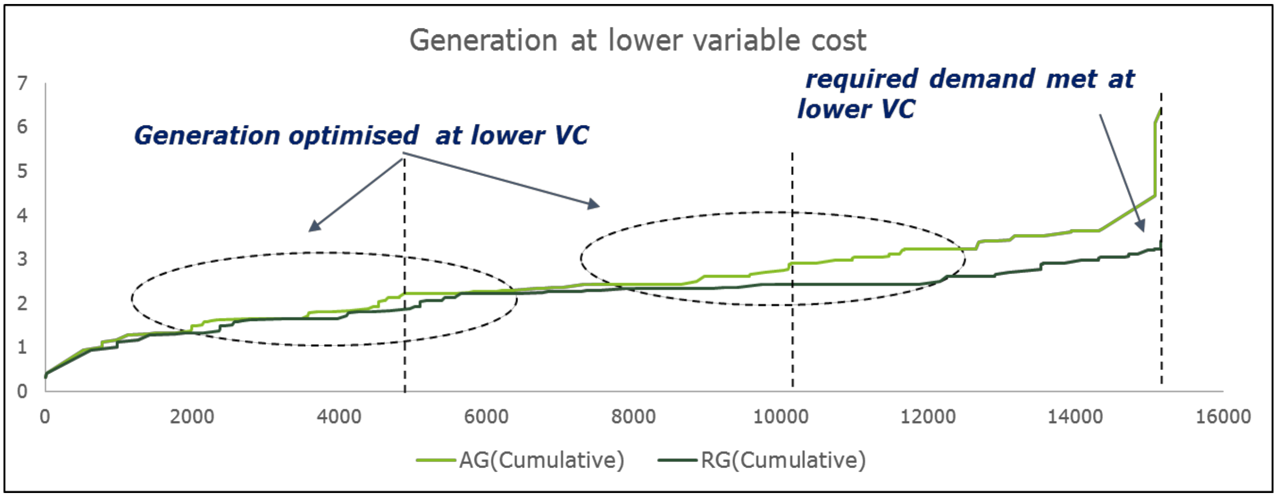


</td></tr>
<tr><td>Cost of power (AG)=
(500*1 + 500*2 + 500*3 + 500*4)*250
= Rs 12.5 lakhs</td><td>Cost of power procured (RG)= a-b
a) Payment at MCP: 2000 *3* 250 = Rs 15 lakhs
b) BCS= [500*(3-1)+600*(3-2)+700*(3-3)]*250 = Rs 4 lakhs
Cost of power (a-b) = Rs. 11 lakh
Net Savings = (12.5 – 11)= Rs. 1.5 lakhs</td></tr>
</table>

As is evident from the above table the gains for a discom are higher when the MCP is less than its contracted price.

6.5 The efficiency of the proposed framework has also been tested based on simulation on one-year historical data for five states in India. The system costs were computed for the contracted generating stations in the five states (AP, Karnataka, Telangana, Maharashtra, and Chhattisgarh) to meet the demand in the present self-scheduling framework as well as the proposed Market based economic dispatch framework (after factoring in the constraints, viz., Technical Minimum requirement, Ramp Up/Down Capability and Transmission Constraint). The detailed methodology and the assumptions used for the simulation have been attached as Annexure -1. Figure 25 below shows the actual cumulative generation (AG) from contracted generators of five states stacked up in merit order and the revised cumulative generation (RG) as per MBED framework to meet the aggregated demand for the month of July 2016.

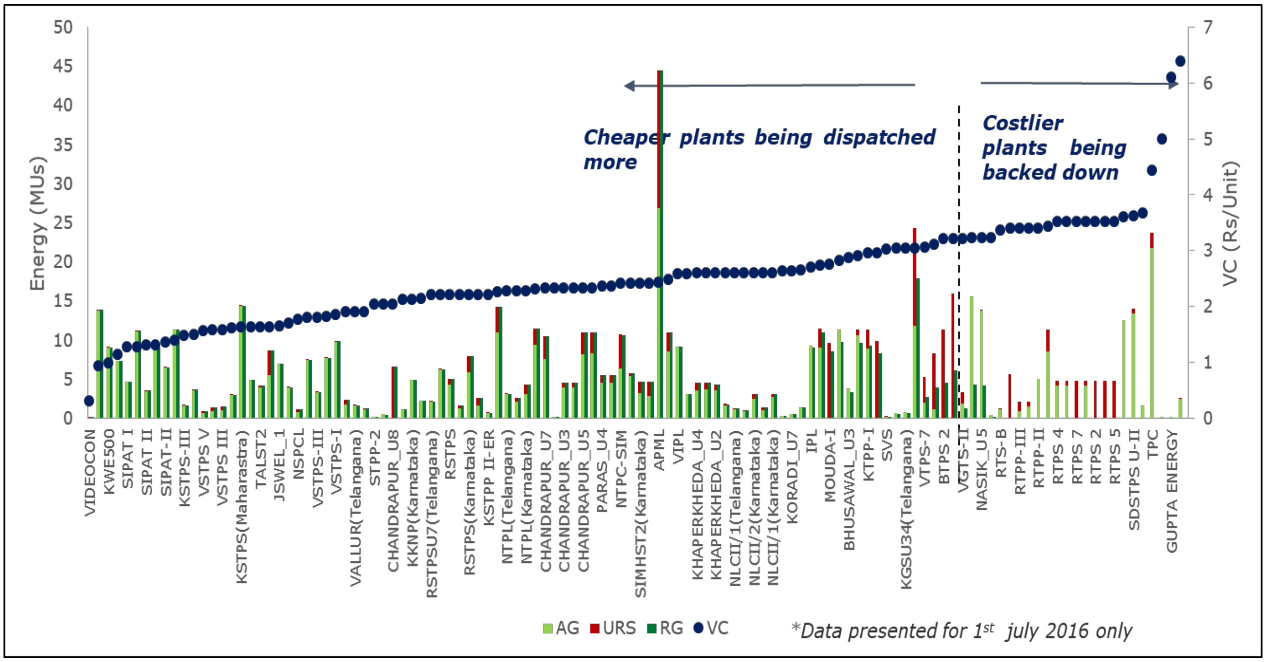
Figure 25. Meeting System Demand at Lower Variable Cost- July 2016



Source: CERC Staff Analysis

6.6 The revised generation optimizes on the unutilized low-cost generation to meet the load. Therefore, the total load is met at a significantly lower variable cost than the current dispatch framework. This is also evident from the representation of generator wise dispatch (actual and revised) as shown in Figure 26.

Figure 26. Actual generation and Revised Generation in MBED mechanism for 1st July, 2016



Source: CERC Staff Analysis

The above Figure shows the utilization of cheaper generation to meet the aggregate demand of five States for a day in the month of July 2016. While, the light green bars represent actual generation and red area the URS available with the generator, dark green bars show the revised generation after MBED mechanism. It can be seen that with MBED the system demand can be achieved with cheaper generation (represented by dotted line). The generators on the left side of the dotted line (cheaper generators) are getting utilized maximum reducing their URS significantly, while the generators on the right side of the dotted line (costlier generators) are getting backed down. Similar analysis for each State has been shown in the Annexure -2.

6.7 The above optimization yields significant savings in overall system costs. Table 4 summarizes the system costs in the present and proposed framework from the simulation for the month of July 2016 and financial year 2016-17.

Table 4. Saving in cost of generation in MBED (simulations for 5 states)

	System Costs (Total Cost of Generation) (All figures in Rs. Cr)			
	Present Self-Scheduling Framework	Market Based Economic Dispatch Framework	Net Savings	In Percentage (%)
July 2016	3781	3343	438	12%
FY 2016-17	58949	52729	**6221**	**11%**

Source: Simulation Result based on the data from Five States for FY 2016-17

The potential benefits of the MBED mechanism are substantial as observed by optimizing dispatch in just five states. Table 4 estimates the overall saving in the system cost by optimum utilization of the cheaper generation available in the system to reduce the system cost by 11%.

6.8 As a result of optimization of the generation cost under the MBED as indicated in Table 4, the cost of power procurement of the State (constituting all discoms in the State put together) is also likely to reduce. A simulation was carried out to compute the State wise landed cost of power procurement under the MBED model after factoring in the POC charges'. The Table 5 summarizes the result of the simulation.

Table 5. Benefits to State Discoms for Five States –Simulation Results

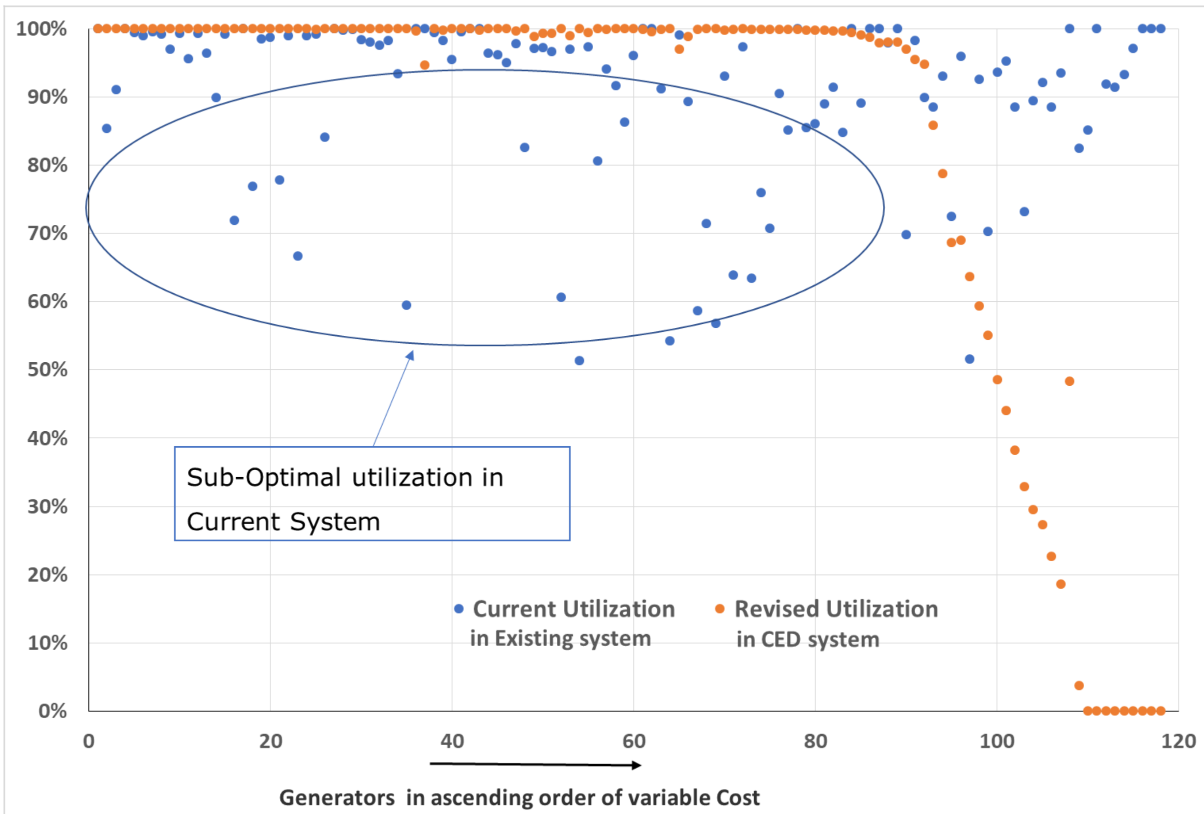
	Reduction in Cost of Procurement (Rs. Cr)					
	Andhra Pradesh	Chhattisgarh	Maharas htra	Telangana	Karnataka	**Total**
In (Rs. Cr)	703	218	3392	234	77	**4,624**
In Percentage	6.00%	6.56%	11.85%	2.72%	0.74%	**7.37%**

Source: Simulation Result based on the data from Five States for FY 2016-17

As it is evident from the above Table, the benefits/savings in cost of procurement accrue to all the five States considered.

6.9 The Figure 27 shows how the utilization of Declared Capacity (DC) changes in the proposed dispatch framework. All generators in the portfolio of the five states are stacked as per merit order and consistent with the results displayed earlier and the hypothesis, that current self-scheduling framework sub-optimally utilizes the available low-cost generation. Dispatch optimization through MBED framework increases utilization of low-cost generators while reducing and backing down in certain cases, the expensive generators. Total cost of fuel input reduces as expensive generators are being backed down. Consequently, reduction in fossil fuel consumption has positive environmental impact that can help India progress towards its climate goals

Figure 27. Utilization day ahead declared capacity (DC) of Generators



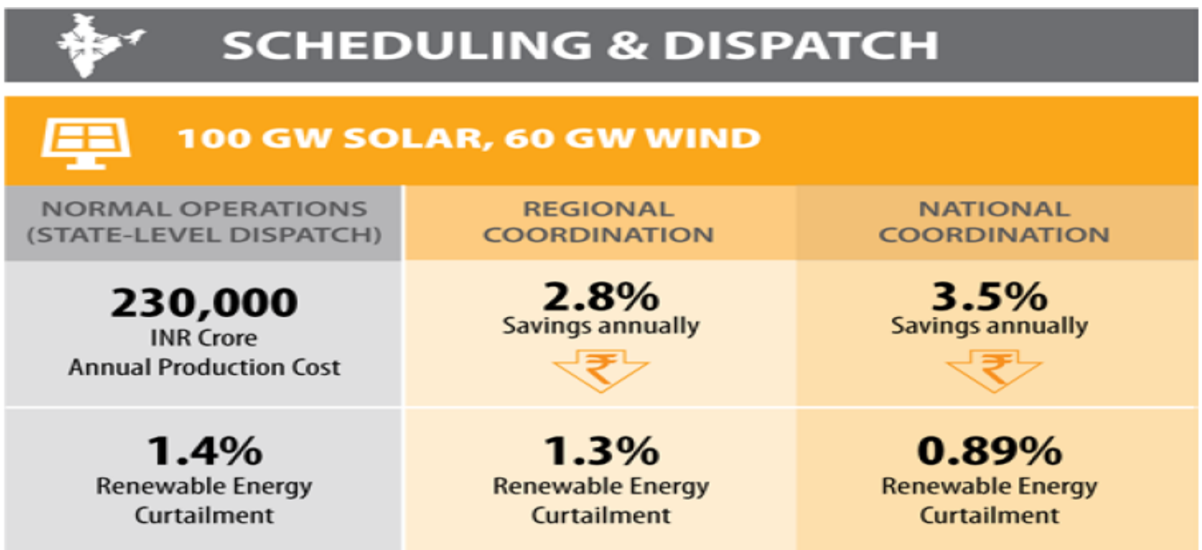
Source: CERC Staff Analysis

6.10 Another study (Greening the Grid Report, 2017) carried in the Indian context states that, "larger pool of conventional generators is also more cost effective to operate because a broader customer base can access energy from the most cost-efficient plants in the balancing region without the incentive to use generation in their state."[16]

[16] Greening the Grid Vol I, National Study

Furthermore, with the level of RE penetration envisaged, it is important to look at larger balancing areas which could facilitate reduction in the total production costs of conventional generators as well as reduce RE curtailment. The following Figure 28 shows the impact of regional as well as national level coordination in scheduling and dispatch of power with the inclusion of 100GW solar energy as well as 60GW wind energy. The report estimates that there would be production cost savings of up to 2.8% annually with only 1.3% RE curtailment if regional scheduling and dispatch were implemented for all generation and load.

Figure 28. System Saving with 160GW wind and Solar



Source: Greening the Green, Study Report 2017

Similarly, if scheduling and dispatch was implemented at a national level, it would lead to 3.5% savings with only 0.89% RE curtailment.

6.11 Several experiences around the world and studies have concluded that the uniform price brings in the most efficient outcome in the short as well as the long run. The single biggest advantage of uniform price auction is that it incentivizes the generators to offer their generation at the least possible cost[17].

[17] Uniform Price vs Differentiated Payment Auctions, Brattle Group 2017

6.12 Price discovery takes place at low cost if all buyers and sellers go through the market. The day ahead prices will also allow the buyers and sellers to identify which new contracts can be mutually beneficial to enter into[18]. This will ensure that there is adequate and meaningful information available to both parties while making decision regarding future long-term contracts.

6.13 Utilization of low-cost stranded assets is another benefit of Market Based economic dispatch.

[18] Review of Recent RTO Benefit-Cost Studies, LBNL 2005

7. Challenges and Way Forward

Legal aspects of incorporating BCS

7.1 The proposed MBED mechanism along with BCS mechanism ensures optimum utilisation of cheaper generation and benefits of additional generation would be shared between generators and discoms equally in the ratio of 50: 50. It is envisaged in the proposed mechanism that a generator will get dispatched if its variable cost is lower than the marker clearing price (MCP). Those generators whose variable cost are above the MCP, would not be dispatched but will recover their fixed cost through existing contracts. Further, additional revenue from cheaper generators would be shared with discoms in the ratio of 50:50. Thus the proposed mechanism with BCS mechanism will safeguard interest of both buyers and sellers.

7.2 Given that the MBED and BCS guarantee and safeguard discoms' original commitment of variable cost, the arrangement will also not conflict with the existing coal linkage policy which puts a restriction on the sale of power from the linkage coal based generating stations, to the short-term market. It is based on this philosophy that the Tariff Policy also allows sale of un-requisitioned surplus from the long term contract based generators in the short term market. Relevant extract of the Tariff Policy is reproduced below for ready reference:

"6.2 Tariff Structuring and associated issues

1) .....

Power stations are required to be available and ready to dispatch at all times. Notwithstanding any provision contained in the Power Purchase Agreement (PPA), in order to ensure better utilization of un-requisitioned generating capacity of generating stations, based on regulated tariff under Section 62 of the Electricity Act 2003, the procurer shall communicate, at least twenty four hours before 00.00 hours of the day when the power and quantum thereof is not requisitioned by it enabling the generating stations to sell the same in the market in consonance with laid down policy of Central Government in this regard. The developer and the procurers signing the PPA would *share the gains realized from sale, if any, of such un-requisitioned power in market in the ratio of 50:50, if not already provided in the PPA. Such gain will be calculated as the difference between selling price of such power and fuel charge. It should, however, be ensured that such merchant sale does not result in adverse impact on the original beneficiary (ies) including in the form of higher average energy charge vis-à-vis the energy charge payable without the merchant sale. For the projects under section 63 of the Act, the methodology for such sale may be decided by the Appropriate Commission on mutually agreed terms between procurer and generator or unless already specified in the PPA."*

7.3 Further, the existing long term contracts covered under Section 62 of the Electricity Act, 2003 provide reference to CERC regulations for scheduling, dispatch and recovery of cost for such generators. Hence, the amendments in the CERC regulations would automatically get inroads into such contracts. For generation capacities under Section 63, in order to participate in MBED on day ahead basis, there might be a need for supplementary PPA based on mutual agreement between the generator and the buyer. The fixed cost under Long term PPA could be settled as per the existing arrangement, and generators could participate in the MBED market for their energy cost only. BCS mechanism would not only ensure the hedging for discoms but also earn additional benefits for additional generation. The appropriate Commission needs to approve such supplementary PPA in to order to enable such generating capacities to participate in the MBED day ahead market mechanism

Contracts in times to come

7.4 Currently, the long/medium-term contracts include both capacity and energy obligations as discussed in the paper. Going forward, there can be capacity markets to achieve long-term security of supply to meet the present and future demand and also facilitate investments into capacity additions. Secondly, as we look ahead at high levels of RE in the grid, the objective of the buyer must go well beyond just procuring capacity for existence but procuring capacity with specific attributes which can deliver as needed.

Therefore, the price of a MW of an inflexible coal plant should not be the same as the price of highly flexible gas plant. Future contracts must focus on capability of the power plant to deliver when needed. High RE penetration will bring situations where certain capacities may need to ramp up or down in a matter of minutes or even seconds. Therefore, capability contracts must be explored going ahead. These contracts are to ensure that capacity with specific characteristics and attributes is available to the buyer as needed. A portfolio can have various such capability contracts to ensure that all levels of deviations and emergencies are covered.

7.5 It is believed that the proposed MBED framework – where the existing legacy contracts are proposed to be brought to the market only on their variable costs – will help develop the desired level of capacity market in future. The discoms will re-align their strategy about the capacity contracting in future - depending on whether and to what extent they have to bear the fixed cost of those generators (legacy contracts) which don't get cleared in the DAM (because of high variable cost) ; or whether they have to face high price in the energy only market in the absence of hedging through capacity contracting. As a corollary, the generators will also take a considered call on the extent to which they need to hedge their revenue through capacity contract and the proportion for which they would play purely in the energy only market. Such intrinsic demand and supply is expected to yield a robust framework for ideal capacity market in future.

7.6 Secondly, as we envisage a future with capacity/Capability contracts and energy only markets, we have to explore several hedging instruments and mechanisms that can cater to different risk sources and profiles. This is a common feature of a well-functioning market, where participants explore different instruments and trading arrangements which reduce their exposure to the market risk. -There are financial derivatives such as futures and options contracts which can help hedge the spot price volatility. Fuel price hedging can cover the price volatility against gas or coal prices. Hedging instruments act as an insurance against the uncertainty against the various elements of risk such as spot price volatility, fuel prices, demand, regulations etc. A higher risk coverage would call for a higher premium. Therefore, a plethora of hedging instruments can be developed and stakeholders will have to explore the most suitable way to manage their risk. These transactions can take place 'over-the-counter' or in a formal trading exchange.

Resource adequacy (RA)

7.7 Resource adequacy (RA) is commonly defined as the ability of a utility to meet the consumer load at all times. Utilities or discoms have to demonstrate periodically that they have sufficient reliable capacity resources to be able to meet the forecasted peak demand and have a reserve over and above that. California's RA program which was developed after the 2001 crisis provides a good understanding and example. The program ensures that the Load Serving Entities (LSEs) under the jurisdiction of the California Public Utilities Commissions (CPUC) must demonstrate that they have sufficient reliable capacity to meet their peak demand forecasted by the California Energy Commission (CEC) plus a 15% reserve margin[19]. This allows California ISO (CAISO) to operate the grid in a more reliable manner. RA is highly dependent on the type of the contracting framework or market that is present. It is important to dwell on the fact that capacity additions must be coupled with the capability of the capacity to deliver as needed by the system operator.

Market Monitoring

7.8 An optimized electricity system should yield the same outcome as that discovered by a well-functioning centralized market. If any difference between the two is noticed, then it could potentially be an indicator that the market may not be functioning well and this is where the role of an independent and universally trusted market monitor is crucial.

7.9 All commodity markets have their peculiarities, and a key peculiarity of an electricity market arises from the fact that electricity is relatively expensive to store. A consequence of this peculiarity is that the electricity market can be manipulated by

[19] *Resource Adequacy,* California Public Utilities Commission

withholding production. Reducing market concentration can ensure that no supplier has the ability to withhold production. Further, the competitiveness of the market must be monitored and enforced as close to real time as possible.

7.10 Interventions such as price controls for mitigating market power may be necessary where measures to reduce market concentration are weak or non-existent, however, they undermine legitimate price formation. Effective competition is a necessary condition for well-functioning markets.

7.11 Market monitoring needs to be enforced under the following broad heads:

a) *Market surveillance* to identify and address wrongdoing; and
b) *Market performance assessment* to examine and improve the economically efficient functioning of the market, including the efficient formation of prices when supply meets demand, usually referred to as "price formation."[20]

The Commission recognises the need for strengthening the market monitoring and enforcement and is already working in this direction.

Price-Coupling, Margin Money and Transaction Charges for Power Exchanges

7.12 CERC Regulations allow for multiple power exchanges to ensure competition in Day-Ahead and intra-day markets. Structurally, the same can continue, however for better system efficiency, one option is to combine the bids and offers of both the exchanges. This would help not only in discovery of the same area clearing prices (instead of multiple ACPs due to multiple power exchanges) but also in achieving higher social welfare as compared to the sum of maximum social welfare in multiple power exchanges. This can be implemented through two alternative mechanisms:

i) Market clearing engine could be operated by one of the power exchanges by rotation. Here, the said (nodal) power exchange could receive "masked" buy bids and sell offers from other power exchange. The names of the buyers and

20 Keay-Bright, S. (2016, July 27). The case for market monitoring—A key to successful electricity markets [Blog post]. Retrieved from http://www.raponline.org/blog/case-for-market-monitoring/.

the sellers would be masked. The dispatch schedules would then be notified by the individual exchanges; or

ii) Market clearing engine can be operated by an independent entity. All the power exchanges could forward the bids and offers received in their individual exchanges, to the independent entity. The dispatch schedules would then be notified by the individual exchanges.

The clearing house in both the above options could be managed by an entity selected by the Commission in accordance with procedures in this regard.

7.13 On implementation of the proposed MBED framework, the volumes of transactions in the DAM as well as the RTM are expected to grow substantially. In this context while the margin money requirement of the power exchanges is important for guaranteeing payment security, a balance needs to be maintained to make sure the participation of the discoms in the market does not become cost prohibitive. Similarly, the transaction charges charged by the power exchanges need be reviewed with increase in the volume of transactions in the market.

Annexures

Annexure –I Methodology of Benefits Estimation of a Market Based Economic Dispatch

This effort is an illustration of the benefits of centralized market operations in the day ahead market. The power generation resources of five states are combined for the purpose of scheduling and dispatch to assess the scope of savings if the Market Based economic dispatch mode across regions, were to be adopted. For this, a Python based optimization tool has been used to simulate and demonstrate these benefits for the states assumed to be participating in the market in a closed mode. The period of simulation is Apr'16 to Mar'17.

Actual data on 15 minute block interval for each day in the past 12 months period specified has been collected from the states/ SLDCs.

Assumptions used in the simulation

The simulation has been carried out using the following data and assumptions:-

<table>
<tr><th>Particulars</th><th colspan="5">Details</th></tr>
<tr><td>No of states considered</td><td colspan="5">5 (Andhra Pradesh, Telangana, Karnataka, Chhattisgarh, Maharashtra)</td></tr>
<tr><td rowspan="3">Number of generation plants considered</td><td colspan="5">121</td></tr>
<tr><td>Andhra Pradesh</td><td>Telangana</td><td>Karnataka</td><td>Chhattisgarh</td><td>Maharashtra</td></tr>
<tr><td>37</td><td>26</td><td>38</td><td>13</td><td>41</td></tr>
<tr><td>Type of generation plants</td><td colspan="5">Thermal and Hydel (Hydel plants have been assumed to be operating at full availability hence there would be no scope for optimization)</td></tr>
<tr><td>Ramping rate for coal based plants</td><td colspan="5">1% per minute as per IEGC grid code</td></tr>
<tr><td>Technical minimum limits for operation of coal based plants</td><td colspan="5">55%</td></tr>
<tr><td>Transmission congestion charges</td><td colspan="5">Congestion charges are assumed to be same as determined in Px day ahead market</td></tr>
<tr><td>PoC charges and losses</td><td colspan="5">As per relevant CERC orders</td></tr>
</table>

Following additional assumptions have been considered:-

1. For a state, the total actual generation of all generation plants has been considered equal to the scheduled demand for a slot. Dispatch of plants is then carried out to fulfil the total scheduled demand for all the states put together.
2. Contract prices of generation plants are assumed to be same as the variable costs
3. The entire demand of each of the state is assumed to be totally met in the centralized day ahead market

<u>Methodology for simulation</u>

- **<u>Base case scenario</u>**

In the base case scenario, we have assumed participation of thermal and hydel plants (State, Central and IPPs) of all the 5 states mentioned above. While thermal plants would have URS available with them (Difference of Declared capacity less Actual generation), it is understood that hydel plants would have been dispatched to their maximum possible extent and hence there would not be any scope for additional generation from hydel plants. Thus, actual generation from hydel plants has been factored in and assumed to be same in Centralized day ahead dispatch as well.

The simulation for benefits estimation has been carried out in the following steps:-

1. **Estimation of scheduled demand**: Sum of actual generation for all the gencos for each slot is calculated. In absence of scheduled demand by SLDC, the sum of actual generation for all the gencos is assumed to be same as scheduled demand. Block-wise scheduled demand has been calculated
   For a given time block,

$$Scheduled\ Demand\ (SD)(MW) = \sum_{i=1}^{N} AG_i$$

   Where, N is the total number of thermal and hydel generators, AG_i is the Actual generation in MW of i^{th} generator.

2. **Base case dispatch**: Merit order stacking of generation plants is done considering the actual generation quantum provided by SLDC. Total cost of generation (variable cost) is determined for this scenario.
   For a given time block, considering total number of generators (thermal and hydel) after stacking in merit order is N.
   Total Cost of generation (Base case) for a given time slot is:-

$$Cost\ (BC)(INR) = \sum_{i=1}^{N} AG_i * VC_i * 0.25 * 1000$$

   Where, i is the i^{th} generator considered in the merit order, AG_i is the Actual generation of i^{th} generator in MW and VC_i is the Variable Cost of i^{th} generator in INR/kWh.

   Total cost of generation for a complete year is calculated as per the formula given below

$$Total\ Cost\ (BC)(INR) = \sum_{d=1}^{365} \sum_{s=1}^{96} Cost\ (BC)_{s,d}$$

Where s is the time slot for a day and d is the day of the year

3. **Dispatch of stations as per available DC**: Post step 2, stations are again dispatched as per merit order stacking according to the quantum of Declared Capacity available with each of the stations. There would be situations where cheaper generation plants would have URS and hence MW dispatched from them would be more than what was dispatched in step 2. Total cost of generation based on total demand required and entitlements are determined.

   An optimization problem is executed where the objective function is to minimize the cost of power generation over the optimization timeframe subject to demand supply balance constraint, a constraint requiring that any generator cannot operate below its technical minimum and a ramp up/down constraint. Consideration of all the generators here ensures that they are dispatched based on their combined merit order, that is in the ascending order of their variable costs. This results in cost savings in comparison to the present mechanism where the generators are normally dispatched as per their respective portfolio of contracts. The extant mechanism results in more efficient (lower variable cost) generators remaining under-utilized while costly (or rather relative inefficient generators) serve the demand. The dual (marginal value) of the demand supply balance constraint in this optimization problem gives the Market Clearing Price (or the System Marginal Cost of Generation).

4. **Calculating net system charges**: Total system costs arising out of the model (With actual generation) are calculated and compared with the revised system costs incurred by the states (With Centralized dispatch as per Declared Capacity). Net reduction in system costs due to implementation of the Centralized mechanism is then determined.

$$Net\ System\ Charges\ (NC)(INR) = \sum_{k=1}^{365}\sum_{j=1}^{96}\sum_{i=1}^{N} AG_{k,j,i} * VC_{k,j,i} * 250 - \sum_{k=1}^{365}\sum_{j=1}^{96}\sum_{i=1}^{N} RG_{k,j,i} * VC_{k,j,i} * 250$$

   Where, N is the number of generators, j represents slot from 1 to 96, and k represents day from 1 to 365. $AG_{k,j,i}$ and $VC_{k,j,i}$,is the Actual generation and variable cost of i^{th} generator j^{th} slot and k^{th} day, respectively.

5. **Calculating procurement costs of states**: Savings in procurement cost by state discoms are calculated as follows**:-**
   a. State wise Actual Generation and Revised Generation is determined.
   b. Cost of power procured for Actual Generation for each state are calculated as sum product of quantum of energy dispatched from each generator and corresponding variable cost of the generator. Mathematically, the same is depicted as follows:-

Cost of power procured = ∑ Quantum of energy generated from each generation plants X Variable cost, $\sum_i \boldsymbol{AG_i} * \boldsymbol{VC_i}$
PoC charges for each of the states is also calculated. Total procurement cost of each state is thus:-
Total procurement cost = Cost of power procured + PoC charges

Slot-wise Procurement cost is given by:

$$TPC_s(INR) = \sum_{i=1}^{N} AG_i * VC_i * 250 + POC\ Charges_i$$

$$Total\ Procurement\ Cost\ for\ year\ \left(TPC_y\right)(INR) = \sum_{d=1}^{365}\sum_{s=1}^{96} TPC_{s_{d,s}} + PoC\ Charges$$

Where, $TPC_s$is the total procurement cost for a slot and TPC_y is the total procurement cost for an year, s represents slot and d represents day $TPC_{d,s}$ is total procurement cost for s slot and d day.

c. Procurement costs for Revised Generation is determined as below:-
   i. **States having surplus generation post Market Based Economic dispatch (from own portfolio)**: Assuming Andhra Pradesh has an actual generation of 8000 MW (from thermal and hydel plants) but has a revised generation of say, 9000 MW from the same portfolio of plants due to centralized dispatch of generators. Out of 9000 MW of revised generation, 8000 MW will be procured at marginal cost in the power exchange and subsequently the generators would refund the difference of marginal cost and contract price to the discoms through existing Contracts for Difference with contracted beneficiaries. Hence, effectively 8000 MW would be procured at contract price (Variable cost of each genco after implementation of BCS) and excess revenue generated from the rest 1000 MW (sold at marginal cost), which represents the additional surplus power generated in the state, is shared between the generators of Andhra Pradesh and its discoms in the ratio of 50:50.

   For instance, for a surplus State with Scheduled Demand, S_{SD} in a particular slot, let's assume N is the number of generators from that state's portfolio which are dispatched as well as required to meet S_{SD} and M be the total number of generators dispatched in state's portfolio.

If

$$\left(S_{SD} - \sum_{i=1}^{N-1}(RG_i)\right) > 0$$

Then,

$$Effective\ Cost\ of\ Procurement\ (ECOP)$$
$$= \sum_{i=1}^{N-1} RG_i * VC_i * 250 + \left(S_{SD} - \sum_{i=1}^{N-1}(RG_i)\right) * VC_N * 250$$

$$Revenue\ (R) = \left(RG_N - \left(S_{SD} - \sum_{i=1}^{N-1}(RG_i)\right)\right) * (MCP - VC_N)$$
$$+ \sum_{i=N+1}^{M}(RG_i) * (MCP - VC_i)$$

Where MCP is the Market Clearing Price

If

$$\left(S_{SD} - \sum_{i=1}^{N-1}(RG_i)\right) = 0$$

Then,

$$Effective\ Cost\ of\ Procurement(ECOP) = \sum_{i=1}^{N} RG_i * VC_i * 250$$

$$Revenue\ (R) = \sum_{i=N+1}^{M}(RG_i) * (MCP - VC_i)$$

ii. **States having deficit generation post Market Based Economic dispatch (from own portfolio)**: Assuming Andhra Pradesh has an actual generation of 8000 MW (from thermal and hydel plants) but has a revised generation of say, 7000 MW from the same portfolio of plants. The entire 7000 MW will be procured at marginal cost of the pool and subsequently the generators would refund the difference of marginal cost and contract price to the discoms through existing Contracts for Difference with contracted beneficiaries. Hence, effectively 7000 MW would be procured at contract price (Variable cost of each genco after implementation of BCS) whereas the 1000 MW of deficit power will be procured at the marginal cost from the pool. There would be no revenue sharing with discoms in this case.

Subsequently, PoC charges for each of the states are also calculated. Total procurement cost of each state is thus:-

Revised procurement cost = Revised Cost of power procured + PoC charges

Mathematically,

$$Effective\ Cost\ of\ Procurement(ECOP) = \sum_{i=1}^{N} RG_i * VC_i * 250 + \left(S_{SD} - \sum_{i=1}^{N}(RG_i)\right) * MCP * 250$$

Where MCP is the Market Clearing Price

For a given slot for all the states put together,

$$Total\ Cost\ of\ Procurement(TCP_S)(INR) = \sum_{st=1}^{5} ECOP_{st} + PoC\ Charges$$

$$Total\ Revenue(R_s)(INR) = \sum_{st=1}^{5} R_{st}$$

Where st represent states and $ECOP_{st}$ is the Effective cost of Procurement st^{th}state. R_{st} represents revenue of st^{th} state

For the entire year,

$$Total\ cost\ of\ Procurement\ for\ year\ \left(TCP_y\right)(INR) = \sum_{d=1}^{365}\sum_{s=1}^{96} TCP_{s_{d,s}}$$

$$Total\ Revenue\ for\ year\ \left(R_y\right)(INR) = \sum_{d=1}^{365}\sum_{s=1}^{96} R_{s_{d,s}}$$

Based on the above, the difference in procurement costs of the state are calculated for actual generation and revised generation profile. The additional revenue earned by each of the surplus generating states, as a result of revenue sharing by generators, is also determined.

<u>Additional constraints in the modelling:-</u>

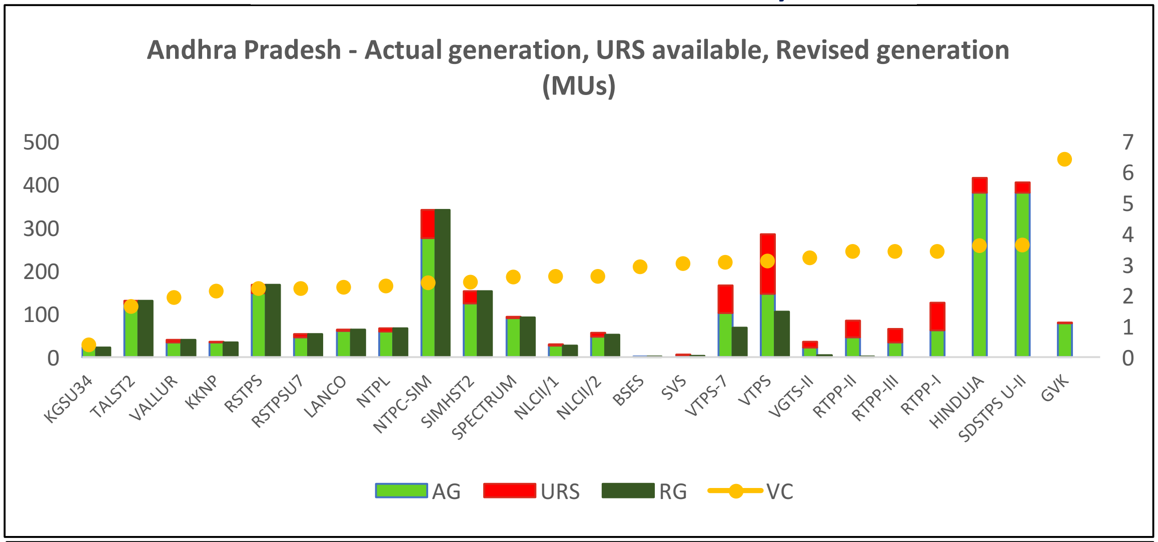
1) To calculate the extent of optimization possible, we have considered the Day-ahead Declared capacity of the generators (State, Central, IPPs) and the actual dispatch. The difference of both suggests the scope of optimization for each of the generator. We have not considered any possible schedule revisions until intra-day time, which may result in lowering of availability of these generators and subsequent reduction in scope of optimization.
2) Currently, discoms in the states follow decentralized self-scheduling practice wherein they self-schedule (i.e. requisition power from) generating stations with which they have long-

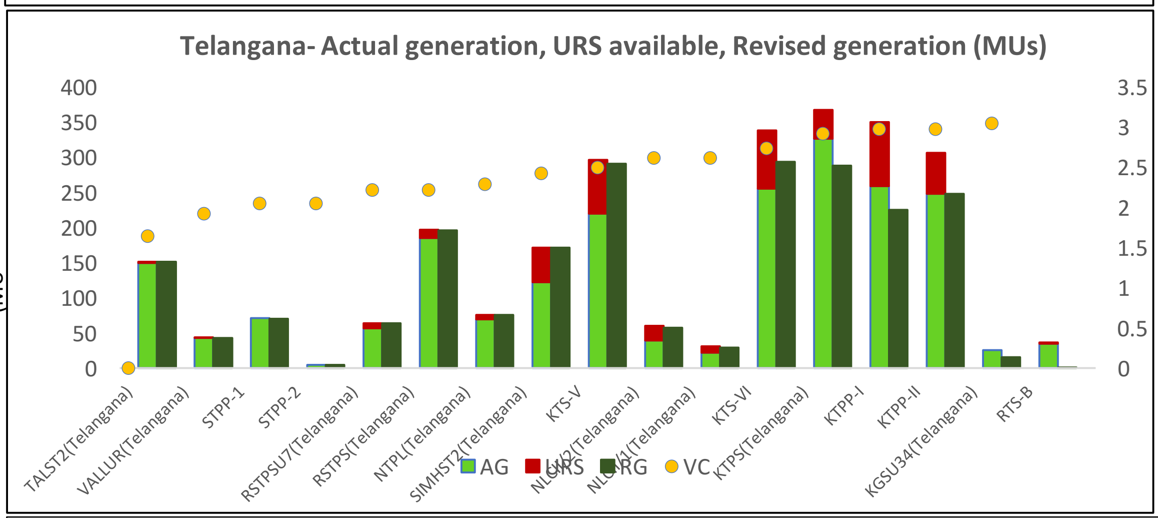
term contracts. There is a possibility of unscientific planning which may result in Day ahead availabilities of generators being not in line with real time demand requirements and hence the extent of optimization may be greater.

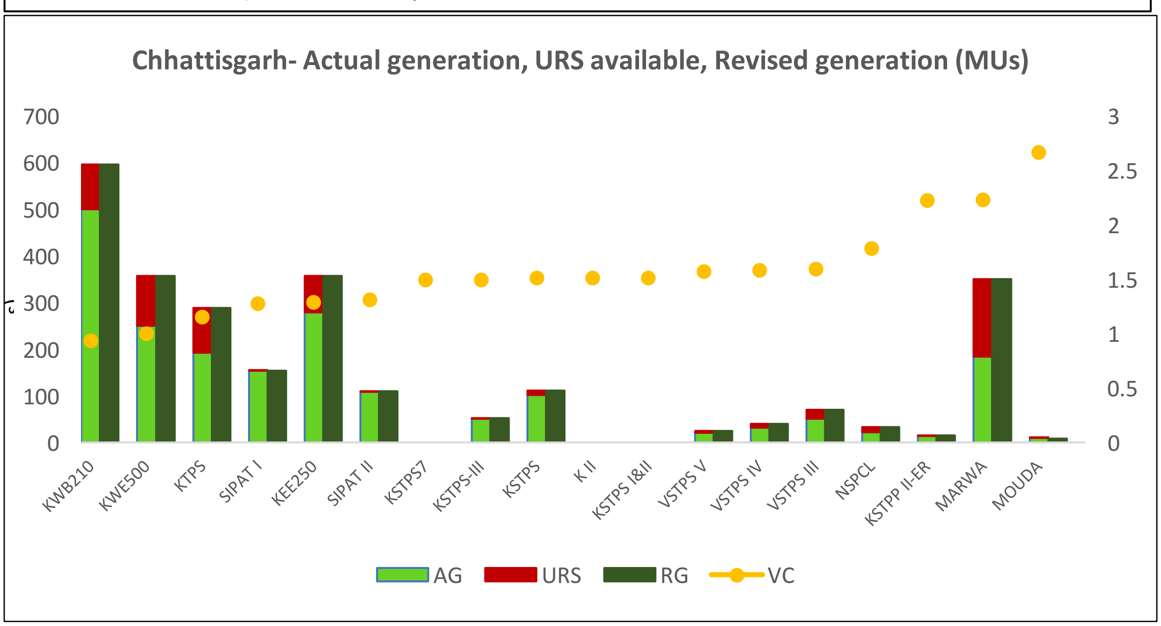
3) The calculated URS values (DC less actual dispatch) for each generator would also include effects of unit-tripping of generators, forced outages, transmission network overloading causing outages etc. all of which would lead to actual dispatch being less than DC values. Identification of the same is not possible under the current scope.
4) The simulation has been carried out for a closed system of five states. It is possible that when the scope is extended to cover additional states, the growth in benefits may not be linear and hence overall % benefits would change / reduce.
5) There is a possibility that a few generating stations would be declaring the DCs but power is actually not dispatched from them continuously due to multiple reasons.

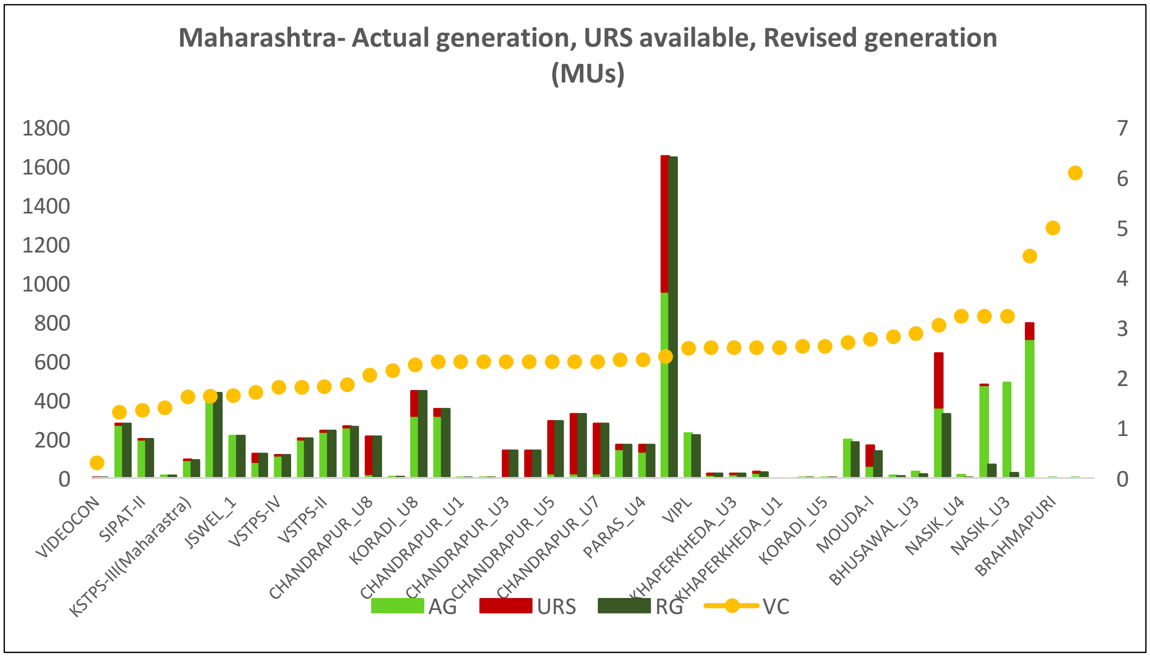
Annexure II – Actual Generation vs Revised Generation, Simulation Analysis

Overview for the month of July

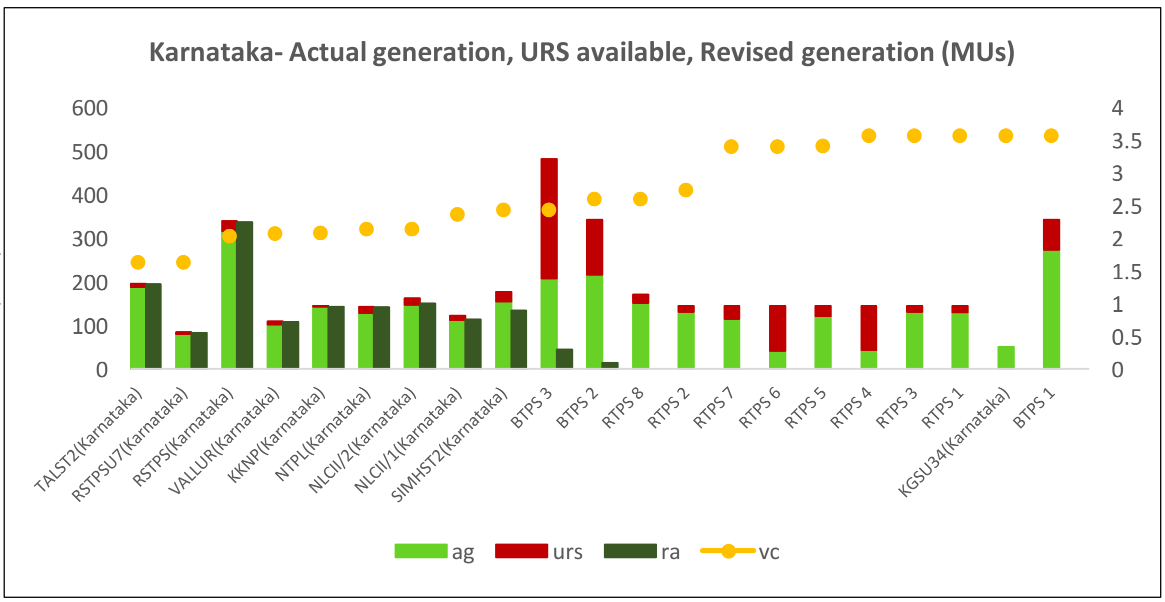








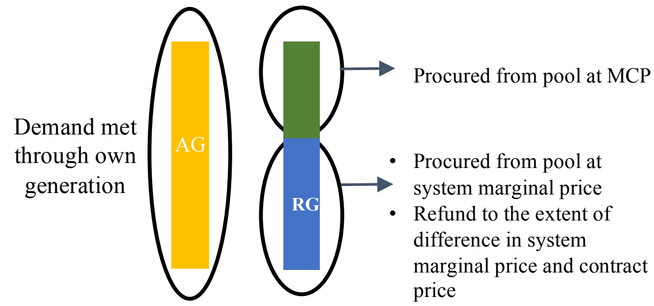
Overview for the month of September



Annexure III – Cost of Procurement and Additional Revenue, Simulation Analysis

Andhra Pradesh – 1st April, Time Block – 0000hrs – 0015hrs

Actual Generation	AG = 3866 MW
Revised Generation	RG = 2016 MW
MCP Discovered	Rs. 3.072

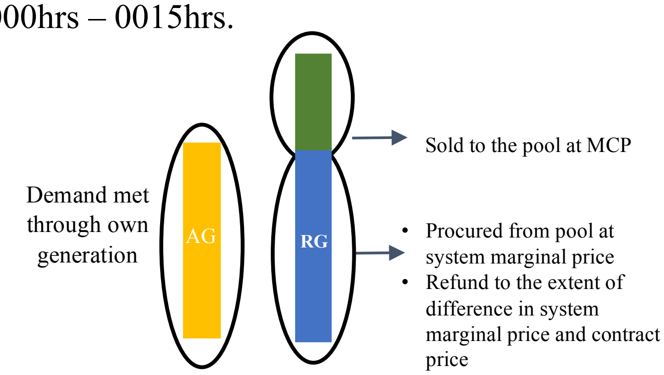


Procurement Cost – Actual Generation	
Discom Payment	Rs. 32,64,871
PoC Charges	Rs. 1,36,201
Total Cost of Procurement	**Rs. 34,01,072**

Procurement Cost – Revised Generation	
Cost of Power at Contract Price (BCS))	Rs. 10,65,256
Cost of Power Procured from the Pool	Rs. 14,21,154
PoC Charges	Rs. 3,59,478
Total Cost of Procurement	**Rs. 28,45,888**

Maharashtra – 1st April, Time Block – 0000hrs – 0015hrs.

Actual Generation	AG = 10678 MW
Revised Generation	RG = 12032 MW
MCP Discovered	Rs. 3.072



Procurement Cost – Actual Generation	
Discom Payment	Rs. 63,63,324
PoC Charges	Rs. 2,66,531
Total Cost of Procurement	**Rs. 66,29,854**

Procurement Cost – Revised Generation	
Cost of Power at Contract Price (BCS)	Rs. 57,08,103
PoC Charges	Rs. 2,70,186
Total Cost of Procurement	**Rs. 59,78,289**
Additional Revenue Share (50%)	**Rs. 12,191**

State	Net Benefits
Andhra Pradesh	**Rs. 5,55,184**
Maharashtra	**Rs. 6,63,756**

Annexure IV – Final Settlement - Post MBED and RTM for different scenarios

Time Block of RTM: 0000-0100 hrs:

Considering a generator has DC 1200 MW and variable cost: Rs 4000 / MWh. It sells a total of 1200 MW in the MBED D-1 market:-

- 200 MW is sold to the market at MCP of Rs 5000 / MWh to its contracted beneficiary The Bilateral contract settlement will happen for the 200 MW power sold to the market for use by the contracted beneficiary.
- Balance 1000 MW surplus power is sold to the market at MCP.

Further, the discom in the real time market utilizes its right to recall at the specified time block and requisitions for additional 100 MW power from the same generator when the RTM price is Rs 5000 / MWh.

Particulars						
		MBED (D-1)			RTM (D)	
Generator DC (MW)	VC (Rs / MWh)	Sold to beneficiary (MW)	Sold to market (MW)	MCP (Rs / MWh)	Additional requisition from discom (MW)	MCP (Rs / MWh)
1200	4000	200	1000	5000	100	5000

Settlement mechanism			Pre-MBED- Revenue / Payment as per contract	MBED	RTM
Generator	Revenue from beneficiary (pre-MBED)	(a)	= Rs (200*4000) = Rs 8,00,000		
	Revenue from beneficiary (MBED)	(a1)		Rs (200 * 5000) = Rs 10,00,000	
	Revenue from URS sale	(b)		Rs (1000*5000) = Rs 50,00,000	
	Revenue from URS sale if power was sold in pre-MBED	(c)		Rs (1000*4000) = Rs 40,00,000	
	Additional revenue from URS sale	(d) = (b)-(c)		=Rs. 10,00,000	
	Bilateral Contract Settlement (BCS)	(e)		Rs (200*(5000-4000)) = Rs 2,00,000	
	Net revenue from beneficiary	(f) = (a1)-(e)		= Rs 8,00,000	
	Payment by generator for additional power procured	(g)			=Rs (100*5000) = Rs 5,00,000
	Additional revenue to generator from Discom for exercising recall	(h)	= Rs (100*4000) = Rs 4,00,000		=Rs (100*4000) = Rs 4,00,000
	Net gain from URS sale	(i) = (d)-(g)+(h)			=Rs 9,00,000
	Net revenue to generator after 50% sharing (50% of (h))	(j)=(i)/2			=Rs 4,50,000
	TOTAL GENERATOR REVENUE		**(a) + (h) = Rs 12,00,000**	**(f)+(j)= Rs 12,50,000**	
Discom	Payment to generator	(k)	= Rs (200*4000) = Rs 8,00,000	Rs (200 * 5000) =Rs 10,00,000	
	Bilateral Contract Settlement	(l)		Rs (200*(5000-4000)) = Rs 2,00,000	
	Net payment to generator	(m) = (k)-(l)		= Rs 8,00,000	
	Payment to generator for RTM purchase	(n)	= Rs (100*4000) = Rs 4,00,000		Rs (100*4000) = Rs 4,00,000
	Net revenue to discom after sharing	(o)			= Rs 4,50,000
	TOTAL DISCOM PAYMENT		**(k)+(n)= Rs 12,00,000**	**(m) + (n) - (o) = Rs 7,50,000**	

Note: This scenario will apply only if the generator sells the URS in the day ahead market despite such URS having been identified by the discom for right to recall before the gate closure in real time. In case the discom does not identify such URS by 9.45 am on D-1 for exercise its right to recall before RTM, then the entire gains out of the sale of URS power to the market, on day ahead basis, will be shared equally (in the ratio of 50:50) between the generator and discom.

<u>Time Block of RTM: 0600-0700 hrs</u>

Considering a generator has DC 1200 MW and variable cost: Rs 4000 / MWh. It sells a total of 1200 MW in the MBED D-1 market:-

- 200 MW is sold to the market at MCP of Rs 5000 / MWh to its contracted beneficiary The Bilateral contract settlement will happen for the 200 MW power sold to the market for use by the contracted beneficiary.
- Balance 1000 MW surplus power is sold to the market at MCP.

Further, the discom in the real time market utilizes its right to recall at the specified time block and requisitions for additional 100 MW power from the same generator when the RTM price is Rs 6000 / MWh.

Particulars						
		MBED (D-1)			**RTM (D)**	
Generator DC (MW)	VC (Rs / MWh)	Sold to beneficiary (MW)	Sold to market (MW)	MCP (Rs / MWh)	Additional requisition from discom (MW)	MCP (Rs / MWh)
1200	4000	200	1000	5000	100	6000

Settlement mechanism			**Pre-MBED- Revenue / Payment as per contract**	**MBED**	**RTM**
Generator	Revenue from beneficiary (pre-MBED)	(a)	= Rs (200*4000) = Rs 8,00,000		
	Revenue from beneficiary (MBED)	(a1)		Rs (200 * 5000) = Rs 10,00,000	
	Revenue from URS sale	(b)		Rs (1000*5000) = Rs 50,00,000	
	Revenue from URS sale if power was sold in pre-MBED	(c)		Rs (1000*4000) = Rs 40,00,000	
	Additional revenue from URS sale	(d)		= Rs. 10,00,000	
	Bilateral Contract Settlement (BCS)	(e)		Rs (200*(5000-4000)) = Rs 2,00,000	
	Net revenue from beneficiary	(f) = (a1)-(e)		= Rs 8,00,000	
	Payment by generator for additional power procured	(g)			= Rs (100*6000) = Rs 6,00,000
	Additional revenue to generator from Discom for exercising recall	(h)	= Rs (100*4000) = Rs 4,00,000		=Rs (100*4000) = Rs 4,00,000
	Net gain from URS sale	(i) = (d)-(g)+(h)			=Rs 8,00,000
	Net revenue to generator after 50% sharing (50% of (h))	(j) =(i)/2			=Rs 4,00,000
	TOTAL GENERATOR REVENUE		**(a)+(h)= Rs 12,00,000**	**(f)+(j)= Rs 12,00,000**	
Discom	Payment to generator	(k)	= Rs (200*4000) = Rs 8,00,000	Rs (200 * 5000) =Rs 10,00,000	
	Bilateral Contract Settlement (BCS)	(l)		Rs (200*(5000-4000)) = Rs 2,00,000	
	Net payment to generator	(m) = (k)-(l)		= Rs 8,00,000	
	Payment to generator for RTM purchase	(n)	= Rs (100*4000) = Rs 4,00,000		Rs (100*4000) =Rs 4,00,000
	Net revenue to discom after sharing	(o)			= Rs 4,00,000
	TOTAL DISCOM PAYMENT		**(k)+(n) = Rs 12,00,000**	**(m) + (n) - (o) = = Rs 8,00,000**	

Note: This scenario will apply only if the generator sells the URS in the day ahead market despite such URS having been identified by the discom for right to recall before the gate closure in real time. In case the discom does not identify such URS by 9.45 am on D-1 for exercise its right to recall before RTM, then the entire gains out of the sale of URS power to the market, on day ahead basis, will be shared equally (in the ratio of 50:50) between the generator and discom.

Time Block of RTM: 1200-1300 hrs

Considering a generator has DC 1200 MW and variable cost: Rs 4000 / MWh. It sells a total of 1200 MW in the MBED D-1 market:-

- 200 MW is sold to the market at MCP of Rs 5000 / MWh to its contracted beneficiary The Bilateral contract settlement will happen for the 200 MW power sold to the market for use by the contracted beneficiary.
- Balance 1000 MW surplus power is sold to the market at MCP.

Further, the discom in the real time market utilizes its right to recall at the specified time block and requisitions for additional 100 MW power from the same generator when the RTM price is Rs 3000 / MWh.

Particulars						
		MBED (D-1)			RTM (D)	
Generator DC (MW)	VC (Rs / MWh)	Sold to beneficiary (MW)	Sold to market (MW)	MCP (Rs / MWh)	Additional requisition from discom (MW)	MCP (Rs / MWh)
1200	4000	200	1000	5000	100	3000

Settlement mechanism			Pre-MBED- Revenue / Payment as per contract	MBED	RTM
Generator	Revenue from beneficiary (pre-MBED)	(a)	= Rs (200*4000) = Rs 8,00,000		
	Revenue from beneficiary (MBED)	(a1)		Rs (200 * 5000) = Rs 10,00,000	
	Revenue from URS sale	(b)		Rs (1000*5000) = Rs 50,00,000	
	Revenue from URS sale if power was sold in pre-MBED	(c)		Rs (1000*4000) = Rs 40,00,000	
	Additional revenue from URS sale	(d)		= Rs. 10,00,000	
	Bilateral Contract Settlement (BCS)	(e)		Rs (200*(5000-4000)) = Rs 2,00,000	
	Net revenue from beneficiary	(f) = (a1)-(e)		= Rs 8,00,000	
	Payment by generator for additional power procured	(g)			= Rs (100*3000) = Rs 3,00,000
	Additional revenue to generator from Discom for exercising recall	(h)	= Rs (100*4000) = Rs 4,00,000		=Rs (100*4000) = Rs 4,00,000
	Net gains from URS sale	(i) = (d)-(g)+(h)			=Rs 11,00,000
	Net revenue to generator after 50% sharing (50% of (h))	(j) =(i)/2			=Rs 5,50,000
	TOTAL GENERATOR REVENUE		**(a)+(h)= Rs 12,00,000**	**(f)+(j)= Rs 13,50,000**	
Discom	Payment to generator	(k)	= Rs (200*4000) = Rs 8,00,000	Rs (200 * 5000) =Rs 10,00,000	
	Bilateral Contract Settlement (BCS)	(l)		Rs (200*(5000-4000)) = Rs 2,00,000	
	Net payment to generator	(m) = (k)-(l)		= Rs 8,00,000	
	Payment to generator for RTM purchase	(n)	= Rs (100*4000) = Rs 4,00,000		Rs (100*4000) =Rs 4,00,000
	Net revenue to discom after sharing	(o)			= Rs 5,50,000
	TOTAL DISCOM PAYMENT		**= (k)+(n)= Rs 12,00,000**	**(m) + (n) - (o) = Rs 6,50,000**	

Note: This scenario will apply only if the generator sells the URS in the day ahead market despite such URS having been identified by the discom for right to recall before the gate closure in real time. In case the discom does not identify such URS by 9.45 am on D-1 for exercise its right to recall before RTM, then the entire gains out of the sale of URS power to the market, on day ahead basis, will be shared equally (in the ratio of 50:50) between the generator and discom.

Time Block of RTM: 1800-1900 hrs

Considering a generator has DC 1200 MW and variable cost: Rs 4000 / MWh. It sells a total of 1200 MW in the MBED D-1 market:-

- 200 MW is sold to the market at MCP of Rs 5000 / MWh to its contracted beneficiary The Bilateral contract settlement will happen for the 200 MW power sold to the market for use by the contracted beneficiary.
- Balance 1000 MW surplus power is sold to the market at MCP.

Further, the discom in the real time market puts forward a downward requisition of 50 MW for the specified time block from the same generator. The generator can sell the specified quantum of power in RTM. RTM price is Rs 6000 / MWh.

Particulars						
Generator DC (MW)	VC (Rs / MWh)	MBED (D-1)			RTM (D)	
		Sold to beneficiary (MW)	Sold to market (MW)	MCP (Rs / MWh)	Downward revision from discom (MW)	MCP (Rs / MWh)
1200	4000	200	1000	5000	50	6000

Settlement mechanism			Pre-MBED- Revenue / Payment as per contract	MBED	RTM
Generator	Revenue from beneficiary (pre-MBED)	(a)	= Rs (200*4000) = Rs 8,00,000		
	Revenue from beneficiary (MBED)	(a1)		Rs (200 * 5000) = Rs 10,00,000	
	Revenue from URS sale	(b)		Rs (1000*5000) = Rs 50,00,000	
	Revenue from URS sale if power was sold in pre-MBED	(c)		Rs (1000*4000) = Rs 40,00,000	
	Additional revenue from URS sale	(d) = (b)-(c)		= Rs. 10,00,000	
	Bilateral Contract Settlement (BCS)	(e)		Rs (200*(5000-4000)) = Rs 2,00,000	
	Net revenue from beneficiary	(f) = (a1)-(e)		= Rs 8,00,000	
	Revenue to generator from Sale of power at RTM	(g)			=Rs (50*6000) = Rs 3,00,000
	Payment by generator to discom for revised quantum of power	(h)	= Rs (50*4000) = Rs 2,00,000		=Rs (50*4000) =Rs 2,00,000
	Net gain from URS sale	(i) = (d)+(g)-(h)			= Rs 11,00,000
	Net revenue to generator after 50% sharing (50% of (h))	(j) =(i)/2			= Rs 5,50,000
	TOTAL GENERATOR REVENUE		**(a)-(h)= Rs 6,00,000**	**(f)+(j)= Rs 13,50,000**	
Discom	Payment to generator	(k)	= Rs (200*4000) = Rs 8,00,000	Rs (200 * 5000) =Rs 10,00,000	
	Bilateral Contract Settlement BCS)	(l)		Rs (200*(5000-4000)) = Rs 2,00,000	
	Net payment to generator	(m) = (k)-(l)		= Rs 8,00,000	
	Receivable from generator for RTM sale	(n)	= Rs (50*4000) = Rs 2,00,000		=Rs (50*4000) =Rs 2,00,000
	Net revenue to discom after sharing	(o)			= Rs 5,50,000
	TOTAL DISCOM PAYMENT		**= (k)-(n)= Rs 6,00,000**	**(m) - (n) - (0) = Rs 50,000**	

Total consolidated revenue for entire day:-

Total revenue / (payment) for entire day (Rs crs)	Generator*	Discom**
Pre-MBED	2.52	(2.52)
Post MBED and RTM settlement	3.09	(1.35)

*∑ (Generator revenue (Time Block1)*6) + (Generator revenue (Time Block 2)*6) + (Generator revenue (Time Block 3)*6) + (Generator revenue (Time Block 4)*6)

**∑ (Discom revenue (Time Block 1)*6) + (Discom revenue (Time Block 2)*6) + (Discom revenue (Time Block 3)*6) + (Discom revenue (Time Block 4)*6)