APP Comments on CERC Discussion Paper on Market Based Economic Dispatch of Electricity: Re-designing of Day-ahead Market (DAM) in India

Before coming to the specific comments, we submit that there are many aspects which require more deliberations in the proposed Market Based Economic Dispatch (MBED) mechanism – based on technical, financial and legal issues involved. Hence, we request that the proposed mechanism may not be considered without further deliberations with various stakeholders across the Country to understand the concerns.

You would agree that keeping in view the importance of predictability of regulations – especially when project viability has been appraised on basis of cash flows of 25 years, and then on downstream/ upstream legally binding contracts, having long term financial implications – a move of this nature has to be considered with a 360-degree perspective, with due consideration of all stakeholders and various contractual obligations.

Looking at the stress in the sector, we request the Hon'ble Commission not to move hastily on this subject, without detailed further deliberations with various stakeholders across the Country, to understand the issues and challenges involved.

#	Extracts from Discussion Paper	Views/Observations and Suggestions
1	**Other observations**	It is apparent that the proposed mechanism requires review of existing laws and regulations unless voluntarily agreed by all the states to agree for centralised dispatch and decentralised balancing mechanism.
2	**Para 2.8 (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	In order to have a robust market, the following needs to be ensured: 1. A registry of power generating capacity (all sources of energy) as is being envisaged above 0.5 MW. 2. CERC and a few states have notified the Balancing and Scheduling Code applicable for RE generators. Similar Codes need to be notified for the all states which have installed RE capacities beyond 0.50 MW.

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	to be taken explicit cognizance of while scheduling other conventional sources.	
3	**<u>Para 4.6</u>** 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. *Read with* **<u>Para 7.7</u>** 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 margin19. This allows California	It needs to be ensured that procurers, mainly Discoms, schedule for their full power demand and **not resort to curtailing of demand**. Draft Tariff regulations of Hon'ble CERC have proposed a higher incentive for meeting peak demand. Though the final regulations are yet to be announced, Discoms should not curtail their demands to economize at their ends as they would benefit from the optimization which is the objective of this scheme. Any such curtailment action by Discoms might be detrimental to capacities currently contracted through bilateral/ power exchange and short-term contracts. In this respect, it is relevant here to mention that rules, processes and procedures should be in place to ensure and enforce Resource Adequacy by Discoms as mentioned in Clause 7.7

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	ISO (CAISO) to operate the grid in a more reliable manner.	
4	**Para 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).	What happens to short-term bilateral contracts discovered through DEEP portal? These capacities are likely to be replaced by procurers by the variable/ marginal cost of generation based bids from LT/MT bidders. Moreover, the ST bids (single part) are based on e-auction coal and coal from sources other than LT linkage and are not likely to be as competitive as that of the LT/MT bidders which are based on linkage coal. This will create an undesired disruption in the market for generation capacities which are stranded due to no long term PPA and consequently do not have linkage coal and are recovering costs through the short-term PPA route.
5	**Para 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.	The following points with reference to RE generation needs to be noted: 1. RE generation capacity must continue to be "must run" as per the existing policies and contracts 2. The entire RE generation capacity in the past and most in recent times has been installed for RPO compliance. This fact needs to be honoured in the current mechanism. One way of doing this is to recognize the RE wind and solar tariff as **fixed charge** with the **variable charge** of these capacities being deemed to be **zero**. So, when the RE capacity gets dispatched @ MCP, under BCS, he would refund that to the existing procurer. And the Discoms would continue to pay fixed charges to contracted generators **outside the market** as envisaged in MBED. 3. Alternately, RE capacity for RPO may be kept out of the ambit of MBED, also for the fact that this market mechanism will not help in that direction.
6	**Para 5.19** Provision for self-scheduling: Self-scheduling will continue to operate as in the existing framework for long term	Under the current mechanism, URS mechanism provides that for any URS being traded by the generator, generator is allowed to first recover its variable charges/cost of generation and the balance

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	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, <u>but the net revenue earned by these capacities (URS)</u> by participating in the DAM or RTM shall be shared in the ratio of 50:50.	left after netting off the variable costs and other incidental costs like selling costs are considered for sharing with the respective beneficiaries. In line with the above, it may be explicitly mentioned "net revenue earned after recovery of variable cost of generation and other incidental costs like selling costs".
7	**<u>Para 5.21</u>** <u>After the transition period, the Discoms will still have the right to self-schedule until 9.45 am.</u> 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.	After the transition period, the Discoms will still have the right to self-schedule until 9.45 am - **after transition, self-scheduling by Discoms is supposed to end**. The underlined section contradicts the very basis of the MBED mechanism.
8	**<u>Para 5.26</u>** 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 unrequisitioned 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.	The very idea of dispatch through market even for power under long term contracts is not expected to work at all if the gate closure for long term contracts does not happen on a day ahead basis, else, The whole mechanism becomes discouraging for the generator as on one hand if they sell the URS, they would be required to share the proceeds for such sale and on the other hand, upon recalling such power, generator is required to procure power through real time market. This is contradicting **clause no. 5.19**.
9	**<u>Para 5.5</u>** Congestion Amount will be sufficient to pay out all the bilateral contract holders	The Discussion Paper makes a significant departure from the accepted principle to channelize congestion revenue to remove its cause. In simple

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	if the "bilateral contracted capacities" required to be transferred (by duly considering the direction) across the congested points do not exceed the network capacity.	words, congestion revenue arising from higher market price in the market with restricted supply and lower prices in the market with surplus supply is not supposed to be given to the generators or PPA holders in the surplus region as a profit. It has to be channelized for the purpose of strengthen the transmission system and removing constraints in the flow of power to the deficit area with a view to achieving uniform market clearing price for the whole of India. Even during periods of transmission adequacy, transmission congestion can arise due to power system outages or generation failure but congestion revenue accrued to the Exchange should go to the agency responsible for transmission development. At present the congestion revenue goes to Power System Development Fund. The approach of the Discussion Paper would create a conflict of interest between the buyers upstream of congestion who are benefited from super profit and the buyers in the downstream of congestion who have to pay more during congestion event.
10	**<u>Para 6.3</u>** 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….. 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 <u>50:50 revenue sharing mechanisms</u> from the sale of URS to the market.	The sharing should be 50:50 of **net** revenue after factoring in the variable costs and the associated power sale costs incurred by GENCO to facilitate the URS sale
11	**<u>Para 6.9</u>** 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 Central Electricity Regulatory Commission 51 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-	Under the circumstances, when backing down high cost generators is a big possibility, rights of receiving the Fixed Charges under the present contracts needs to be ensured and enforced through adequate payment security mechanisms which are a part of the contracts but often not adhered to.

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	cost generation. <u>Dispatch optimization through MBED framework increases utilization of low-cost generators while reducing and backing down in certain cases, the expensive generators.</u> 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…	
12	**Para 6.13** Utilization of low-cost stranded assets is another benefit of Market Based economic dispatch.	It has been observed that most of the stranded assets are struggling with the problem of untied capacity and subsequently lack of fuel tie-up and the proposed idea of redesigning Real Time Market does not seem to ease of woes of such generators for two major reasons: • The proposed mechanism does not provide the stressed assets with any comfort of a long term tie up to secure their recovery of fixed assets. • In line with current market mechanism, in the proposed mechanism as well, complete tariff (FC + VC) of such stressed assets with untied capacities would be required to compete with VC of Power plants having PPAs, which implies of either lower dispatch/PLF or under recovery. Hence, the assumption is inappropriate. On the other hand, there is a possibility that it might increase the woes of the sector as the implementation of this mechanism will further discourage the Discoms to tie up LT/MT power with such generators which would bring further uncertainties in the sector and would exacerbate the situation. In fact, Generation Capacities tied under Sec. 62 of the Act are also likely to develop uncertainties in FC recovery as dispatch uncertainties under the proposed mechanism would further make it difficult for such generating stations to plan for coal offtake, O & M maintenance schedule and logistics for operating its station.
13	<u>**Other observations**</u>	As we are aware that currently Generating Stations are facing many challenges as far as the coal supply under existing Coal linkages/FSAs are concerned

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		and the coal supplies are just enough/not sufficient to meet the needs of the Generating Stations. In such a scenario, the generating companies may develop a need of higher coal under existing FSAs or may have to procure coal from other sources. This may be explained with an example. Let's assume that there be a Station 1 with Energy Charge of Rs 1.8/kWh which is contracted with State A and Station 2 with Energy Charge of Rs 1.85/kWh is contracted with State B. So, given a situation that State A offers to take only part offtake from Station 1 leaving some unutilised quantum from Station 1. Accordingly, as per the proposed procedure, Station 1 would be required to increase its generation and Station 2 would get a lower dispatch. In this process, State B would benefit out of reduced Energy Costs as envisaged, but generation from Station 1 is increased due to additional drawl from such Station by State B. In such a case Station 1 may end up consuming its ACQ of coal as per FSA much earlier than the completion of FY and hence may require to procure more expensive coal either by paying higher incentive as per the existing FSA or by procuring coal through some other sources like E -Auction for the balance period of FY. In such a situation, State A (which is actually the Beneficiary of such station) would end up paying higher energy cost for such generation from Station 1 or worse, Station 1 will be pushed down in the MOD stack in the later months. Thus, in the long to medium term, the aggregate outgo from a state for power procurement might remain the same. Hence some re-alignment and modification of fuel tie-up and FSAs will be required to cater to requirements under the MBED scheme.
14	**<u>Other observations</u>**	A market mechanism works best when there are adequate number of buyers and sellers with adequate capacity to sell and buy. There must be a continuous focus on capacity addition from varied generation sources (to build up the capability as alluded to in the staff paper) as well as on capability to pay by the procurers. Otherwise, in a scenario with economic growth and growing per capita power consumption, if adequate signals are not sent out for growth of the power sector, MCPs will increase. This might start the downward spiral of Discoms all over again. Hence along with this, there is an urgent need

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		to focus on growth of generation capacity as well on Discoms' reforms.
15	**Other observations**	The settlement period, mitigation of risks through margin money etc. needs to be finalized to make MBED work both for gencos and procurers.
16	**Other observations**	MBED design may consider to suitably incorporate the guidelines of cross-border trade issued vide notification in December, 2018.
17	**Other Major Issues**	**Must run status for generators** Embedded hydro generators and generators in a constraint environment for grid stability should be identified as must run generators. At least 20% of the schedules should be given to these must run generators based on the technical minimum requirements.
18	**Other Major Issues**	**Generation on concessional coal [coal linkages]** Buyers may include Open Access customers. Power generated on concessional coal which was earlier meant for Discoms may get allocated to these buyers at a huge disadvantage to the Discoms. Discoms' interests may be protected through suitable measures.
20	**Other Major Issues**	**Proper mapping of the transmission capacities** Power exchanges currently conduct collective transactions considering transmission corridor availability on the margins [short term]. Suitable mechanism will have to be put up to map long term transmission rights available with LTA/MTOA holders. **Impact of transmission charges [Delivery Points under bilateral contracts vs. Power Exchange]** MCP discovered at Power Exchanges have Delivery Points as Regional Periphery. Bilateral Contracts may have different Delivery Points thereby having transmission cost impact on power procurement in MBED. Settlement of transmission costs may be made similar to the settlement of fixed costs under bilateral contracts.
21	**Other Major Issues**	Transmission capacity was erstwhile being planned considering the location of the generators and the procurers and the capacity to be transmitted along with the spare capacity keeping future demand in mind. MBED is expected to bring about some

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		changes in power flow with some generators being dispatched more and some generators not being dispatched at all. This might result in congestion in some areas requiring transmission capacity to be augmented. In fact, the premise of transmission planning will have to undergo a change to cater to MBED.
22	**Additional points**	1. As also mentioned above, the proposed mechanism if implemented would worsen the situation of the sector as the Untied capacities looking for recovery of full tariff would be required to compete with variable cost (as bid price) of Central Generators, State Generators and IPPs which are having two-part tariff structure, which will result to low or no schedule under proposed MBED day ahead model. Further, such untied capacities which are dependent on E-Auction route for coal procurement face uncertainties as compared to generators having coal linkages in lieu of long term PPAs. Hence, there is a possibility that a generating station having tied up capacity and operating on a two part tariff structure would replace a single part Short term Bilateral even after having a higher fuel cost. This would replace the short-term bilateral volume due to their relatively higher price (as Single part) currently discovered though DEEP. 2. Huge investments were made in creating generation assets which have been made operational keeping in view of the economics of the state and requirement of power for that state and the procurement of power in such states have been done through tariff based competitive bidding guideline. Now, mapping the low-cost generation asset with the beneficiary state with whom there is no long-term contract, would not be appropriate while optimizing the total cost of the system. In the present context of stressed power sector mainly arising out from Generation side, it is more desirable if a mechanism be evolved to increase the dispatch from stranded and

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		stressed generation rather maximizing the dispatch from low cost generation which in fact would de-stress the generation and create opportunities for sale of power from stranded/stressed generation through short to medium term tenders by DISCOMs. Both the aspects i.e. competitive procurement of Power under long term/Short term/Medium term by DISCOMs and then maximizing the dispatch of low-cost generation by out of way arrangement as under MBED should not be mixed which would though result in total system cost optimization but would however lead further burdening of the stressed generation and would create fresh Non-performing assets. 3. At present, many Captive generators and STU connected generators are being easily scheduled in day ahead Power Exchanges as well as day ahead bilateral market under third party Open Access. Such category of sellers which have been building the short-term market for years would also be impacted. Considering few Central Generators with contracted quantum say 2000 MW having low/lowest variable cost, if participate in proposed MBED, they would likely to be scheduled close to 100%. Same set of generators of 2000 MW is expected to be scheduled sub optimally (say 70% PLF) due to current contract structure and the same is also explained in the paper. The proposed MBED while providing an opportunity for maximum dispatch from such low/lowest cost of generation, close to 100%, the differential up side in schedules (i.e. 30% of 2000 MW i.e. 600 MW) for 2000 MW set of generators would partially replace captive, small and STU connected generators currently forming a major chunk of short-term day ahead market. In view of above, the proposed MBED would discourage and discriminate such captive, small STU connected generators at the cost of reducing system cost and

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		increasing PLF of mainly Central Generators. 4. As market clearing price is discovered for 96-time blocks in a day, under current Day Ahead Market on Exchanges, it may so happen that few hours of bid of sellers do not clear under MBED i.e. sale bid price exceeds the clearing price, such scenario may come up during off peak and night hours. In such a situation, sellers (Long term generators) may have to shut down. 5. Under proposed MBED, chances of market splitting would be higher as price would be discovered by aggregating all sell bids (of Central Generators, State Generators, IPPs & Merchant Generators) and all demand bids (of all DISCOMs and Open Access Customers) i.e. making supply and demand curve for all over India. As generation capacity is relatively dense in ER and WR regions, chances of congestion would occur while export of power from ER/WR to NR. Further, market split would increase the price of deficit region which would lead to increase in overall system price under MBED.