Transforming India's Electricity Markets

The Promise of Market-Based Economic Dispatch and the Path Forward

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About RMI

RMI is an independent non-profit founded in 1982 that transforms global energy systems through market-driven solutions to align with a 1.5°C future and secure a clean, prosperous, zero-carbon future for all. We work in the world's most critical geographies and engage businesses, policymakers, communities, and NGOs to identify and scale energy system interventions that will cut greenhouse gas emissions by at least 50 percent by 2030. RMI has offices in Basalt and Boulder, Colorado; New York City; Oakland, California; Washington, D.C.; and Beijing. RMI has been supporting India's mobility and energy transformation since 2016.

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List of acronyms and abbreviations

AEMO	Australian Electricity Market Operator
APPC	Average Power Purchase Cost
BCS	Bilateral Contract Settlement
BRP	Balance Responsible Parties
CAISO	California Independent System Operator
CERC	Central Electricity Regulatory Commission
DAM	Day-Ahead Market
Discom	Distribution Company
EA	Electricity Act of 2003
Euphemia	Pan-European Hybrid Electricity Market Integration Algorithm
FERC	Federal Electricity Regulatory Commission
FTR	Financial Transmission Rights
GW	Gigawatt
IEX	Indian Energy Exchange Limited
ISGS	Interstate Generating Station
ISO	Independent System Operator
ISO-NE	Independent System Operator of New England
ISP	Integrated System Plan
MBED	Market-Based Economic Dispatch
MOP	Ministry of Power

MW	Megawatt
NDC	Nationally Determined Contribution
NEM	National Electricity Market
NEMO	Nominated Electricity Market Operator
NEPOOL	New England Power Pool
NER	National Electricity Rules
NLDC	National Load Dispatch Centre
PCR	Price Coupling of Regions
OASIS	Open Access Same-Time Information System
POSOCO	Power System Operation Company
PPA	Power Purchase Agreement
PXIL	Power Exchange India Limited
RE	Renewable Energy
REZ	Renewable Energy Zones
RLDC	Regional Load Dispatch Centre
RTM	Real-Time Market
RTO	Regional Transmission Organization
SCED	Security-Constrained Economic Dispatch
SLDC	State Load Dispatch Centre
TSO	Transmission System Operator
TWh	Terawatt Hours
URS	Unrequisitioned Surplus
VRE	Variable Renewable Energy
WEIM	Western Energy Imbalance Market

Executive Summary

India declared it aims to meet 50% of its power generation capacity from non-fossil-fuel sources by 2030 as part of its updated nationally determined contribution (NDC).[1] Moreover, rapid economic growth coupled with universal electricity access could nearly double the country's electricity demand growth rate over the next five years.[2] A paradigm shift in India's electricity market is necessary to rise to the twin challenges of facilitating new generation capacity to meet the growing demand and integrating high levels of non-fossil-fuel generation. As the next step in market evolution, the Ministry of Power (MOP) proposed the Market-Based Economic Dispatch (MBED) mechanism, which reforms and optimizes day-ahead generator scheduling and dispatch at the national level.[3] Economic and system benefits reduce power system operations costs, ease integration of renewable generators with fewer curtailments, optimize power procurement costs, and realize cost savings for distribution companies (discoms).

India's distribution sector continues to face many challenges. Discoms are financially distressed and collectively owe more than INR 1 lakh crore (US$12.3 billion) in debt, resulting in delayed payments to generators, inadequate investment in grid infrastructure, and insufficient resources for effective operations.[4] This contributes to the financial risk faced by renewable generators. A fiscally healthy distribution sector and robust renewable growth are vital for India to meet its rising electricity demand and NDC targets.

Suboptimal scheduling and dispatch of generators at the wholesale level is a key factor contributing to the financial strain faced by discoms. Currently, discoms self-schedule generation at the state/regional level and lack visibility beyond their generation portfolio, resulting in overreliance on inflexible long-term contracts and dispatch of generators with high variable operating costs.

The MOP's MBED proposal tasks a national market operator with accepting bids from discoms and generators and establishing a national merit order bid stack. This ensures all generators are scheduled and dispatched on economic principles, subject to plant and network constraints. RMI's analysis across two states demonstrates cost savings through the efficient dispatch of a pooled generator portfolio and finds potential system cost savings of INR 1.5–4 crore (US$184,000–US$491,000) per day over business-as-usual (BAU). These savings are affected by constraints such as technical minimum load, ramping, network congestion, and other issues that affect grid operations in real time, in addition to being unequal for different participating states.

The successful implementation of MBED requires carefully addressing stakeholder interests and system enhancements. A smooth transition warrants aligning diverse stakeholder interests by taking into account concerns about stranded assets and impact on existing contracts and financial settlements. Essential system enhancements may need the MOP to assess system preparedness to implement a centralized dispatch. For example, the absence of consistent and transparent data hinders the discovery of the actual system marginal cost.

This report summarizes the current market design in India and the MBED proposal (its benefits and barriers to the transition) based on an extensive review of stakeholder comments. It shares the lessons learned from international electricity markets and recommendations to successfully transition to the MBED mechanism in India's power sector. This report also clarifies the critical aspects of the MBED proposal for stakeholders.

To ensure success of the MBED market restructure, RMI recommends the following:

- The MOP propose a robust transition plan outlining the structure and responsibilities of the market operator, pathway for assessing and meeting technological readiness needs, and process for the financial transition for discoms.
- Establishing a public data portal to assess wholesale market operations.
- Updating the transmission planning process to reflect shifts in generation resulting from optimizing dispatch pan-India and minimizing the risk of increased costs associated with congestion and market splitting events.
- Developing a roadmap for complementary wholesale markets to maximize the benefit of the MBED mechanism and ensure adequate reserve margins at the state level.

Introduction

India's power sector underwent significant developments in the past decade. The electricity demand nearly quadrupled from 369 terawatt hours (TWh) in 2000 to 1,380 TWh in 2021, driven by rapid economic growth, industrialization, urbanization, and over 900 million citizens gaining access to electricity as the country aspires for universal, reliable access.[5] Despite a decline in 2020 due to COVID-19, India's electricity demand growth rate is projected to nearly double in the next five years.[6]

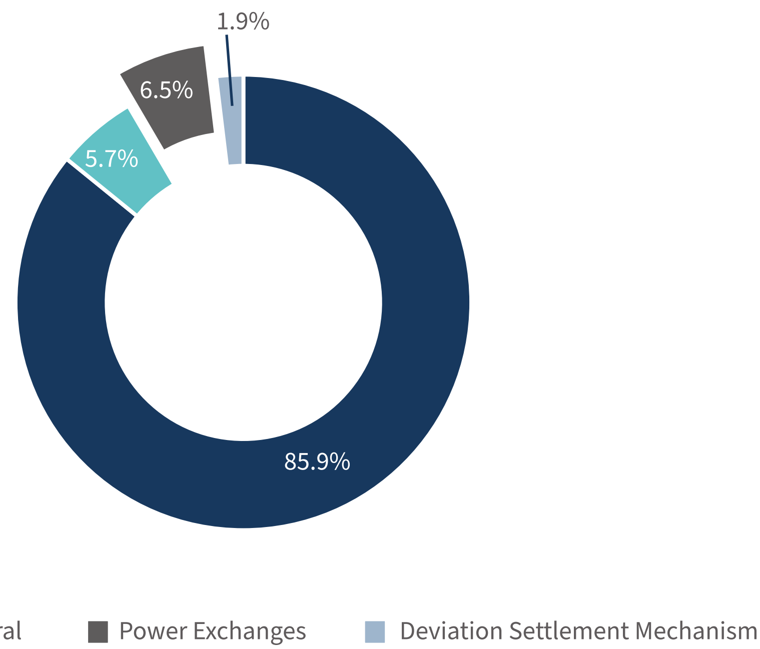
The projected electricity demand growth highlights the ambition of India's nationally determined contributions (NDCs). The prime minister declared the goal of achieving national net zero by 2070 at COP26 — a first for India. This commitment is part of the Panchamrit principles, including increasing renewable generation capacity and renewable share of energy consumption across the economy and achieving a 45% decline in carbon intensity by 2030.[7]

The twin challenges of facilitating installed generation capacity to meet demand growth and integration of high levels of renewable generation sources are opportune for India's power sector. A policy framework that allows for a reliable, resilient, and flexible grid will enable further economic growth through an uninterrupted flow of power to all off-takers. The Electricity Act (EA) of 2003 was a crucial step in India's power sector evolution, as it introduced policy features such as the introduction of competition through open access, multiyear tariff frameworks, distribution franchises, de-licensing generation, establishment of renewable purchase obligations, and creation of independent regulatory bodies.

Nevertheless, the distribution sector continues to face difficulties, with high aggregate technical and commercial losses and expensive long-term contracts creating financial distress for Indian distribution companies (discoms). In June 2022, discoms cumulatively held in excess of INR 1 lakh crore (US$12.3 billion) in debt, resulting in delayed payments to generators, inadequate investment in infrastructure, and insufficient resources for effective operations such as metering, billing, and collection.[8]

Long-term contracts such as power purchase agreements (PPAs) are valuable for hedging risk for the distribution sector by limiting exposure to volatile wholesale markets. However, overreliance on long-term contracts prevents retail distributors from capturing the full benefits of declining generation costs. During FY2021–22, discoms procured nearly 86% of the bulk electricity through long-term contracts (see Exhibit 1).

Exhibit 1 Volume Share of Different Power Procurement Modes, FY 2021–22

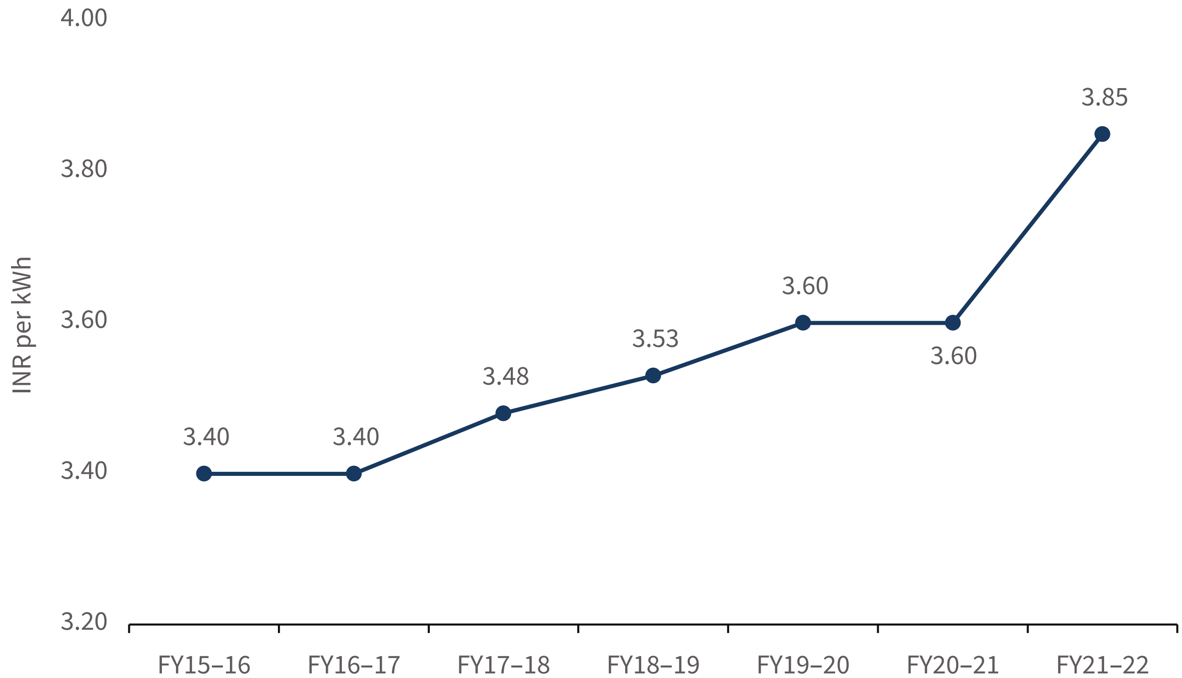


Source: Central Electricity Regulatory Commission (CERC)

Typically, discoms enter 25-year PPAs, which constitute two payments: (1) to compensate fixed charges based on the capacity declared available by generators and (2) to compensate variable charges based on the scheduled generation as required by discoms.[9] Many long-term PPAs are inflexible and limit discoms' ability to purchase low-cost power, further affecting their financial viability as they are burdened with high fixed-charge payments for inefficient plant capacity that is minimally utilized.[10] Inefficiencies in power procurement are reflected in the rise in the national average power purchase cost (APPC) of over 13% since FY2015–16 (see Exhibit 2).[11, i]

i The national APPC is determined by computing the average of APPC of all states and union territories, weighed by the volume of conventional power purchased by a state/union territory.

Exhibit 2 **National Average Power Purchase Cost**



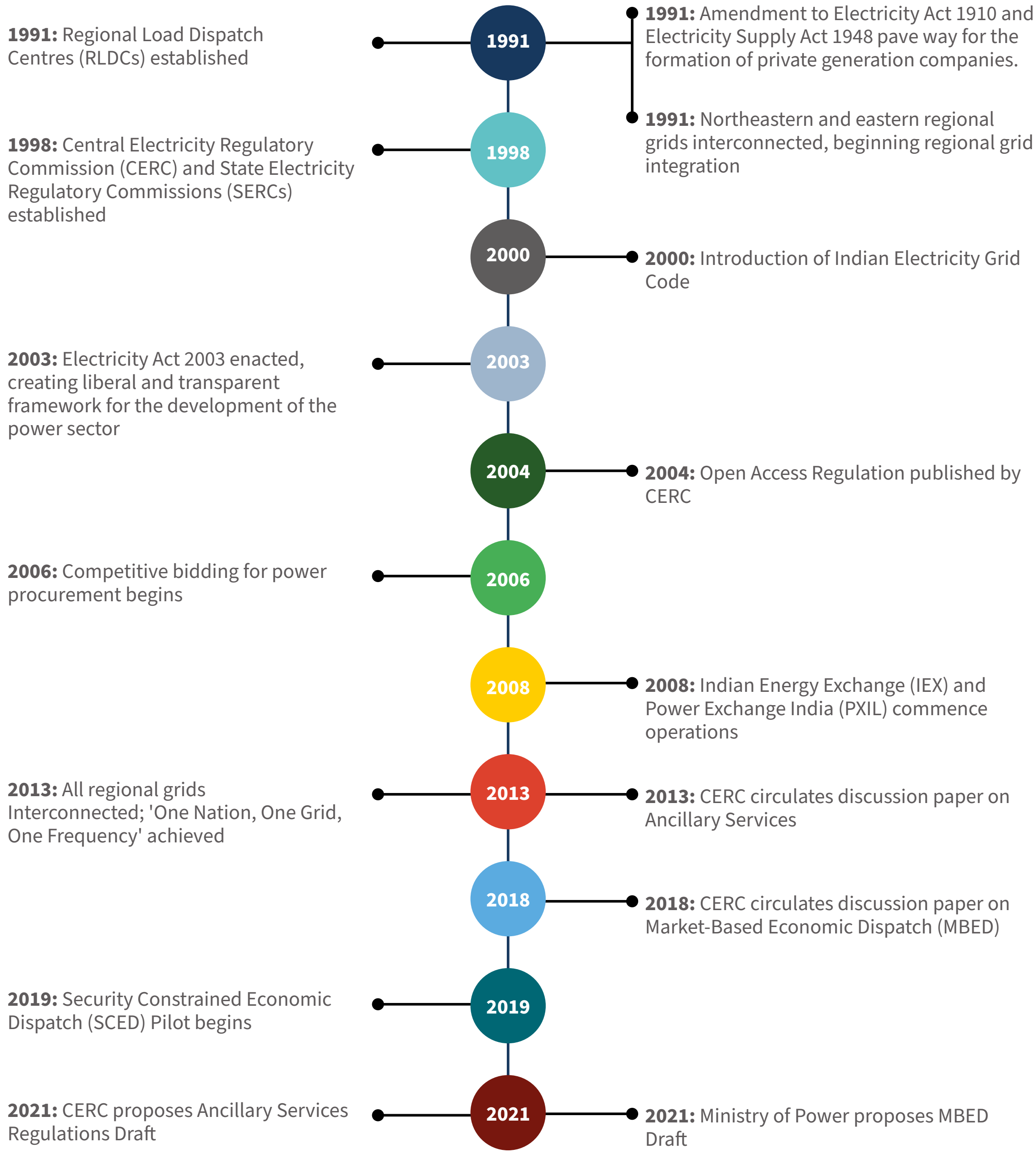
Source: Central Electricity Regulatory Commission (CERC)

In addition to late payments from discoms, renewable generators face financial risk due to curtailment. Curtailment occurs either in case of insufficient grid availability or when transmission network capacity is not enough to transfer the power generated to consumers. The scale-up of variable renewable generation and its geographic concentration compelled grid managers to resort to sporadic curtailments.[12] While renewable generators in India have a "must-run" status, and curtailment must be limited to reasons related to grid security or else the curtailed generators may be entitled to compensation, increased curtailment rates still pose a risk for renewable generators.[13] Financial loss of the tariff payments may lead to financiers seeking high risk premiums that could potentially limit the availability to project financing.[14]

India's wholesale power sector must be restructured to tackle the challenges of overreliance on long-term contracts and rising electricity costs, integrate renewable energy (RE), and minimize renewable generation curtailment. To this end, the MOP proposed the Market-Based Economic Dispatch (MBED) Program as a key step towards extensive market liberalization. MBED would establish a national day-ahead wholesale power market, wherein bids from generators and discoms would be used to create a national merit order bid stake. A national market clearing price can be estimated by matching buyers and sellers at each time interval.[ii] The MBED proposal is a step towards the power sector market liberalization implemented in India since 1991 (see Exhibit 3).

ii Transmission and congestion costs will reflect in area clearing prices that account for regional surplus and deficit of generation, which will adjust the national marginal clearing price.

Exhibit 3 Timeline of Power Sector Development in India



The implementation of MBED will depend on how electricity is scheduled and dispatched within India. It could progressively reduce wholesale prices by maximizing low variable cost production nationally and cut inefficient investments by different states in installing new generation capacity by enabling shared reserves across states and shifting to short-term electricity contracts. However, this shift will bring challenges. Understanding power markets and challenges faced in market liberalization internationally can ensure the proposed restructuring proves effective in reducing costly risks to the Indian grid and markets.

Electricity Markets

Released in June 2021, the MOP's MBED proposal addresses the challenges in maximizing the efficiency of installed generation capacity, integrates variable renewable generation, and mitigates rising power procurement costs. To understand the proposed changes to market design, it is important to contextualize electricity markets with the unique characteristics of electricity, potential benefits of market liberalization, and pillars of market design — with a focus on the distinction between centralized and decentralized wholesale markets. Additional context on unbundled wholesale electricity markets can be found in Appendix B.

Global Wholesale Market Liberalization

Discoms are tasked with ensuring their customers have uninterrupted access to electricity. The characteristics of electricity as a commodity make this challenging. Although global storage costs are anticipated to decline, electricity is currently difficult to store economically in large quantities. As a result, electricity must largely be consumed as it is generated. In addition, electricity demand varies by the minute and must be coordinated in real time. Historically, supply and demand is matched through a mix of baseload, load following, and peak generation capacity. Today, low-cost but intermittent wind and solar generation has increased the need for flexibility on the demand and supply sides. Generally, retail consumers are shielded from generation price volatility, resulting in demand being unresponsive to price signals.[iii] When supply and demand fall out of sync, the grid's frequency is affected.[15] Excessive deviation from the grid's normal operating frequency can lead to cascading failures, including brownouts and, in extreme cases, blackouts. These system failures come with enormous costs.

Historically, due to the high level of coordination required, vertically integrated utilities managed most electricity transactions globally with monopoly ownership over generation, transmission, distribution, and retail. Regulators oversaw these monopolies according to diverse, jurisdiction-specific frameworks. Over the past 35 years, policymakers in many countries introduced competitive markets to parts of the electricity system to reduce cost and improve reliability. Generally, competitive markets have effectively lowered costs, but many geographies grapple with the benefits and challenges of competitive markets due to the unique nature of the electricity system.[16,iv] Currently, 40% of the global electricity demand is met through fully competitive wholesale markets, while an additional 47% is met through a system with some element of competition.[17]

iii India and other countries are taking efforts to reduce demand inflexibility through demand flex or demand response programs. For additional information, see **"Demand Flexibility: The Key to Enabling a Low-Cost, Low-Carbon Grid."**

iv For additional information on global trends in electricity market transformation, see RMI's **The Global Energy Transformation Guide: Electricity Market Structures.**

Market Design

Electricity markets are built upon two key functions: (1) wholesale markets — the mechanism by which distributors contract generation (and may include other products such as RE credits, ancillary services, and capacity) and (2) system operation — the mechanism by which contracted power is transmitted while maintaining the integrity and function of the grid. These can be considered the financial and physical operations, respectively. A distinguishing factor across market designs is the participant or actor responsible for managing these two functions. The two bookends of market design options are decentralized self-dispatch and centralized dispatch (see Exhibit 4). Beyond this, market design reflects many distinct geographic, political, and economic realities. Any combination of certain elements of market design, such as structure, finance, and physical operations, could exist for electricity market functioning in a given geography.

Exhibit 4 Main Features of Centralized and Decentralized Electricity Market Designs

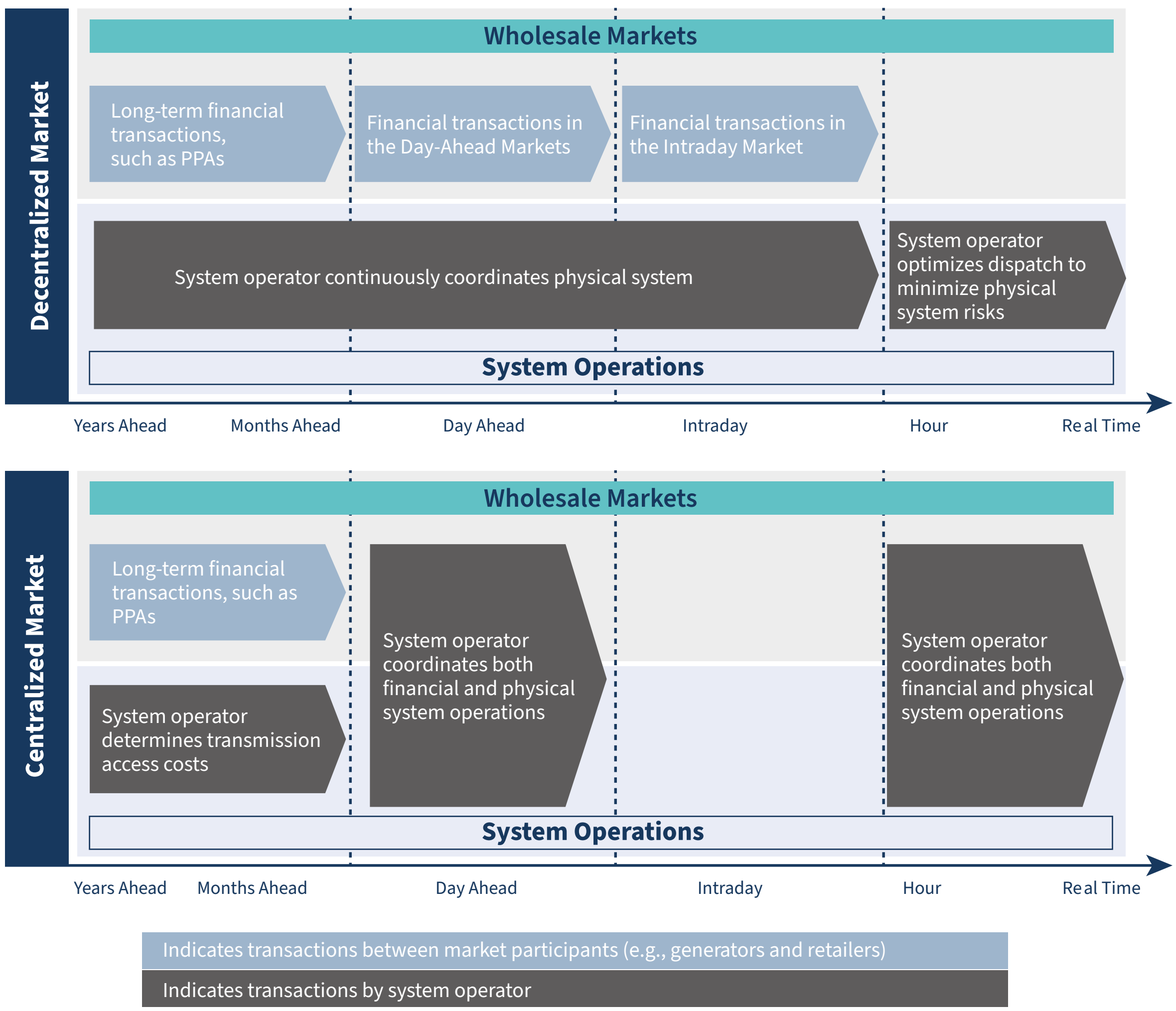
<table>
<tr><th></th><th>Decentralized Market</th><th>Centralized Market</th></tr>
<tr><td>Structure</td><td>Financial energy markets and physical system operation undertaken by separate entities.</td><td>Financial energy markets and physical system operation undertaken by the same entity.</td></tr>
<tr><td>Wholesale Markets</td><td>Financial transactions in energy markets undertaken by participants such as retailers and generators. These may be direct bilateral contracts, such as PPAs, or short-term transactions through a power exchange.</td><td rowspan="2">System operators coordinate financial markets and physical system management. Financial transactions, scheduling, and dispatch are cooptimized with the system management to ensure reliability, security, and minimization of congestion risks.</td></tr>
<tr><td>System Operations</td><td>System operators oversee physical systems, including ensuring reliability, security, and minimization of congestion risks.</td></tr>
<tr><td>Transmission System Ownership</td><td>Typically, this implies publicly owned by system operators.</td><td>Typically, this implies privately owned but operated by system operators.</td></tr>
<tr><td>Transmission System Planning</td><td>Responsibility is typically coordinated between system operators and other organizations, including market operators.[v]</td><td>Responsibility typically lies with system operators.</td></tr>
<tr><td rowspan="3">Years and Months Ahead</td><td colspan="2">Market participants may engage in long-term contracts such as PPAs.</td></tr>
<tr><td>System operators procure adequate reserves.</td><td>System operators may procure adequate reserves through central auctions, for example, a capacity market.</td></tr>
<tr><td>System operators establish access to transmission across borders.</td><td>System operators may hold auctions to determine the transmission access costs through a financial transmission rights (FTR) market.</td></tr>
<tr><td rowspan="2">Day-Ahead Market (DAM)</td><td>Cleared through power exchanges with “simple” bids representing net load obligations.</td><td rowspan="2">Unit-specific bids containing economic and technical parameters, allowing system operators to optimize schedule.</td></tr>
<tr><td>Generators self-schedule.</td></tr>
<tr><td>Intraday</td><td>Continuous trading by market participants; can be used to balance the deviations between the DAM and actual demand.</td><td>Generally, no intraday trading; deviations between the DAM and actual demand will be realized in RTM.</td></tr>
<tr><td>Real Time</td><td>System operators perform redispatch.</td><td>Deviations from day-ahead schedule settled at RTM price.</td></tr>
<tr><td>Examples</td><td>Market operations throughout Europe.</td><td>Regions with liberalized electricity markets within the United States, such as the California Independent System Operator (CAISO).[vi]</td></tr>
</table>

v Market coupling refers to harmonizing multiple power exchanges, linking different control and market areas. Redispatch refers to requests from system operators to plants to adjust power feed-in for avoiding or resolving system operation issues such as congestion.

vi There are currently seven independent system operators (ISOs)/regional transmission organizations (RTOs) operating in the United States, covering about half of the geographic region and two-thirds of the electricity load. For this report, the differences between an ISO and RTO are largely semantic; for simplicity, the term ISO will be used. Regions in the United States not covered by ISOs follow a vertically integrated utility business model.

Exhibit 5 demonstrates the distinct operations of decentralized and centralized markets. In a decentralized context, financial markets do not involve system operators. Trading occurs in distinct phases such as long-term years or months in advance, day-ahead, and intraday. System operators are not involved in financial transactions but coordinate the physical system to reduce risks. Prior to dispatch, system operators may align with market participants (such as generators) to ensure grid stability. This process is then settled by the appropriate parties after dispatch. Long-term transactions in a centralized market may not involve system operators but those undertaken in the DAM and RTM will be coordinated by system operators. These transactions will be optimized to reduce physical system risk and transmission congestion risk.

Exhibit 5 **Centralized and Decentralized Electricity Market Designs**



Source: Adapted from European University Institute, Florence School of Regulation

Although decentralized and centralized market approaches are distinct, the objective is similar: procuring electricity at least-cost prices to meet the projected market demand while ensuring system reliability. Market design should be appropriately informed by regional history and market context, with regulatory frameworks, private and public participation, and transmission ownership being the influencing factors. Reviewing the past two decades of development in the Indian market is an important factor in evaluating the MOP's MBED proposal.

Electricity Sector and Markets in India

India currently has a decentralized wholesale electricity market structure. Energy market transactions are handled by market participants, while physical systems operations are performed by the National Load Dispatch Centre (NLDC) and regional load dispatch centres (RLDCs). Discoms are responsible for procuring and providing electricity to end-users. Other market participants include generators and large off-takers, which may procure electricity directly through markets or captive generators. The NLDC and RLDCs have no role in financial energy market transactions. Oversight and regulation of the electricity sector is shared by the central and state governments, with private sector participation in key activities such as generation and transmission (see Exhibit 6).

Exhibit 6 **Indian Power Sector Structure**

Policymaking	**Central Government**		**State Governments**	
Regulations[vii]	Central Electricity Regulatory Commission		State Electricity Regulatory Commissions	
System Operators	Grid Controller of India (Grid-India)[viii]	NLDC	5 RLDCs[ix]	State Load Dispatch Centres (SLDCs)
Generation	Central Generating Stations		State Generating Stations	Private Sector Players
Transmission	Central Transmission Utility		State Transmission Utilities	Private Sector Players
Distribution			State-Owned Discoms	Private Discoms
Protection & Rights	Independent Appellate Tribunal			

vii Includes provision of licenses, tariff setting, approval and enforcement of contracts, and adjudication.

viii Formerly the Power System Operation Corporation (POSOCO), renamed in September 2022.

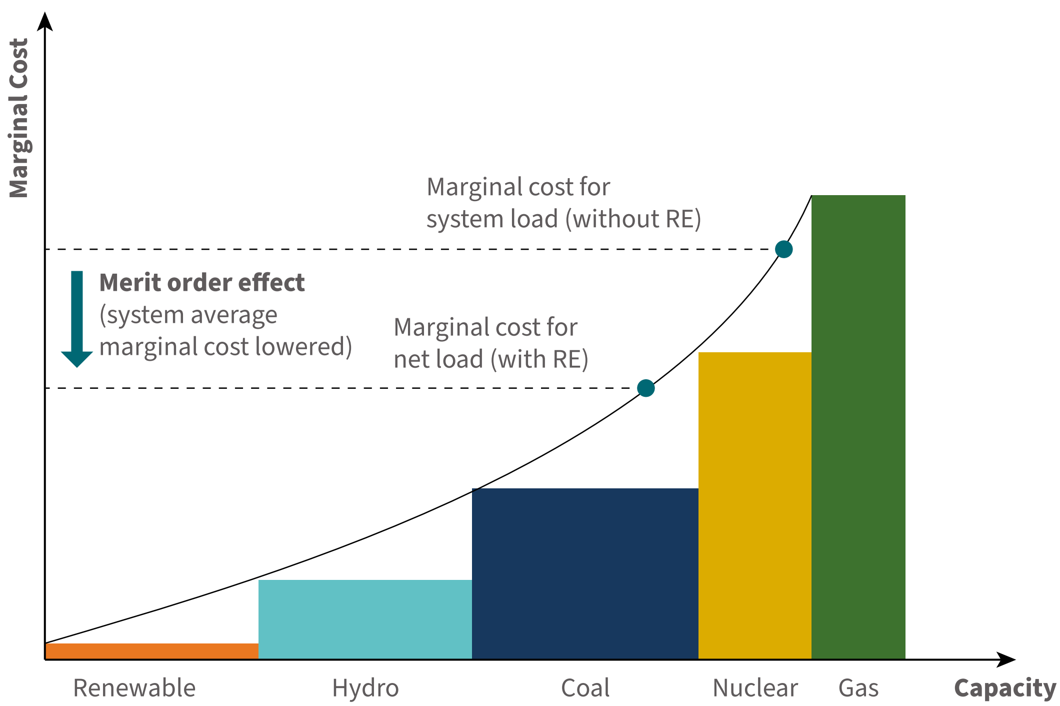
ix These include the Northern Regional Load Dispatch Centre, the Western Regional Load Dispatch Centre, Eastern Regional Load Dispatch Centre, Southern Regional Load Dispatch Centre, and North-Eastern Regional Load Dispatch Centre.

Scheduling and Dispatch

Power scheduling is the logistical planning of physical power flow in the market, including determining which generators will supply how much power in specified time-blocks. Discoms are largely responsible for scheduling of generation in India. They predominantly schedule from their portfolios of long-term contracts with generation companies and procure any remaining shortfall through bilateral transactions with other discoms, trading companies, or power exchanges. The self-schedule is based on their entitlements and access to the power exchanges for the balance of their energy requirements.

For DAM, bid schedules from states are sent to system operators, which decide and communicate the merit order dispatch that follows a least-cost principle. Exhibit 7 demonstrates an example merit order bid stack, wherein generators are arranged by marginal cost. Based on merit order principles, lowest-cost generators are dispatched first until the point of demand is found. Within India, generators such as solar and wind plants also have a "must-run" status, indicating these are dispatched unless there is curtailment due to grid security. Peaking generators such as gas and oil-fired plants have relatively high marginal costs but are critical to meet peak loads and flexibility requirements of the grid. As the share of renewables in the generation mix grows, system average marginal cost reduces (see Exhibit 7). This translates to low generation cost at the wholesale level, which can be passed on to consumers.

Exhibit 7 **Illustrative Merit Order Dispatch**



Source: Next Kraftwerke and MERIT India [18]

As shown in Exhibit 6, grid management and dispatch are handled and coordinated by organizations at three levels: the NLDC, RLDCs, and SLDCs. The NLDC supervises and coordinates with RLDCs to achieve maximum economy and efficiency in the operation of the national grid, in addition to scheduling and dispatching electricity over inter-regional links.[19]

Inter-state generation stations (ISGSs) are an exception to the general scheduling and dispatch model. ISGSs share entitlements across multiple states and are scheduled and dispatched via the coordinated multilateral model. In this process, the ISGS provides a declaration of availability to RLDCs, and SLDCs communicate requisition. Discoms have contracted right of sale, gate closure, and backing down, which is provided to SLDCs. Revisions are then undertaken based on demand forecast changes, and the injection schedule and drawl schedule (amount of generation provided by ISGS and that received by an entitled entity, respectively) is determined by the RLDC.[20]

Challenges in India's Electricity System

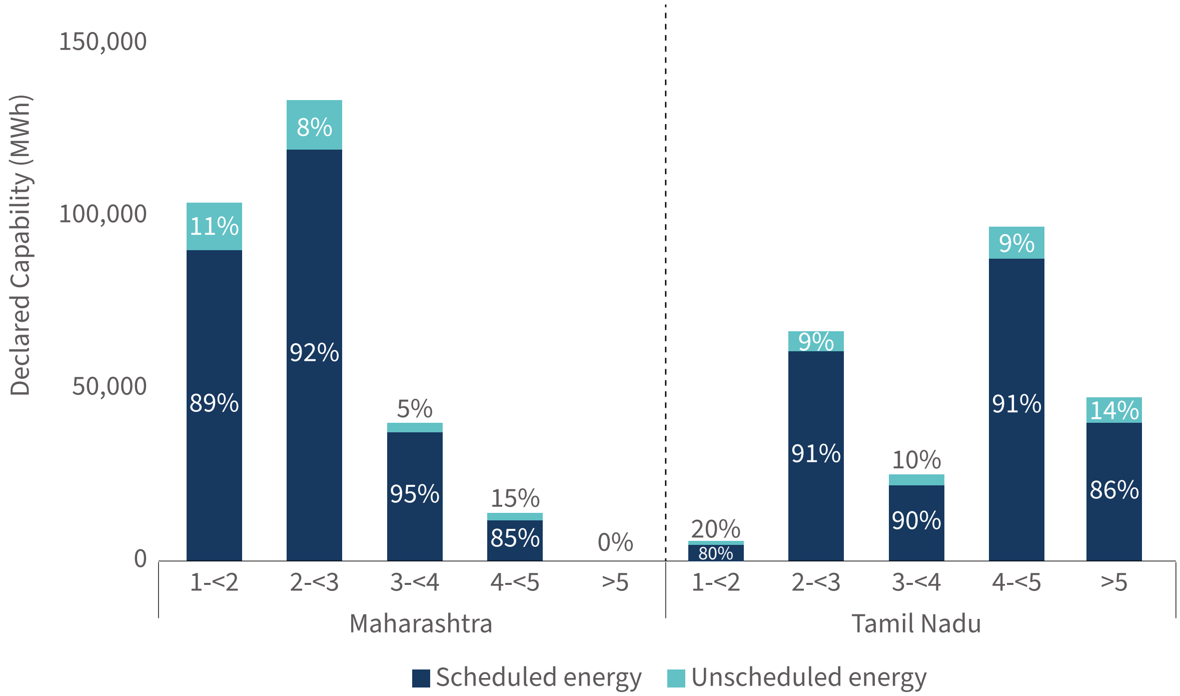
While the Indian power sector landscape drastically changed in the past two decades, existing structural limitations negatively affect system efficiency. The current self-scheduling dispatch system, adopted after the EA was implemented, involves discoms largely deploying electricity from long-term contracts. This results in several limitations across the power sector. For example, one region may have power surplus, while an adjoining region may have acute power shortage and high power prices. This can be addressed through inter-regional trade but requires improved coordination to fully capture potential. Several interconnected issues include (1) lack of visibility across discom portfolios exacerbated by (2) lack of consistent and transparent data, resulting in systemically (3) low short-term procurement, which can bring about (4) limited geographic and seasonal flexibility.

The following paragraphs detail these issues further:

- **Lack of Visibility Across Discom Portfolios:** Merit order dispatch ensures discoms optimally schedule power from their portfolio of generators while respecting grid security. However, lack of transparency across discom portfolios hinders the ability to optimize scheduling and dispatch nationally. For example, Maharashtra's power generation portfolio is more economical than that of Tamil Nadu (see Exhibit 8). The unscheduled electricity from Maharashtra's low-cost generators could be utilized to offset expensive generators in Tamil Nadu and lower their power procurement costs. Discoms can sell unrequisitioned surplus (URS) to other discoms, and generators have the opportunity to place URS on one of the power exchanges. However, these processes often occur after a day-ahead schedule is set and may not necessarily result in ensuring optimal scheduling and dispatch. Self-scheduling adds a layer of opaqueness to the system, making it difficult for system operators to identify and dispatch unused low-cost generation.[21]

- **Lack of Consistent and Transparent Data:** Discoms are neither required to report or otherwise publish marginal cost data nor do they have a standardized format to publish marginal cost data. While ERC directives and grid code regulations require many discoms to disclose data, this is neither nationally consistent nor readily available from a centralized source. Lack of standardized data hampers the discovery of the actual system marginal cost, creating a barrier to ensuring system transparency and efficient scheduling and dispatch across the national grid.

Exhibit 8 **Merit Unscheduled Surplus Capacity Availability with Tamil Nadu and Maharashtra for a Sample Day, September 2022**



Note: Excludes must-run plants

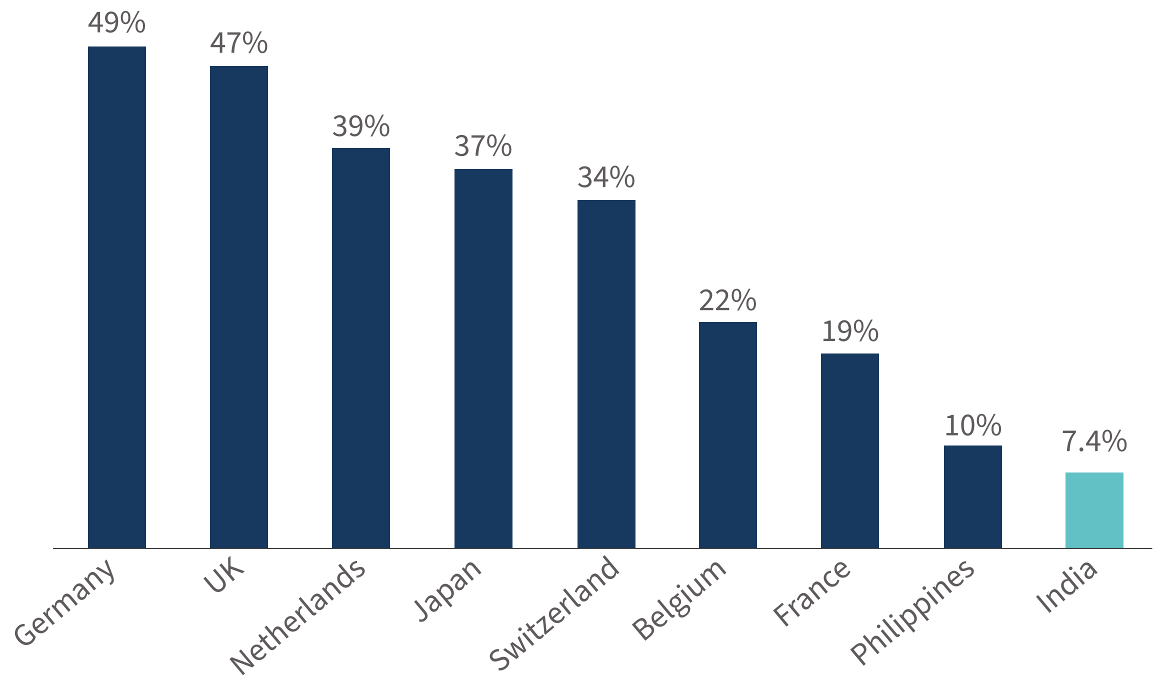
Source: EData from MERIT India for 15 September 2022; excludes must-run plants.

- **Limited Geographic and Seasonal Flexibility:** The self-scheduling mechanism also hinders the system's flexibility, limiting its ability to react to seasonal changes or geographic variability of generation. Self-scheduling may further contribute to curtailment of low-cost RE generators, which have limited opportunity to sell through alternative avenues due to lack of visibility to other discoms. For example, a discom that has contracts with hydro generators may not need to use other low-cost generation capacity during monsoon season. Nevertheless, discoms may be compelled to keep running more expensive generators at the technical minimum in off-peak periods, resulting in cheaper generation being available but backed down. An additional consequence may be RE generators having limited ability to service a broad geography of demand, increasing the risk of curtailment during periods of high generation.

- **Limited Opportunities for Short-Term Power Procurement:** Discoms rely on a high volume of long-term contracts for power procurement. These contracts are often inflexible, and locked-in prices may not fully capture savings from efficiency gains or declining capital costs of the new generation. In FY2022, less than 13% of the total electricity consumption in India was served through short-term markets and 7.4% through power exchanges.[xi] By comparison, regions with mature, deeply liberalized markets are often 30%–80% (see Exhibit 9), while several emerging power markets such as the Philippines have a spot market penetration above 10%.[22]

xi This excludes captive generation plants.

Exhibit 9 **Share of Power Procured Through Spot Power Markets by Geography**



Source: India Energy Exchange (IEX), Argus, IEMO Philippines

Policy changes to scheduling and dispatch that enhance visibility across discoms, improve transparency and standardization of data, and reduce curtailment risks of low-cost generation will be key to unlocking a successful, reliable, and flexible power sector. Pilot projects demonstrate improved optimization of scheduling and dispatch results in cost savings (see Box 1). MOP's MBED proposal is aimed at enhancing the realized efficiencies by coordinating nationally among generators and discoms.

Box 1: Security Constrained Economic Dispatch (SCED) Pilot [23]

Grid-India undertook a pilot project on a scheduling and dispatch model called Security Constrained Economic Dispatch (SCED) beginning in April 2019. This pilot aimed at minimizing wholesale power generation costs by optimizing the dispatch of ISGS generators. Multiple beneficiaries are allocated shares (within and across regions) of ISGSs, but generation remains unrequisitioned for certain ISGSs depending on the requirement of the states. The objective was to minimize the total generation cost while honoring the technical constraints of the generating plants and grid. These constraints included, among others, the technical minimum of plants, transmission constraints, and ramp up and ramp down rates.

The SCED pilot successfully demonstrated the value of streamlining the scheduling process while accounting for RTM and balancing the system. By February 2022, 49 plants participated in the SCED pilot, representing a total capacity of 58,180 MW. The pilot successfully demonstrated a total variable cost reduction of INR 2,070 crore or INR 1.94 crore a day, amounting to nearly 1% cost savings on variable charges.

The SCED pilot provides insight into the technical and regulatory capacity readiness necessary to successfully transition to a more centrally coordinated scheduling and dispatch mechanism. This includes understanding the software needs for pan-India scale scheduling and communication infrastructure. The pilot also highlights the regulatory frameworks that need to be built for sharing benefits and meeting the spinning reserve requirements.

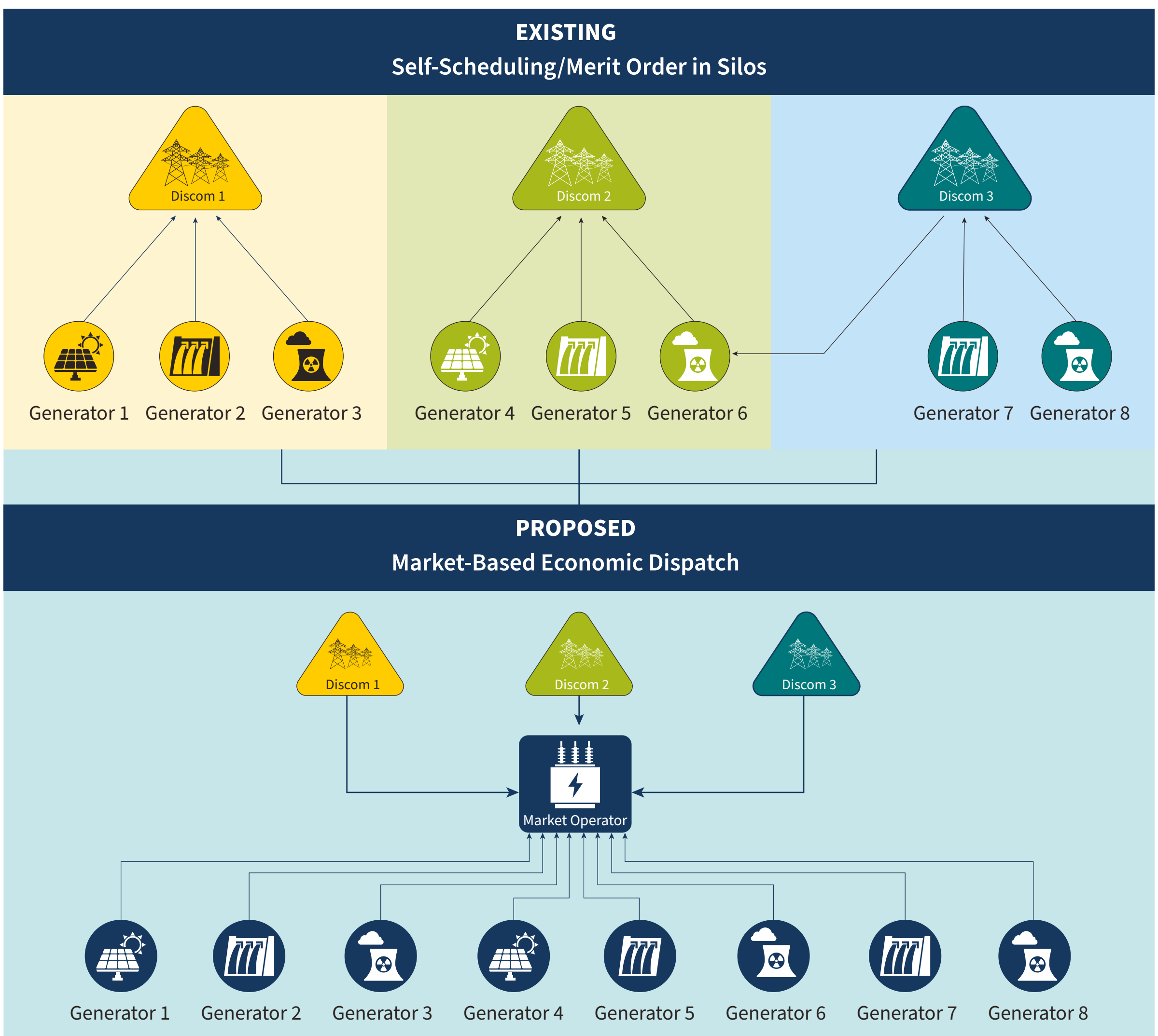
Despite the significant value unlocked by SCED, the pilot faced two key limitations: it only applied to voluntary ISGS generator participants and accounted for noneconomic factors such as a plant's technical minimum. Additional cost savings, among other benefits, could be captured through a scheduling and dispatch system that prioritizes optimization based on variable cost. This can be realized by allowing unit commitment for the cheapest generators first rather than optimizing after plants are committed and scheduled.

Source: **Power System Operation Corporation Limited**

Market-Based Economic Dispatch

The MOP proposes establishing a centralized day-ahead wholesale market in India, known as Market Based Economic Dispatch (MBED), based on the principles of economic dispatch. The MOP's vision is to establish an efficient and transparent market with a uniform, national market clearing price as an extension of previous policies that sought to unify India's grid. The proposal is a shift from the existing model for electricity dispatch within India and in line with historic shifts towards a liberalized, market-based approach for the power sector. Exhibit 10 demonstrates the change in approach for scheduling and dispatch.

Exhibit 10 **Transition from Existing Framework to Proposed Market-Based Economic Dispatch**



The previous section describes the existing model as decentralized, with discoms self-scheduling generation. Currently, discoms predominantly schedule from their portfolios of long-term contracts and procure the remaining shortfall through bilateral transactions with other discoms, trading companies, or power exchanges. Within individual states, the merit order dispatch allows for least-cost dispatch. We have a less efficient national dispatch, as transparency issues across states often mean states may possess high volumes of low-marginal-cost generation, while other states are more reliant on high-marginal-cost plants (see Exhibit 8).

The MBED policy proposal centralizes certain market operations and optimization functions. These changes bring India's power markets closer to a centralized market design while maintaining several aspects of the existing decentralized market design. The proposal will have distinct market and system operators, such as in the decentralized approach. However, it establishes a centralized approach for scheduling and dispatch through a day-ahead market on national basis, with bids from generators and discoms (or other market participants) utilized to form a national merit order bid stack.

Buyers and sellers shall submit bids and offers to market operators on a day-ahead basis. These bids and offers shall be pooled and utilized to create the national merit order bid stack. The market clearing price will then be discovered per common merit order for each time-block of the upcoming day. This enables scheduling and dispatch of all generation on economic principles, subject to plant and network constraints. Cleared buyers will pay the market clearing price to the power exchange, which will then pay it to cleared sellers. Buyers will continue to pay the fixed costs outside the market.

As of 2022, approximately 86% of the bulk electricity procured by discoms is from long-term contracts. Transitioning to the MBED mechanism can encourage increased reliance on short-term contracts for meeting future electricity demand growth.

Bilateral Contract Settlement Mechanism

The MOP developed the bilateral contract settlement (BCS) mechanism as a step towards the broad implementation of MBED. Through MBED, discoms can self-schedule generators on long-term contracts, but generators and discoms are required to participate in the DAM of the power exchanges for bidding. Generators are paid the market clearing price according to the execution of their selection bids. The BCS mechanism is implemented after the market clearing price is determined and selected bids are executed. Under the BCS mechanism, discoms with long-term contracts are refunded the difference between the market clearing price and contracted price, per the quantum of power self-scheduled.

Final settlements between generators and discoms are executed as per the terms of the contract through the BCS mechanism, including the reimbursement timeline. The oversight for appropriate execution of contracts is shared between CERC and the Securities and Exchange Board of India (SEBI). CERC's jurisdiction covers ready delivery contracts and nontransferable specific delivery contracts, while SEBI's jurisdiction includes commodity derivatives in electricity other than nontransferable specific delivery contracts.

Summary of Phase 1 (since April 2022)

MBED is set to change how power is scheduled and dispatched. As part of the transition, the MOP proposed the initial phase (Phase 1) beginning in April 2022. During Phase 1, state-owned thermal generation plants have adjusted activities and responsibilities. Key changes for thermal plants under Phase 1 are summarized in Exhibit 11.

Exhibit 11 Summary of Activities and Responsibilities under Phase 1

SCHEDULING	MARKET CLEARING	DISPATCH	PAYMENT	SETTLEMENT
Discoms and generators shall participate in the day-ahead market segment of the power exchanges for bidding. Discoms and buyers shall be required to submit bids for all the time-blocks of the upcoming day.	Once the bids and offers are received, the market clearing engine will seek to optimize the dispatch of the generation sources accounting for technical constraints. National merit order shall be formed and all generators scheduled.	The entire demand shall be met by dispatching the least-cost generation mix while ensuring the security of the grid.	Discoms or other buyers will pay the market operator at the MCP for the day-ahead demand. Generators will be paid at the MCP according to the execution of their scheduled bids.	Buyers under long-term contracts will be refunded the difference between the market clearing price and the contracted price as per the quantum of power self-scheduled through the Bilateral Contract Settlement (BCS) mechanism.
Discoms may choose to submit "fixed demand" in each time-block, which is price-inelastic and must be served. Any demand exceeding the fixed demand in each block will be price-sensitive.	Market clearing prices shall be discovered for each 15-minute time-block of the upcoming day.	Cheaper plants shall be dispatched to the maximum extent; costlier plants will run as required.	Discoms will not pay generators the variable charges directly.	BCS would be carried out accounting the quantum of power, which is self-scheduled as "fixed demand."
Generators shall submit offers with no adjustments for retrospective revisions in fuel and other charges. Generators shall be cleared based on the total demand bid into the day-ahead market.	Plants shall not have the Right to Revise (RTR) until the results of the day-ahead market are announced. RTR will be reinstated considering the quantum not cleared in the day-ahead market from candidate plants.	Beneficiaries needing to buy or sell additional power closer to real time can participate in the Real-Time Market and correct their day-ahead positions suitably.	Generators who have a long-term contract and are due the fixed charge, will continue to be paid the fixed cost separately outside the market.	Generators may sell URS power through the power exchange. Net revenue earned by generators selling URS power will be shared with concerned beneficiaries in the ratio of 50:50.

In summary, the MBED proposal represents a major change in how the power sector currently functions by establishing a centralized approach to determine the national market clearing price. However, market integration has multiple benefits that can address persisting challenges and inefficiencies in India's power sector. These anticipated benefits are detailed in the following section.

Anticipated Benefits of MBED

The MBED policy proposal is expected to add a dimension of uniform clearing prices to the existing "One Nation, One Grid, One Frequency" framework in India. Transitioning from a state-level siloed approach of scheduling and dispatch of energy to a national merit order ensures generation resources are utilized efficiently and cost-effectively and unlocks savings on system operations that can be passed on to discoms. As India plans to meet its increasing electricity demand and NDC targets of 50% non-fossil fuel generation capacity by 2030, fostering market integration and inter-regional sharing of resources will play an increasingly important role in ensuring a reliable and secure grid.

The current structure of wholesale markets in India relies more on long-term PPAs, limiting a discom's cost efficiency and operational flexibility. There is scope for cost efficiency at the national level by enabling least costly and most efficient generators to meet a significant share of demand that can help lower states' power procurement costs. Centralized scheduling and economic dispatch can introduce flexibility in the existing PPAs by enabling discoms to buy cheaper power from the market and allowing price discovery for generators, thereby making the market increasingly competitive, efficient, and transparent.

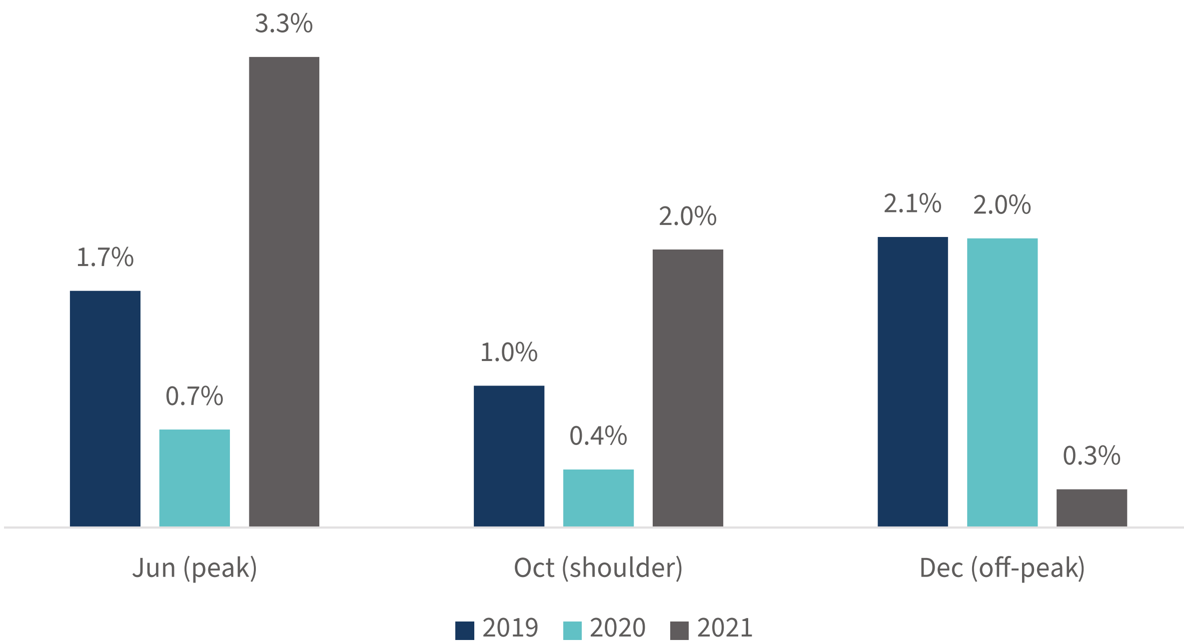
The proposed market reform would also make it easy for the national grid to absorb high shares of renewable capacity. In recent years, discoms displayed a reduced appetite for new long-term bilateral contracts due to falling RE tariffs. Concurrently, RE developers are increasingly cautious of signing contracts due to counterparty risk from financially distressed discoms.[24] In the near term, both these factors can act as barriers to India's ambitious RE targets. Promoting inter-regional coordination and ensuring market-based dispatch can reduce the risk of curtailment and enable states to meet a high share of power procurement from renewable sources.

India can draw from policy reforms in other global markets that successfully realized the benefits of creating integrated power markets and improving regional coordination to facilitate the penetration of variable RE while enabling necessary grid flexibility. By implementing MBED, India can expect similar benefits as the ambit of participation is expanded to a national scale.

System Cost Savings

India has taken strides towards energy security, ensuring energy access to consumers in the past decade and transitioning from a power-deficit to a power-surplus scenario. The installed generation capacity and peak demand stood at nearly 400 GW and 190 GW, respectively, in FY21, indicating availability of sufficient capacity at the national level.[25] However, demand shortfalls (in energy and peak terms) exist in some states and vary across seasons as electricity demand during the summer increases (see Exhibit 12). While some states have limitations of contracted capacity due to self-scheduling, surplus generation is available in other states.[xii] The mismatch of excess capacity as well as poor liquidity in the spot market (~6%) indicate enabling a pan-India pool of generators for dispatch can unlock monetary gains for the system.

Exhibit 12 **Peak Demand Shortfall for Northern Region**



Source: CEA

Note: Shoulder month refers to moderate demand period, typically when many thermal plants are scheduled for planned maintenance.

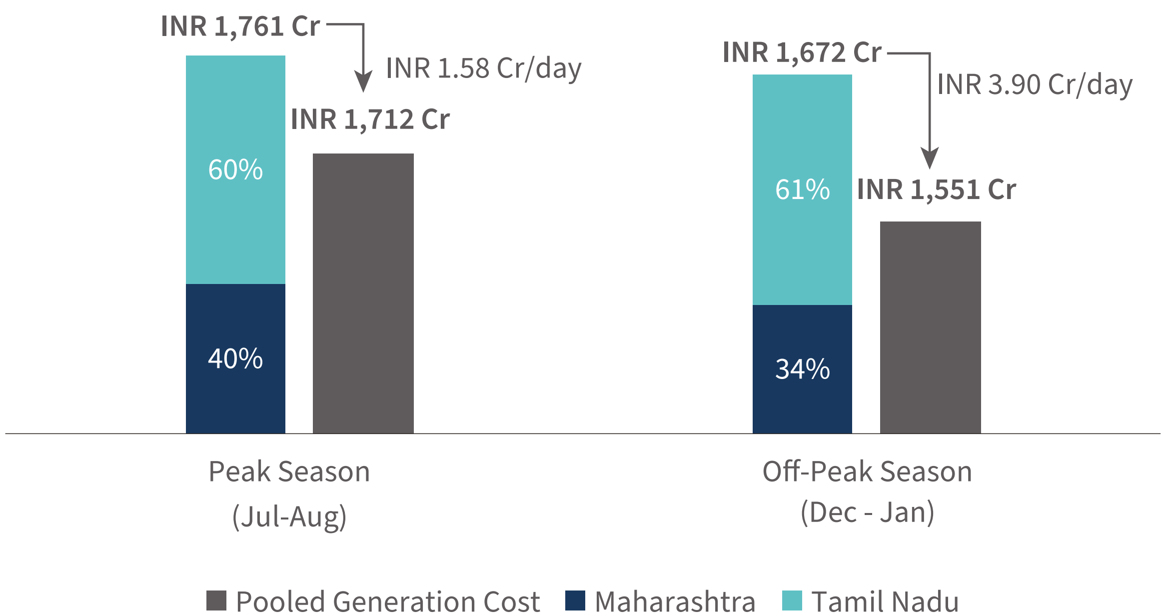
Centralized scheduling and dispatch under the MBED framework can have cascading benefits for system operations. Reallocating the available surplus capacity from the highest- to the lowest-marginal-cost generator for each time-block ensures the demand is met with least cost. This can improve power procurement for state discoms and lower their average cost of supply, transmitting the benefits to end consumers. In addition, the MBED framework incentivizes the dispatch of plants with the lowest marginal cost and ensures high utilization of pit head coal plants and reduced transportation-related emissions from the sector.[xiv]

xii Planned and unplanned outages of generators, transmission constraints, and generator technical requirements (ramping, technical minimum) are also key reasons.

xiv Pit head coal plants refer to generation plants located in proximity to coal mines.

This section assesses the potential benefits of MBED by comparing system operations costs and generator utilization for two states (Maharashtra and Tamil Nadu) under the base case of siloed dispatch (where each state dispatches its contracted plant capacity without visibility of surplus capacity in other states) compared with pooled, centralized dispatch where the total demand is met by a reordered stack of generators based on new merit order. The empirical analysis utilizes generator-level data on costs, declared capacity, and actual generation for plants for two historical periods representing peak and off-peak demand seasons. Our analysis reveals potential savings of INR 1.5–4 crores (US$184,000–US$491,000) per day across peak and off-peak seasons or 2.8%–7.0% annual savings from the BAU scenario, respectively (see Exhibit 13). Savings during the off-peak season are expected to be high as low demand allows increased scope of optimizing the dispatch of least costly plants against expensive plants.[xxvi]

Exhibit 13 **Assessment of variable cost savings during peak and off-peak season for Maharashtra and Tamil Nadu**



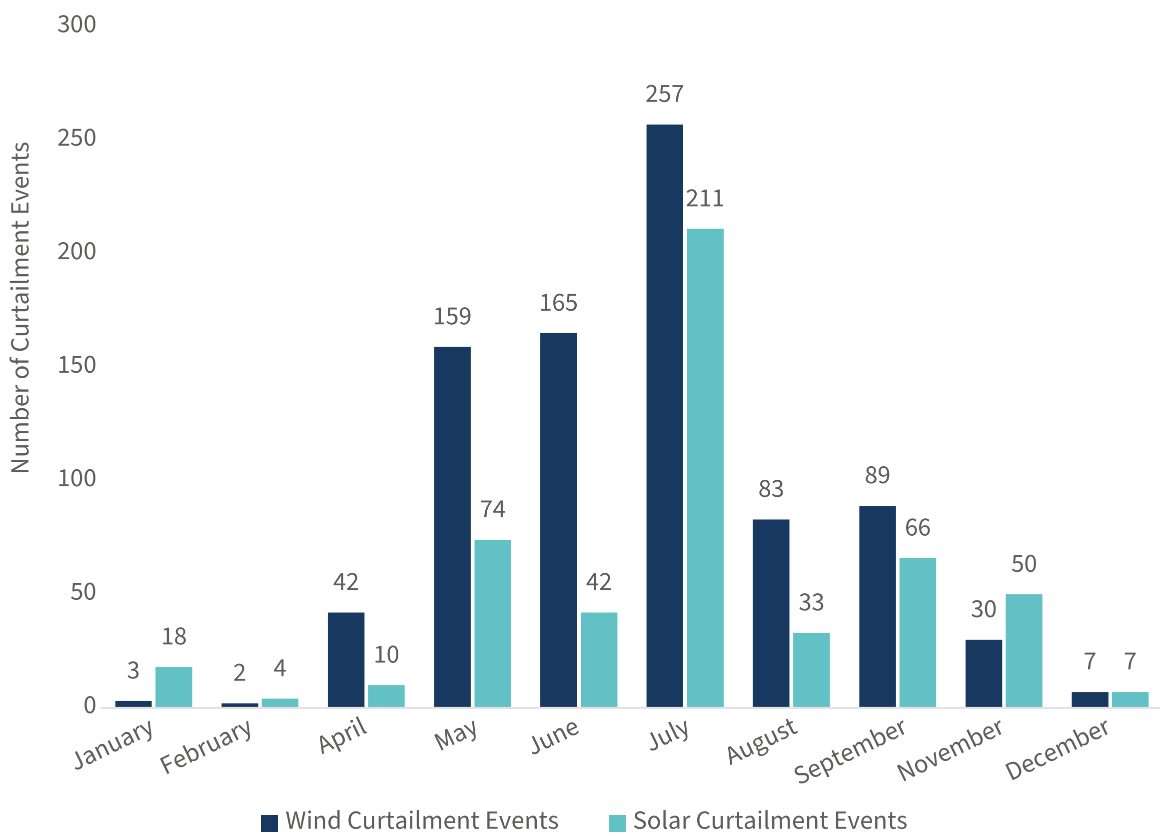
Source: RMI Analysis

The benefits of pool-based dispatch under the MBED framework are related to the degree of participation from generators, as a wide spread of variable costs and balancing area offers significant potential for savings from the reallocation of generation. A 2017 study by the US National Renewable Energy Laboratory (NREL) estimates transitioning from the current self-scheduling scenario to regional coordination could result in 2.8% annual savings or INR 17.6 crores/day (US$2.2 million/day), with national coordination increasing the benefits up to 3.5% or INR 22 crores/day (US$2.7 million/day).[26] Another study by Lawrence Berkeley National Laboratory (LBNL) determines potential cost savings of 5% or INR 38 crores/day (US$4.7 million/day) by 2030 under MBED due to a more efficient dispatch, resulting in a 5% reduction in the emissions intensity of the grid.[27] However, the scale of benefits may not be similar for all regions, as the western and eastern regions have higher capacity of low-marginal-cost coal plants, which will be utilized more at the cost of more expensive plants in the southern region.

Unlocking High RE Integration

The penetration of RE in India is geographically concentrated, with the top six states — Karnataka, Andhra Pradesh, Tamil Nadu, Maharashtra, Gujarat, and Rajasthan — accounting for nearly 80% of the intermittent renewable capacity installed nationally.[28] RE-rich states such as Andhra Pradesh face significant system integration and RE curtailment challenges (see Exhibit 14). Owing to high RE generation during summer and monsoon, the number of curtailment events rise significantly from that in the rest of the year. Although RE generators have a must-run status in India, which means curtailment may not be permitted due to commercial reasons, many plants are curtailed due to system constraints such as insufficient flexibility of generators within the state. This highlights the need for a large balancing area and promoting inter-regional transfer of surplus generation from these states to facilitate RE integration required for India to meet its NDC targets.

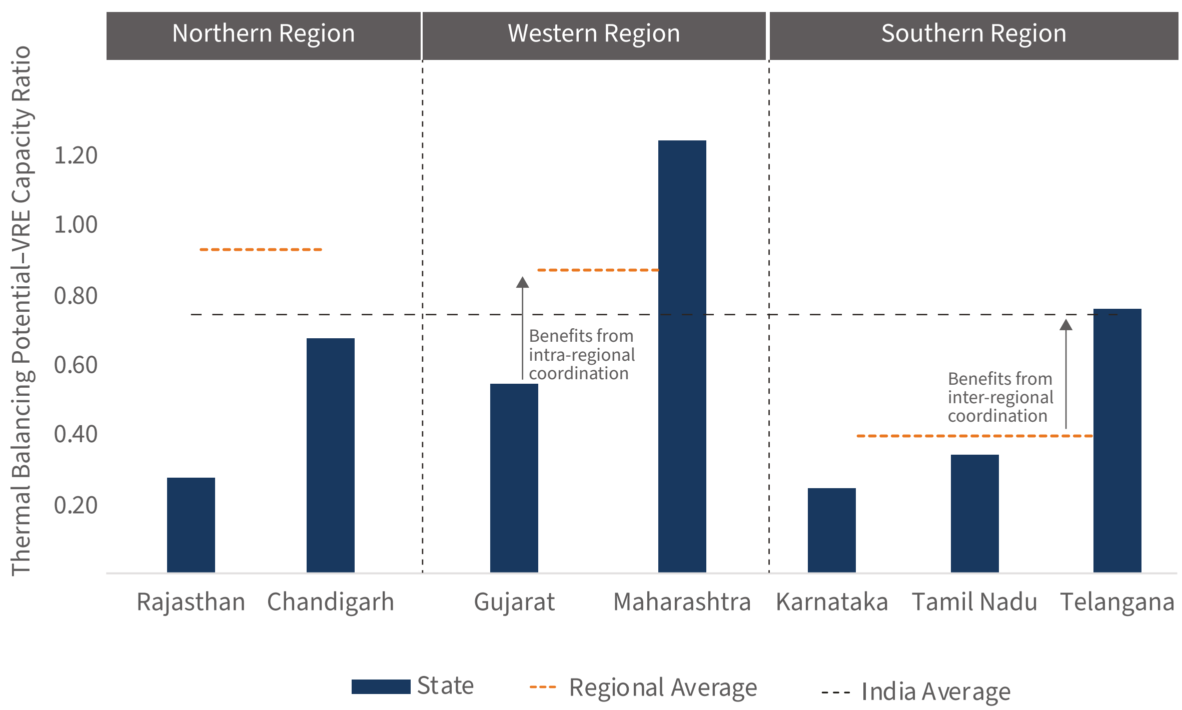
Exhibit 14 **Number of Wind and Solar Curtailment Events Reported for Andhra Pradesh**



Source: Transmission Corporation of Andhra Pradesh

MBED helps balance the variability in RE generation by expanding the geographical area from the state level to the pan-India level to reduce the number of frequency excursions beyond acceptable limits at the regional grid level and lessen the risk of RE curtailment. As MBED allows RE-rich states access to balancing resources beyond their state borders, discoms can lower investments in the necessary reserve capacity. The regional and national balancing potential is significantly higher than most of the individual state's balancing potential (see Exhibit 15). As a result, RE-rich states can realize incremental benefit from expanding the scope of coordination from the existing state level to the pan-India level by sharing balancing reserves available in other regions, thereby reducing the overall volume of balancing reserve requirement at the national level. MBED plays a key role in addressing RE curtailment challenges in RE-rich states due to lack of flexibility margin available within the said states.[29]

Exhibit 15 **Thermal Balancing Potential at State and Regional Level**



Note: A low bar size indicates a high degree of variable renewable energy (VRE) penetration in states/regions compared with thermal capacity. A higher balancing potential ratio (y-axis) at the regional level compared with states indicates a larger volume of thermal balancing capacity is available at the regional scale.

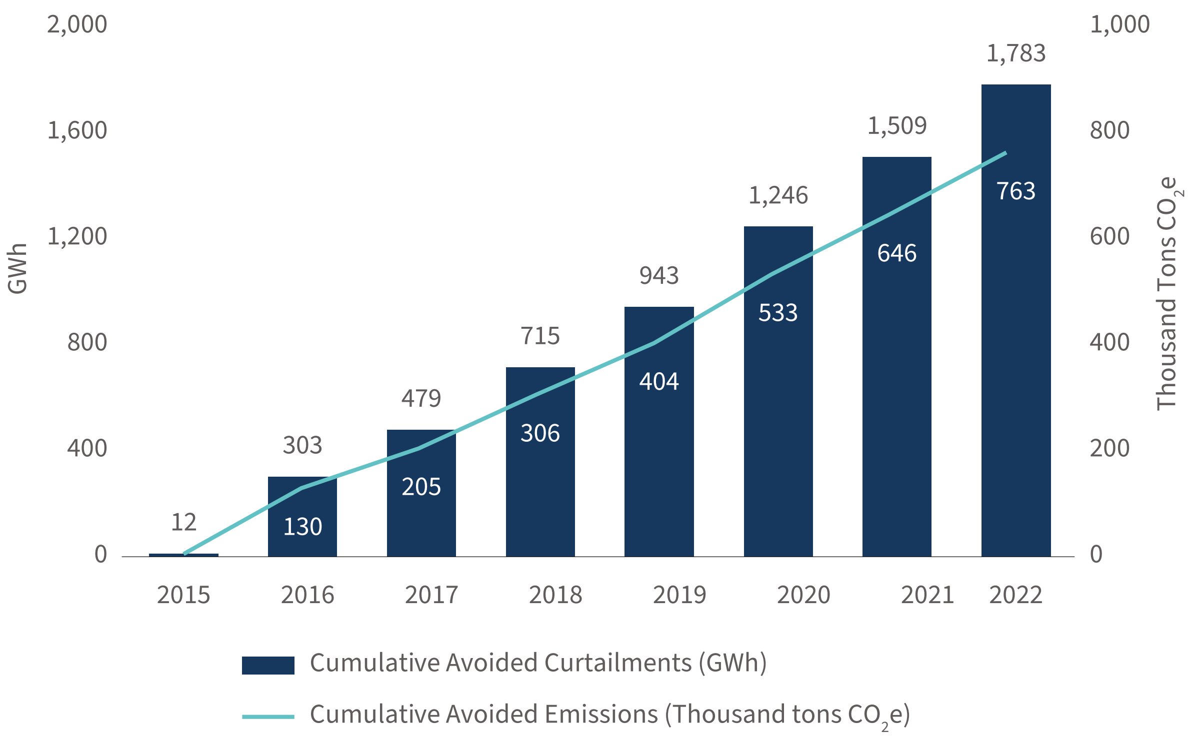
Markets and system operations must be effectively designed to create the synergies required for integrating high share of intermittent RE into India's power mix. Globally, national and regional energy markets have progressed to varying degrees of integration to coordinate RE generation and demand across a wide geographical area. These markets have created interactive wholesale energy, imbalance, and ancillary service markets, in addition to strengthening inter-regional networks to facilitate high penetration of RE generation while managing the reliability of grid operations. A summary of the benefits achieved in the expanded balancing across regions under the Western Energy Imbalance Market in the United States and Nord Pool in Europe is presented in Exhibit 16. Similar benefits in power costs and RE capacity addition can be unlocked in India with market reforms such as MBED.

Box 2: Western Energy Imbalance Market (WEIM) in the United States

The WEIM is a voluntary RTM run by CAISO in the United States. It was created in 2014 to address the challenges and opportunities of change in demand patterns and an anticipated increase in variable renewable generation from wind and solar in the western regional grid (termed the Western Electricity Coordinating Council), driven by renewable portfolio standards. Before the WEIM was formed, most entities in balancing areas outside of independent system operator (ISO) control in the Western Interconnection, such as CAISO and AESO, procured a large share of their power requirement through bilateral contracts. This led to poor liquidity and operational inefficiency in the market, hampering the addition of new RE capacity without compromising on reliability.

WEIM optimizes dispatch at the intra- and inter-regional levels for participating utilities and balances variability in renewable generation over a wide area, thereby reducing curtailment. Since its inception, the number of participating entities has grown from 2 in 2014 to 19 as of 2022. Due to a more efficient and economic dispatch in the RTM, WEIM participants have unlocked nearly $2.4 billion since 2014 by having more balancing areas participate in a coordinated dispatch, displacing expensive generation, and avoiding curtailment of nearly 1.8 TWh of intermittent RE generation. The associated emissions reductions are nearly 0.8 million tons of CO_2 (see Exhibit 16), the equivalent of emissions from powering 96,000 homes for a full year.[30]

Exhibit 16 Avoided Curtailments and Emissions Under WEIM, 2015–22

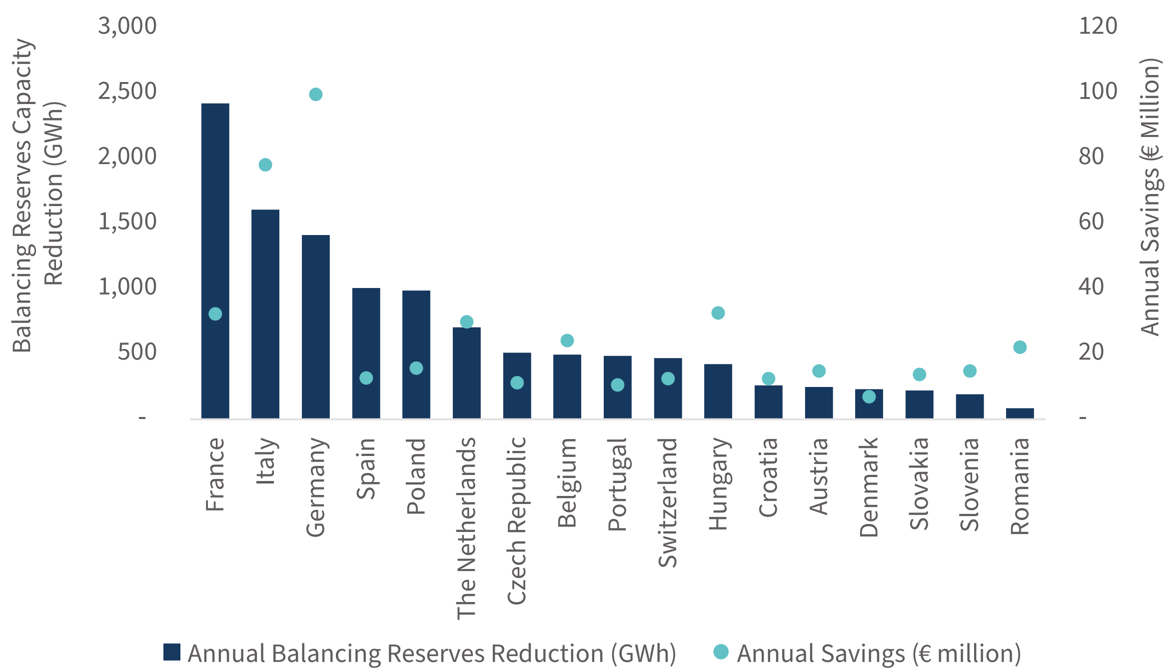


Box 3: Nord Pool – Integrated Market in the EU

The first example of multinational wholesale markets in Europe was the Nord Pool, which involved market-based cross-border trading of power between Norway and Sweden. The EU council has since strived to introduce competition and improve system operational efficiencies through cross-border trade among member nations to establish an integrated European electricity market. This is identified as a key framework to achieve EU targets of 40% reduction in emissions and 32% share in renewable generation by 2030.[31]

The European market has nine power exchanges that organize day-ahead and intraday markets adopting a price coupling mechanism for uniform price discovery across countries. The benefits of efficient utilization of generation capacity across regions and improved RE penetration were estimated at nearly €34 billion (US$37 billion) in 2021.[32] An additional €203 million (US$220 million) could be realized in savings annually if market coupling in the DAM is extended pan-Europe, as it is limited to 27 countries. Regional integration also enabled sharing of balancing reserves among countries required to maintain grid stability as RE capacity grows (termed imbalance netting). This unlocked nearly 11.8 TWh in energy savings during 2021, reducing operational costs by €444 million (US$482 million) at the country level (see Exhibit 17).[33] The distribution of these savings for individual nations depends on the level of RE penetration and cross-border interconnection capacity, among other factors.

Exhibit 17 Benefits of Balancing Reserve Sharing in Integrated European Market, 2021



Note: Reduction in balancing reserves (termed netted volumes) activated simultaneously to preserve grid stability is possible due to cross-border regional trade.

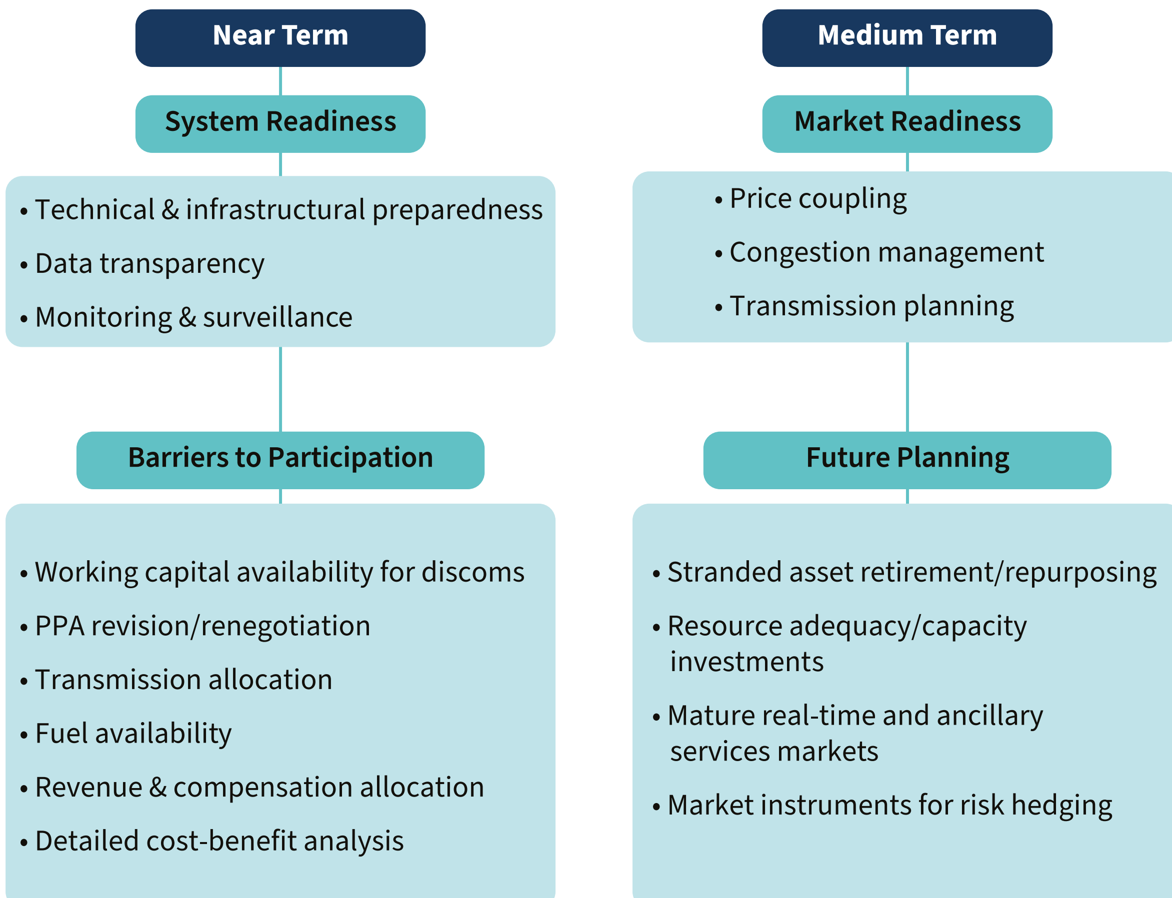
Source: European Network of Transmission System Operators for Electricity (ENTSO-E)

Barriers to Seamless Transition to MBED

Reliable daily operation of the electricity grid involves close coordination between various stakeholders such as generators, discoms, power exchanges, and system operators at the state, regional, and national levels. MBED looks to transform a key status quo in the way the existing Indian electricity market operates — how efficiently generators are scheduled in the day-ahead spot market to deliver the benefits of low overall system costs to states and end consumers. MBED also plays an important role in meeting India's NDC target of integrating 50% share of non-fossil-fuel generation capacity in the generation mix by 2030, by improving the visibility of price signals reflective of actual marginal costs. Price visibility can lead to ripple effects on how deviations from generator schedule in real time, congestion in the transmission network, and reserves required to address grid contingencies are treated. Clear operational guidelines for these mechanisms will be the first step in addressing uncertainties and aligning stakeholders with the vision of the proposed framework.

The MOP pursued a comment solicitation process that was open to the public for several months, bringing in candid perspectives from a range of stakeholders. RMI's analysis of the comments received from nearly 37 agencies and expert groups highlights diverse perspectives on the operational challenges, acknowledgement of the present structure of market regulations in India, and uncertainties in MBED implementation.[34] Exhibit 18 highlights some key implementation challenges and uncertainties. The MOP proposes a phased implementation approach to MBED to enable stakeholders, market, and system operators to adapt to the new mechanism while drawing operational experience from an initial pilot exercise with voluntary participation of all generators except ISGS.

Exhibit 18 Challenges and Barriers to Implementation Highlighted in Stakeholder Consultation Process



This section assesses the degree of system preparedness and implementation challenges for the MBED transition and highlights successful market design and integration case studies from international markets. The following section discusses how a smooth MBED transition requires aligning diverse stakeholder interests by addressing concerns about stranded assets, impact on existing contracts, and financial settlements.

System Preparedness

Data Transparency and Reliability

Under MBED, all generators must place selling bids for the following day through market operators based on their marginal costs. The marginal cost basis is expected to determine the true system-wide cost, as envisioned under the framework of One Nation, One Grid, One Frequency, One Price. System operators must ensure accurate and standardized reporting of bids and system data (such as reliable forecast of load and generation for each state, and transmission network capacity at the inter- and intra-state levels) to optimize the scheduling and dispatch of plants. However, existing mechanisms on data disclosure and adjustment for settlements between contracted generators and discoms after the delivery date are not aligned with this principle.

- **Cost Data:** The actual marginal cost of generation for plants on a daily basis can differ significantly from the variable cost determined by state regulators and can change monthly. In addition, there is no reporting of the marginal costs of plants other than ISGS and some state generators. Lack of granular and standardized data reporting can affect the day-ahead bidding schedules.

- **System Operational Data:** System operators do not have access to granular data on the transmission capacity available at the state level, which can prevent intra-state generators from participating in MBED. As the number of generators participating in MBED increases, the transmission flow on specific intra-state or inter-state lines may increase beyond the available limits, as in the southern region during the SCED pilot.[35] System operators require detailed availability of network capacity to ensure sufficient margins are available to accommodate these variations in the power flow.[xv] Furthermore, high VRE penetration necessitates robust generation forecast at the state periphery to enable reliable grid operations.

Market Management Systems

The volume of transactions to be managed for each settlement period is expected to be high as MBED scales up. This warrants an integrated market management system that includes IT services such as meter data management and EMS for scheduling, resource commitment, and dispatch for the DAM and RTM. The existing monitoring and surveillance system may be inadequate to verify if system operations are consistent with efficiency and reliability needs, detecting manipulation (including information withholding and false reporting), and ensuring a competitive market. Power exchange — which acts as market operator — will bring about an exponential rise in bid volumes, necessitating the incorporation of a clearing corporation facility that can handle the transactions. These are currently self-clearing and cannot accommodate the increased transaction volumes.

Key Questions

- How can technology readiness (IT, SCADA/EMS, etc.) for system operators be scaled up over the next couple of years to facilitate a full shift to market?
- What are the barriers to standardized data disclosure and reporting (costs, network capacity, etc.) at the state and national levels and how can these be addressed?

xv General Network Access (GNA) regulations announced by CERC in June 2022 and procedures for the allocation of transmission corridors under GNA, as outlined by the system operator, foster open access for an integrated electricity market and require detailed reporting of transmission capacity and margins for all regions/states.

Mature Real-Time and Ancillary Services Markets

MBED DAM is one step in the evolution of electricity market design for India — it needs to work in tandem with RTM to ensure intraday balancing to accommodate high share of variable renewable capacity. Currently, the liquidity on RTM is low, as the volumes traded were nearly 1.3% of the total generation in FY21.[36] Additionally, as the ancillary services market matures, MBED energy offers must be cooptimized to determine the reserve requirement on regional basis. This calls for reliable and detailed reporting of generator technical data and costs to provide the price signals to the market. This is still in its nascent stage in the Indian power market and must be prioritized by the planner and regulator to chart out an implementation plan for a market-based mechanism for both markets as complements to the day-ahead energy market under MBED.

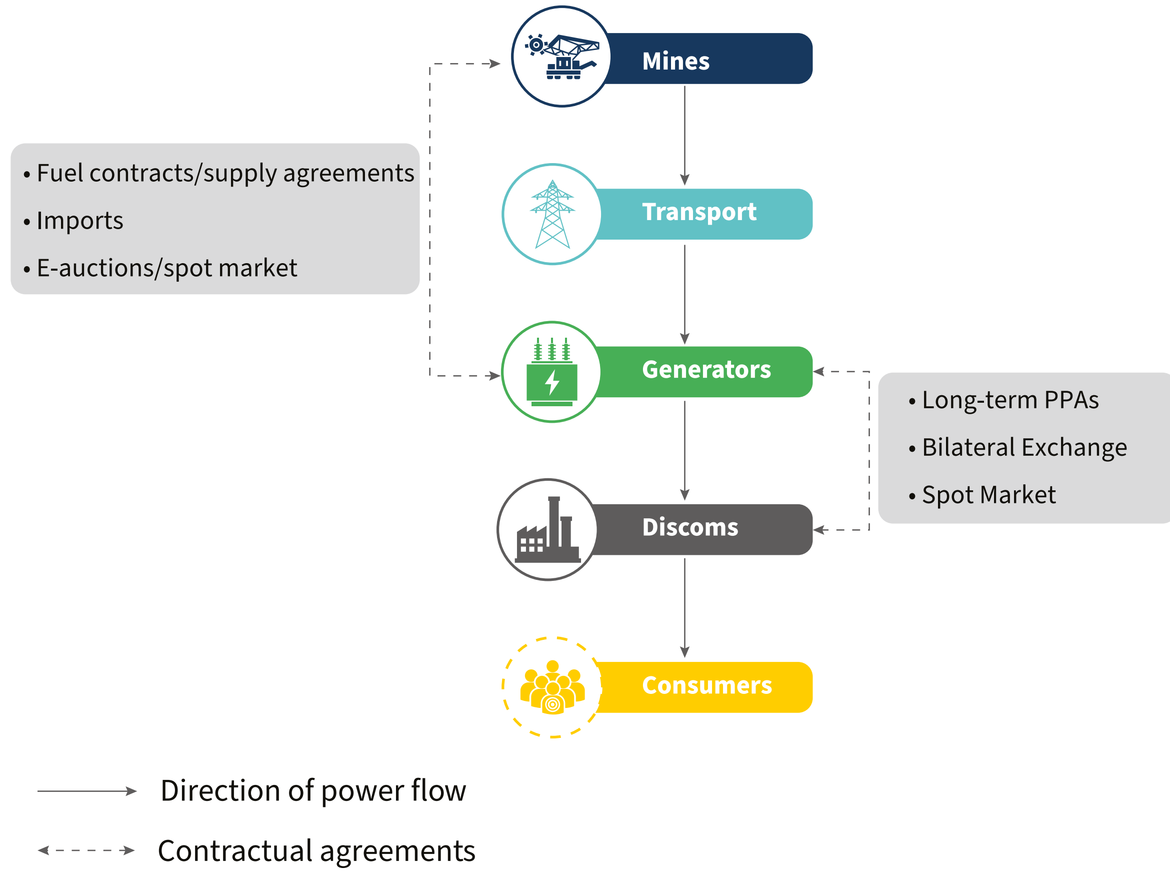
Key Questions

- Which regulatory and policy enablers ensure high liquidity in RTM?
- How can the implementation of a market-based mechanism for ancillary services be accelerated to allow the participation of fast-response technologies such as battery storage and demand response?

Fuel Availability

Energy markets have a critical dependence on fuel markets — volatility and vulnerability in reliable fuel supply are transmitted upstream to power markets, creating operational and financial challenges for buyers. In the current scenario, long-term power purchase contracts between discoms and generators are supplemented by similar fuel supply agreements between generators and fuel markets (see Exhibit 19). While plants with long-term offtake contracts can secure low-cost coal (e.g., through linkage policy), merchant plants are unable to do so and must buy expensive coal through auctions, raising their marginal cost. This could be a significant barrier to the participation of efficient generators in dispatch. Unless all coal plants assuredly receive a contracted quantity adequate to run the plant at normative PLFs, as required by regulations, the MBED framework could lead to a non-level-playing field for generators as the pit-head plants benefit from assured coal availability and lower marginal costs on average due to reduced fuel transport costs.

Exhibit 19 Linkages Between Fuel and Electricity Markets in India



Source: Adapted from Khanna, et al., 2021[37]

In addition to fuel allocation issues, the merit order under the existing self-scheduling mechanism is based on dated fuel cost data from one to three months before the physical delivery of power. The fuel price component of marginal costs is adjusted between beneficiary discoms and generators over several months after the actual date of delivery. Under MBED, this reporting lag would lead to an inefficient merit order clearing. Gas generators' average variable cost could be based on domestic gas pricing, but they often resort to imported RLNG (expensive) due to APM gas shortage, making it difficult to schedule them in merit order.[xvi] However, these plants are required to be on bar to meet peak loads and address grid flexibility issues. These plant-specific concerns, unless addressed, could prevent participation.

Key Questions

- Which policy interventions ensure that fuel allocation and adequacy concerns do not hamper the participation of generators?
- How can a level-playing field be ensured for captive generators and merchant plants to maximize participation?

xvi The administered pricing mechanism (APM) price refers to an "assessed price" set by the government for domestically produced gas in key offtake sectors such as power and fertilizer.

Box 4: Fuel Security in New England

The Independent System Operator of New England (ISO-NE) serves an area covering six states in the United States. The ISO-NE service area recorded a series of issues related to fuel security during 2004–06. These included winter temperatures in January 2004, which disrupted supply infrastructure and natural gas supply disruption caused by Hurricane Katrina in 2005. Increased reliance on natural gas for heating and power made wholesale market prices in ISO-NE particularly sensitive to natural gas price volatility.[38] Winter fuel reliability is a persistent challenge in the ISO-NE service area.

To address the ongoing fuel security concerns, ISO-NE undertook scoping and planning for infrastructure capacity to ensure that the growing reliance on natural gas is credible. ISO-NE began providing economic incentives in 2013 for generators to acquire firm fuel supplies. Wholesale market rules were also adjusted to better align natural gas and electricity market timelines, providing generators additional time to procure natural gas and a better opportunity to recover fuel costs under specified conditions. [39]

Stakeholder Buy-In

The structure of the Indian power sector reveals institutional relationships that must align on agendas and vision for the development of policies. Electricity is listed as a concurrent topic in the constitution, empowering state and central governments to regulate the sector and drive institutional change. Transitioning the existing decentralized mechanism of energy scheduling to a centralized control requires extensive negotiations with states, discoms, and asset owners (generation and transmission) before MBED can be operationalized.

Discoms

The MBED transition could accelerate reduced utilization of high-marginal-cost plants, many of which are tied up in long-term contracts. A proactive approach to renegotiating the pricing terms and tenure of these contracts can help discoms reduce the average cost of power procurement and move to short-term markets. Generators may also benefit from freed-up power, which can be sold to other buyers on the market. Since discoms are proposed to purchase power through the exchange under MBED, concerns regarding the renegotiation of existing PPAs need to be addressed before pilots can be implemented. India can draw lessons in this aspect from global case studies involving renegotiation of long-term contracts to retain some degree of commercial value for buyers and sellers, such as California’s experience after the market crisis of the early 2000s and that of the Philippines during the power sector reforms in 2001.[40]

Box 5: Legacy PPA Renegotiation during California's Electricity Crisis

California entered into costly long-term power purchase contracts with generators in 2001 in response to the supply crunch in the state (see Box 9). However, as spot market prices stabilized because of low demand in summer, the state sought to renegotiate contract terms with 14 suppliers to avoid paying for costly power in the long run. The state agency renegotiated several long-term contracts, saving nearly $3.5 billion in power costs while ensuring future capacity commitments from generators and reliable contract structures to supply power during peak periods.[41] The focus areas of restructuring legacy PPAs included shortening the duration of contracts (in one case with Calpine Corp. — from 20 years to 10 years) and commercial terms such as the share of nonfirm versus firm power delivery, in essence reducing the average cost of power over the life of the contract.[42] Similar processes need to be undertaken to set the stage for MBED implementation, which may also provide discoms more financial confidence to continue with renewable PPAs.

Asset Owners

The implementation of MBED across India risks the creation of new stressed/stranded thermal plants and transmission network lines, which are underutilized, leading to cost recovery issues for asset owners. Buy-in from these stakeholders calls for a coordinated plan for refinancing using measures such as debt securitization.

A wholesale market reform at the scale proposed by the MBED mechanism must overcome and address various challenges in ensuring participation from all stakeholders, reliable and accurate price formation, and operational aspects of the market. However, stakeholders are broadly aligned on the overall benefits that can be unlocked by the MBED transition. Achieving consensus will require creating confidence for participation in the market reform based on pilots (similar to SCED) that can allay stakeholder concerns.

Key Questions

- Which existing policies need to be harmonized with MBED to clarify mechanisms for deviation settlement, fixed cost recovery, and additional compensation to generators based on technical parameters such as performance beyond normative PLF?
- How can discoms' exposure be minimized due to revenue allocation of surplus capacity sales to generators, and additional transmission costs?
- Can congestion revenue be allocated to transmission network operators for grid upgrades and address the root cause of market splitting events?
- How can a plan to operationalize MBED be charted in the near term while managing transitional risks such as price spikes?

Box 6: Gross Bidding as an Efficient Market Mechanism

A smooth transition of market operations to MBED will require regulatory interventions and entail a shift away from decentralized planning and operations, which are at the crux of market design in the country. IEX proposed an alternative mechanism called gross bidding to enable discoms to procure power through the exchange by placing buy and sell bids for the volume of power, which would otherwise be procured through bilateral contracts. The mechanism enables merit order dispatch and price discovery in a similar fashion as MBED while preserving the market outcomes as expected under PPAs with voluntary participation. The mechanism is borrowed from the Nord Pool and Japan's JEPX, where this was introduced for the same objective — improving the liquidity of spot markets. As a result, JEPX posted an increase in market participation from under 8% in 2017 to nearly 35% in 2021.[43]

This could help stakeholders navigate market reform while avoiding challenges such as working capital requirements for discoms. However, the mechanism could have several implementation barriers in common with MBED, such as additional transmission charges and accounting for generator technical constraints. Detailed feedback from stakeholders is necessary to determine how the proposed mechanism could fit within market design in India.

Successful MBED Transition – Recommendations

Transitioning to the MBED mechanism requires further clarity on regulatory procedures and accompanying market operations to help achieve buy-in and wide participation of stakeholders. CERC and other planning agencies can drive the successful implementation of MBED and other upcoming market reforms by tapping specific levers related to developing the necessary technology base and institutional capabilities. In addition to outlining key enablers, specific recommendations are provided for a successful transition to MBED and further developments necessary to optimize market operations.

This report seeks to drive action to set up the right conditions for the adoption of MBED in the near term and successfully driving value through MBED and other improvements to India's electricity market in the medium to long term.

Near Term

National Market Operator Governance Structure and Scope of Operation

The MOP must provide clarity on the intended governance structure of the national market operator implementing MBED, including the nature of its relationship with other participants and scope of responsibilities. This should also address how this structure appropriately responds to the short- and long-term challenges optimization through MBED. A national market operator empowered to act independently of other stakeholders can assure transparency and fair competition. Key points of cooperation will be between the national market operator and the power exchanges and relate to whether the national market operator is responsible for developing a market coupling process akin to the Euphemia algorithm developed for the European markets (see Box 7). In addition, the process of communicating scheduling and dispatch among the national market operator, discoms, the NLDC, and RLDCs will be fundamental for ensuring market and grid reliability.

Box 7: Governance Structure of Market Operators in the United States and Market Coupling in EU

Independent System Operators in the United States

The establishment of independent system operators (ISOs) in the United States followed guidance by the Federal Electricity Regulatory Commission (FERC). In 1996, FERC Order 888 required mandatory open transmission access to all users and promoted the idea of ISOs.[44] The advantage was that centralized system operators were allowed to manage physical operation of the grid and optimize wholesale markets. The ISOs are independent of existing stakeholders, allowing for the establishment of competitive wholesale markets for participants. Currently, seven ISOs operate in the United States.[xvii]

The transition in New England exemplifies the benefits of the ISO model. Regional coordination of power scheduling and dispatch in New England began in 1971, in response to the Northeast Blackout of 1965. The New England Power Pool (NEPOOL) was formed by generators and utilities to align transmission planning and improve reliability benefits with coordinated regional dispatch of power. However, NEPOOL was directly managed by stakeholders, limiting the ability to govern independently. In 1997, NEPOOL proposed the formation of a wholesale power market managed by an ISO.[45] The transition to an ISO enabled a transparent and independently operated wholesale power market and tariff design process.

Euphemia – Market Coupling in the EU

To improve the integration of European markets, the Price Coupling of Regions (PCR) project was established by seven nominated electricity market operators (NEMOs) in 2012.[xviii] The covered area encompasses 26 European countries, with an average daily value of matched trades of over €200 million (US$217 million). This initiative developed a price coupling algorithm to calculate electricity prices across Europe, respecting the capacity of relevant network elements.[46] Composing a common algorithm would create a transparent mechanism to determine day-ahead electricity prices and net position of a bidding area across Europe.

The PCR announced the Pan-European Hybrid Electricity Market Integration Algorithm (Euphemia) in February 2014 to calculate energy allocation and electricity prices across Europe, maximize overall welfare, and increase transparency of price computation and flows. Participants may bid in block, complex, and merit orders.[47] Euphemia, which is coupled with multiple power exchanges, demonstrates how India's current market, which operates with three power exchanges, can be coordinated to maximize efficacy in social welfare and power flow.

Moreover, the national market operator's scope of responsibility, ranging from daily market operations to crisis management, must be clearly delineated. The national market operator may be empowered to respond in circumstances where volatility or other unforeseen risks threaten successful operation of markets. The national market operator may also play a key role in capacity or transmission planning in the medium and long term. The MOP can address stakeholder concerns and improve buy-in by clearly outlining the intent and scope of responsibilities of an independent governance structure.

xvii These are California ISO (CAISO), Electricity Reliability Council of Texas (ERCOT), Midcontinent ISO (MISO), New York ISO (NYISO), New England ISO (ISO-NE), PJM Interconnection (PJM), and Southwest Power Pool (SPP).

xviii These include APX, Belpex, EPEX SPOT, GME, Nord Pool, OMIE, and OTIE. SEMO is an associate member.

Box 8: Crisis Management in Australian Electricity Market

The Australian Electricity Market Operator (AEMO) is empowered to declare the spot market suspended when it becomes impossible to operate in accordance with the provisions of the National Electricity Rules (NER) or following the declaration of a state of emergency. For example, the NER set a maximum spot price, which takes effect if prices are too high for too long and trigger market suspension. AEMO publishes the Quarterly Energy Dynamics (QED) report on market dynamics, trends, and outcomes for participants and the public. The QED report for Q2 2022indicated wholesale spot prices increased due to high international commodity prices, coal-fired generation outages, rise in gas-fired generation, and abnormally high demand driven by atypically cold temperatures. Cumulatively, these factors drove the frequency of NEM spot prices that exceed AU$100/MWh (US$70/MWh) from 14% in Q2 2021 to 86% in Q2 2022. Frequency of NEM spot prices that exceeded AU$300/MWh (US$211/MWh) rose from 1% in Q2 2021 to 26%.[48]

In response to the price spikes, AEMO suspended trading on the National Electricity Market (NEM) Spot and Ancillary Services markets during 16–24 June, 2022. During market suspension, prices are set by the regulations outlined in the NER, and AEMO is required to cap spot prices in regions upstream of the suspended region to minimize the accrual of negative inter-regional settlement residues.[49] AEMO declares the resumption of spot markets after the specified criteria are met, including that the conditions leading to suspension are unlikely to recur within 24 hours.[50] Investigation into the causes of suspension is underway, and AEMO's chief executive and the federal energy minister support the development of a capacity market to reduce the risk of future volatility-driven market failures.[51]

Propose Robust Transition Plan

The MOP can provide a transition plan and MBED implementation timeline beyond the pilot project included in the initial proposal. India's electricity sector remains in a cost-plus regime, and some risks related to market participation may be passed onto consumers. Establishing a robust transition plan is necessary to protect end-users. This transition plan should outline the timeline for establishing the national market operator, introducing new or anticipated data reporting procedures, and ascertaining the policies to be implemented for a successful transition. Included in this scope should be pilots assessing how the national market clearing price may affect open-access consumers and demonstrating the impact on risk hedging. Transparent sharing of results by MBED pilots will minimize risk going forward and should be available before PPA renegotiation exercises take place.

The MOP may also consider contingencies in case of a crisis. Unanticipated disruptions to market transition, such as unexpected fuel price spikes, should be addressed by adopting the right strategy. A transition to a centralized market-based dispatch must also account for resource adequacy at the state level in the near term to ensure the required supply volumes and reserve margins are available.

Box 9: Risks of Poor Transmission Planning, California Electricity Crisis

California's initial energy transition included the establishment of CAISO to perform real-time balancing, manage congestion, and provide ancillary services. The California Power Exchange (PX) was established to oversee the voluntary day-ahead, hour-ahead, and year-ahead markets, with other scheduling coordinators handling bilateral markets or other exchanges. Various market design flaws, poor market transition strategy, and unanticipated demand–supply tightening conditions led to a crisis in California's wholesale electricity sector through 2000 and 2001. Retail prices were frozen during the transition period, while fuel and other input costs spiked, leading to financial distress for investor-owned utilities (IOUs). In addition, day-ahead schedules in the PX did not account for transmission security constraints in real-time dispatch, forcing CAISO to redispatch generators to account for congestion limitations. This enabled market participants to manipulate congestion management, further driving up prices. This led to two of the three IOUs defaulting on payments to the PX and the PX defaulting on payments to CAISO. The costs led to a surcharge on retail tariff for customers in California.

Outline Pathway for Meeting Technological Readiness

The MOP can work to develop the technological infrastructure necessary for successful implementation. This should include developing a program to assess the technological readiness of stakeholders, understanding the accounting and settlement system needs to accommodate an increase in transactions, and market monitoring systems to ensure the market is efficiently and transparently operated. In addition, considerations must be made for addressing cybersecurity concerns.

As part of the technological development, the MOP may also create a training and onboarding program for stakeholders to improve integration. The system CAISO developed to align governance, monitoring, and reporting to integrate new participants into the WEIM serves as a strong model.

Detail Process for Addressing Discoms' Financial and Operational Transition

The MOP can provide additional details on relevant financials, payment, and bidding. For discoms, the MOP proposes a method to provide the necessary liquidity to transition from long allowable payment periods to advance payments. Additional details, such as a timeline for how and when these resources will be available in the transition, must be provided. The MOP should also clarify how discoms barred access to short-term markets will be allowed to participate through MBED. In addition, the MOP should include details on the intent of the bidding structure for generators — such as whether they anticipate MBED to utilize simple bids for net volume of energy provided (common to European markets) or multipart bids including technical parameters such as ramping and flexible capacity (common to US markets such as ISO-NE). Clarity provided in the early stages of the transition allows generators and discoms to improve planning and readiness for MBED implementation. To align market reform with wide implementation, discoms and SLDCs must invest early in capacity building to develop capabilities necessary to tackle their respective responsibilities in the MBED transition. Enhancing operational competence will be crucial to operate with a move to market-based power procurement and planning.

Propose Data Portal to Enable Transparency and Accountability

Publicly available, standardized, and consistent data will be essential for evaluating the efficacy of the MBED policy. As part of this proposal, the MOP should assign the national market operator to develop the required data reporting procedures for stakeholders. This should present accounting data for settlements in a standardized format — available transmission capacity, load-generation balance, deviation statements, and losses at every time-block. The MOP may also consider including monthly or fortnightly power purchase details per actual invoices, with the breakdown of the costs incurred. A detailed cost-benefit analysis of URS reallocation at the state level for peak- and off-peak seasons will strengthen confidence in the end benefits of the framework. Centralized publication of data, akin to the OASIS portal outlined by FERC, improves transparency and accountability and allows for opportunities to improve efficient dispatch, transmission management, and system planning.

Box 10: Value of Centralized Data Portal in California

The Open Access Same-time Information System (OASIS) details real-time data related to the ISO transmission systems and markets. The OASIS concept was formalized by FERC in the mid-90s to facilitate efficiency during the transition to open access transmission. The system includes demand forecasts, transmission outage and capacity status, market prices, and market result data.[52] Each US ISO is required to maintain an OASIS portal, which facilitates the transparent review of market operations for all stakeholders, allowing for a clear evaluation of ISOs' performance as market operators. The OASIS portal also creates a standardized data reporting mechanism that parties interested in participating in the WEIM can align operations with. The WEIM can work with interested parties in establishing and transitioning data reporting processes to comply with OASIS, making participation seamless and maximizing economic and environmental benefits. This can serve as a valuable model for Indian market operators to integrate states into a national market mechanism.

Medium Term

Anticipate Need to Update Transmission Planning Process

The MOP should consider how the implementation of MBED will affect transmission needs and alter existing transmission planning and investment strategies. Implementation at the pan-India level will result in drastically different power flow scenarios compared with models used at the time of long-term transmission planning and investment. RE generators with zero marginal cost of generation (and a must-run status) will be dispatched at the top of the merit order stack; the majority of this RE capacity will come online in six states, necessitating the scale-up of high-voltage DC lines to evacuate surplus generation to load centers. Price discovery under MBED does not account for associated inter-state transmission charges and losses (which discoms currently account for under self-scheduling). As the transmission network use deviates significantly from planning models, it may lead to underutilization of several corridor lines and threaten investment recovery. Lack of updated transmission planning may make congestion and market splitting events more frequent, risking high associated costs that will reflect in area clearing prices.

In the long term, the planning strategy must be revamped as this is currently based on long-term contracts between generators and beneficiary states. The MOP should clarify the role of national market operators in providing market signals to investors and transmission companies to ensure transmission planning is efficient and capable of meeting new supply dispatch.

Develop Roadmap for Resource Adequacy and Complementary Markets

In the medium and long term, the MOP can establish goals for incorporating increased competition in additional aspects of the power sector. Without adequate mechanisms in place, scheduling low-variable-cost plants in the DAM may result in driving up costs in the RTM as high-variable-cost plants may be left uncommitted. Market forces can be utilized to efficiently meet the key methods of ensuring grid stability and reliability, such as ancillary services and capacity expansion. Introduction of additional reserve products may also allow some units to remain committed and operate at minimum generation to ensure market prices stay at acceptable levels. Fostering robust markets with clear metrics for participation for these services can provide additional revenue streams for generators, decrease volatility risk, and provide signals for procuring and maintaining adequate fuel reserves.

In 2021, CERC introduced draft regulations on ancillary services to increase market maturity, drive increased competition in ancillary services procurement and facilitate participation of fast-response technologies such as battery energy storage systems and demand response in providing reserves. The establishment of a national market operator may aid the development of robust market mechanisms for meeting frequency and voltage controls efficiently and growth of efficient markets facilitating the integration of the increasing VRE generation in the country.

In addition, the MOP should consider whether to pursue an energy-only market (such as Australia) or develop a discussion paper for capacity markets (such as ISO-NE). The former prioritizes low wholesale power prices at the risk of increased exposure to market volatility, while the latter provides reliability but at higher cost. The MOP can clarify the role of the national market operator in capacity planning. In addition, resource adequacy planning should account for needs or adjustments required by the transition to and implementation of MBED. Adequacy supply must be available in the market to maintain reserve margins at the state level and may require a separate mechanism.

Box 11: Varying Approaches to Transmission Planning in New England and Australia

Integration of renewables increases the focus on transmission planning and ensuring transmission availability for the cross-border flow of electricity. When appropriately developed, access can be coordinated with market coupling, long-term, day-ahead, and intraday levels. Market operators may be designated with a varying degree of responsibility for planning, with ISO-NE and AEMO representing models with different approaches.

ISO-NE

ISO-NE is responsible for maintaining system reliability, including transmission planning. Although the transmission network is largely owned by the incumbent utilities, ISO-NE must ensure the transmission system meets the reliability criteria set by the national and regional standards. ISO-NE is responsible for identifying transmission upgrades that provide a net reduction in total production cost. When needs are identified, they are met through a competitive process.[53] ISO-NE also operates a financial transmission rights (FTR) auction, allowing market participants to hedge against the economic impact associated with transmission congestion. Market participants can bid for FTRs to receive a share of congestion fees.[54]

AEMO

AEMO's role in planning is more passive, allowing stakeholders a high degree of agency. AEMO is tasked with developing a long-term integrated system plan (ISP) to reflect anticipated power sector changes over 20 years. The ISP is a whole-of-system plan that informs market participants, investors, policymakers, and consumers on power sector transformations. It also identifies actionable projects to maximize consumer benefits.[55] The 2020 ISP set an optimal development path, identifying committed projects as well as the actionable and preparatory activities required for successful development. It also includes projections on generation retirements, distributed energy resources, VRE growth, and volumes of new dispatchable resources.[56] To ensure transparency, the ISP model is made publicly available.

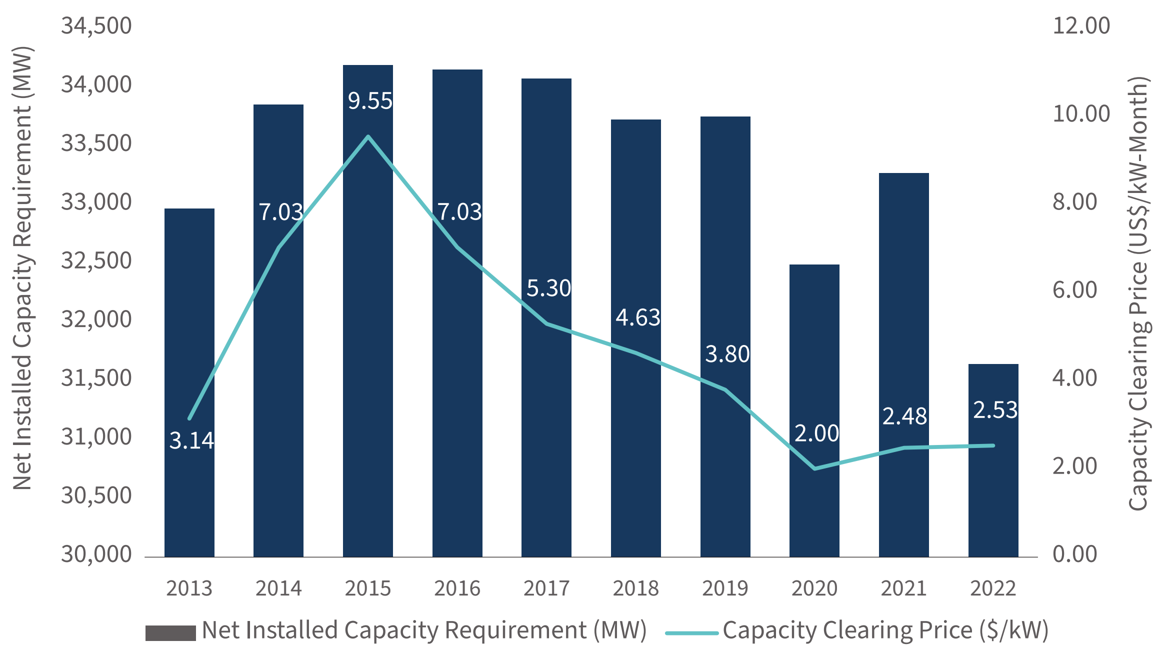
The state and territorial governments of Australia have the power to establish RE zones (REZs) within their jurisdiction. REZs identify key regions that have abundant solar and wind potential and are a planning tool to ensure renewable development coordinates with transmission and demand. Once REZs are identified, the state or territorial government communicates the planned capacity to AEMO, and the REZ is integrated into AEMO's ISP model. Through the model, AEMO can anticipate transmission and distribution infrastructure costs and needs.

Box 12: Capacity Markets in ISO-NE

ISO-NE is one of the four US ISOs that meet resource adequacy requirements through a capacity market.[xix] Capacity markets ensure grid reliability standards are met by paying power plants to meet peak electricity demand at a future date. In capacity markets, the system operator holds auctions based on projections of the electricity demand in the next three years.[57]

ISO-NE holds forward capacity auctions (FCAs) on annual basis, procuring capacity for four zones.[xx] ISO-NE develops resource-adequacy based requirements to determine the annual installed capacity requirement (ICR). Accounting for reliability benefits obtained from tie-ins outside the market (such as Quebec) helps determine the net installed capacity requirement (NICR) value. Aggregate demand is based on a system-wide demand curve to account for the marginal value of capacity and is not perfectly inelastic.[58] A general trend of declining capacity market clearing prices was noted in the past decade (see Exhibit 20). Low cost of new entry and minimal retirements put downward pressure on capacity market clearing prices.[59]

Exhibit 20 Forward Capacity Auction Clearing Price and Net Installed Capacity Requirement Trends



Note: Capacity clearing prices vary by region; prices for the Southeast New England and Rest-of-Pool were slightly higher in 2021 and 2022 than displayed here.

Source: ISO-NE

xix The other three are New York Independent System Operator (NYISO), PJM Interconnection, and Midcontinent Independent System Operator (MISO).

xx These are Maine, North New England, Southeast New England, and Rest-of-Pool.

Conclusion

Growth in electricity generation is fundamental to maintaining robust economic development. India has the opportunity and goal to ensure reliable electricity access and accelerate industrialization. The country has set an ambitious target of meeting 50% of the installed electricity generation capacity from non-fossil-fuel sources by 2030, underpinning the ambitious climate targets set by the government.

India's non-fossil-fuel generation capacity grew rapidly over the past decade, with about 150 GW of installed renewables and hydro now exceeding 40% of the installed capacity.[60] Nevertheless, the fiscal and operational challenges facing India's distribution sector risk deter continued growth. Wholesale market reforms are necessary to address these persistent issues. The MOP's MBED proposal optimizing day-ahead scheduling and dispatch realizes system cost savings by maximizing the utilization of low-cost generators. However, a successful transition to the MBED mechanism will require a thoughtful approach to implementation. Understanding and addressing short- and long-term barriers is vital and will require buy-in from market stakeholders.

MBED is the first step towards creating system operational efficiency and reducing costs with an integrated pan-India approach for generators' day-to-day scheduling and dispatch. Building off two decades of evolution, India needs to ensure the right electricity market operational structure to develop a reliable, flexible, and cost-effective power sector. The growth of installed renewable generation capacity will bring many opportunities in the future; markets well suited to integrate variable generation will be key to fully capturing this innovative sector's economic and environmental benefits. India's actions towards deepening markets and maximizing cost efficiency through competition can help realize its bold ambitions and create lasting benefits for the country and the world.

Appendix A: Milestones of Electricity Market Development in India

The Electricity Supply Act of 1948 established India's power market as largely government-owned and operated by state electricity boards. However, in the early 90s, India began to participate in the global trend towards power sector market liberalization. This appendix highlights key milestones in India's transition to a liberalized electricity market, from the beginning of the transition in 1991 to the Electricity Act of 2003, opening of the power exchanges in 2008, and unification of the grid in 2013.

In 1991, the Electricity (Supply) Act of 1948 was amended to allow the establishment of private generating companies (except hydro) selling bulk power to the grid or other off-takers. New generators presented opportunities for investment, bringing capital into India's electricity sector. Other critical steps through the 90s included establishing independent regulatory bodies at the central and state levels, and making transmission a separate activity.[61] Since then, there have been three key milestones for power sector transition: Electricity Act of 2003 (EA), establishment of power exchanges in 2008, and achievement of One Nation, One, Grid, One Frequency. These milestones fostered the environment for an efficient, market-based power sector in India.

Electricity Act of 2003

The steps taken towards power market liberalization in India throughout the 90s culminated in the Electricity Act of 2003. The EA entailed major reorganization of India's power sector, which improved coordinated development of the power sector through a comprehensive framework. Objectives included consolidating laws related to generation, transmission, distribution, and trading of electricity; promotion of competition in the power sector; and efficient and environmentally sound policies.[62] The EA was key for unbundling India's power sector by delicensing generation of activities for most fuel sources, opening access to distribution, and recognizing electricity as a trading activity.[63]

Power Exchanges Set Up in 2008

Since 2003, three power exchanges have been established in India under the EA: Indian Energy Exchange Ltd. (IEX), Power Exchange of India Ltd. (PXIL), and Hindustan Power Exchange Ltd. (HPX). The first power exchanges were established in late 2008. Unlike long-term contracts, the power exchanges provide flexibility to participants to capitalize on changing market circumstances. Buyers are provided multiple means to secure power, enabling a mix of short- and long-term commitments, while generators are ensured timely payments.[64] The power exchanges provide various products, including power procurement through the DAM and RTM, energy saving certificates (ESCerts), and renewable energy certificates (RECs).[65] The power exchanges provide different functions and approaches to exchanges, for example, the HPX will initially focus on trades of contingency contracts, green contingency contracts, and RECs.[66]

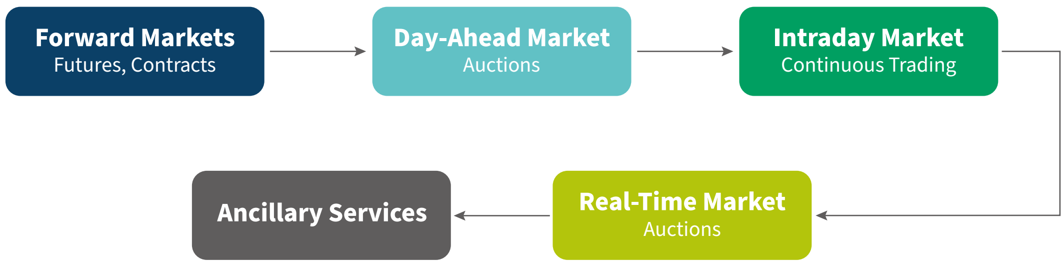
One Nation, One Grid, One Frequency

The Indian power system was divided into five regional grids in the 1960s. The Government of India aimed to integrate the five regions into a single national grid in 1981, and the national grid was achieved in 2013.[67] Successful integration of the five regional grids required a single grid frequency to enable interconnection synchronicity, which was established at 50 Hz in 2010.[68] The One Nation, One Grid, One Frequency policy improved transmission, and optimized the utilization of resources by enabling transfer from high-generation regions to load-intensive regions. It also enabled an improved electricity market with trading across regions.[69]

Appendix B: Elements of Electricity Market Design

Sequence of Markets

Exhibit 21 Timeline of Electricity Markets



The wholesale market includes several components necessary for functioning; these typically follow in a sequence with the longest contracting to real-time balancing. While each market is structured differently with distinct time intervals, they generally include forward markets, DAM, intraday market, RTM, and ancillary service market.

Forward markets include long- and medium-term contracts, usually bilateral agreements. Forward markets are a complement to spot markets, hedging risk by reducing the quantity of energy that trades at the more volatile spot price. Appropriately designed forward markets can also enable resource adequacy, with a transparent competitive process for identifying and pricing these resources.[70]

Day-ahead trading entails buying and selling electricity in the 24-hour period prior to production and anticipated delivery. Day-ahead trading can include trading in a spot market of the power exchange or through bilateral contracts in over-the-counter deals.[71] In liberalized markets, the DAM represents the bulk of energy transactions (in US markets, this can be as high as 95% of the transactions) based on the forecast load for the next day.[72]

Intraday power trading refers to ‘‘continuous buying and selling of power at a power exchange that takes place on the same day as the power delivery’.’[73] By operating several times daily, intraday markets allow for adjustments to the day-ahead commitments, improving grid efficiency. Intraday markets can play an important role in allowing RE generators to adjust their schedules closer to real time, accounting for updated production forecasts.[74]

The RTM is responsible for dispatching power to end-users during the operating day, as required. Typically, the RTM operates in regular intervals such as five minutes of the day. It is utilized to balance the power system in real time between the DAM commitments and real-time demand for energy.[75]

Ancillary services are procured by system operators to ensure grid reliability. They are used to keep the system operating within the acceptable frequency and voltage levels and restore the system when contingencies occur (such as unexpected power plant or transmission line outages). Specific ancillary services will vary by market but often include (1) regulating reserve, supply that ramps up or down in seconds; (2) spinning reserve, supply that ramps up within minutes; (3) nonspinning reserve, supply that is available in 10 or more minutes; (4) voltage support, supply that provides reactive power to maintain proper voltage; (5) and black start, supply that starts without power to restore the system after an outage.[76]

Dispatch

Self-scheduling is a dispatch mechanism that allows producers, or parties responsible for scheduling a generator, to choose how to deliver the committed energy. This is practiced within decentralized markets, where system operators have limited authority over the day-ahead scheduling in the transmission network.[77] Self-scheduling may also be referred to as portfolio-based bidding, which minimizes operators' monopoly influence on markets.

Economic dispatch focuses on short-term operation decisions, specifically how the system operator can best use available resources to meet customers' electricity needs reliably at the lowest cost. Economic dispatch practices must take into account serval factors, including continuous variation in loads and generators' inability to respond instantaneously; need to maintain reserves and plan for contingencies to maintain reliability; and scheduling requirements imposed by environmental laws, hydrological conditions, and fuel limitations.[78] As the geographic and electrical scope integrated under unified economic dispatch increases, additional cost savings result from pooled operating reserves, which allow an area to meet loads reliably using less total generation capacity than is otherwise needed.[79]

Security Constrained Economic Dispatch (SCED) is a form of dispatch that modifies the least-cost dispatch to account for security constraints. These constraints are often for ensuring grid reliability and include factors such as generation and transmission facility conditions and availability, line capacities, and ambient weather conditions that could impact line thermal performance, and availability of other grid facilities such as circuit breakers.[80]

Congestion Pricing

The approach to congestion management is another distinction across market designs with two potential approaches based on nodal pricing or zonal pricing. Nodal pricing varies depending on the congestion in the transmission system, and compensation for power producers/suppliers is determined by the local price at a particular node. The nodal pricing is also cleared in a single stage. Zonal pricing aggregates nodes into zones with uniform pricing and may be cleared through multiple stages.[81]

India utilizes a zonal model for congestion management with a market splitting mechanism. When congestion occurs between a zone with a surplus of generation and a zone with a deficit, an area clearing price is found that is equivalent to the available transfer capability.[82]

Appendix C: SCED Pilot

Grid-India undertook a pilot project on a SCED scheduling and dispatch model in April 2019 to minimize ISGS variable cost by optimizing dispatch. Multiple beneficiaries are allocated shares (within and across regions) of ISGSs, but generation remains unrequisitioned for certain ISGSs depending on the requirement of the states. The objective was to minimize the total generation cost while honoring the technical constraints of the generating plants and grid.[83]

Identified constraints include the following:

- Meeting total requisition by states from ISGS
- Transmission constraints; available transmission capability (ATC)
- Technical minimum of plants
- Maximum generation
- Ramp up/down rates

Under the SCED pilot, the NLDC was responsible for developing and implementing a system for scheduling participating ISGSs and utilizing it to generate SCED schedules to be communicated to RLDCs.

Participating generators provided monthly technical data encompassing variable charge, technical minimum, and maximum possible generation (including ramp up and ramp down rates) to the relevant RLDC or NLDC. The SCED schedules were communicated by the NLDC to respective RLDCs approximately one time-block in dvance.[84]

Distinction between MBED and SCED

Grid-India's SCED pilot is distinct from the MBED proposal, wherein bids reflect marginal costs and do not account for technical minimums.

The MOP provides a comparison between four generators, with 70 MW scheduled under the status quo self-scheduling mechanism, SCED mechanism, and proposed MBED mechanism (see Exhibit 22). In this example, each generator maintains the same variable cost in each proposed mechanism. In the SCED example, high-cost generators are scheduled for dispatch accounting for technical minimum, while generators are scheduled only based on variable cost in the MBED example. This distinction saves cost by avoiding the scheduling and dispatch of high-marginal-cost generators. This example is illustrative of the distinction for scheduling and dispatch strategies but does not account for how a generator's bidding strategy may change under each mechanism.

Exhibit 22 **Timeline of Electricity Markets**

Generators (with variable cost)	Declared capacity (MW)	Schedule as per self-scheduling mechanism (MW)	Revised schedules as per SCED (MW)	Revised schedules per MBED (MW)
Gen 1 @ INR 1/kWh	25	20	25	25
Gen 2 @ INR 2/kWh	25	20	25	25
Gen 3 @ INR 3/kWh	25	15	10	20
Gen 4 @ INR 4/kWh	25	15	10	-
Total system cost (INR)		INR 200	INR 145	INR 135

Source: CERC

While MBED and SCED differ in scope, implementation challenges from SCED pilots can serve as guide stones and lessons before the rollout of MBED. Key insights include the following:

- IT-related (software development and capacity building for pan-India SCED scheduling), communication infrastructure.
- Regulatory framework for sharing benefits.
- Streamlining scheduling process while accounting for RTM (balancing).
- Offering incentives based on generators' technical constraints (ramp rates, etc.).
- Regulatory framework for spinning reserve requirement.

Appendix D: Methodology for Estimating Cost Savings under MBED

The analysis considers actual generation and declares the capability of generators for two states — Tamil Nadu and Maharashtra — to assess potential cost savings from reallocating surplus capacity under MBED.

Base Case: Each state self-schedules generators to meet demand as per merit order.

Pooled Case: Generator portfolios of both (states pooled and dispatched as per new merit order).

Steps:

1. Daily generator-level data on costs (variable and fixed), and declared capability and actual generation (both in MWh) scraped from MERIT India and respective RLDC portals for two periods:
   July 15–August 15: peak demand season
   December 15–January 15: off-peak demand season

2. Determine cumulative system variable costs for two states under base case based on actual generation profile.

$$\textit{System variable costs} = \sum \textit{Actual generation} \times \textit{Variable cost (INR/kWh)}$$

Note:
- Must-run plants not considered in analysis.
- Intraday generation profile and transmission network constraints not considered.
- Generator portfolio screened for plants under outage during the period.

3. Pool generator fleet for both states to create new merit order based on marginal costs.

4. Determine system variable costs under the pooled case scenario, wherein an aggregate fleet of two states is dispatched to meet the total demand.

Note:
- Scheduled generation is used as proxy for the demand served.
- Variable costs assumed to be similar at the generator level for both periods of analysis.

5. **Savings per day** = (Cost under base case - Cost under pooled case)/31

It must be noted that an accurate cost-benefit assessment of centralized dispatch at the state level must account for various system and generator constraints such as technical minimum loads, ramping constraints, network congestion, and transmission and wheeling charges, which affect grid operations in real time. These are beyond the current scope of analysis.

Appendix E: Methodology for Determining Thermal Balancing Potential

Balancing potential refers to the level to which other generators (thermal, hydro, etc.) can be backed down to accommodate renewable generation. Oversupply of RE generation cannot be integrated into the grid and must be curtailed to maintain frequency.

The methodology used to estimate the balancing potential of thermal generators at the state and regional levels follows from a 2015 study by GIZ.[85] Thermal balancing potential is calculated as installed capacity of a thermal/gas plant multiplied by one minus the minimum load.

$$\text{Thermal balancing potential} = \text{Installed capacity (MW)} \times [1 - \text{Minimum load}]$$

This represents the theoretical maximum capability of a given generator to back down when needed. The installed capacity/capacity share of thermal and gas plants at the state level and ownership (central/state) is obtained from MERIT India's website and aggregated for regional scale. VRE capacity is calculated as the sum of installed capacities of wind and solar at the state level as obtained from MNRE for July 2022.

Assumptions:

Generator Type	Ownership	Minimum Load
Thermal	Central	55%
	State	65%
Gas	Central	40%
	State	40%

Endnotes

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