Discussion Paper on Market Based Economic Dispatch (MBED)
Development of power market in India and Phase-I implementation of MBED

MoP issued a discussion paper on Market based Economic Dispatch (MBED) on 1st June, 2021. It's Phase-I operation is slated to begin on 1st April, 2022. The discussion paper proposes the redesigning of Day-ahead market (DAM) with the following key objectives:

- Meeting the system load with least-cost and efficient generation plants
- Encouraging efficient generation capacity addition in the future through Uniform pricing framework
- Facilitating increase in VRE integration through larger balancing area and reserve sharing
- Achieving the target towards "**One Nation, One Grid, One frequency, One Price**" framework

Potential advantages of MBED for stake holders:

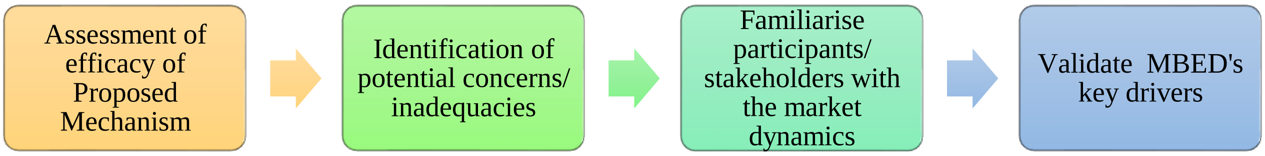
Particulars	Benefits
DISCOMs	- Boosts the utilisation of low-cost generators - DISCOMs would receive a portion of the additional market revenue due to utilisation of low-cost generators. - The overall procurement cost will be reduced
Generators	- Cheaper and more efficient plants will be fully utilized - Reduction in coal transportation costs as pit-head plants will be utilised to its full capacity - Additional Revenues will be provided to generators for selling URS power
Others	- The demand for reserves (Ancillary Services) might be appropriately assessed - Expansion of the balance area from the state to the national level that would result in better RE integration and reduced RE curtailment - Merit-order despatch would be more systematic - System marginal price would be much more transparent.

The key differences between and MBED are follow as:

Parameters	SCED	MBED
Operating mode	Administrated by POSOCO	Market-based
Time frame	Initiated after ISGS's Right to Revision (RTR) of schedule ends and final schedules are prepared	Designed to be deployed after DISCOMs release day-ahead schedules and

		generators provide their capacity to the market
Objective	Assures system cost optimization for the share of demand contracted from ISGS and other associated regulated generators with implementation of optimum generation schedule while considering ramp and technical minimum constraints.	Expensive plants may not get cleared as MBED doesn't ensure unit commitment. Uniform system marginal prices will establish the basis for market-based generation capacity additions in the future.

- **Objectives of phase-1 implementation:**



- **Key changes in procurement of power and scheduling for introduction of MBED framework for NTPC thermal stations:**

	Existing Mechanism	Modified Mechanism
Scheduling mechanism	The DISCOMs schedule the NTPC generators as per their entitlement and reach-out the Power Exchanges (PX's) to meet the remaining electricity demand As DISCOMs are unsure of cheaper alternatives outside the states, hence many low-cost generation capacities are partially or sub-optimally utilized During off-peak times, DISCOMs tend to run expensive generation capacity at its technical minimum, even at the cost of limiting the output of cheaper generation	DISCOMs can still schedule generators themselves, although both DISCOMs and generators must bid in DAM. The amount of power that is self-scheduled would be taken into consideration while settling bilateral contracts The entire demand shall be met by dispatching the least-cost generation mix from NTPC plants while maintaining grid security NTPC stations that are less expensive will be dispatched to the largest extent possible, whereas more expensive will run optimally as per the requirement.

Action by buyers, sellers and PXs	Generator's self-scheduling by DISCOMs results in a sub-optimal Merit Order Despatch (MOD) for scheduling and dispatch. In this mechanism, the true marginal cost would never get discovered.	Generators must bid in DAM based on their own , with no changes for fuel and other charge in the future. A national MOD will be formed and subsequently dispatch all generators The market clearing engine of PX's will schedule the generating units based on optimal dispatch principles, once the bids and offers are submitted
Schedule revision	Generators and DISCOMs can revise their schedules before 7/8-time blocks without any financial liability	Till the results of the DAM are disclosed, there will be no RTR for the NTPC plants Beneficiaries can also take part in the RTM and fine tune their day-ahead positions properly
Payment and settlement	DISCOMs pay the variable charges to scheduled generators based on the quantum of energy scheduled. URS power can be used by a DISCOM that is not the original beneficiary of the generators, after exhausting their contracted power in such ISGSs. Such beneficiaries would bear the fixed cost liability for URS scheduled instead of the original beneficiaries.	DISCOMs/buyers will pay the market operator at MCP for the day-ahead demand. Generators will be paid at the MCP based on the execution of their selected bids. Under LT agreements, buyers will be refunded the difference between MCP and the contracted price based on the quantum of power self-scheduled via Bilateral Contract Settlement (BCS). The net revenue earned by NTPC generators from URS will be shared equally with the concerned beneficiaries subject to a ceiling of ₹7paise/unit.
	NTPC generators with long-term PPA are paid for the fixed cost separately outside the market	

- **Working capital management for Stakeholders:**

Stakeholder	Benefits
Generators	Ensures payment as per the rules of PXs
DISCOMs	Provides necessary support with the time frame (within 45-60 days from the date of disbursement) to repay back the amount to designated agencies.
Exchange	Addresses counterparty risk of exchanges
Sponsoring Agencies	Agencies like PFC/REC provides room to increase their loanable quota and revenues from power market

- **Need for Price Coupling:**
  In order to achieve better system efficiency, there is a need to combine bids and offers from multiple PXs as already regulated by CERC. It leads to following impacts:
  - Discovery of uniform ACP
  - Reducing constraints and fulfil higher social welfare

  Key Issue:
  - Both entities get cleared at different Clearing prices leading to disparity in BCS settlement

  Suggested Measure:
  - Based on the mutual choice of corresponding buyers and sellers, they need to submit their bids and offers on particular PXs. This ensures same clearing price and liquidity to both the parties.
- **Additional relief for upfront payments by DISCOMs:**
  - According to the current mechanism, DISCOMs receive 1.5% rebate if they pay the GENCOs within 5 days of the invoice date, and 1% rebate if they pay within 30 days of the billing date.

  Suggested Measures:
  - Because DISCOMs would be paying upfront for the cost of power procurement under MBED, they would need to be rewarded with total 2% rebate for making an advance payment.

- **Treatment of BCS:**
  - The final settlement between generators and DISCOMs would be resolved through BCS.
  - MoP would set up a committee on "Efficient Regulation of Electricity Derivatives" to mitigate the jurisdictional conflict between SEBI and CERC to examine the technical, operational and legal framework for electricity derivatives.

- **Relaxation/reduction of transaction charges levied by PXs:**
  The adoption of MBED would lead to the significant increase in electricity volume, thereby increasing the transaction fees charged[1] by PXs. This would eventually impose additional burden on DISCOMs

The draft discussion paper can be accessed here

[1] The current transaction charges levied by Indian Power exchanges is substantially higher than their European counterparts

EAL Opinion

1. **Relevance of MBED:** Experience with short-term power market development provides a test case for the maturity of the sector to adopt such a change, and the preparedness of most of the stakeholders to participate in the same. However, the experience varies across states in terms of the avenues for optimisation and the ability of the available practices and tools to do so.

   It is also important to mention that the current market design provides for voluntary participation. MBED is a departure from the same as it entails broader participation across the distribution utilities.

   Competition for fixed charges (through capacity market)
   Competition on variable charges (VC) through MBED.

2. **SCED Vs MBED:** Security Constrained Economic Despatch (SCED) optimises power procurement from eligible ISGSs. **MBED, if implemented only for the eligible NTPC generators (as proposed), the gains (in terms of optimised cost of power procurement) would be limited and may be of similar order as in the case of SCED.** Without participation of intra-state generators, true gains of MBED would not be realised.

3. **Gate Closure and Right to Recall:** MBED, implemented on a day ahead basis would require the utilities to forego 'right to recall'. Post submission of the bids to MBED (i.e., at gate closure), the generators as well as the DISCOMs commit themselves to sell/buy the cleared quantity. **This loss of flexibility (associated with 'right to recall') to the distribution utilities is of value on account of the uncertainty associated with demand as well as RE generation forecast.**

   Under MBED, DISCOMs can rebalance their portfolio in the Real Time Market (RTM). Depending on the market conditions and the need to buy/sell, the DISCOMs would have to bear the additional burden due to rebalancing of their portfolio.

4. **Long-term impact on Investment and Need for Capacity Market:** MBED is designed as an energy market, wherein existing beneficiaries of the PPAs continue to pay the associated capacity charges. The market participants, procuring energy through the MBED platform, only bear the market clearing price associated with such capacities. This does not provide an incentive for signing long-term PPAs tied up to payment of such fixed (capacity) charges.

   To ensure that adequate investment is undertaken to maintain resource adequacy in the system, **MBED should be supplemented with a capacity market**. Design of such a capacity market would need to take into account a reasonable estimate of resource adequacy that needs to be tied up with the existing consumer base of the load serving entities, as well as other entities (for e.g., large consumers) who would be eligible to directly participate in the MBED in the near future.

5. **Generator's Bid and variable charges and flexibility thereof: The generators, whose tariff is regulated u/s 62 of the Electricity Act 2003 should bid at their variable charge.** Given the adopted price discovery mechanism, i.e. the uniform market price, the marginal generator would dictate the market clearing price in MBED to ensure efficient price discovery in MBED, wherein the generators should be close to their marginal cost, the generators with regulated tariff should therefore bid at their variable charge or below[2]. This will ensure that a higher bid by such marginal plants do not dictate the market clearing price, and hence increase the overall burden for distribution utilities, and hence the end consumers.

6. **'Margin' on Sale of Un-Requisitioned Surplus (URS)** Any benefit arising out of sale of URS above their variable charge is proposed to be shared between the two entities in a 50:50 ratio with a limit of 7p/kWh for the generators.
   In the absence of any demand, commercial or payment risk, the suggested ceiling of 7p/kWh on the sale of URS power is significantly high. On the contrary, the demand risk associated due to 'right to recall' till the SCED gate closure, available at present, will also be negated by MBED. Now the MBED 'schedule' would have greater certainty for the generators. It is also important to note that there is no commercial risk to be borne by the generators as the associated fixed charges (as per the existing regulatory framework) would be paid by the respective beneficiary. The 'margin' on sale of URS power is an additional income for which no additional risk is involved. Furthermore, the payment risk associated with sale of this power is nil as all the URS power sold through a MBED market platform, which would have an inbuilt payment security mechanism requiring advance payment/margin money. (Section 2)

   The 'margin' for sale of URS by generators (under MBED) cannot at all be compared with the 'trading margin' limit of 7 paise/kWh for the licensed traders, who are exposed to comparatively much higher risk. It is also worth noting that the 'actual' trading margin is generally less than 7 paise/kWh. The trading licensees are allowed to charge trading margin up to 7 paise/kWh[3]. Against this, the actual weighted average trading

[2] On account of constraints due to ramping, technical minimum operation, minimum runtime, and to reduce the impact of art load compensation charges (as applicable under the fourth Amendment to the IEGC, 2016), such generators should have the flexibility to even with below their regulated variable charges.

[3] As per the CERC (Procedure, Terms and Conditions for grant of trading licence and other related matters) Regulations 2020. https://cercind.gov.in/2019/regulation/154.pdf

margin charged by the trading licensees during 2019-20 was only 3.1 paise /kWh[4]. The trading margin recorded during Jan-Mar 2021 was 2.1-2.5 paise/kWh. **It is clear that the proposed 'margin' limit of 7** paise**/kWh on sale of URS under MBED is very high, and should be appropriately revised. This should be limited only to compensate the generators against the 'additional risks' over and above the prevailing tariff and, scheduling and despatch framework.**

7. **Optimal operation of generation assets:** MBED, in its current proposed form, provides an opportunity to optimise cost of power procurement for the buyers but does not provide a similar opportunity to the generators. Post-MBED market clearing, opportunities on account of cumulative supply obligation (e.g., due to participation in RTM) and certain (eligible) technical constraints may present an opportunity for the generation companies to operationally optimise generation across co-located units, and even other generation assets subject to transmission availability[5]. Any gains arising out of such operational optimisation should be shared amongst the generators and the beneficiaries with proportionately larger share of gains for the generators.

8. **Price Coupling of Multiple Power Exchanges:** The regulatory framework for power market development in the country provides for multiple power exchanges. The contracts traded on the power exchanges are open for voluntary participation. In contrast, MBED mandates participation for the identified buyers and sellers.

   In this context, operation of multiple power exchanges for a 'theoretically' unified market platform would present a few economic challenges. Price coupling of multiple power exchanges may seem to be a plausible solution, but may present relative disadvantage to the incumbent and dominant power exchange (PXs), who may have a larger clientele base. It is important to highlight that price coupling is being suggested for a 'new market' segment rather than an existing one[6]. The proposed alternate solution wherein 'corresponding buyers and sellers choose to participate in **a** (emphasis added) power exchange' would dimmish the very basis of MBED as differentiated bids would now have limited opportunity to compete with each other. Further, this would also skew the economics of URS power that would be sold through the PXs.

[4] CERC's Report on Short-term Power Market in India: 2019-20 https://cercind.gov.in/2020/market_monitoring/Annual%20Report%202019-20.pdf
[5] This would require necessary regulatory oversight to address any gaming especially in the view of transmission constraint.
[6] One can also visualise that MBED, once implemented in totality, may obfuscate or significantly reduce the relevance of DAM.

It is suggested that a modified form of 'bid allocation' mechanism be adopted wherein instead of horizontal segregation of pair of buy-sell bids, it may be segregated vertically to allow competing bids to appear on all the PXs. This, being a sub-optimal solution, may need to be revisited with an assessment of the market outcome within 4-6 months.

Table 1: 'Choice' of PX Platform for buy-sell contract pairs (MBED Proposal)

		PX 1	PX 2	PX 3
G1-D1	100	100		
G2-D2	200		200	
G3-D3	60			60

Table 2: 'Sharing' of buy-sell contract pairs across PXs (Suggested Alternative)

		PX 1	PX 2	PX 3
G1-D1	100	40	40	20
G2-D2	200	100	40	60
G3-D3	60	20	20	20

Note: The pair of buyer-sellers should ensure that same quantity of buy as well as sell bids are placed on the respective PX.

The basis of 'allocating' share of buy-sell pair of contracts may be decided by the corresponding parties. However, it would be beneficial for the sector if the stakeholders are able to evolve a fair and dynamic basis for such allocation while ensuring that economic efficiency as well as oversight over market power is not compromised.

9. **Need for a Comprehensive Market Monitoring Framework:** The Electricity Act 2003 empowers the CERC to monitor power market and ensure that unwarranted market behaviour does lead to an economically adverse outcome for the market. The existing framework for 'market monitoring' needs to be enhanced to enable CERC to effectively monitor market behaviour of buyers/sellers on alternate contracts across the market platforms.

10. **MoD Vs MBED - Impact of Transmission Charges and Transmission Losses:** Merit order despatch (MoD) principle adopted by the respective distribution utility takes into account, amongst other factors, the associated transmission charges and transmission losses. In contrast, price discovery in MBED would not take into account the associated transmission charges and transmission losses. MBED, in general, would enhance schedule of pit=head based generators at the cost of those near the load centres. This would have a resultant impact on utilisation of transmission assets, and also place

greater demand for transmission investment to support additional flow of power from pit-head stations to load centres. The resultant cost of the cheaper power to a beneficiary state may either reduce the overall benefits of MBED. **An interim analysis of the MBED considering the overall incident of all charges should be undertaken to identify the scale of impact of such clearing mechanism.**

It will also be useful to clarify, if the simulation presented in the discussion paper took into account the transmission charges and transmission losses.

11. **Treatment of part load compensation and incentives/penalty:** In case of generator, which was not earlier scheduled and was rather placed under reserve shutdown by the respective beneficiary, gets a part load schedule under the MBED, the burden of part load compensation would be due on the original beneficiary of the PPA. The following specific charges/incentive/penalty applicable under the prevailing regulatory framework for tariff,

- Compensation Part load operation
- Incentive structure for higher availability during the peak/off-peak hours[7]
- Incentive/penalty for demonstrating/failure to demonstrate ramping capability of the generating plants[8]

Some of the generating plants, particularly those with low variable cost, would see a reduction in part-load compensation as their schedule would increase.

These issues may present a legal as well as a regulatory challenge if the distributional impact of such cost components places significant impact on the buyers. These regulatory issues can be addressed if the incentive/penalty framework is integrated with the market (and some may need to be discontinued) rather than the same being implemented through individual regulations.

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[7] See previous comments on the incentive structure,
Singh, A. Regulatory Insights, Volume 3, Issue 4, April 2021, Centre for Energy Regulation (CER), IIT Kanpur. https://cer.iitk.ac.in/newsletters/regulatory_insights/Volume01_Issue04.pdf

CERC's Terms and Condition of Tariff Regulation, 2019 https://cercind.gov.in/2019/regulation/Tariff%20Regulations-2019.pdf

[8] See previous comments on the proposed structure of incentive/penalty,
Singh, A. Power Chronicle, Volume 3, Issue 4, April 2021, Newsletter of Energy Analytics Lab, IIT Kanpur. https://eal.iitk.ac.in/assets/docs/Power_Chronicle_Vol_03_Issue_04.pdf

POSOCO "Detailed Guidelines for Assessment of Ramping Capability" of Inter State Generating Stations (ISGS)" 2020. https://posoco.in/wp-content/uploads/2020/01/Ramp_Assessment_detailedguidelines_6Jan2020.pdf