Kashish Shah, Research Analyst
September 2021

Institute for Energy Economics and Financial Analysis
IEEFA.org

Finessing India's Power Market Design to be More Competitive

MBED and FCAS Markets to Unlock New Opportunities

Introduction

The Government of India's plan to commission 450 gigawatts (GW) of renewable energy capacity by 2030 has set the country's power market on a transitionary path. Ultra-low-cost renewables have already been extremely disruptive for the Indian power market. Whilst the expensive and emission-intensive coal-fired power generation assets have been affected most by the disruption, some has also trickled down to India's power distribution sector.

India's state-owned power distribution companies (discoms) are now confronted with the challenge of adhering to contractual obligations of legacy coal-fired power purchase agreements (PPAs) while there is an availability of solar and wind power in the market at 40%-50% cheaper tariffs than that of coal-fired power.

The response to this challenge by the discoms has been regressive to a large extent in our view. Discoms have cancelled auctions that resulted in already low-cost renewables to strike deals at even lower prices. In some cases, PPAs have been cancelled or forced to be negotiated to bring tariffs lower than the signed PPAs. This has significantly derailed India's near-term target of 175GW of renewable energy capacity by FY2021/22; the renewables capacity stood at about 100GW as of July 2021.

India's state-owned power distribution sector has been a troubled segment of India's power sector value chain for more than a decade now. The key reasons behind discoms' ailing financial health have included high technical and commercial losses; high power procurement costs; state-imposed cross-subsidy burdens on tariffs; and other operational inefficiencies. Identifying all of these weaknesses in discoms' operational and financial structure in our report '*The Curious Case of India's Discoms*' from August 2020,[1] IEEFA had recommended a national pooling of

MBED aims to reduce power procurement costs by Rs12,000 crore (US$1.6bn) annually.

[1] IEEFA. The Curious Case of India's Discoms. August 2020.

electricity market resources for optimising India's power generation resources.

The Ministry of Power's recent proposal of a market-based economic dispatch (MBED) mechanism for procuring bulk power to begin in April 2022 aims to optimise the country's power generation resources. By moving away from just state-level pooling of resources and dispatching power through a central clearing mechanism, MBED aims to reduce power procurement costs by Rs12,000 crore (US$1.6bn) annually.[2]

In our view, the MBED model is a welcome move. We discuss its benefits and potential implementation roadblocks in this note.

In another progressive market development, India's Central Electricity Regulatory Commission (CERC) has come up with regulations for Frequency Control Ancillary Services (FCAS). These regulations broadly aim to provide mechanisms for procurement, through administered as well as market-based mechanisms, deployment and payment of ancillary services for maintaining the grid frequency close to 50 Hertz (Hz). It also provides regulation for restoring the grid frequency within the allowable band as specified in the Grid Code. It aims to regulate services that help relieve congestion in the transmission network, ensuring smooth operation of the power system, safety and security of the grid.

Penetration of large-scale variable renewable energy capacity into India's grid would require addressing grid stability and security-related concerns. The grid would be weaker in new and untapped zones as India's power transmission network is gradually expanding to access the renewable energy-rich zones.

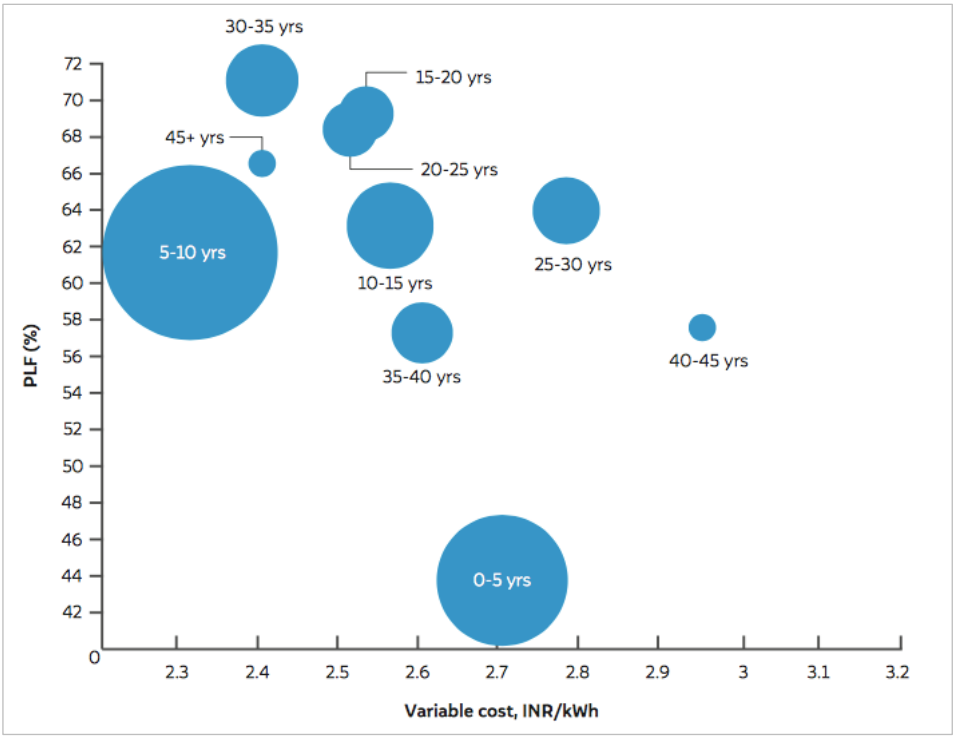
We aim to discuss these two new market design-related developments and their effects on India's power market transition.

Market Based Economic Dispatch Model

A recent study from the Council for Energy Environment and Water (CEEW) found that the newer coal-fired power plants (commissioned between five and 10 years ago), had lower plant load factors (PLF) in the 30 months leading up to the Covid-19 pandemic in India, despite having lower variable costs than some of the oldest coal-fired power plants (between 20 and 35 years old).[3] Similarly, plants younger than five years old operated at plant load that was 20% lower, despite having a lower variable cost than some of the oldest plants. (See Figure 1.)

[2] Ministry of Power. Discussion Paper on Market Based Economic Dispatch (MBED). May 2021.
[3] CEEW. Coal Power's Trilemma. July 2021.

Figure 1: Coal Power Plants Age, PLFs, Variable Costs



Source: CEEW. Note: The bubble size represents the capacity share of each age group.

CEEW notes that the underutilisation of newer coal power plants can be explained by the fact that plants that are contracted (either entirely or partially) are dispatched only to the extent they are contracted. The uncontracted capacity either is typically treated as merchant power and sold on the exchange or through other open market mechanisms. The open market transactions contribute about 10% of the total procurement of electricity in the country.

Discoms need to pay fixed charges to thermal plants for the capacity contracted, regardless of the amount of power drawn from the plant.

One of the key reasons of such inefficiency could be attributed to some extent to the two-part tariff structure of thermal power plants—fixed charges that comprise the capital and operational costs of the plant, and variable charges that mainly include fuel costs.

Discoms need to pay fixed charges to thermal plants for the capacity contracted, regardless of the amount of power drawn from the plant. The variable charges are only paid for the quantity of power drawn from the plant. Once the discoms have

committed the sunk cost of the fixed charges, then it is about choosing the lowest variable cost for drawing power. So even renewable energy sources with zero fixed charges but slightly higher variable charges would be more expensive than contracted coal-fired plants.

This is illustrative of the inefficient market design of the state-level (decentralised) mode of power procurement in the country.

Discoms in India currently schedule generation on a day-ahead basis from amongst their portfolio of contracted generators. Self-scheduling has proven to be a sub-optimal outcome for the power system in the country, with relatively higher costs being borne by ratepayers (discoms) and eventually consumers. In some instances, it is also noted that the states have violated their own merit dispatch orders.

Self-scheduling restricts the discoms to share the generation resources across the country. This also leads to technical constraints on the amount of variable renewable energy (VRE) that a state can deploy within its boundaries. A centralised market-based scheduling and dispatch will ensure enlarging of the balancing area from the state boundaries to regional or national boundaries, bringing the desired flexibility for reliably deploying much higher levels of VRE.

Proposed Mechanism of MBED

The MBED will function on a day-ahead scheduling of all generation on economic merit basis, subject to plant and network constraints.

Pooling of sell and buy bids—Seller (generator) and buyer (discom) would submit their bids one day in advance; the sell and buy offers based on quantum ad prices will be pooled.

Price discovery, scheduling and dispatch—Based on the sell and buy offers, a national merit order stack would be prepared. A Market Clearing Price (MCP) would be discovered as per the merit order for 15-minute time blocks (96 blocks per day) for the delivery day.

Payments and settlement—The payment settlement in MBED will partially move to the power exchange while adhering to contracted tariffs of the PPAs.

Cleared buyers would pay the MCP to the power exchange, which would in turn pay the MCP to the cleared sellers. Final settlements would be as per contract for the portion of demand cleared in relation to contracted megawatts (MW). The buyers would still continue to pay the fixed costs outside the market. If there are gains realised due to sale of surplus power over the scheduled quantum, the gains would be shared between the beneficiaries, as stipulated by CERC.

Financial Implications of MBED

As the market becomes more competitive, cheaper plants will get dispatched first, raising the stranded asset risk on expensive thermal power plants.

As the settlements move to the open market, discoms initially will require financial support for the increased cash flow requirements. Gradually, the efficiency and the competitiveness in this mechanism would ensure lower power purchase costs and result in an improvement in discoms' financial position by moderating their liquidity requirements.

We believe that the MBED mechanism will be highly beneficial for renewable energy assets by reducing payment delays and adding more protection to contracts. This will improve the bankability of renewable energy PPAs and potentially lower the cost of capital, reducing the cost of renewable energy.

The MBED mechanism will be highly beneficial for renewable energy assets by reducing payment delays and adding more protection to contracts.

Gross Bidding – An Alternative Mechanism

The Indian Energy Exchange (IEX) has suggested an alternative mechanism of gross bidding to overcome the regulatory and structural changes required to implement the MBED model.[4]

The note provides an excellent explanation of the gross bidding mechanism that is already being used in Nordpool (European power exchange owned by Euronext and the continental Nordic and Baltic transmission system operators) and Japan Electric Power Exchange (JEPX).

Under the gross bidding mechanism, both the generator and the discom that have a long-term power purchase agreement (PPA) will participate in the market and schedule their transactions through the day-ahead market. The discom will place both buy as well as sell bids simultaneously for the contracted capacity in the market under a gross bidding portfolio (different from the mechanism proposed in CERC's discussion paper, in which the discom only bids for buying power). It will place the sell bids at the agreed-upon variable charges (energy charges) in the PPA and buy bids as price-inelastic bids in the day-ahead market.

To understand this mechanism, we need to also consider the spot market to operate the way it is operating right now, where the generators put in sell bids. The discom

[4] Power Line. Gross Bidding. June 2021.

has the option to choose between the tariffs (energy charges) from the open market or its own contracted generator.

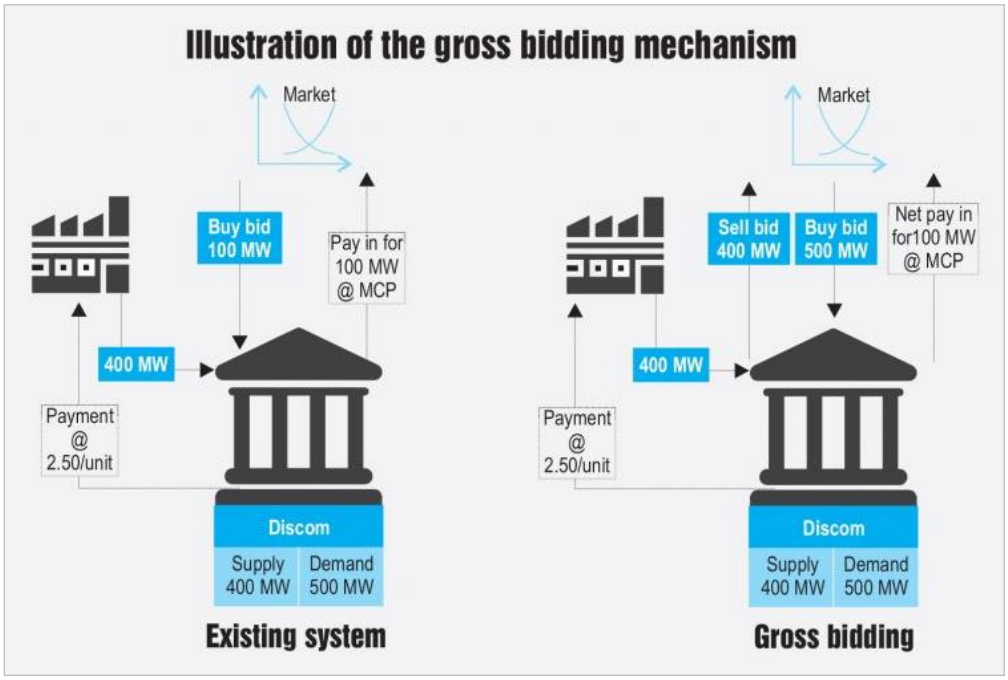
We reference the example provided by IEX to explain the gross bidding mechanism:

Assume that a discom has a demand of 500MW, has entered into a PPA with a generator, and contracted a capacity of 400MW at energy charges of Rs2.50 per kilowatt-hour (kWh). As per the existing practice, the discom will self-schedule 400MW of capacity under the PPA and will look to buy the additional 100MW capacity from the open market. In the proposed gross bidding mechanism, the discom will place sell bids of 400MW at Rs2.50/kWh in the market and buy bids of 500MW.

The discom would ideally choose to buy the 400MW at a price equal or lower than its contracted tariff of Rs2.50/kWh and the remaining 100MW at the best price available in the open market. Similar to the MBED practice, the settlement of capacity charges for thermal generators will happen on a bilateral basis between the discoms and the generators.

Depending on the demand and supply scenario, the sell bids of 400MW will get cleared and the generator will be despatched. (See Figure 2.)

Figure 2: Gross Bidding Mechanism



Source: IEX.

Based on the demand and supply situation in the spot market, three different scenarios may emerge:

- **Market clearing price (MCP) < energy charge:** In this scenario, sell bids will

be rejected, since power will be available at a cheaper price at the exchange. Discoms will buy the entire 500MW from the market at a price lower than the contracted energy charges. As the sell bid will not get cleared and the generator will not get despatched, the discom will not pay any energy charges to the generator. **Discoms will gain in this scenario by procuring power at a cheaper price.**

- **MCP = energy charge:** In this scenario, both buy and sell bids will get cleared. The discom will buy from the market at the same price as energy charges and pass it on to the generator under the PPA. **The discom will not have any loss or gain.**

- **MCP > energy charge:** In this scenario, both buy and sell bids will get cleared. However, the pay-in and pay-out of the discom will get exactly netted out with no additional obligation for the discom.

Consider a scenario where the MCP in the spot market is Rs3/kWh and the PPA tariff from the discom's contracted generator is Rs2.5/kWh:

Since the PPA price is lower for the contracted 400MW capacity, the discom will choose the contracted capacity at a tariff of Rs2.5/kWh. The discom will incur a procurement cost of Rs24 million per day (m) for buying power at Rs2.5/kWh and Rs7.2m per day for buying 100MW of capacity from the spot market.

In the gross-bidding scenario, the discom's sell bid of 400MW will get cleared as it would be offered at a lower tariff of Rs2.5/kWh. On paper, the discom will sell this power to the open market and pay Rs24m per day to the generator while buying the additional 100MW from the spot market at a tariff of Rs3.0/kWh, incurring a cost of Rs7.2m per day.

Under either mechanism , the discom's total power procurement cost turns out to be Rs31.2m per day. **Hence, discoms neither gain nor lose in the scenario where MCP is higher than the PPA.**

The below table compares discoms' gain and loss between the two mechanisms for different scenarios for tariffs from the open market and the PPA.

Figure 3: Discoms' Gain/Loss Comparison in Existing Procurement Model vs Gross Bidding

Discom power procurement cost in different scenarios

Scenario	MCP (Rs per unit)	PPA price (Rs per unit)	Discom power procurement cost (Rs million in a day)						Net gain/loss (Rs million in a day)
			Existing system			Gross bidding			
			Pay-out to genco	Pay-out to market	Total pay-out	Pay-out to genco	Pay-out to market	Total pay-out	
MCP<PPA price	2.00	2.50	24.0#	4.8	28.8	0.0	24.0	24.0	4.8
MCP=PPA price	2.50	2.50	24.0	6.0	30.0	24.0	6.0	30.0	0.0
MCP>PPA price	3.00	2.50	24.0	7.2	31.2	24.0	7.2	31.2	0.0

 # [MW x hours in a day x Rs per unit]/10^2

Source: IEX.

In this mechanism, the discom and the generator both have the option to either sell or buy in the open market or trade bilaterally, as per their PPA. For the market, increased volumes in the open market will increase the liquidity and enable efficient price discovery, bringing down the overall cost in the system. This creates a win-win situation for the discom, the generator and the market.

Prayas, a Maharashtra-based think-tank, highlights a key concern associated with the MBED mechanism proposed by CERC.[5] If the bilateral contract settlements (PPA) are provided by discoms to thermal generators who bid less than their own variable cost and clear in MBED, the risks undertaken during bidding by the generators are hedged by the discoms. The generators then have a free pass to game the system by always bidding lower than their actual variable cost to ensure the bids are cleared in the open market.

This protection potentially allows for risky bidding strategies by the generator. This should be avoided by clear regulations—possibly by not allowing bilateral contract settlement payments to generators who indulge in such risky bidding.

To get the discoms and the generators up to speed on this new mechanism, CERC has planned for a phased implementation. India's largest state-owned power generation company, NTPC, will begin operating through the MBED route with its thermal generation fleet on April 1, 2022.

A similar pilot entailing security-constrained economic despatch (SCED) of interstate thermal generation capacity was performed between April 2019 and January 2021. The pilot registered a saving of Rs1,624 crore (US$210m) of generation costs.[6]

This will help in identifying the shortcomings of the mechanism, as well as identifying regulatory changes required to ensure efficient operation of this market.

Frequency Control and Ancillary Services Regulation

Since solar generation is only available during the day and wind patterns are highly seasonal and intermittent, the power system needs to evolve and modernise to respond to grid stability challenges as the share of variable renewable energy (VRE) generation continues to increase in India's energy system.

Increased frequency and voltage variability on the grid requires supporting services broadly defined as Frequency Control and Ancillary Services (FCAS). These services mainly support the grid operation in maintaining power quality, reliability and security of the grid.

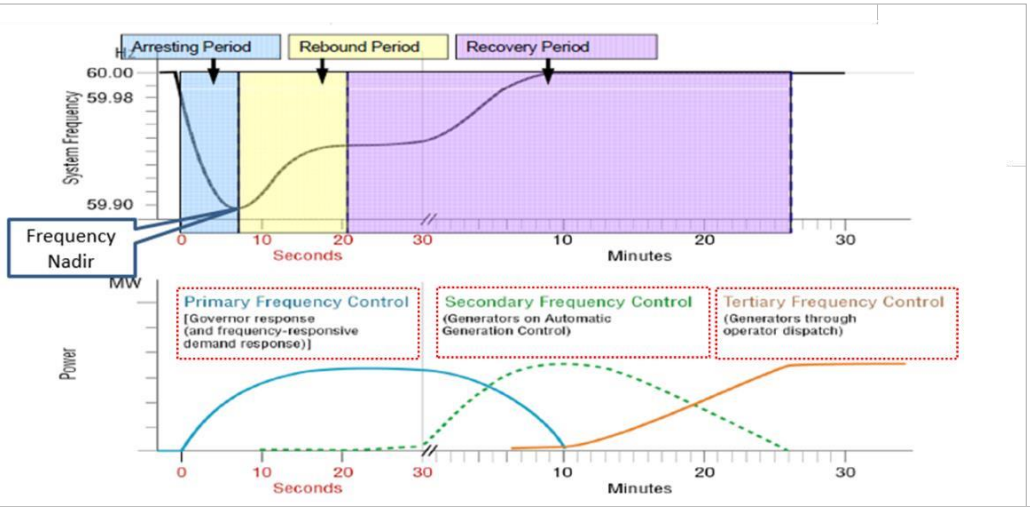
[5] Prayas. Comments on MBED Discussion Paper. July 2021.
[6] POSOCO. Security Constrained Economic Despatch. Interstate Generating Station Pan-India. March 2021.

Achieving effective frequency control requires some form of capacity reserves. Accordingly, different types of frequency reserves are structured in various grid codes worldwide—*i.e.*, primary reserves or equivalent, secondary reserves or equivalent, and tertiary reserves or equivalent—based on their speed and accuracy of response, duration of output (if any), and timing to maintain grid demand-supply balance as shown below.

Other important services include active power support for load following, reactive power support, black start and such other services as defined in the Grid Code.

Increased frequency and voltage variability on the grid requires supporting services broadly defined as Frequency Control and Ancillary Services (FCAS).

Figure 4: Frequency Response Reserves



	Primary Reserve Ancillary Service (PRAS)	Secondary Reserve Ancillary Service (SRAS)	Tertiary Reserve Ancillary Service (TRAS)
Response duration	Few sec – 5 min	30 sec - 15 min	5 min – 30 min

Source: Fluence, AES.

These reserves are organised for a response mechanism in an event where the frequency on the grid deviates from 50Hz.

Contingent events can occur in seconds, resulting from intermittency, outages or inclement weather, to name a few causes. To respond to such challenges, a reliable and responsive resource is necessary to ensure the grid's security and integrity.

These reserves are generally designed such that even in case of failure of the biggest link—the biggest generator or transmission link—reserves can be signalled to ramp up or down in sufficient time to prevent grid collapse.

Some countries follow a system of Frequency Response Obligation (FRO, expressed in MW/Hz, or at times in MW)[7] in their grid code that outlines the required level of reserves to arrest undue large frequency variations. The primary goal of the FRO system is to control frequency change so that it remains within the designed frequency band to prevent tripping, and at worst, blackouts. In case of the North American grid (interconnected grid between Canada, the United States and a part of the Mexican grid), the frequency operating frequency is 60Hz.

Delivering the FRO depends on the resources and capacity of ancillary services allocated under primary reserves (PRAS), secondary reserves (SRAS) and tertiary reserves (TRAS), each operating at different control points. The underlying principle of having reserves is as follows:

During contingent events or instances of imbalances in generation and demand, the hierarchy of reserves is PRAS, then SRAS and finally TRAS. TRAS can be flexible and may be provided through re-dispatch following the merit order on the trading interval but keeping an effective reserve ready should be considered against the risk of availability.

The integration of VRE resources, specifically solar and wind, necessitate an increase in the reserve resources, particularly for PRAS and SRAS, to manage deviations in the frequency due to intermittency of the renewable energy sources. This is one of the most critical factors driving the importance and growth of ancillary services around the globe with different system operators.

India's Ancillary Service Regulation

In May 2021, CERC published draft regulation for Ancillary Services.

CERC's draft regulation has recognised energy storage and demand response, which are digitally controllable, as dispatchable energy and power resources that can respond rapidly and accurately to maintain grid frequency within close boundaries of the 50Hz.

The state and national load dispatch centres—SLDCs and NLDCs—will plan for the quantum of the required SRAS and TRAS on day-ahead basis and any incremental requirement would be assessed on real-time basis.

The SRAS capacity should be at least 1 megawatt, and resources need to either dispatch power into the grid or draw power out within 30 seconds of receiving a grid signal. Resources must be capable of providing their entire capacity obligation within 15 minutes and sustain the obligation for another 30 minutes.

Meanwhile, TRAS participants need to respond and provide frequency regulation within 15 minutes and sustain it for at least 60 minutes. TRAS can be used to replenish secondary reserve resources that have been deployed continuously for 15

[7] University of Pennsylvania. A Market for Primary Frequency Response. A Role of Renewables, Storage and Demand. A working Paper by Thomas Lee. August 2020.

minutes for more than 100MW, as well as in response to other Grid Code-specified events.

The regulation also provides performance-based incentive payments for SRAS based on its response and accuracy.

However, the draft regulation has not included battery storage or demand response resources in the ambit of PRAS.

Grid Tools for Frequency Response

Energy storage systems such as utility-scale lithium-ion batteries or pumped hydro storage (PHS) are capable of operating as important grid tools for frequency control operations. The technologies can dispatch power during grid events as well as absorb power from the grid to manage grid frequency. On the other hand, traditional thermal generation assets and gas peakers can provide these services by dispatching the power but are unable to absorb the power from the grid.

Accuracy and response speed are critical to ensuring the frequency response operation. Both factors contribute to the systemwide cost for controlling grid frequency. Generators can differ dramatically in their ability to follow the system operator's commands or their ability to respond automatically and precisely to frequency changes.

The following table compares the flexibility and response time of various frequency response assets.

Figure 5: Comparison of Flexibility Parameters and Response Time

Plant Type	Hard Coal	Lignite	CCGT	Pumped Storage	Batteries
Load range (%)	40% to 90%	40% to 90%	40% to 90%	NA	0% to 100%
Minimum Load (%)	40% / 25% / 10%	60% / 40% / 20%	50% / 40% / 30%	10%	-100%
Ramp rate (%/min)	2% /4% / 9%	2% /4% / 8%	4% / 8% / 12%	>40%	100%
Start-up time - hot start (within less than 8 hours)	3h / 2h / 1h	6h / 4h / 2h	1.5h / 1h / 0.5h	<0.2h	<1 second
Start-up time - cold start (after more than 48 hours)	7h / 4h / 2h	8h / 6h / 3h	3h / 2h / 1h	<0.2h	<1 second

Source: GIZ,[8] IEEFA estimates. Note: CCGT is combined cycled gas turbine (gas-fired generation).

Utility-scale batteries have the fastest response time—less than a second—in frequency response operations. Also, batteries can either be charged to 100% of capacity or dispatch 100% of capacity if required to maintain the frequency.

In a study conducted by PJM,[9] a U.S. regional transmission organisation, battery-based energy storage assets were found to respond faster and with greater accuracy

[8] USAID – Greening the Grid. Keeping Flexibility at the centre stage of India's energy transition. October 2020.
[9] PJM Study: Performance, Mileage and the Mileage Ratio. November 11, 2015.

to signals from the grid than other technologies. Another study found that 1MW of battery-based capacity can replace almost 2.3MW of traditional generating capacity used for ancillary service reserves.

FCAS Regulations to Drive Up Battery Deployments

There are currently two utility-scale batteries operating in India. A 10MW/10MWh (megawatt-hour) battery is operated by Tata Power's power distribution business in Delhi. An 8MWh battery is reportedly being commissioned by L&T and owned by the Niyveli Lignite Corporation of India Ltd (NLCIL) in the Andaman & Nicobar Island, co-located with a 20MW solar plant.[10]

Recently, the Solar Energy Corporation of India (SECI) rolled out a tender to procure 2,000MWh of stand-alone energy storage system. Similarly, NTPC has issued a similar tender to procure 1,000MWh of capacity.[11]

Other battery projects are being developed by Renew Power, supported by long-term, time-of-day differentiated tariffs with 25-year PPAs.

There also are more than 4GW of operational PHS projects with roughly 3GW under construction. The tariffs for the operational PHS projects exceed Rs7/kWh and are typically operated by the states to meet peak demand.

Batteries and PHS projects could be supported by long-term price signaling and would predominantly operate to shave peak-demand loads. The profitability of these battery assets is reliant on price arbitrage—charging during the time of low-price periods and dispatch during the high-price, peak demand periods.

Presence of a formal FCAS market puts value and merit to accuracy and speed of response to grid management requirements, further improving grid reliability. It would eliminate the grid operator's cheapest avenue of managing the grid in adverse grid events—load shedding.

The development of a formal FCAS market will open up another substantial revenue stream for utility-scale batteries and allow them to operate as an important grid management asset.

Conclusion

A colossal transition is underway in India's electricity sector. The growth in India's renewable energy capacity has been facing short-term policy headwinds that have been complicated by the Covid-19 pandemic.

[10] Mercom India. NLC India Commissions 20MW Solar Project With Battery Storage Energy System in Andaman. 13 July 2020.
[11] Mercom. SECI Floats Tender for 2,000 MWh of Standalone Energy Storage Systems. 31 August 2021.

The two developments discussed in this report are set to substantially change the market design of the power market in India.

The Market Based Economic Dispatch model would materially open up the open market for electricity trade in India. This could significantly bring down the overall power procurement costs for discoms by allowing efficient price discovery. At the same time, the model would improve liquidity in the market and leverage the ongoing momentum in India's spot market platforms—IEX and PXIL.

As the settlements move to the open market, discoms will initially require financial support for the increased cash flow requirements. Gradually, the efficiency and the competitiveness in this mechanism will ensure lower power purchase costs and improve the financial position of discoms by moderating their liquidity requirements.

We believe that MBED will be highly beneficial for renewable energy assets as the mechanism would reduce payment delays and further protect the sanctity of contracts. This will improve bankability of renewable energy PPAs and potentially lower the cost of capital, in turn reducing the landed cost of renewable energy.

Opening up a formal FCAS market will allow competitive price signalling for investment into important flexibility tools such as batteries and PHS projects that are extremely important to integrate large-scale, ultra-low-cost VRE sources.

Opening up a formal FCAS market will allow competitive price signalling for investment into important flexibility tools.

The new mechanisms and regulations of MBED and FCAS do not yet answer all the questions. They will need further amendments and finessing to have the desired effect. However, these are important steps in right direction to transform India's power sector to a low-emission, low-cost and profitable part of the economy.

About IEEFA

The Institute for Energy Economics and Financial Analysis (IEEFA) examines issues related to energy markets, trends and policies. The Institute's mission is to accelerate the transition to a diverse, sustainable and profitable energy economy. www.ieefa.org

About the Author

Kashish Shah

Kashish Shah, a Research Analyst at IEEFA India, has a master's degree in economics from the University of Sydney and an engineering degree from NMIMS University in Mumbai. Kashish has worked in the Global Analytics Division of the Royal Bank of Scotland with a focus on regulatory policies. Kashish has research experiences in India's public sector in his work for a member of Indian Parliament and a University of Sydney-based research group. kshah@ieefa.org

This report is for information and educational purposes only. The Institute for Energy Economics and Financial Analysis ("IEEFA") does not provide tax, legal, investment, financial product or accounting advice. This report is not intended to provide, and should not be relied on for, tax, legal, investment, financial product or accounting advice. Nothing in this report is intended as investment or financial product advice, as an offer or solicitation of an offer to buy or sell, or as a recommendation, opinion, endorsement, or sponsorship of any financial product, class of financial products, security, company, or fund. IEEFA is not responsible for any investment or other decision made by you. You are responsible for your own investment research and investment decisions. This report is not meant as a general guide to investing, nor as a source of any specific or general recommendation or opinion in relation to any financial products. Unless attributed to others, any opinions expressed are our current opinions only. Certain information presented may have been provided by third-parties. IEEFA believes that such third-party information is reliable, and has checked public records to verify it where possible, but does not guarantee its accuracy, timeliness or completeness; and it is subject to change without notice.