FICCI Representation on

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

Submitted to:

Central Electricity Regulatory Commission

Recommendations on Discussion Paper on "Market Based Economic Dispatch of Electricity: Re-designing of Day-Ahead Market (DAM) in India"

A) A Discussion Paper on "Market Based Economic Dispatch of Electricity: Re-designing of Day-Ahead Market (DAM) in India" was published by Central Electricity Regulatory Commission (CERC) on 31st December 2018 vide notification no. RA-14026(11)/3/2018-CERC. CERC had invited comments/suggestions from the stakeholders on the Discussion Paper due for submission by 15th February 2019.

B) In this regard, based on the feedback received from our members, FICCI's comments/suggestions are the following:

1) FICCI welcomes the proposal in Discussion Paper on Re-designing the Day-ahead Market by upholding market-based economic dispatch. FICCI would opine that in the long run, such measure would be instrumental in deepening short-term markets to enable flexible trade and collective transactions necessary to meet the present-day context of supply imbalances, demand uncertainties and net load variations caused by must-run renewable energy generation. Our specific comments are in the context of operationalising the mechanism proposed:

Serial No.	Para Reference	Observations / Comments / Suggestions
1.	**Para 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).	Market Clearing Price is proposed to be operative via Bilateral Contract Settlement (BCS) when the variable cost as determined u/s 62 of the Act is lower. In the interest of uniform market access, it needs to be clarified how capacities having PPA in terms of Section 63 are to be treated. By plain reading, it would appear that the market mechanism of BCS will act as entry barriers for capacities with PPAs u/s 63. Para 7.3 has also mentioned the need for supplementary PPA entered into by generation capacities u/s 63; it is to be kept in view that the proportion of such Case 1 capacities would significantly rise in future in view of the emphasis on competitive procurement of power laid down in Tariff Policy by Discoms. In the economy's context, power procured by competitive bidding also leads to efficient price discovery.

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	Para 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	Considered view is necessary to examine how the market design can be broad-based to enable all eligible capacities to participate and submit their bids.
2.	**Para 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.	The Discussion Paper makes a significant departure from the accepted principle to channelize congestion revenue to remove its cause. In simple 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 strengthening the transmission system and removing constraints in the flow of power to the deficit area with a view to achieving uniform market clearing price across the country. 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

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		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 with the current practice.
3.	**<u>Para 5.16</u>** 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). **<u>Para 5.17</u>** 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).	Earlier Discussion Papers of CERC relate to Ancillary Market and Real Time Market Designs. We would also agree that a comprehensive and an integrated approach is necessary to create a platform of capacity, energy and Ancillary Services (AS) market operating on day-ahead and intra-day basis under the framework of overall market design. This will lead to co-optimisation of energy and AS markets, as is the intent. In such context of co-optimisation, it will be necessary that the price components corresponding to ramp-up / down constraints, minimum up / down time, Technical Minimum, start-up / shut down costs etc. are indicated separately so that market participants are able to decide upon the physical and technical attributes of capacities to be procured for meeting their specific use cases of capacity, energy and / or balancing requirements. Para 7.4 has stated that market design should be such that the buyer should procure capacities with specific attributes, which can deliver as needed.

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4.	**Para 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 havethe 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. **Para 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 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.	Para 5.19 expressly states that Discom will not have the right to recall the Un-requisitioned Surplus (URS) capacities which the generators will be offering in the day-ahead market. Para 5.26 is conflicting in that, it states that generators having sold their URS will have to buy back from real time market in the event Discoms exercise their right to recall. In our view, Discoms should not have such right to recall since it will be in conflict with the transitional scheme and will constraint market operation and restrict flexibility of trade. Secondly, Discoms relinquishing their un-requisitioned surplus are also a beneficiary of 50% net revenue earned by generators. By the same logic, it should be left to Discoms to buy back power from real time market in the event such requirement arises post their surrender of URS. Such provision would seem equitable since the onus of forecasting and scheduling lies with Discoms. A pre-requisite will be that Discoms following a scientific basis of demand forecast by deploying robust data

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5.	<u>**Para 7.1**</u> <u>**Legal aspects of incorporating BCS**</u> 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.	It is an admitted fact that generation with higher variable cost exceeding MCP would not be dispatched; however, it is to be examined how must-run solar and wind energy plants of vintage period having bilateral contracts of higher single part tariff will be accommodated in the market design. Participation of such capacities is a necessity given the requirement in Para 7.4 that buyers will be procuring capacities with specific attributes at higher levels of renewable energy penetration into the grid. Table 1 and Figure 18 under Para 5.6 have also indicated in the calculations the marginal cost of a run-of-the-river of the plant to be zero, but that may not be the case with renewable energy capacities under bilateral contracts.
6.	<u>**Para 7.2**</u> <u>**Legal aspects of incorporating BCS**</u> 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 …..	We would feel that the Coal Linkage Policy is not harmonious with power sale in short-term market as such provision is not expressly stated; on the contrary, the Policy allows long-term and medium term sales only. In broader context, having an administered arrangement to regulate the fuel supply will be counter productive to power market development aiming to free up capacities to meet demand along with the variations. Liberalising fuel supply and providing options of market procurement via exchange-traded operations as a path forward will enable resident capacities to enter into flexible and shorter duration contracts and serve demand both in the forecastable term and via forward trades.

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7.	**Para 7.3** **Legal aspects of incorporating BCS** 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.	It is to be examined how the universe of Case 1 capacities having PPAs u/s 63 are to be accommodated in the market design; of particular note are those capacities which have entered into short term contacts via DEEP portal with single part tariff and also those capacities having medium term contracts for 3 years with fixed charge of 1 P/U [under the scheme of *Procurement of Aggregated Power of 2500 MW for 3 years (covered under medium term) through PFC Consulting Limited as Nodal Agency*]. In such event, the question of settling the fixed cost under BCS does not arise when the energy is traded through the market. Such cases having also arisen due to the need to relieve stranded capacities, the purpose will not be served when the MCP would be lower than their contracted price.
8.	**Para 7.4** **Contracts in times to come** 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	We concur with the view to establish capacity market going forward. Being a forward looking measure, we would also propose the following viewpoints; a. A goal in the long run will be to set up capacity markets so that energy is available on demand. In the immediate term, a power exchange based market for short term trading in capacity could be initiated, wherein all states / suppliers with surplus capacities during certain months / times of the year could place their capacities on offer. The demand curve for capacity would be based on bids by the states / buyers who need to secure capacity for meeting their short term needs as well as fine-tuning their customer loads. Energy charges for

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	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.	such contracts will be discovered and settled through power exchange (energy markets). b. In the long term, each state / load serving entity / supplier could trade capacities through separate capacity markets on the power exchange platform. As experience is gained basis the above for the next few years, such capacity market is to be assessed and evolved. c. To provide for flexible transactions and real time balancing of supply and demand, the option of trading capacities in the exchange when covered under PPAs / bilateral contracts is also to be examined. Suitable contract design and legal framework will be necessary as an enabling condition. A further measure of introducing market flexibility would be to construct future PPAs as capacity contracts which will be tradable via the exchange as will be the energy aligned with such capacities. d. A capacity market will be seen as well-functioning when it engenders new investments and provides the right signals. The market for ancillary services is still in the nascent stage and conditions are necessary to be created by System Operator so that capacities are bid into such markets. Socialisation of system costs that lead to grid stability is another parameter that is not fully addressed. Central Government will have a stabilising role in channelising investments in hydel, nuclear and battery / storage sources so as to supplement not only capacity markets but also energy and ancillary services markets. These considerations will be necessary while making

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		the blueprint for a new market design. The Paper needs to elicit that the market operations will be encompassing all capacities of different genre including hydel, gas-based and nuclear (which is also must-run). How the balance will be obtained to ensure and optimise economic dispatch under market conditions is to be spelt out in the operating framework. It is to be explicit that a significant share of gas-based and hydel generation will be for meeting peak-loads and balancing requirements, for which price signals are to be generated. A pertinent point to consider is if bilateral contracts entered into by Discoms for meeting their RPO should be operated outside the market.
9.	**Resource adequacy (RA)** **Para 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. 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	It is to be expressly stated that all DISCOMs are required to demonstrate resource adequacies for procuring capacities aligned with their demand, including the peak load and seasonal variations, and accordingly, have the contracts in place. Power exchange shall allow only that part of the demand to be hedged through BCS that has been contracted bilaterally. The balance of demand by the states will continue to be procured in Day Ahead / Real Time Markets. Secondly, enforcement of USO will ensure that Discoms plan ahead and ensure capacity adequacy, instead of resorting to load-curtailment. This forms a basic premise for expansion of customer service and reliability of market signals to the users of the system including generators and customers.

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	needed by the system operator.	
10.	**<u>Price-Coupling, Margin Money and Transaction Charges for Power Exchanges</u>** **<u>Para 7.12</u>** 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 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.	While coupling of exchanges with the intent of increasing the trade volumes and optimising the MCP will be the desired option, it is to be examined if the individual operations of the exchanges offer the required scale of operations to enable the maximisation of trade, flexibility of transactions and efficient price discovery under a new market clearing engine.

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General Comments		
11.		**Transmission planning and access is a pre-requisite** Both intermittency ofrenewable energy generation and demand uncertainties have reduced the dependence onlong term contracts, which lock in transmission capacities and lead to lack of margins for theshort term and day-ahead / intra-day markets. While examining a new market design, whichwill allow dynamic balancing of supply and demand, an alternative approach to transmissionplanning and access would be necessary to provide for flexible corridor allocation andtrading of transmission capacities to avoid over-building of the transmission network. Implementation ofGNA regulations is necessary to help congestion management and economic utilisation ofnetworks, leading to benefits for end consumers.
12.		**Capacity building is a necessity** For efficient sector operations, it is essential to ensure that the players are adequately equipped to deal with the opportunities and the operational aspects of the markets, including real time trading. Especially at the state level, the capacity building initiatives need to be ramped up with the SLDCs and Discoms. Specific provisions should be considered along with corresponding funding and institutional arrangements for capacity building.
13.		**Development of Cross-border Power Exchange** India has significantly liberalised its policy on cross-border trade of electricity in 2018 vide notification "**Guidelines for Import / Export (Cross-border) of Electricity – 2018**" dated December 2018. Since the inception of day-ahead power exchange in India, Power Exchange has been opened up for cross-border trade – a long standing requirement of the neighboring countries. Relevant extract from the guidelines is as follows:

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		5.3.1. Any Indian power trader may, after obtaining approval from the Designated Authority, trade in Indian Power Exchanges on behalf of any Entity of neighboring country, for specified quantum as provided in the Approval and complying with CERC Regulations. The Paper may address how it would allow cross-border entities to participate in the pool based market on the Exchange.
14.		**Rational Transmission Pricing** Current transmission pricing of PoC has the advantage of avoiding pancaking. As PoC mimics real transmission losses and charges, it should be applied on real point of injection for generators. However, when a Discom is trying to sell its excess power purchased from a generator, it has to pay two sets of charges and losses, thereby increasing the cost of such power. By mitigating this anomaly, viability and rational pricing will improve the market liquidity.
15.		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 0.5 MW