Discussion Paper

on

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

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CERC

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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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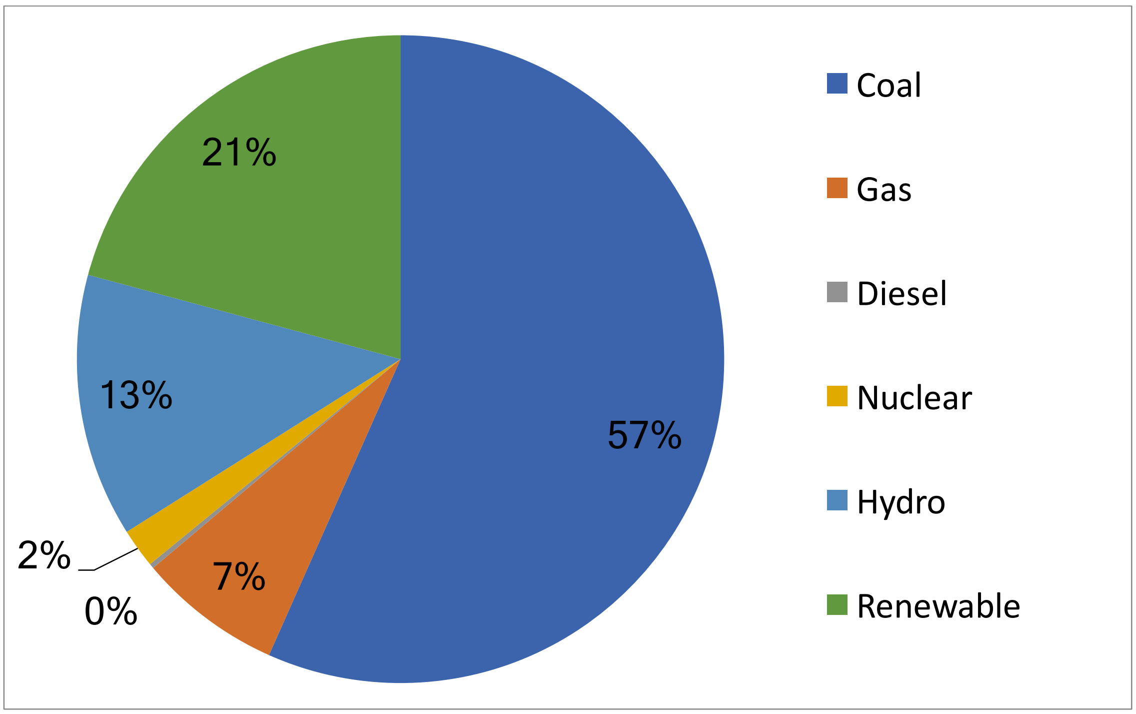
1. Introduction

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)

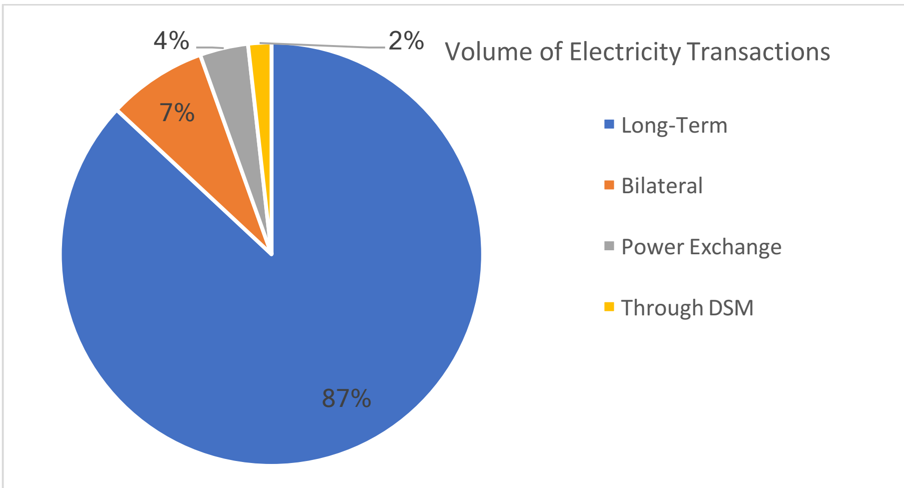
Figure 1. All India Installed Capacity (as on September 2018)



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.

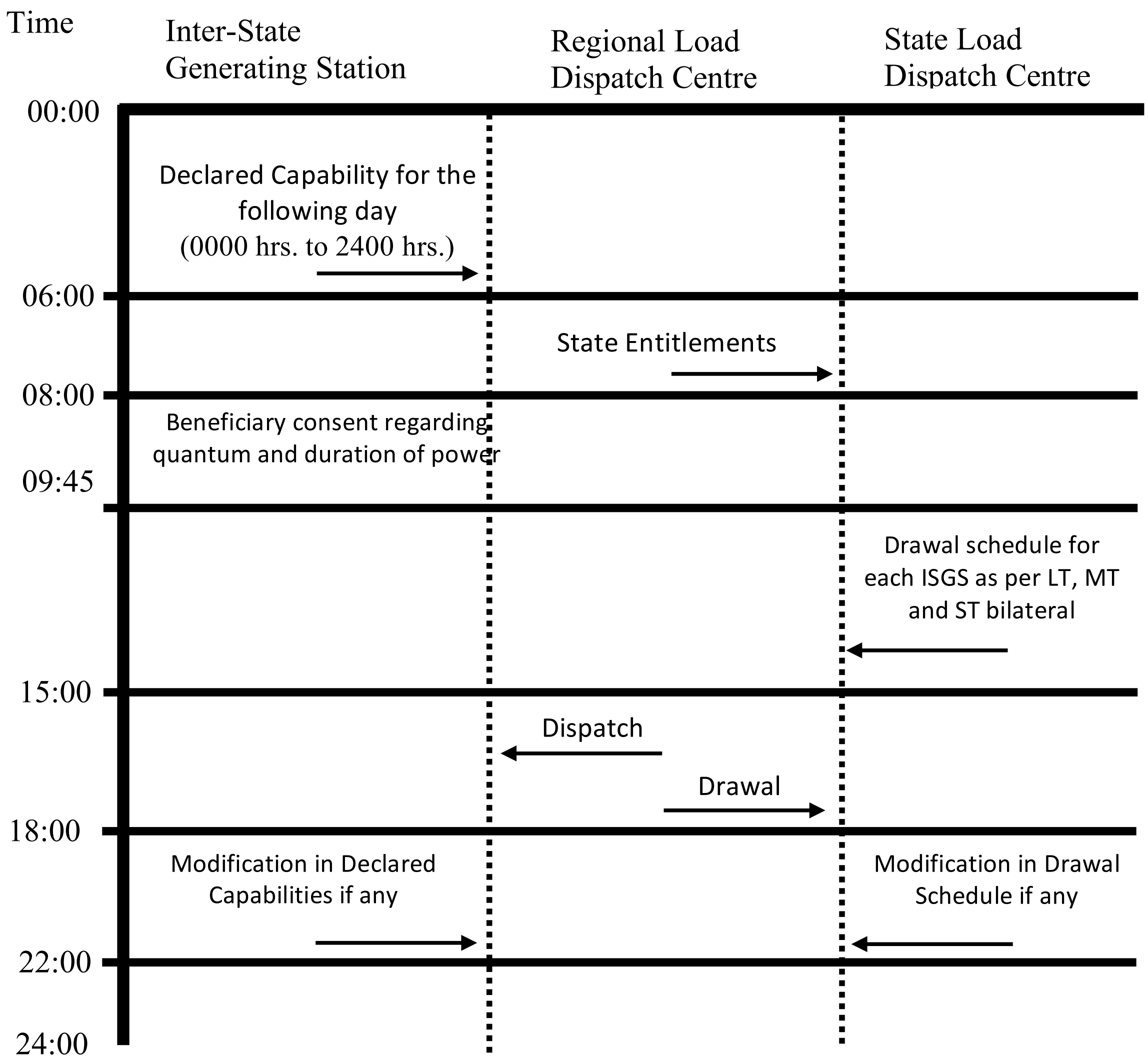
Figure 2. Volume of electricity Transactions in India



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.

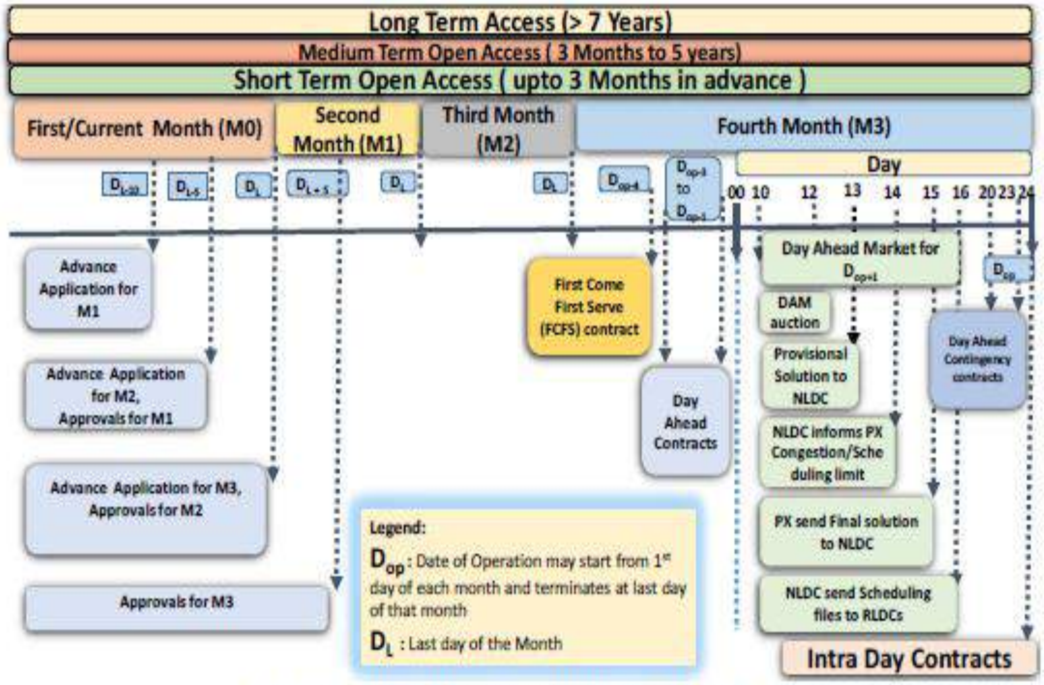
Figure 3. TimeLine for Day Ahead Scheduling of Long Term Transactions



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.

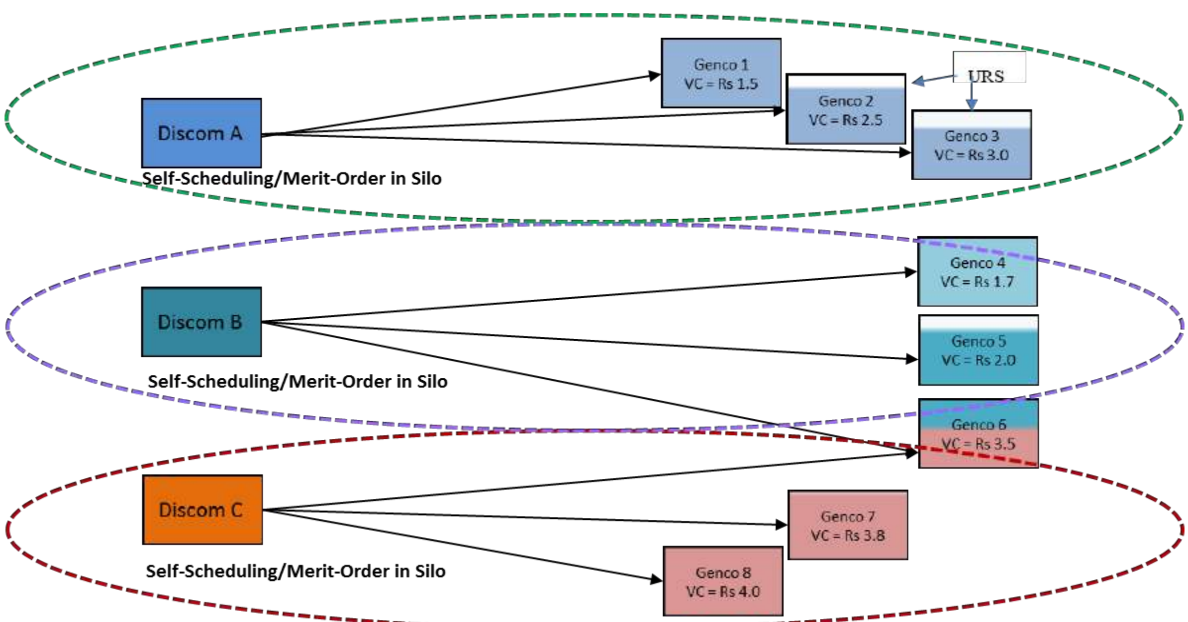
1.7 Day Ahead Markets are a part of a continuum involving the multi settlement markets. While a DISCOM contracts capacity in Long Term, it schedules the power mostly in day-ahead time horizon. Therefore, each of these markets – along the continuum, allows the DISCOM to “correct” its position by either 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

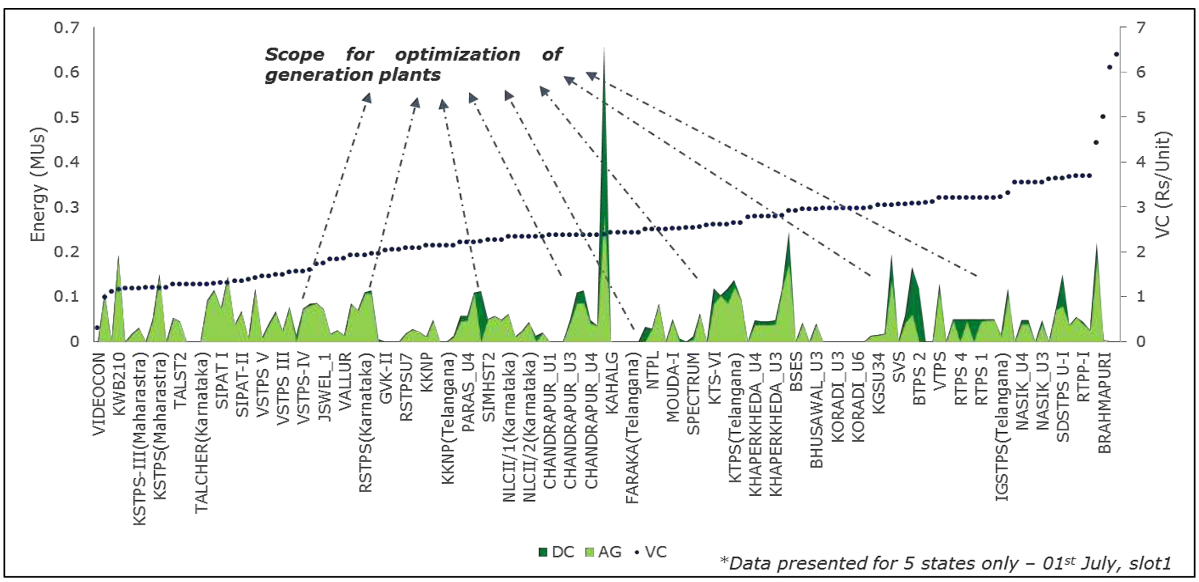


Source:- CERC Analysis

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.

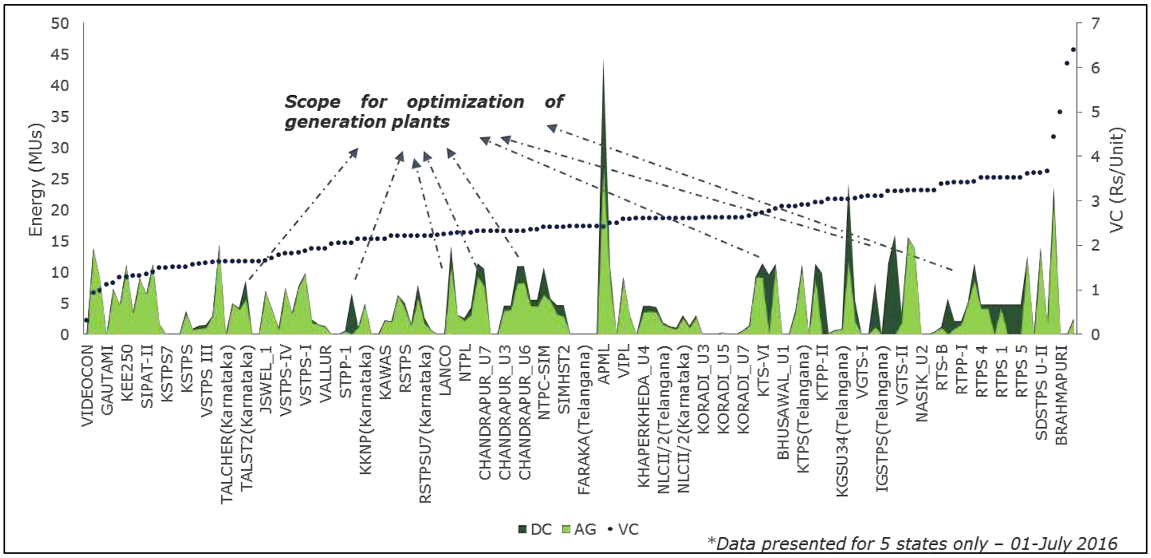
2.3 The Figure 6, theFigure 77 and the Figure 8 show the generation portfolio of five States viz. Andhra Pradesh, Karnataka, Telangana, Maharashtra, and Chhattisgarh (for which primary data have been collected) stacked in the order of their variable cost. The energy dispatched and declared capacity, 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



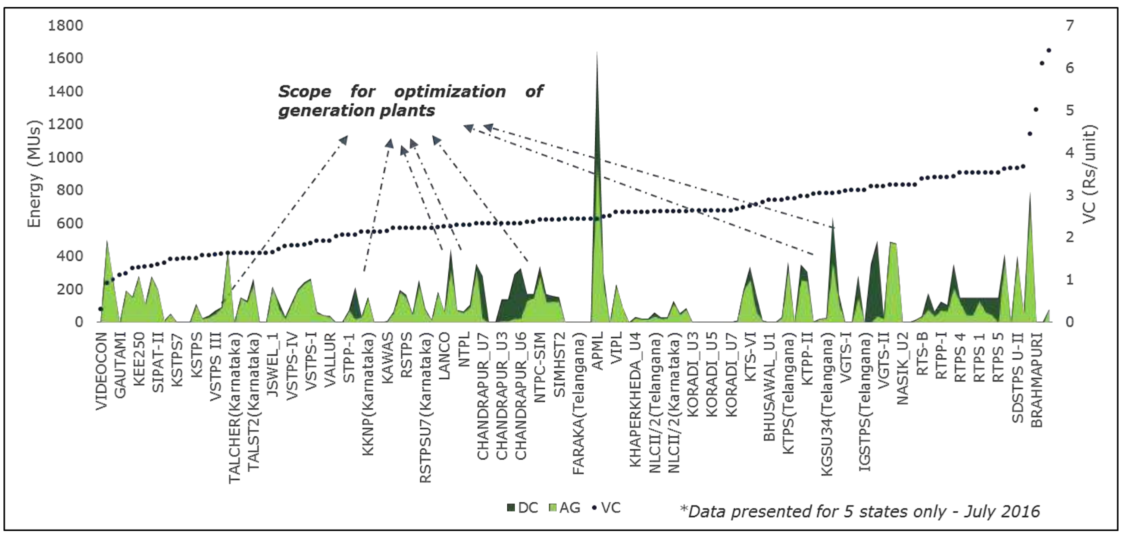
Source: CERC staff analysis

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



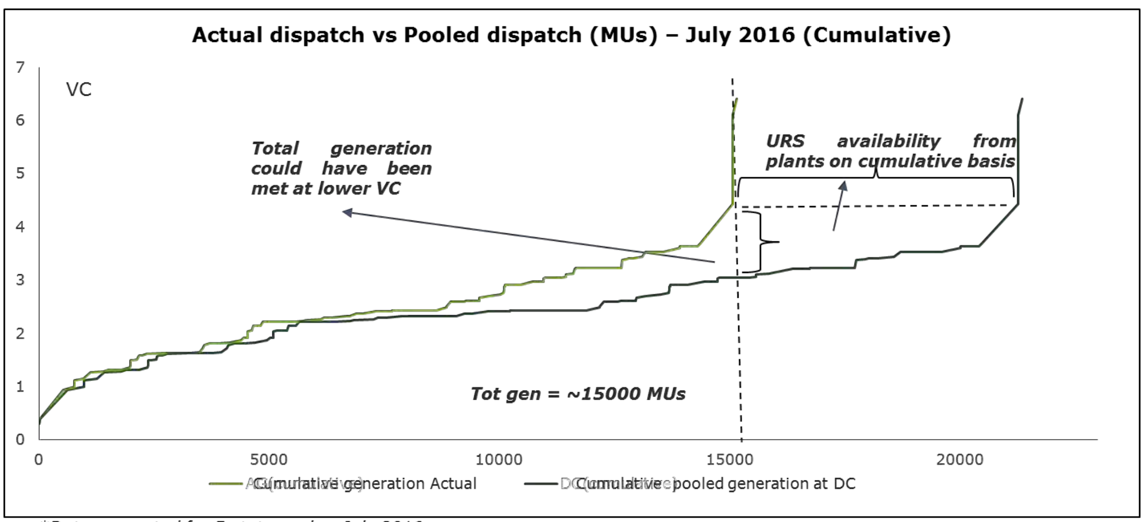
Source: CERC staff analysis

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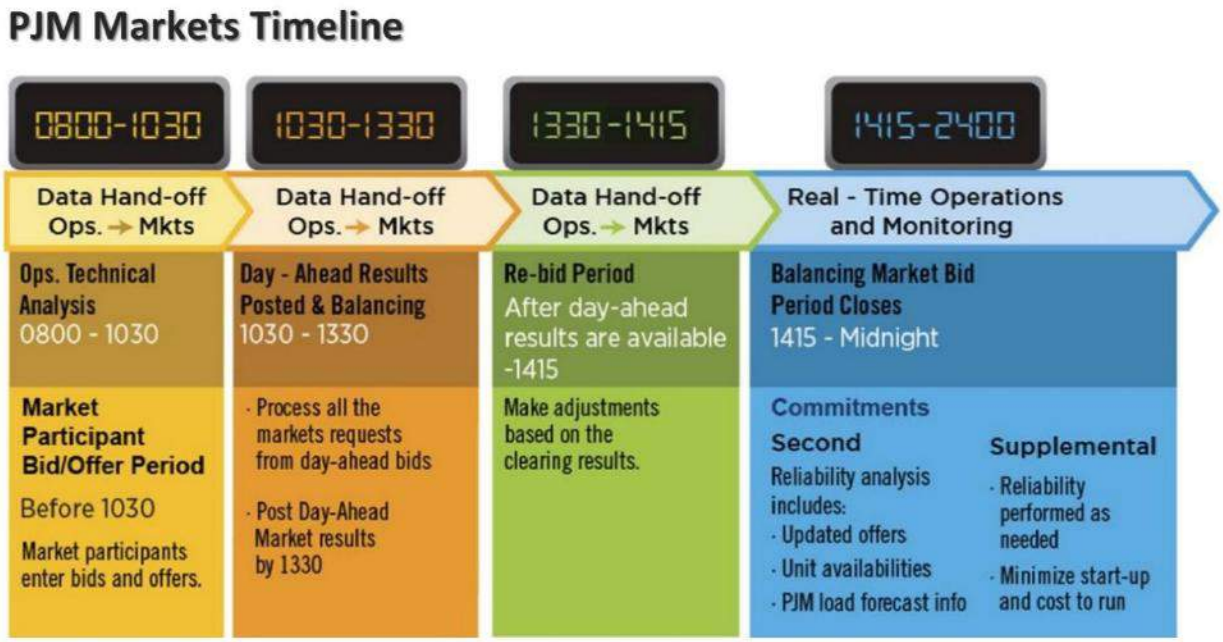
[1] Electricity Contracting in the United States (USAID Report 2018)
[2] Wholesale Market Design Initiatives in the United States (EPRI)
[3] PJM Manual 11, 26th July 2018

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)

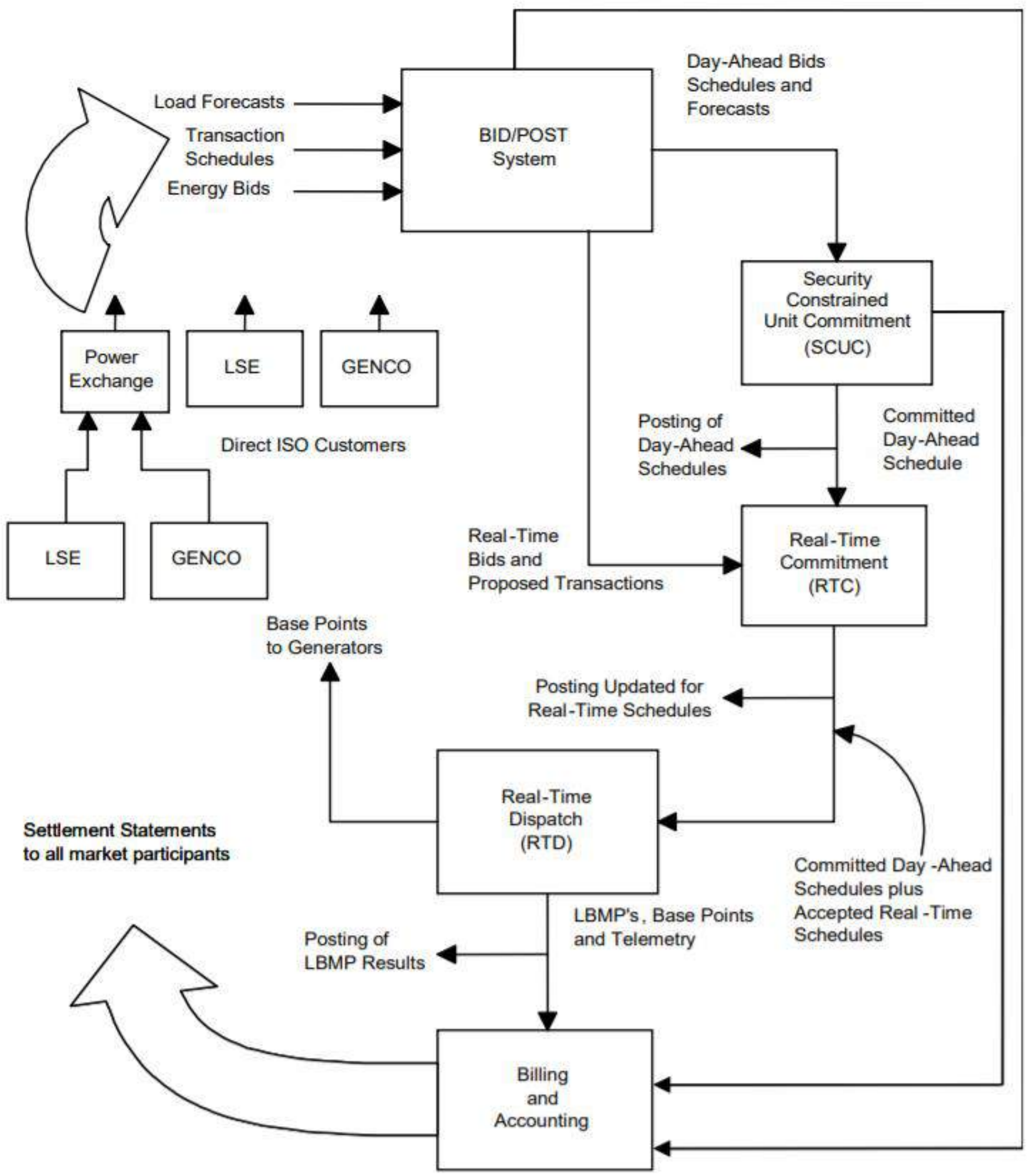
3.5 The ISO then combines all the generator offers which include generators offering electricity in the energy market as well as self-scheduled generators. The bids are processed and schedules are prepared by 11AM. Therefore, the schedule of the contracted generators does not impact the ISOs process 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.

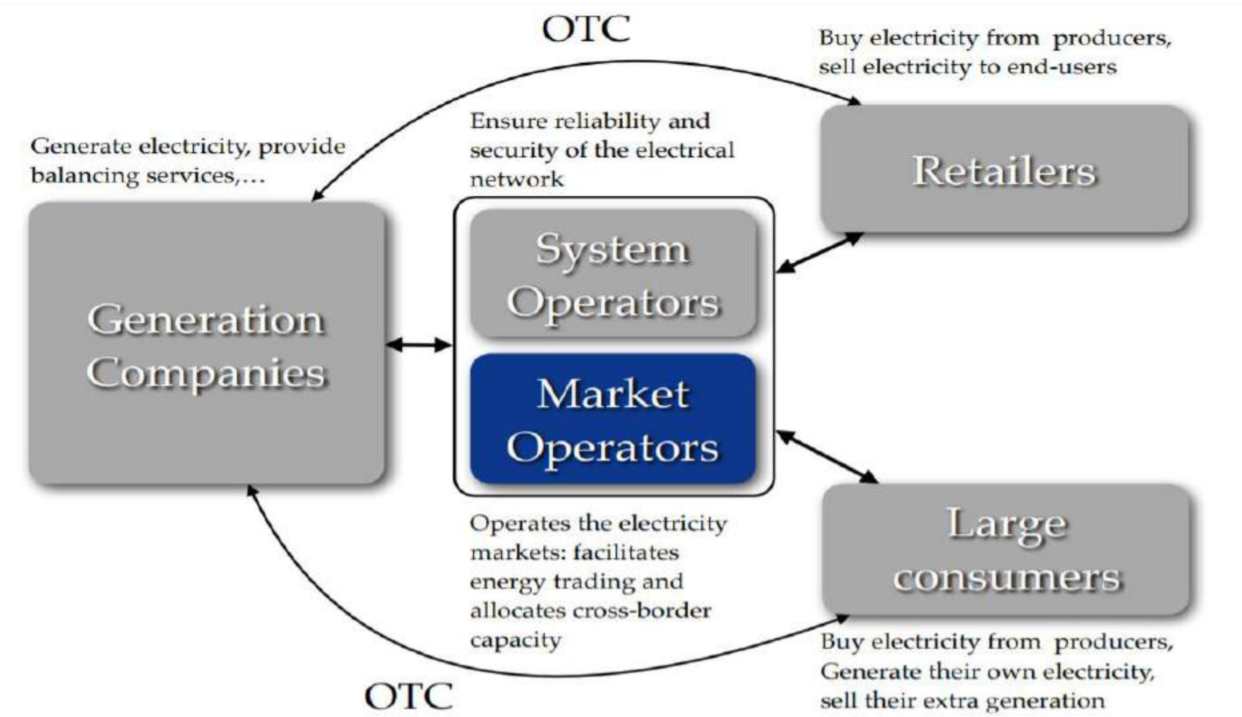
3.10 Production cost savings were examined in the Midwest ISO (MISO) region as the markets transition from a decentralized or less centralized dispatch operations (called as 'Day One') to a centralized market-driven unit commitment and dispatch process (called as 'Day Two')[5]. The analysis suggested 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.

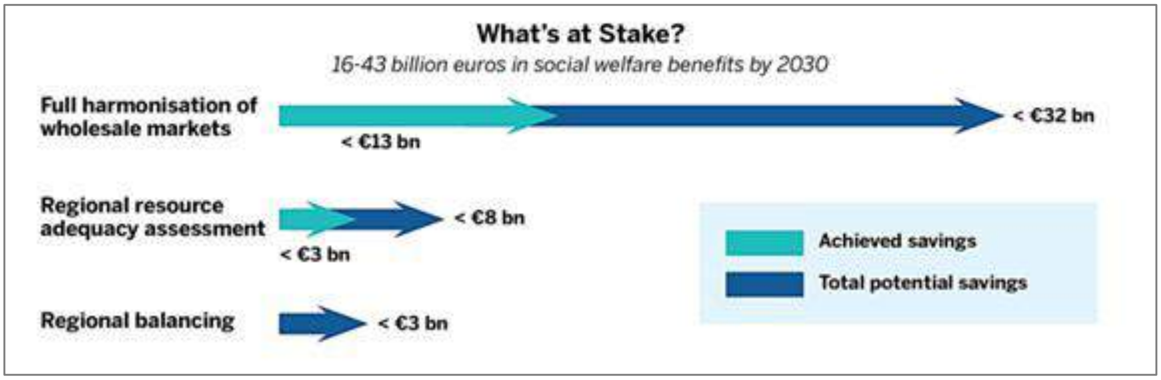
[11] Realizing the benefits of European market integration, *Regulatory Assistance Project,* May 2018

[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.

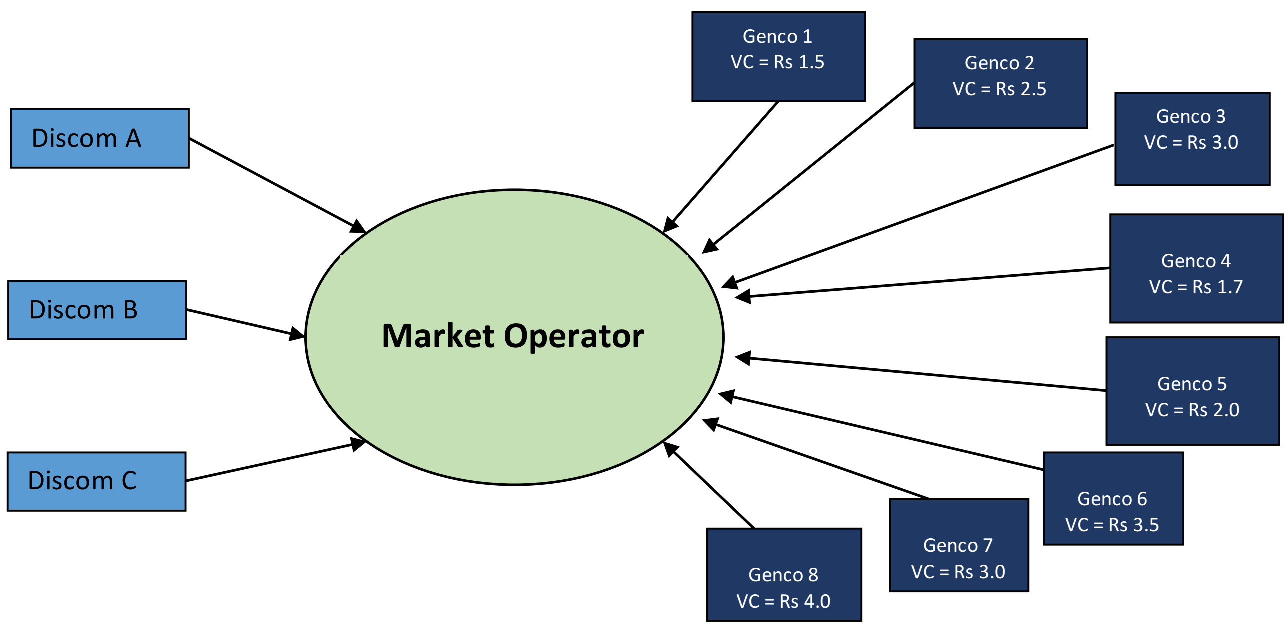
4.3 The MBED model involves primarily the following two aspects, viz., 'Scheduling and Dispatch' and 'Settlement of Contracts', which is being elaborated in the subsequent paragraphs.

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.

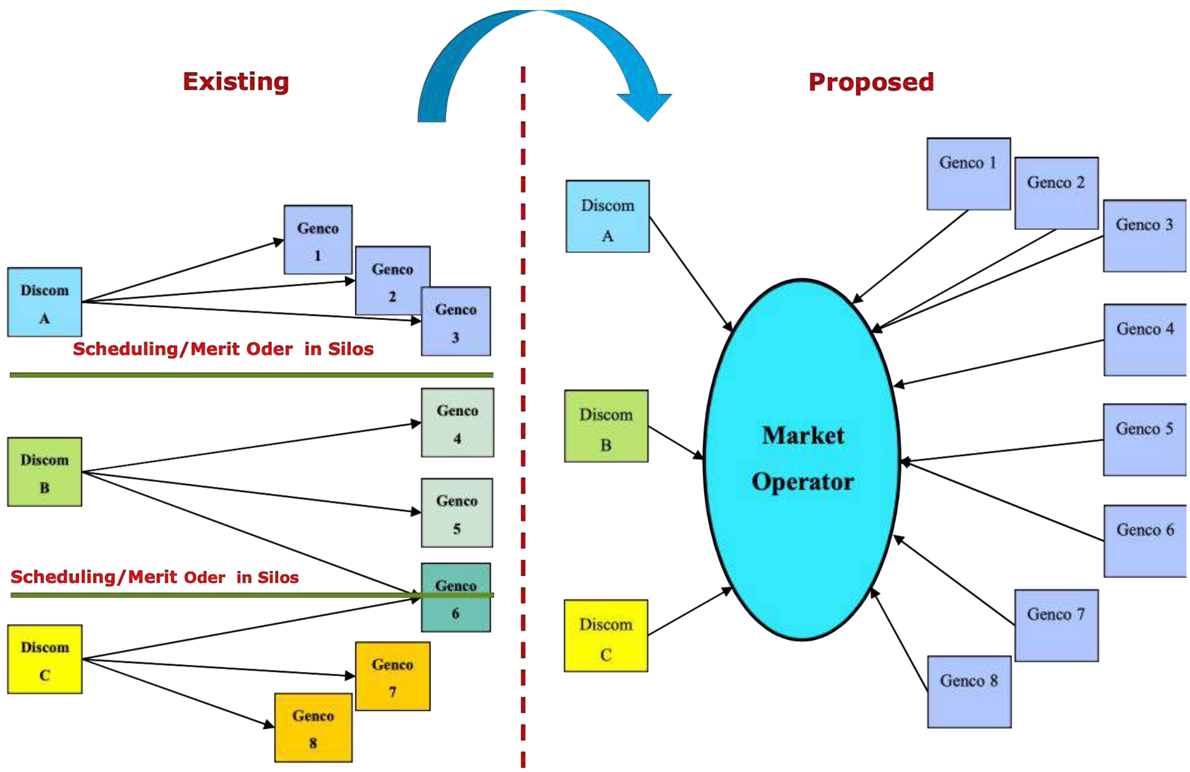
Figure 14. Market Based Economic Dispatch



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

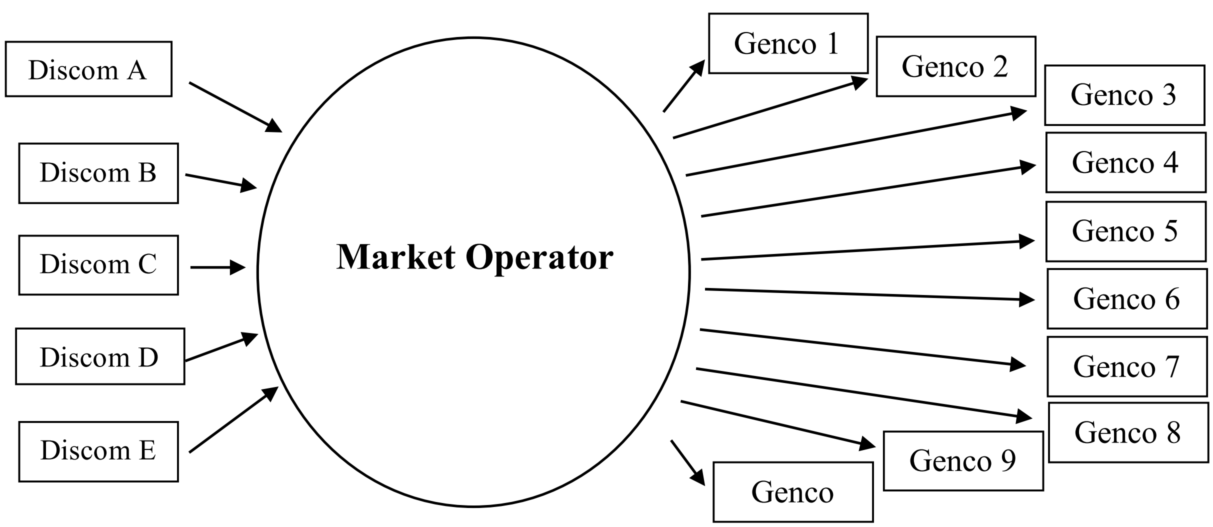


4.6 The generators are expected to bid based on their variable/marginal cost of generation. The existing bilateral contract holders will be paid the fixed cost separately outside the market and as such would also be induced to bid in the market based on their variable/marginal cost of generation. This 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.

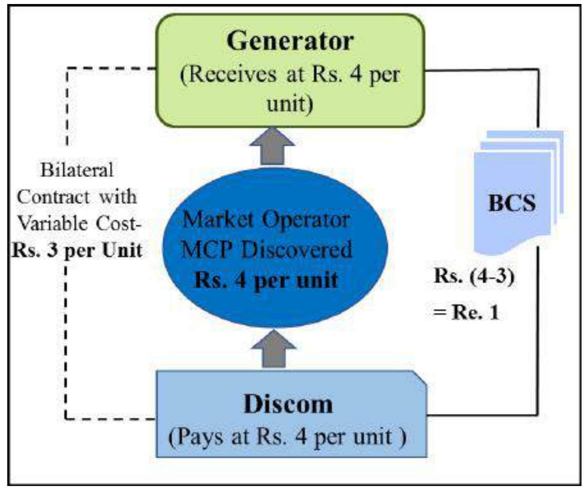
Figure 16. Arrangement for Bilateral Settlement - Simple Case

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.



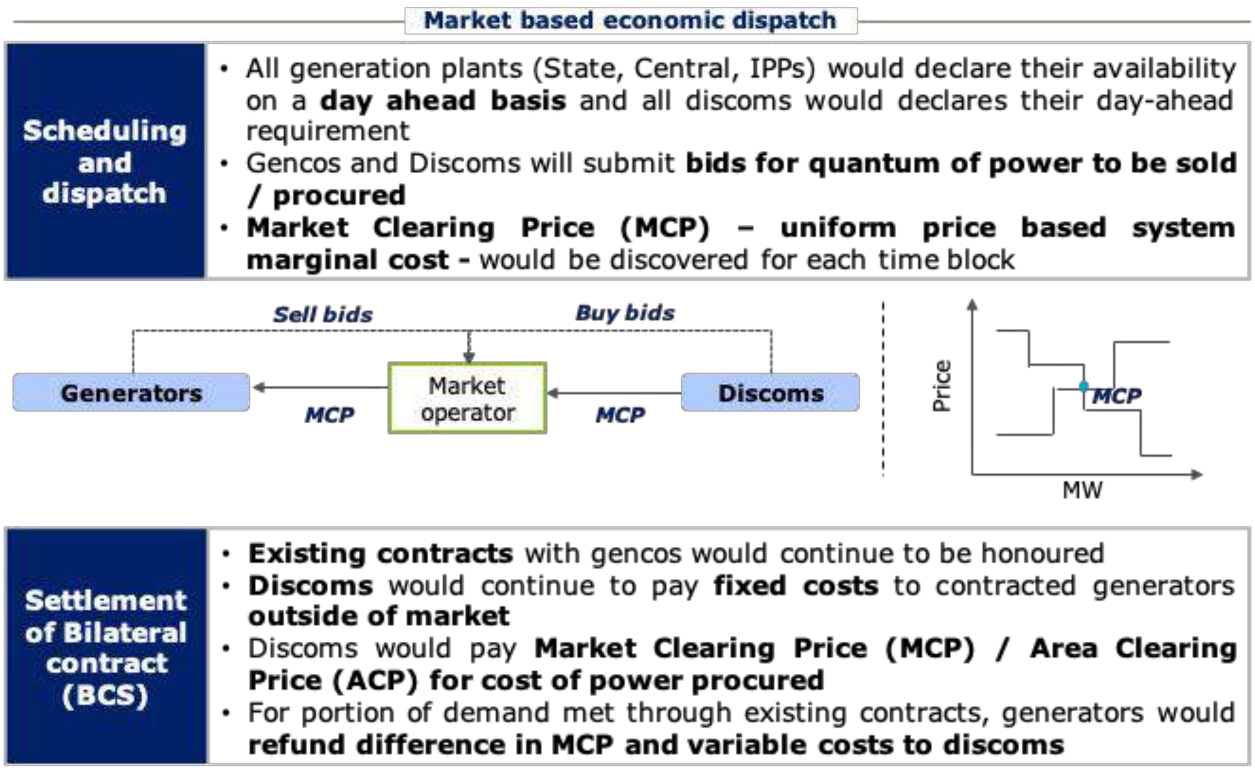
Source : CERC Staff Analysis

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

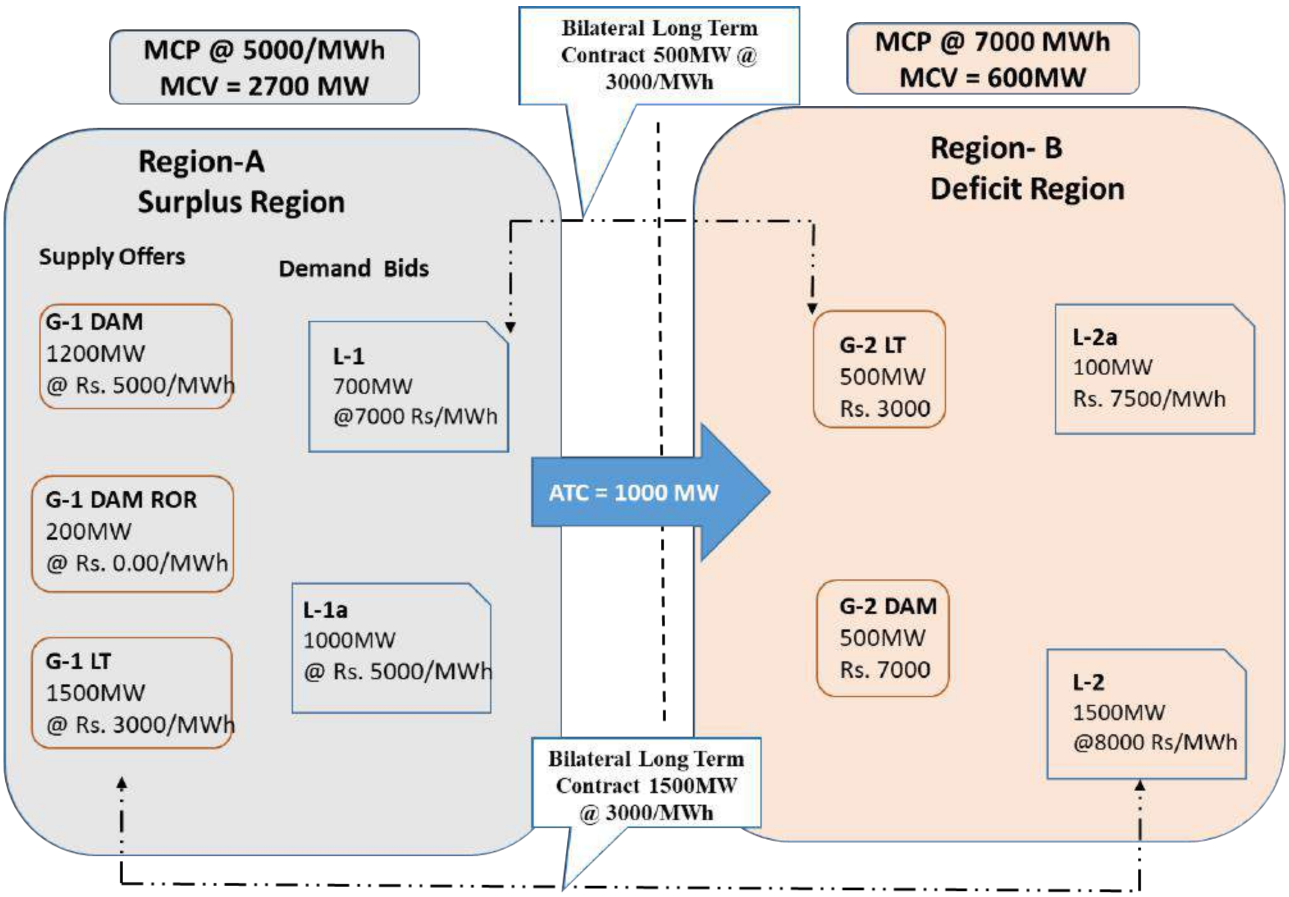
Table 1. Assumptions for Congestion settlement

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.

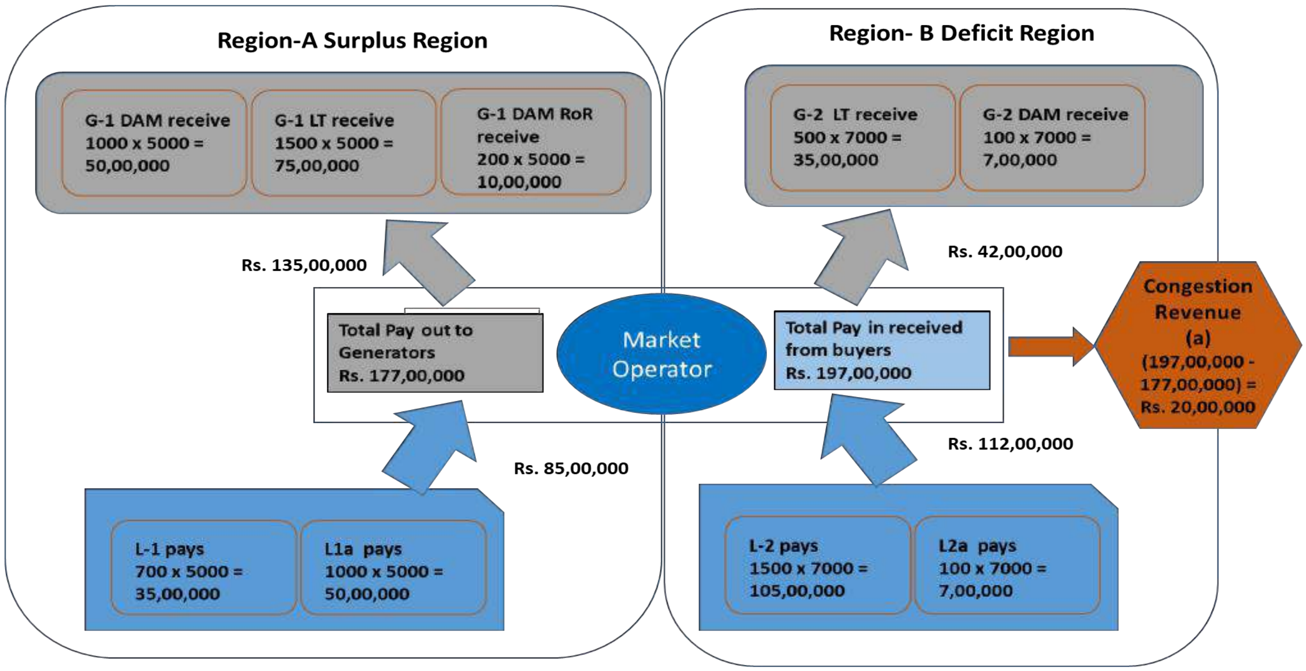
Figure 18. Sample case for settlement under 'Spatial Price Risk'



Source: CERC staff analysis

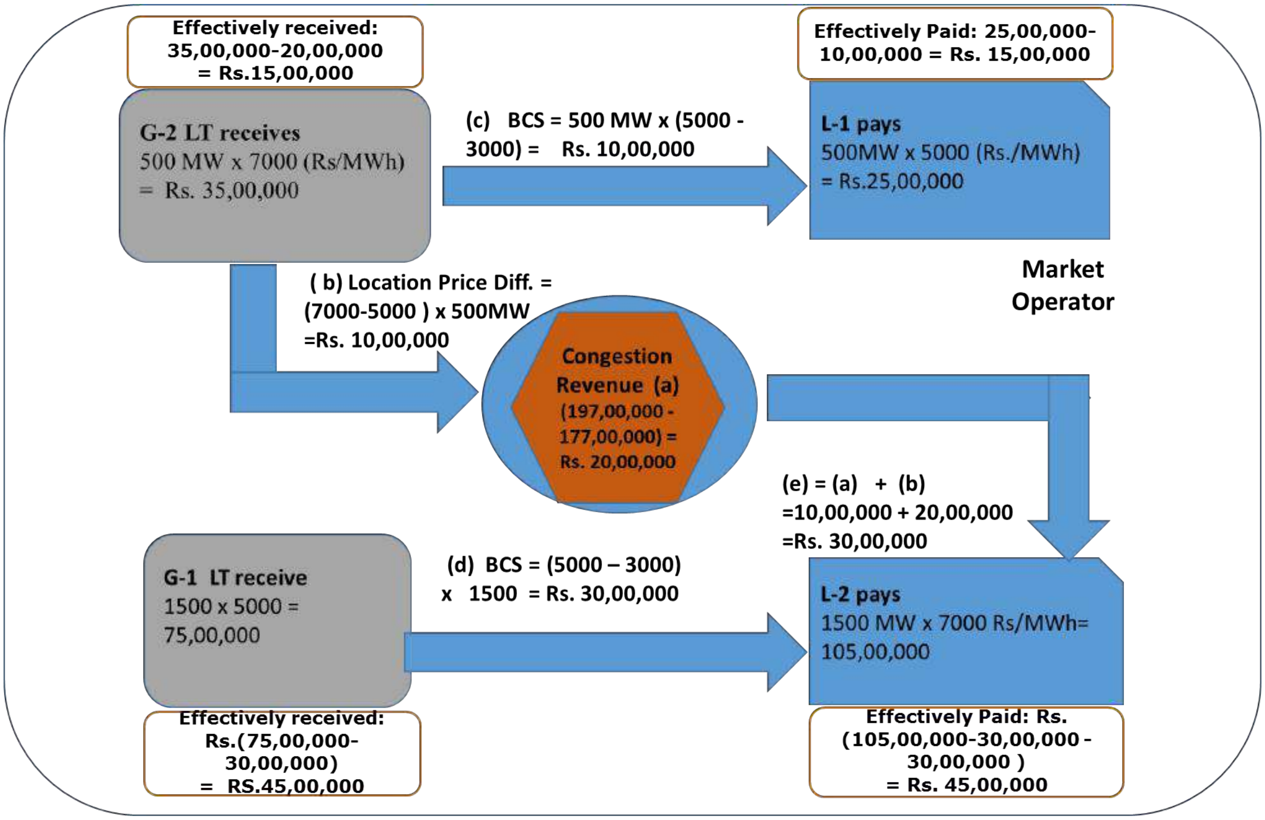
The congestion amount received by the Market Operator would be Rs. 20, 00,000 as shown in Figure 19. The payment settlement for Discoms, L1 and L2 having bilateral contracts of 500 MW and 1500 MW under BCS are explained in Figure 20 and Boxes 2A and 2B.

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)]**	**= Rs. (25,00,000 - 10,00,000)**	**=Rs. 15,00,000**
	which is equal to its obligation to pay under bilateral contract = (a)		
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)]**	**= (35,00,000-10,00,000-10,00,000)**	**=Rs. 15,00,000**
	which is equal to its obligation to receive under bilateral contract = (a)		

	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**