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Power Chronicle

Evolving Electricity Market Frameworks: Perspectives on Market Design, Stranded Connectivity, and Capacity Adequacy

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Editorial

As market coupling is set to become a reality, a number of regulatory and policy issues covering institutional responsibilities, regulation of margin, coupling timelines for market products, as well as market surveillance and monitoring need to be addressed. The geographical coupling in the European market bestows price discovery responsibility onto the existing market operators on a round-robin basis. The use of an identical market engine spread across multiple locations not only enables real-time tests for the market outcome, but also significantly enhances the reliability of the market process. Institutional separation of the market operator and system operator, in the proposed centralised model, would not only enhance accountability but also enable the determination of charges for the two functions. It is important to highlight that the integration of the two functions is suitable in the case of centralised markets due to the commonality of the beneficiaries of the two functions. This is not the situation in the current Indian context.

The combined market and system operation functions do present a relative advantage in terms of the ability of the nodal agency to undertake market operations, especially the monitoring of availability, capacity, and transactions. Market monitoring has remained the weakest pillar in the market design framework so far. The Market Monitoring dashboard developed by the CER for CERC provides a starting point, with scope for the enhancement of capacities.

Stranded assets remain a global regulatory overhang, and avoiding their emergence is the best way to address financial impacts. An estimate at EAL highlights a substantial financial burden for beneficiaries, and socialising private risk hurts long-term stakeholder interests. Regulatory solutions include alignment of connectivity with the Resource Adequacy Planning of Discoms and prioritising connectivity based on PPA-PSA status. To address procurement portfolio rebalancing and ensure sufficient planning reserves, a short-term capacity market is the need of the hour.

A short-term capacity market product should be introduced through an appropriate, credible nodal agency. Given significant seasonal variations in demand-supply mismatch across states/Discoms, a quarterly capacity product is most suitable and provides sufficient liquidity, unlike the proposed one-year product. To ensure competition and prevent market manipulation, a short-term capacity monitoring framework for generating units above 5 MW is a prerequisite. The absence of effective undermines participant faith. A vibrant capacity market also the impacts platforms like DEEP and PusHP and can substitute for power banking.

Furthermore, the existing Resource Adequacy framework is biased toward Discoms, leaving power producers and large open-access consumers out of its scope. However, they should be equally responsible power system constituents. This imbalance is visible in states with large captive power or open-access capacity, placing an unfair additional obligation on distribution licensees and raising costs for their consumers.

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Founder & Coordinator, Energy Analytics Lab

Keywords: Market Coupling, Capacity Market, Resource Adequacy Obligations, Reserve Capacity Market, Net CONE, Missing Money, Grid Security, Dispatchable Capacity, Secondary Capacity Market

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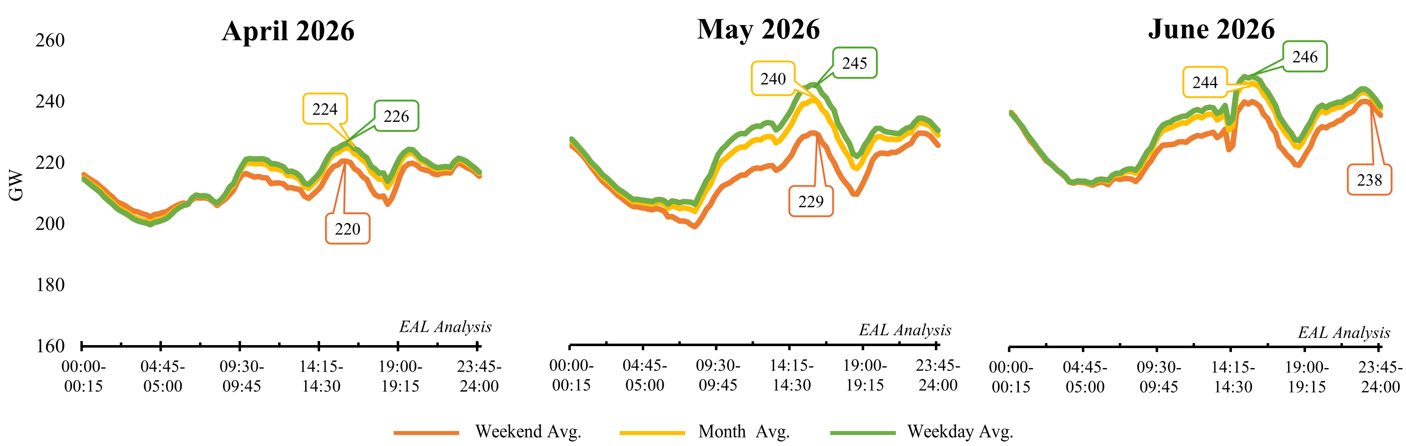
Power System Overview & Analysis

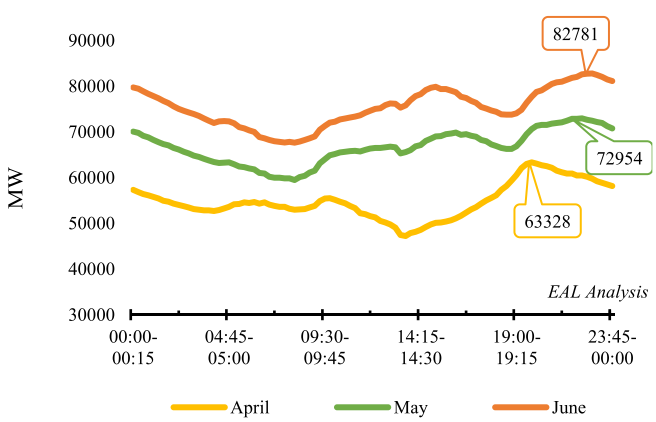
All India Demand Met Profile



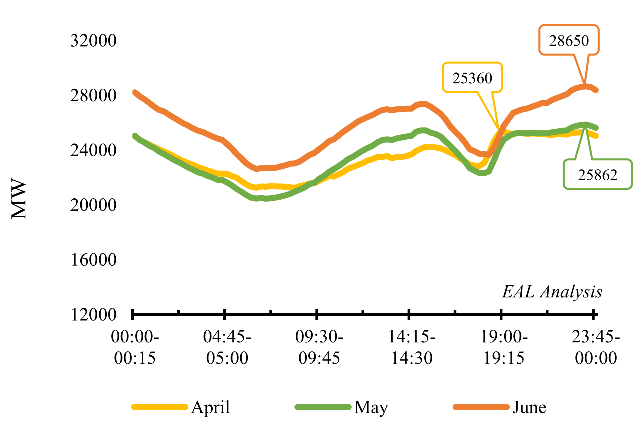
From April to June quarter, all India peak demand reached 270 GW (15:45 - 16:00) on 21st May 2026, about 11.5% higher than the previous year's peak demand recorded at 242 GW (14:30 – 14:45) on 30th May 2025, during the same quarter.

Region-wise Demand Met Profile

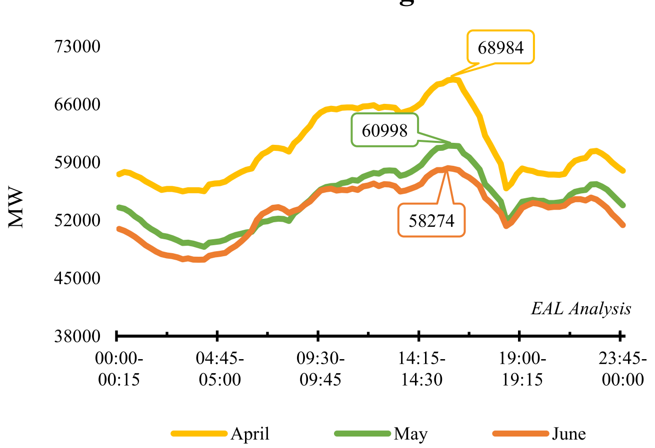
Northern Region



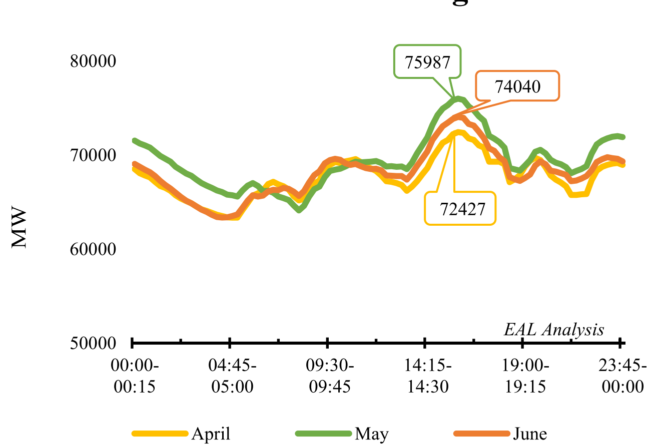
Eastern Region



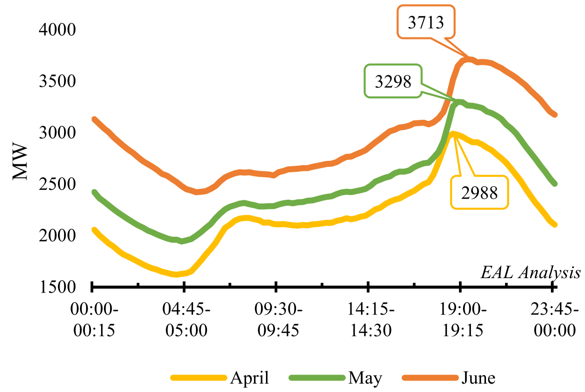
Southern Region



Western Region



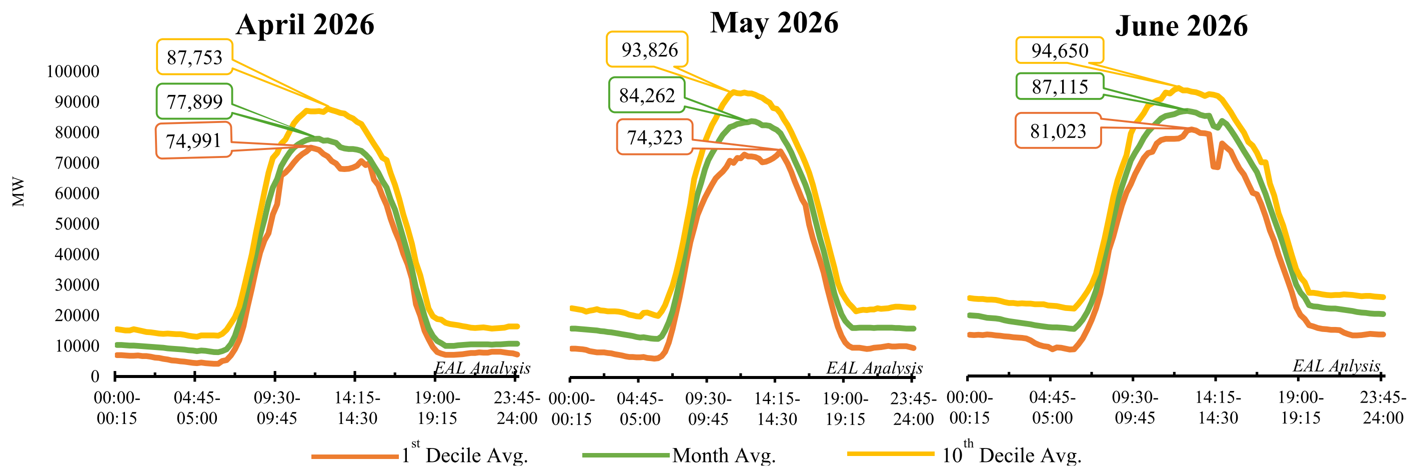
North Eastern Region



- Significant increase in demand can be observed from 18:00 to 19:15 hrs for Eastern Region and 13:00 to 16:15 hrs for Western Region in all three months respectively.
- Decrease in demand can be observed for Northern, Southern, Western, Eastern and North Eastern regions from 00:15 to 04:15 hrs in all the three months respectively.
- Average demand is found to be higher for Northern region as compared to the other regions in the month of June.

Demand and generation profiles at National, Regional and State-level can be accessed on EAL's web portal.

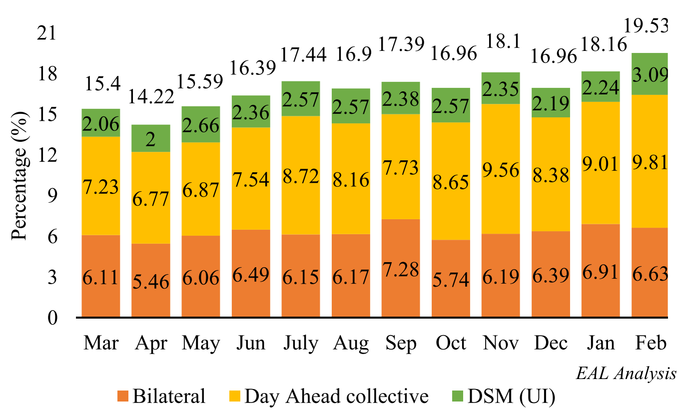
All India Renewable Energy Generation Profile



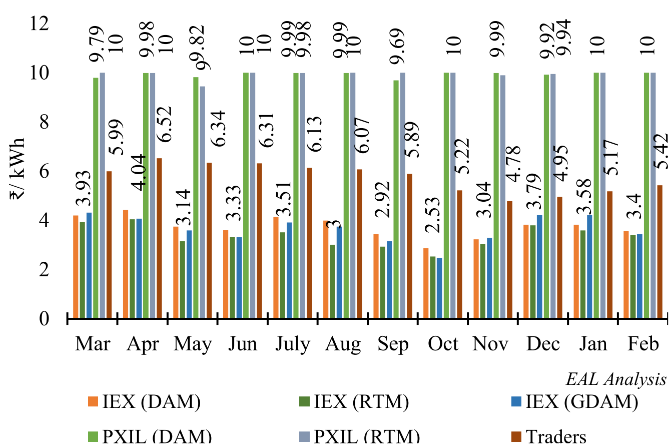
All India peak RE generation reached 97.26 GW (12:15 - 12:30) on 9th June 2026, about 18.19% higher than the previous year's peak of 82.29 GW (13:15 - 13:30) on 2nd June 2025, during the same quarter.

Short-term Energy Transactions

Share of Short-term Energy Transaction of Total Electricity Generation (Mar 2025 - Feb 2026)

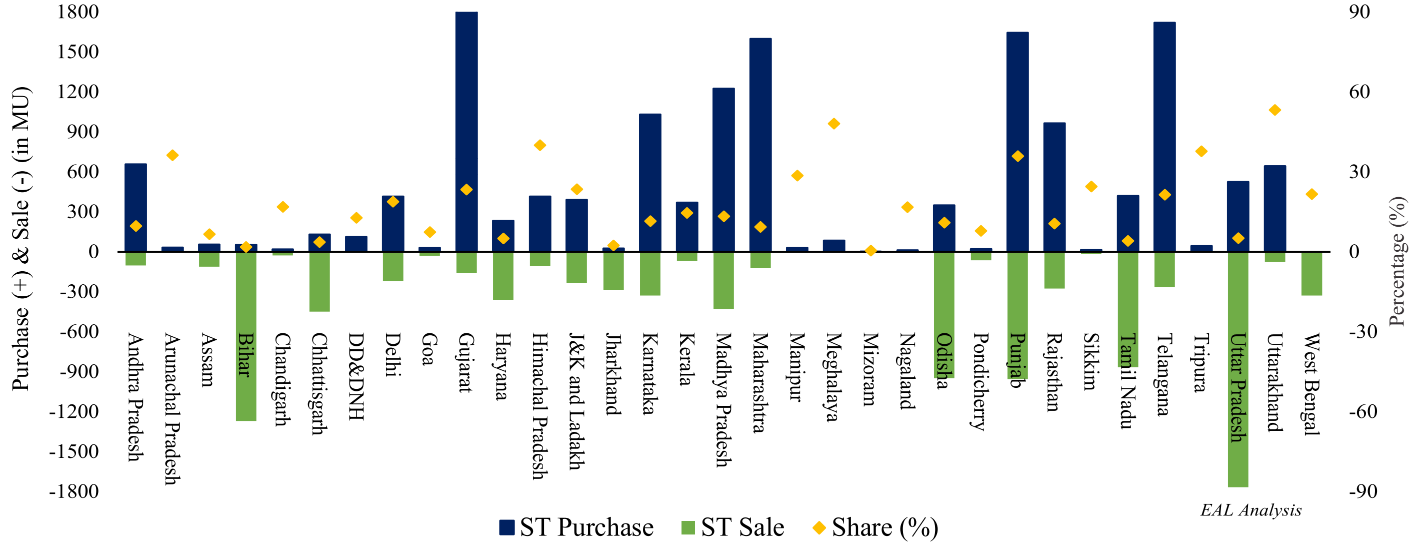


Weighted Average Prices of Short-term Transactions (Mar 2025 - Feb 2026)



Monthly Power Purchase and Sale Quantum through Power Exchange across States

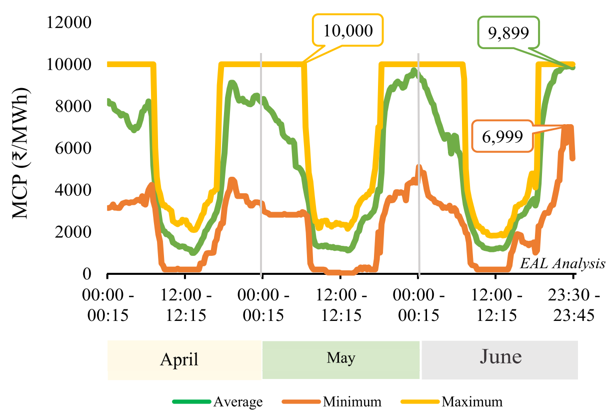
ST Energy Sale, ST Energy Purchase and share of ST Purchase on Total Energy Supplied (February 2026)



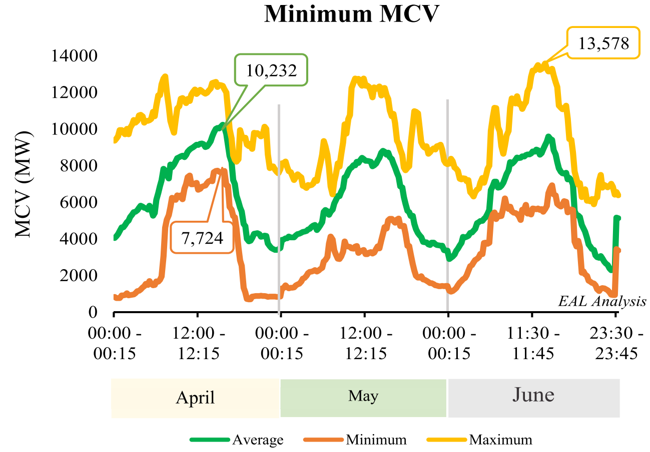
Power Market Overview & Analysis

DAM - Market Clearing Price (MCP) & Market Clearing Volume (MCV)

DAM Monthly Average, Maximum & Minimum MCP

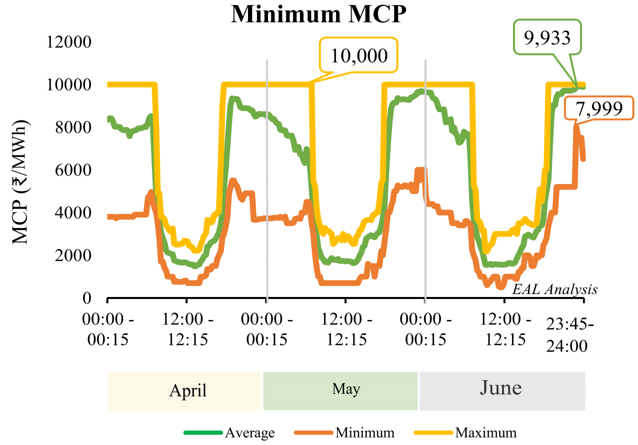


DAM Monthly Average, Maximum & Minimum MCV

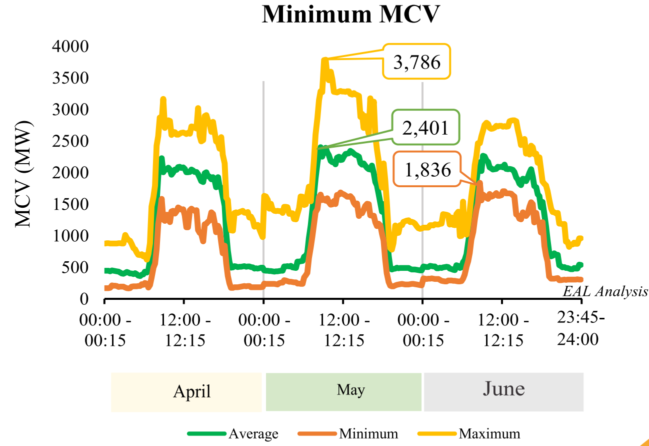


G-DAM- Market Clearing Price (MCP) & Market Clearing Volume (MCV)

G-DAM Monthly Average, Maximum & Minimum MCP

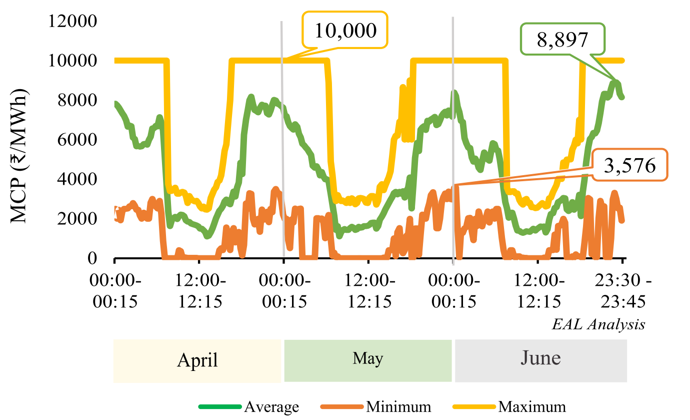


G-DAM Monthly Average, Maximum & Minimum MCV

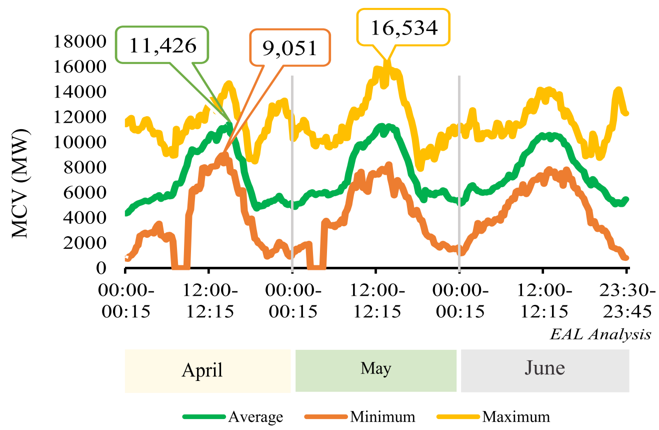


RTM -Market Clearing Price (MCP) & Market Clearing Volume (MCV)

RTM Monthly Average, Maximum & Minimum MCP

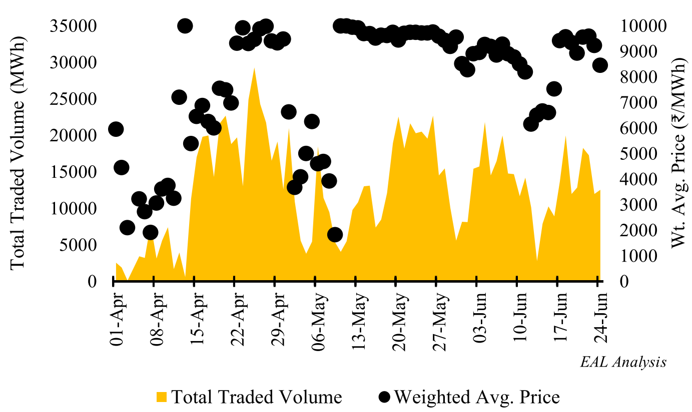


RTM Monthly Average, Maximum & Minimum MCV



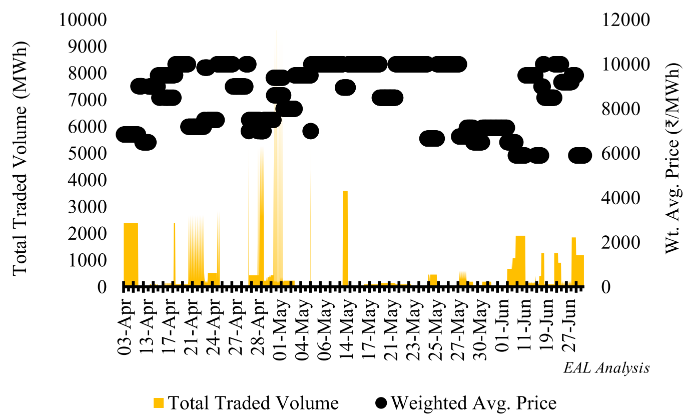
Term-Ahead Market

Day Ahead Contingency (April - June 2026)



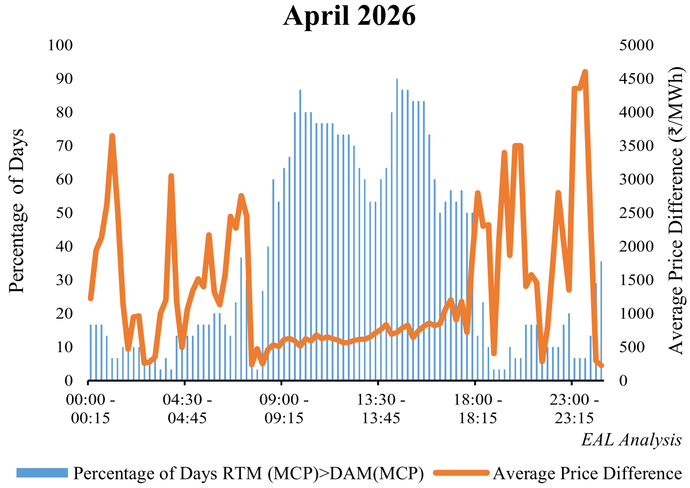
Green Term-Ahead Market

Daily Contracts (April - June 2026)

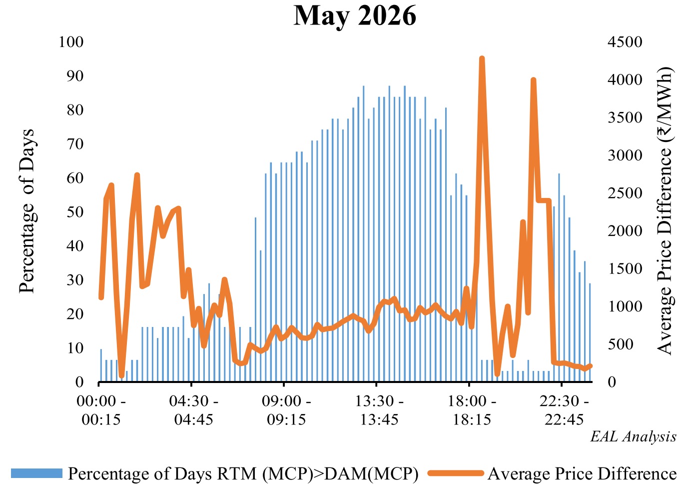


Price Difference between RTM & DAM

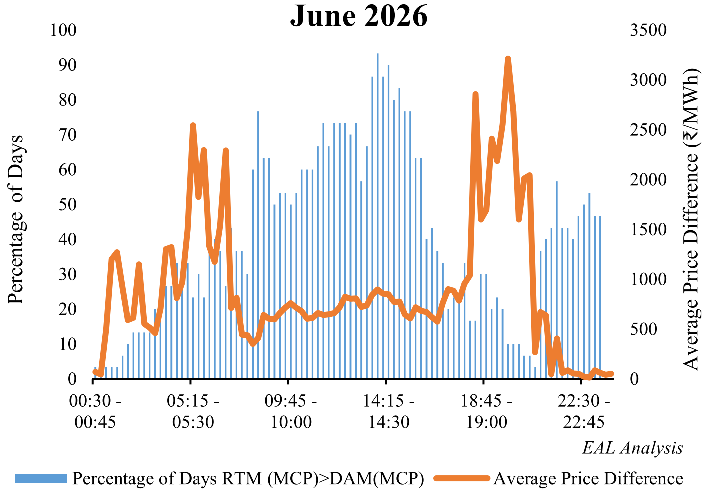
April 2026



May 2026



June 2026

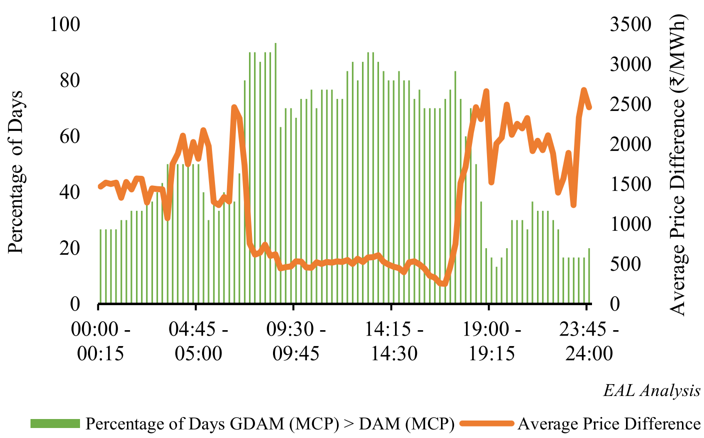


EAL Analysis

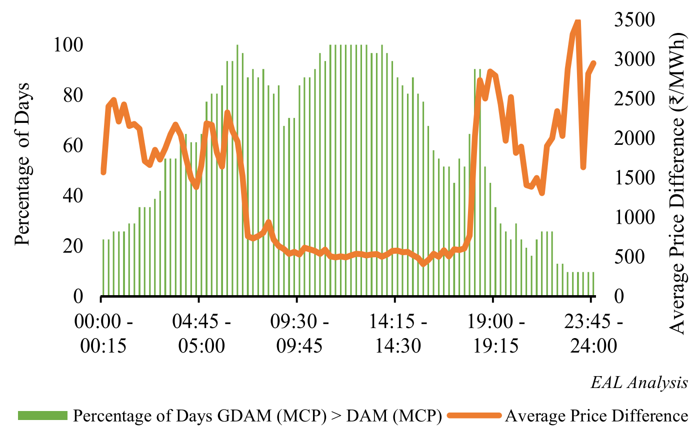
- The analysis is based on comparison between the average price difference of RTM and DAM, when MCP of RTM is greater than DAM for the first quarter of FY 2026-27.
- The graph shows the percentage of days, price for RTM is greater than DAM on the primary axis and the average price difference between the two on secondary axis.
- It has been observed that in 23:30-23:45 the highest average price difference is observed of Rs. 4.60/ kWh for the month of April, 2026.
- The average price difference between RTM and DAM is Rs. 1.10/ kWh for the quarter.

Price Difference between GDAM vs DAM

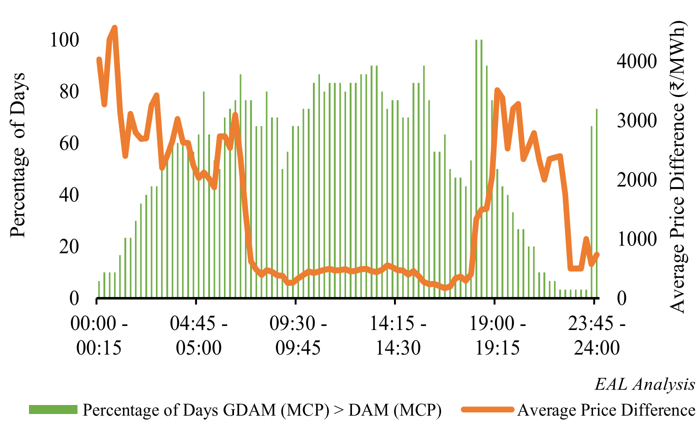
April 2026



May 2026



June 2026



EAL Analysis

- The analysis is based on comparison between the average price difference of G-DAM and DAM, when MCP of GDAM is greater than DAM for the First quarter of FY 2026-27.
- The graph shows the percentage of days, price for G-DAM is greater than DAM on the primary axis and the average price difference between the two on secondary axis.
- It has been observed that in 00:45–1:00 the highest average price difference is observed of Rs. 4.56/kWh for the month of June 2026.
- The average price difference between G-DAM and DAM is observed to be Rs. 1.39/ kWh for the quarter.

Draft CERC (Power Market) (Second Amendment) Regulations, 2026 [1]

The CERC notified Draft on Power Market (Second Amendment) Regulations, issued on 17th April 2026. The main objectives of the draft are given below:

Objective: The draft regulation operationalises Market Coupling in the power market by designating Grid India (Grid Controller of India Limited) as the Market Coupling Operator (MCO), responsible for bid aggregation and price discovery across Power Exchanges for the Day-Ahead Market, Real-Time Market, and other segments. It shifts price discovery from individual Power Exchanges to a centralised MCO framework based on maximisation of economic surplus, with market splitting during congestion, and mandates a Power Market Coupling Procedure (PMCP) within six months to govern implementation.

EAL Opinion

- **Separation between MCO and System Operator:** The proposed draft Regulation 38 states that *"Grid India shall function as Market Coupling Operator (MCO) and shall be responsible for operation and management of Market Coupling. For this, Grid India shall form a separate cell for discharging the functions of MCO."*

  Grid India already functions as the System Operator and recovers its costs under existing tariff regulations. If the MCO function is housed merely as an internal cell within Grid India, the costs related to its function as MCO would not be distinguishable from that as a system operator. While system operator costs are recoverable from the energy scheduled by the system operator, the MCO costs should be recoverable from the market participants, Accounting separation may be mandated under the power market regulation. As an alternate, a separate subsidiary may be established to function as an MCO. Given the exposure related to clearing function that would entail significant capital infusion to ensure capital adequacy, an independent entity would be preferable. A subsidiary structure will not only ensure operational separation between the two functions, but will also enable a clear market accounting separation for the MCO, thereby enabling the Commission to determine the charges to be levied by the MCO in a transparent and verifiable manner. This would also make the MCO more accountability and be also be more amenable to market monitoring.

  In the context of market monitoring, wherein the operation of the MCO and that of the System Operator should be required to have clear operational separation, so as to enable any future investigation or analysis without entanglement between the two activities. Till an independent subsidiary is established, the System Operator and the Market Operator should function with clear operational, accounting and administrative independence.

- **Basis and Limits for Charges for MCO:** In the proposed draft Regulation 39C(2)(g), provides that the PMCP shall include *"such other details related and incidental to implementation of Market Coupling including charges for MCO"*.

  The Regulations should specify:

  (i) The basis on which the MCO's charges will be determined and approved by the Commission;

  (ii) Whether any limit or cap on MCO charges is to be specified, analogous to the cap on Power Exchange transaction fees under Regulation 23 of the Principal Regulations (₹0.02/kWh);

- **Round Robin Mechanism for Price Discovery:** The draft Regulation designates Grid India as the sole Market Coupling Operator (MCO) performing price discovery. In the context of the European electricity market, which has geographical coupling, there are seventeen Nominated Market Coupling Operator (NMCOs), which undertake

[1] Suggested Citation: Singh A. (ed.). (2026), "Opinion on Draft CERC (Power Market) (Second Amendment) Regulations, 2026", Power Chronicle (Vol. 09, Issue 01, pp. 7-9), Energy Analytics Lab (EAL), Indian Institute of Technology Kanpur. https://eal.iitk.ac.in/assets/docs/power_chronicle_vol_9_issue_1.pdf

price discovery on a round robin basis. This approach ensures added reliability, fairness and transparency. The advantages of such an approach include:

(i) Three different market clearing engines (one per Power Exchange) provide independent implementations that can be cross-checked against each other, with the ability to run the same problem across all three platforms and verify consistency of outcomes, especially during the initial phase;

(ii) System reliability is preserved since each Power Exchange continues to maintain their respective market clearing infrastructure, including disaster-recovery servers in different cities. Under the single-MCO arrangement, in the event of a failure of the MCO's system, no other entity is in a position to take over, and the existing market-clearing engine arrangements maintained by Power Exchanges are likely to be discontinued;

Allocation of round-robin responsibilities may be based on the current market share of the respective Power Exchange. For illustration, based on the CERC Market Monitoring Report for December 2025[2], the DAM volumes for IEX, PXIL and HPX stood at 5,932.55 MU, 23.98 MU and 3.10 MU respectively, translating into shares of approximately 99.55%, 0.40% and 0.05%. A direct application of these shares to the days in a year would result in negligible allocations for the smaller exchanges. A minimum allocation (for example, two weeks per year) and a maximum allocation (for example, ten months) should therefore be specified, so that each participating Power Exchange is assigned a meaningful slot. The allocation may further be differentiated by market segment based on segment-wise market shares, and should be reviewed periodically in line with changes in market shares. A periodic review of the allocation may be undertaken in line with changes in market shares.

As an alternative, one of the existing power exchanges may be bestowed responsibility as a backup market clearing engine to address any contingency. This arrangement would also provide a platform for testing new algorithms.

- **Margin and Fee Arrangement under Alternative Models**: Under a round-robin price discovery arrangement, the transaction margin for any given day would accrue only to the Power Exchange performing the clearing on that day. However, the benefit of the round-robin model, namely, redundancy across multiple market clearing engines and cross-verification of outcomes, rests on each participating Power Exchange maintaining its clearing engine, supporting infrastructure and disaster-recovery setup in a ready-to-run state at all times. This imposes ongoing fixed costs irrespective of the rotation. It is therefore suggested that, in addition to the transaction margin accruing to the clearing Power Exchange, a small standing fee be prescribed for the maintenance of the market clearing engine by each participating Power Exchange along with clearing engine at Grid-India, with the basis, quantum and review mechanism specified by the Commission.

  In the alternative Grid India as MCO model, the cost elements, allocation methodology and periodicity of revision of the MCO charges should be transparently specified in the Regulations or the PMCP. The cost-segregation between the System Operator and the MCO functions, enabled through the subsidiary structure suggested earlier, is a necessary precondition for verifiable determination of these charges. The Commission may also consider whether a cap on MCO charges, analogous to the cap on Power Exchange transaction fees under the Principal Regulations, is appropriate.

- **Market Segments to be Coupled:** In the proposed Regulation 39, *"Market Coupling shall apply to the Day-Ahead Market (DAM), Real-Time Market (RTM) and other market segments from such date(s) as may be notified by the Commission:*

  Provided that different dates may be notified for different market segments."

  Significant welfare gain can result from coupling of market products that offer limited liquidity. Market coupling for such products should be a priority as this would also enhance efficiency and competition in price discovery for such market products, especially the Term Ahead Market (TAM) products. This should eventually be extended to

[2]CERC Market Monitoring Report for December 2025
https://cercind.gov.in/2025/market_monitoring/MMC%20Report_short%20term%20market_Dec%202025.pdf

include the Over the Counter (OTC) contracts which witness limited liquidity and competition since the rationale for coupling is system-wide and not restricted to a few segments.

- **Bid Types under Coupling:** In the proposed Regulation 39A (1), *"All Power Exchanges shall collect bids in a uniform bid format from market participants in accordance with the procedure and format stipulated in the Power Market Coupling Procedure (PMCP)"*

  In practice, certain bid types (for example, block bids) that appear similar across Power Exchanges have been designed differently by different Power Exchanges (for example, IEX and PXIL). The proposed amendment and the PMCP should clarify which bid types will be permitted under coupling, for DAM and RTM, and aim at harmonisation of bid formats.

  Equally important is the process for proposing new bid types, since one of the principal concerns raised regarding market coupling has been that it would dampen innovation in bid types and products. To preserve room for innovation, the proposed amendment should explicitly provide that Power Exchanges, individually or jointly, may propose new bid types to Grid India, in addition to any proposals by Grid India itself, with the procedure for such proposals and approvals laid out in the PMCP.

- **Multi-layered Market Surveillance:** Conducting market surveillance at both the Power Exchange level and the MCO level add only an incremental value, as the MCO would, by design, have access to the consolidated bid and transaction data across all Power Exchanges. With access to the wider data, the MCO would have the capability to analyse cross exchange data to identify participants' behaviour not conducive to the market outcome. For example, for round tripping. Where the MCO already holds the entire dataset and is required to set up its own surveillance and reporting procedure, replicating the same exercise locally at each Power Exchange yields little additional regulatory benefit. The exception to this, where Power Exchange–level surveillance can act as a cross-check, would be a scenario in which the MCO itself is implicated in an irregularity; however, such a scenario warrants an independent market monitoring arrangement. It is suggested that the Commission rationalises surveillance responsibilities to avoid duplication and explicitly address the institutional treatment of market monitoring

- **Market Monitoring Framework:** The Draft does not separately set out a market monitoring framework and confines itself to extending the surveillance provisions to the MCO. CER, IITK had earlier proposed a separate and independent Market Monitoring Unit under the comprehensive market monitoring framework for the Indian Power Sector[3]. The current development of market coupling operator paves way for enabling an independent MMU for robust market monitoring. The market monitoring function should be explicitly enforced and articulated in the Regulations rather than being left implicit in the surveillance provisions..

- **Market Data Access:** The power market regulation should also ensure that the MCO shares the detailed market outcome including the aggregate demand and supply curves with clearly identifiable intersection point through its portal in an unhindered manner to enable research as well as development of new products for the market ecosystem.

- **Data Pipeline to CERC at Inception:** Given that the MCO is being set up afresh and is in the process of establishing itself, operational procedures, IT systems and reporting infrastructure, the data pipeline from the MCO to the CERC (for market monitoring and other regulatory functions) should be designed and built into the MCO's systems at the inception itself, rather than added later. This includes the structure, periodicity and protocol of data flow from the MCO to the CERC. A market monitoring dashboard developed by the Centre for Energy Regulation (CER), Market Oversight and Numerical Investigations of Trading Operations and Reporting (MONITOR), for CERC may be suitably adopted to enable daily analysis as well as report generation across different market products.

[3] Sing, A., Shivhare, M. and Anand, H., 2025. Market Monitoring Framework for the Indian Power Sector. Kanpur: Centre for Energy Regulation (CER), Department of Management Sciences, Indian Institute of Technology Kanpur. Submitted to Central Electricity Regulatory Commission (CERC), New Delhi.

CERC Draft Order on Mechanism for treatment of connectivity granted under the GNA Regulations based on the LoA where the PPA has not been signed within a period of 12 months from the date of issuance of the LoA

Cite

The CERC notified Draft on "Mechanism for treatment of connectivity granted under the GNA Regulations based on the LoA where the PPA has not been signed within a period of 12 months from the date of issuance of the LoA", issued on 06th May 2026. The main objectives of the Draft are given below :

Objective: The draft order proposes a mechanism to address Connectivity granted on the basis of Letters of Award (LoA) issued by REIAs where the PPA has not been signed within 12 months, leading to stranded transmission capacity. It offers affected entities three options, exit from the LoA route with a fresh SCOD and PBG, substitution of the LoA with a PPA under another LoA, or surrender of Connectivity for reallocation/auction, invoking the Commission's powers under Regulations 41 and 42 of the GNA Regulations to prevent Connectivity from remaining unutilised.

EAL Opinion

- **Alignment with Resource Adequacy Planning:** The proposed mechanisms, appear to operate largely independent of the resource adequacy planning processes undertaken by DISCOMs and overseen by State Electricity Regulatory Commissions (SERCs). In the absence of such alignment, 'stranded' costs would be socialised and would be paid by the discoms and hence the final consumers. The speculative nature of connectivity, which banks on a probability that the discoms would ultimately sign the PPAs, places additional costs of transmission on the consumers, which is over an above the cost associated with their resource adequacy obligations. The allocation mechanisms thus needs a relook ensuring that the consumers do not end up being the 'risk bearer' for generators whose investments are not aligned with RA obligations of the discoms. Incase such generators wish to participate as a merchant player, significant financial stake should be mandated before issue of connectivity and hence transmission investment to be undertaken by the transmission licensees. In the present scenario, the undeclared 'stranded assets' has been created (till the capacity is re-allocated or utilized in future. Till then, the additional burden of such 'stranded assets' would be borne by the discoms and hence the end consumers. The regulatory approach should keep the interest of the consumers paramount so that such investments do not end of being 'stranded assets' (in part or full) while both the transmission licensee as well as the prospective generators do not face any associated risk or cost burden. Lack of financial commitment while granting such LOA has resulted in such an outcome.

  Our previous inputs on the matter highlighted this risk of stranded assets that may arise post the proposed amended regulation proposed in 2024[5].

  The Commission may therefore consider explicitly integrating the proposed framework with resource adequacy planning, including structured consultation with DISCOMs and SERCs prior to auctioning vacated connectivity. Such coordination would ensure that reallocated connectivity supports system-level planning objectives, demand forecasts, and consumer interest, rather than enabling short-term arbitrage disconnected from long-term power system requirements.

- **Need for Differentiated Priority Based on PPA–PSA Status and Project Readiness:** It is important to recognise that PPAs and PSAs represent two distinct contractual layers in the renewable energy procurement chain, typically structured as RE Developer → PPA → Intermediary (e.g., SECI) → PSA → DISCOM. The degree of contractual

[4]Suggested Citation: Singh A. (ed.). (2026), "Opinion on CERC Draft order on Mechanism for treatment of connectivity granted under the GNA Regulations based on the LoA where the PPA has not been signed within a period of 12 months from the date of issuance of the LoA, 2026", Power Chronicle (Vol. 09, Issue 01, pp. 10-14), Energy Analytics Lab (EAL), Indian Institute of Technology Kanpur. https://eal.iitk.ac.in/assets/docs/power_chronicle_vol_9_issue_1.pdf

[5]Singh A. (ed.). (2024), Opinion CERC (Connectivity and General Network Access to the inter-State Transmission System) (Second Amendment) Regulations, 2024, Regulatory Insights (Vol.06, Issue 04, pp. 20-22), Centre for Energy Regulation (CER), Indian Institute of Technology Kanpur. https://cer.iitk.ac.in/periodicals/regulatory_insights/Volume06_Issue04.pdf

and physical readiness across this chain varies significantly across projects and has direct implications for the risk of assets becoming stranded.

In this context, treating all PPAs or PSAs at par for the purpose of connectivity substitution, conversion, or auction may lead to inefficient outcomes. Projects against which a PSA has already been executed, and which have achieved 100% land acquisition represent the highest level of readiness and commitment from both supply and demand sides. Such projects should therefore receive the highest priority in allocation or retention of connectivity, as they are least likely to result in stranded capacity.

The following prioritisation framework, which may be suitably modified, could be considered in the following order:

(i) projects with both PPA and PSA executed and 100% land availability;

(ii) projects with PPA and PSA executed and at least 50% land availability;

(iii) projects with PSA executed and 100% land availability;

(iv) projects with PSA executed and at least 50% land availability;

(v) projects with only PPA executed and 100% land availability; and

(vi) projects with only PPA executed and at least 50% land availability.

Such a differentiated approach would better align connectivity allocation with actual project maturity, reduce the risk of entire projects becoming stranded assets, and ensure that transmission capacity is utilised by projects most likely to achieve timely commissioning.

- **Site-Specific Constraints and Non-Interchangeability of RE Projects:** The proposed framework appears to proceed on the implicit assumption that project sites and renewable energy technologies are broadly interchangeable for the purpose of substitution or reallocation of connectivity. However, such an assumption may not hold in practice. A key concern arises where the underlying technology and resource intensity vary across sites at which alternate connectivity is being offered to respective grantees.

The proposed criteria for grant of connectivity are primarily based on either commonality of ownership within grantees or contractual linkages on the REIA side. It is important to highlight that various renewable energy projects that have been granted connectivity, or are seeking connectivity, may differ significantly in terms of site-specific resource endowment as well as the mix of technologies deployed. These differences have direct implications for project viability, expected generation, and compliance with contractual obligations.

Furthermore, the substitution of connectivity with different capacity requirements, may result in sub-optimal outcome for the applicant to be granted connectivity. The sub-optimality may result either due to the generator being granted lower than required connectivity (through re-allocation) thus influencing its economics, or the transmission asset remaining underutilized (i.e. still partially stranded) if the capacity granted connectivity is lower than the one substituted. The proposal also assumes that adequate and substitutable land parcels, in terms of area, suitably, as well as costs are available without any legal/financial encumbrance.

To ensure that the proposed mechanism does not give rise to legal disputes, thereby further extending the costs associated with stranded assets, as previously highlighted **in Regulatory Insights**[6], it is essential to explicitly recognise these site-specific constraints. To minimize the scope for dispute while protecting the economic viability of projects, it is suggested that **the following criteria be considered while permitting substitution or reallocation of connectivity:**

i. resource endowment of the site;

ii. technology mix;

iii. vintage of the PPA;

[6] Singh A. (ed.). (2024), Opinion CERC (Connectivity and General Network Access to the inter-State Transmission System) (Second Amendment) Regulations, 2024, Regulatory Insights (Vol.06, Issue 04, pp. 20-22), Centre for Energy Regulation (CER), Indian Institute of Technology Kanpur. https://cer.iitk.ac.in/periodicals/regulatory_insights/Volume06_Issue04.pdf

iv. vintage of the GNA; and

v. size of the granted connectivity.

- **Definition of Parent and Subsidiary Entities:** In Annexure 1, Option II (b), *"PPA signed under LoA2 may have been issued by any REIA or such PPA may have been entered into by a distribution licensee or authorised agency on behalf of a distribution licensee. A PPA under LoA2 could be signed either by the Connectivity applicant itself,* **its subsidiary, or its Parent or another subsidiary of the same Parent Company**. *SCOD of the project, including extension thereof, shall be considered as per PPA, subject to the condition that such SCOD shall not be more than 30 months from the date of conversion." (emphasis added)*

  The draft order permits substitution of connectivity where the PPA is held by a parent, subsidiary, or sister concern of the original connectivity grantee. However, the terms *parent company*, *subsidiary*, and *sister concern* are not explicitly defined in the document. In the absence of clear definitions, differing interpretations may arise, potentially leading to disputes and inconsistent application of the provisions.

  To ensure legal certainty and uniform implementation, it is recommended that the definitions of parent and subsidiary entities be explicitly aligned with the provisions of the Companies Act, 2013, including relevant thresholds of control, shareholding, and management control. Clear statutory alignment would prevent ambiguity, restrict opportunistic restructuring, and ensure that substitution benefits are available only to entities with genuine corporate relationships recognised under law.

  Also, in the absence of a clearly defined cut-off date for establishing such corporate relationships, there exists a risk of ***post-facto*** restructuring undertaken solely to avail the benefits of substitution. **To prevent misuse of this provision and to avoid *post-facto* trading of connectivity or gaming of the regulatory framework, it is recommended that eligibility for substitution be restricted to corporate relationships that existed as on the date of execution of the latter of the two Letters of Award (LOAs).** Fixing the cut-off date in this manner would preserve the flexibility intended for protecting corporate interests while ensuring that the provision is not exploited through opportunistic restructuring.

- **Need for Disclosure of Technology-wise Data and Its Relevance to the Proposed Mechanism:** The draft order addresses cases of stranded connectivity arising due to non-signing of PPAs. However, the absence of disaggregated data on the types of generation technologies involved in such cases limits a full understanding of the underlying problem. Information on whether stranded assets predominantly pertain to solar, wind, hybrid, or storage-linked projects and their respective capacities would have been extremely valuable in assessing the suitability and likely impact of the proposed mechanisms. Such data would help stakeholders evaluate whether the proposed solutions are proportionate, targeted, and aligned with technology-specific realities.

- **Analysis of technology-wise data would strengthen the basis of the proposal and enhance confidence that the proposed framework effectively addresses the actual composition of stranded connectivity.**

  Public Disclosure of Implementation Status: Given the complexity and multiplicity of mechanisms proposed in the draft order, including conversion, substitution, surrender, and auction of connectivity, it is essential that implementation remains transparent and traceable. At present, there is no explicit requirement for systematic public disclosure of actions taken under these provisions.

  It is therefore recommended that the implementation status of all cases processed under the proposed framework be periodically updated on the website of the relevant authority (CTUIL). Such disclosures should include details of surrendered, converted, substituted, and auctioned connectivity, along with capacity, location, timelines, and current status. Public access to this information would enhance transparency, reduce information asymmetry among stakeholders, and strengthen confidence in the regulatory process, while also limiting the scope for disputes and allegations of discretionary decision-making.

- **Surrender of Connectivity Must Strictly Follow CERC Regulations:** While flexibility in dealing with delays in PPA/PSA signing is necessary, it is critical that any surrender of connectivity strictly follows the existing regulatory framework prescribed under the GNA Regulations. Deviations, implicit relaxations, or ad-hoc exemptions, if not clearly anchored in the regulations, risk undermining the certainty and enforceability of the framework.

  If a regulatory regime is not followed in letter and spirit, it creates an incentive for entities to seek *ex-post* relaxations, encouraging strategic delays and regulatory arbitrage. Over time, this erodes market discipline and weakens the credibility of the regulatory process. Such outcomes are detrimental to long-term investment confidence and may ultimately shift costs and risks onto DISCOMs and end consumers.

  To preserve regulatory sanctity and ensure predictable outcomes, the Commission may consider explicitly reaffirming that surrender of connectivity under all proposed options shall be governed strictly by the applicable provisions of the GNA Regulations, without dilution or discretionary departures.

- **Adequacy of Milestone Extension Charges vis-à-vis Time Value of Money**: Milestone Extension Charges (MEC) is proposed as a mechanism to allow limited extensions for achieving project milestones such as land acquisition, financial closure, or commissioning. While the intent is to discourage delays and ensure timely project execution, it is necessary to examine whether the proposed MEC adequately reflects the time value of money and the economic cost imposed on the system due to stranded connectivity.

  In practical terms, stranded transmission capacity imposes an interest cost burden on the system, reflecting the cost of capital for transmission assets. When viewed against this benchmark**, the proposed MEC, linked to Bank Guarantee (BG) amount, may be insufficient to internalise the true economic cost of delay,**

  particularly where the BG quantum is relatively small compared to the capital locked in the transmission system. This creates a risk that delays are effectively underpriced, thereby weakening the intended deterrent effect.

  The Commission may therefore consider examining whether MEC levels should be explicitly benchmarked to the time value of money associated with stranded transmission assets, so as to ensure economic equivalence between the cost imposed on the system and the charges levied on delayed projects.

- **Location-Specific Constraints in Option-II Substitution:** In Annexure-1 Option-II c(iii), *"No Objection Certificate from the concerned REIA or distribution licensee or authorised agency on behalf of the distribution licensee who issued LoA2 or PPA, with the approval of the change in the project location, if required."*

  Ambiguity arises when the PPA under LOA-2 explicitly specifies a project location that differs from the LOA-1 connectivity location. In such cases, retaining connectivity at the LOA-1 location may lead to contractual non-compliance, as generation would not originate from the PPA-designated site. Conversely, shifting connectivity to the LOA-2 location raises questions regarding permissibility under the GNA framework and potential prejudice to other applicants awaiting connectivity at that location. The draft order does not clarify how such location conflicts are to be resolved thus avoiding legal disputes later.

- **Mode and Refundability of Milestone Extension Charges:** The Draft Order provides for Milestone Extension Charges (MEC) to allow limited extensions for achieving prescribed milestones. However, it does not clearly specify the mode of payment of MEC, nor does it clarify whether such charges are refundable or adjustable at a later stage. This lack of clarity may weaken the deterrent effect of MEC and create scope for interpretational disputes.

  Given that MEC is intended to compensate the system for delay and continued blocking of scarce transmission capacity, it is recommended that **MEC be non-refundable and payable only in cash or cash-equivalent instruments, rather than through adjustment against Bank Guarantees.** Further, the permitted modes of payment (such as direct bank transfer or demand draft) should be explicitly specified. Such clarity would strengthen enforceability, ensure seriousness of applicants seeking extensions, and align MEC with its intended economic and regulatory purpose.

- **Need for Clearly Defined Auction Windows**: In Annexure 1, 5(c) , "There shall **be two windows** for calling the auction of such surrendered Connectivity based on whether the evacuation system exists or is under construction." *(emphasis added)* The draft order does not define the timing, duration, or periodicity of these windows. It is unclear whether these windows are annual, bi-annual, financial-year based, or would be triggered event-wise upon surrender.

In the absence of clearly defined windows, surrendered connectivity may either be auctioned prematurely in fragmented tranches or be unduly held back, resulting in inefficient utilisation of the transmission system.

The Commission may consider explicitly defining fixed auction windows (e.g., twice a year with specified dates), and clarifying that all connectivity surrendered up to a defined cut-off date shall be pooled and auctioned together within that window. In its absence, the mechanism may be prone to gaming and defeat the regulatory objective of efficiency and fairness.

- **Insufficient Competition and Auction Outcome Risk:** Given the location-specific nature of renewable projects, auctions may attract limited bidders for certain substations, resulting in outcomes close to the reserve price and limited competitive discovery. The draft does not address scenarios where auctions receive low participation or fail to discover adequate premiums.

  It is recommended that the Commission specify fallback mechanisms, such as re-auction, reserve price revision, or alternate allocation routes, in cases where auctions receive insufficient participation or fail to achieve effective price discovery.

- **Implicit "Copper Plate" Assumption in Auction Design:** In Annexure 1 (5), *"Treatment of Connectivity freed up under Option-III."*

  The auction mechanism proposed under implicitly treats connectivity as a homogeneous and fungible commodity, akin to a "copper plate" assumption, where connectivity at different substations is presumed to be economically and technically interchangeable. In practice, however, the value of connectivity is highly location-specific and depends on multiple factors such as CUF, transmission losses, congestion, land availability, evacuation constraints, and proximity to load centres.

  This implicit copper-plate treatment may undermine effective price discovery, as developers are unlikely to bid competitively for connectivity located in regions misaligned with their project economics. Consequently, auctions may see limited participation, outcomes close to the reserve price, or repeated failures in certain locations. **The Commission may therefore consider explicitly recognising this heterogeneity and evaluating whether segmentation by substation, location-specific reserve prices, or differentiated auction groupings are required, rather than assuming uniform substitutability of connectivity across the grid.**

- **Addressing Transmission Access Constraints for Standalone ESS:** Standalone Energy Storage Systems (ESS) require access to transmission capacity for both charging and discharging cycles to operate effectively. In cases where connectivity is granted for only charging or discharging, or for one instead of contractually required two cycles, such ESS projects would effectively be pushed back into the queue for transmission access. This may defeat the very purpose of facilitating storage deployment and may render such projects commercially unviable despite their system-level value. While the current situation may not include multiple cases of standalone ESS, the order may provide clarity on the issue so as to remove uncertainty around it.

  In scenarios where full-cycle connectivity cannot be simultaneously granted, the framework may consider enabling local adjustment mechanisms for ESS. Such mechanisms could allow ESS to utilise locally available generation or surplus connectivity through a structured barter-type arrangement, with or without the existence of PPAs between the concerned parties. Conceptually, this approach is **analogous to the SHAKTI policy in the coal sector**, which enabled optimisation through contractual flexibility without altering underlying ownership. **Introducing a similar approach for ESS would improve utilisation of local resources, reduce congestion, and prevent storage assets from becoming stranded due to procedural constraints in transmission access.**

CERC Staff Paper on "Capacity Market for Electricity in India"

Cite

The CERC notified the Staff Paper on "Capacity Market for Electricity in India", issued on 29th April 2026. The main objectives of the proposed public notice are given below:

Objective: The **CERC Staff Paper on Capacity Market for Electricity in India** discusses the need for a separate capacity market framework to address future resource adequacy concerns in India. It notes that India's existing long-term PPAs already function as capacity contracts because generators recover fixed costs based on availability and discoms hold scheduling rights. However, with increasing renewable energy integration, system stress during peak/net-load ramp periods, and inadequate reserve availability, the paper argues that the existing contracting framework may not be sufficient to ensure capacity availability when the system needs it most. The paper reviews international capacity market models such as capacity obligations, centralised capacity auctions, strategic reserves, and resource adequacy mechanisms in Germany, Great Britain, PJM, and California.

For India, the paper proposes three broad market interventions: a capacity market for resource adequacy obligations, a reserve capacity market for secondary and tertiary reserves, and a secondary/short-term capacity market for existing surplus capacity. The overall idea is to move from traditional bilateral contracting toward a framework where capacity remuneration, dispatch, and energy settlement are increasingly linked to the energy market. The paper suggests that capacity providers should be incentivised or penalised based on their availability during peak/stress hours, while discoms should be able to meet their RA obligations through market-based procurement. It also proposes centralised reserve procurement by NLDC/RLDCs where States fail to maintain allocated reserves.

EAL Opinion

- **Drivers for capacity market in the Indian power sector:** India's power sector is moving from traditional procurement by discoms to a more formal resource adequacy framework, under which they must secure sufficient firm contracted capacity to reliably meet consumer demand across solar and non-solar hours. In this transition, discoms face growing uncertainty from changing demand patterns, increasing renewable energy variability, and consumer migration through open access, which can leave some utilities with surplus contracted capacity and others with shortages. At the same time, surplus discoms remain locked into fixed capacity payment obligations, while deficit discoms often rely on volatile short-term energy markets during scarcity periods. In such a context, a capacity market can provide an efficient mechanism for trading surplus and deficit capacity, help manage stranded capacity, support compliance with short-term resource adequacy requirements, and strengthen grid reliability as competition and consumer choice expand in the electricity sector.
- **RA Obligation Capacity Market (Option 1):** Under the proposed RA Obligation Capacity Market (Option 1), the discom may invite bids based solely on the capacity charge, with the cleared capacity being tied up for a period of 15 years. The present proposal, where each discom individually conducts a capacity auction, may not be an efficient starting point for introducing a new capacity product. Discom-level procurement of long-term capacity under a new market design may lead to fragmented auction outcomes, differing contract structures, and uneven regulatory treatment across states. Before introducing such a mechanism, the existing Section 63 procurement framework and corresponding guidelines may need to be reviewed and strengthened to incorporate capacity products, payment security, contract tenure, rights and obligations of buyers and sellers, and the treatment of such contracts in resource adequacy compliance.
- **Long-Term Vs Short-term Capacity Market:** The long-term capacity market in India is primarily based on long-terms PPAs wherein the contracted price is discovered either through a regulatory process (Section 62) or a process

[7] Suggested Citation: Singh A. (ed.). (2026), "Opinion on CERC Public notice on Staff Paper on "Capacity Market for Electricity in India", 2026" Power Chronicle (Vol. 09, Issue 01, pp.15-20), Energy Analytics Lab (EAL), Indian Institute of Technology Kanpur. https://eal.iitk.ac.in/assets/docs/power_chronicle_vol_9_issue_1.pdf

of competitive bidding (Section 63). The proposed tenure of 15 years for a capacity product seems akin to a long-term PPA, which would have a limited liquidity due to varying resource gaps across discoms. In the context of renewable energy (particularly hybrid energy and that with storage), the auctions conducted through an intermediary, like SECI, already provide a similar product. The Indian power sector is undergoing a structural transition, with increasing renewable energy obligations, greater emphasis on resource adequacy, expansion of storage, India's longer-term net-zero commitment, emerging demand response and retail competition. In such a dynamic environment, tying up discoms in long-duration capacity contracts may recreate the very rigidity that the market design seeks to address. A discom may remain obligated to pay for capacity contracted under this framework even when its future procurement requirement shifts towards renewable energy, storage-backed capacity, or other flexible resources. This may lead to stranded capacity and the need for further rebalancing of portfolio in short-term.

- **Scheduling Rights of the Discoms:** The distinction between the proposed mechanism and the existing mechanism of capacity procurement under Section 63 of the Electricity Act, 2003 is not adequately clear. In the existing tariff-based competitive bidding framework, discoms procure long-term power through competitive bidding and secure scheduling rights over the contracted capacity. Under the proposed design, the discom would continue to undertake long-term capacity contracting and bear the capacity cost, but without corresponding scheduling or dispatch rights. Therefore, the proposal appears to reduce the rights of the contracting buyer without clearly demonstrating the incremental benefit over the existing procurement framework.

- **Guidelines for Competitive Bidding:** It is also not clear whether the proposed arrangement would be governed by the existing tariff-based competitive bidding guidelines issued under Section 63 of the Act. The present competitive bidding guidelines are primarily designed for procurement of electricity through energy-related products and bilateral contracting structures. They may not be directly applicable to a capacity-only product discovered through the proposed capacity market design. Since the proposal does not appear to be a power exchange-based market with multiple buyers and multiple sellers, and is instead based on discom-specific procurement, there may be a need to amend the existing competitive bidding guidelines or issue separate guidelines for procurement of capacity as a distinct product. In the absence of such clarity, the proposed design may create regulatory uncertainty and scope for future disputes.

- **Payment security mechanism:** Since the capacity provider would be relying on capacity remuneration over a long tenure, the payment security framework becomes a critical element of bankability. At the same time, the extent of payment security required, its cost, and its implication for discom finances and consumer tariff need to be enunciated. Without such clarity, the framework may not provide adequate investor confidence and may also expose discoms to additional financial obligations without corresponding operational control over the contracted capacity.

- **Capacity contract vs actual available energy:** Another important aspect that requires clarity is the treatment of fuel, resource availability, and actual dispatchability of the cleared capacity. The proposed framework focuses on capacity availability and market participation, but it does not clearly specify how the underlying resource availability would be ensured. For instance, if coal-based capacity clears in the capacity market, the framework should specify whether and how adequate coal availability would be ensured during the relevant period, particularly during peak or stress hours. Similarly, in the case of gas-based plants, hydro resources, storage-backed capacity, or renewable energy firmed with storage, the relevant fuel, water availability, state of charge, or firming arrangement would need to be demonstrably available.

  Capacity remuneration alone may not ensure actual energy availability unless the capacity provider is also required to maintain adequate fuel or resource readiness. In the absence of such provisions, a capacity provider may technically clear the capacity market but may not be capable of delivering energy when called upon by the system. This would weaken the reliability objective of the capacity market and may lead to capacity payments being made without corresponding assurance of dispatchable energy during system stress.

  Further, even where fuel or resource availability exists, the capacity may still not be scheduled or dispatched if the start-up cost, minimum run requirement, ramping cost, or other commitment-related costs are too high relative to expected market revenue. This is particularly relevant for thermal and gas-based generating stations, where the decision to bring a unit online may depend not only on the energy price but also on start-up time, minimum technical limit, ramping capability, and recovery of commitment costs. The proposed mechanism does not clearly address how such costs would be treated, or whether a capacity provider would be compensated for being technically available but commercially uneconomic to schedule under the prevailing market conditions.

This creates a distinction between capacity availability, market participation, economic scheduling, and actual dispatch. Unless this distinction is addressed, there may be situations where the capacity provider receives capacity remuneration but the resource does not contribute to reliability during system stress because it is either not fuel-ready or not economically schedulable. Therefore, the framework should not merely require participation in the DAM/RTM or clearing during peak/stress hours, but should also specify the conditions under which the resource is expected to be committed, scheduled, and dispatched.

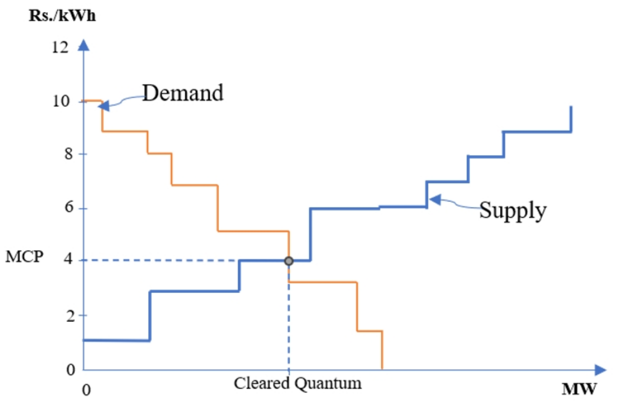
It is therefore suggested that the **framework should clearly specify resource-availability and dispatchability obligations for different technologies. Such obligations may include demonstration of fuel tie-up, coal stock, gas supply arrangement, hydro availability, storage state-of-charge requirement, or firming arrangement, as applicable**. The framework should also clarify the treatment of start-up cost, ramping cost, minimum run cost, and other commitment-related costs. The penalty framework should distinguish between failure to participate in the market, failure to ensure actual resource availability, and failure to deliver when economically and technically scheduled. This would help align capacity remuneration with reliability outcomes and reduce the risk of paying for capacity that is not practically available to the system when needed.

- **Dispatch of the contracted capacity through energy market:** The proposed design provides that the capacity contracted through the RA Obligation Capacity Market would be dispatched through the Day-Ahead Market/Real-Time Market. To guarantee the discom's right over the contracted capacity, the proposal suggests that the demand curve or price bid of the contracting discom for such contracted capacity may be drawn slightly above the price cap. Further, the capacity provider may be mandated to participate and clear in the market as a price taker during peak/stress hours to be notified by the NLDC.

These provisions need to address following questions –

- Whether the discoms with contracted capacity through capacity market will be allowed to bid above the price cap?
- What is limit on bidding above the price cap?
- Can the discoms with contracted capacity through capacity market bid at price cap beyond their contracted capacity?
- How will the energy be allocated when the energy market is administratively cleared at price cap?
- The capacity providers are mandated to offer their contracted capacity as price takers only during stress/ peak hours as specified by NLDC. Can the capacity providers offer their contracted capacity at any other price during non-stress periods?
- How will the stress hours be defined?

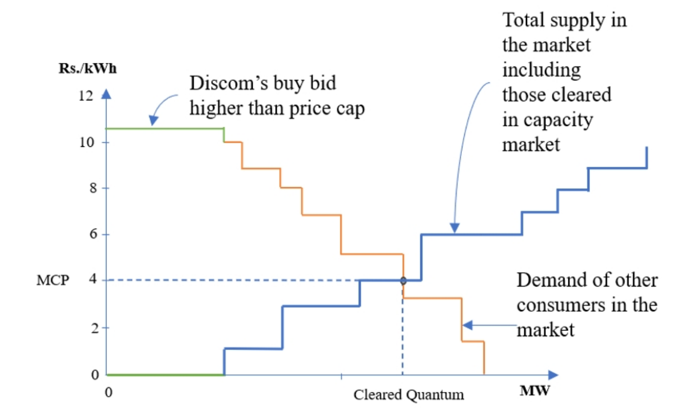
Without answering the above questions, the present proposal will lead to inefficient market outcome and inflate the price discovery during non-stress hours. Thus, it is also suggested that contracted generators be mandated to offer their capacity as price takers in all time blocks. Following illustration explains the effect of proposed bidding and offer mechanism on existing energy markets.



(A)

Typical demand and supply in energy market prior to implementation of capacity markets and with no shortage.

Figure 1: Demand-Supply curve in energy markets without capacity markets



(B)

No change in MCP only if capacity contracted through capacity market is offered as price taker.

Figure 2: Energy market clearing post implementation of capacity market (RA obligation option 1 and 3)

- **Definition of peak/ stress hours:** It is suggested that the peak/ stress hours be determined through detailed and transparent process including the timeline for notifying such peak/ stress hours. Also, protocol for modification/ withdrawal of such notice for stress/ peak hours should be included in the process determined by the NLDC.
- **RA Obligation Capacity Market (Option 2):** The proposed RA Obligation Capacity Market (Option 2) may need to be reconsidered in terms of its basic characterization. The proposal provides that the discom would invite bids based on total cost, as is done presently, retain scheduling rights until the day-ahead market window, and thereafter both the buyer and the generator would bid into the day-ahead/real-time market for market-based dispatch. This design appears closer to a market-based economic dispatch framework rather than a capacity market. Thus, all the issues related to the initially proposed MBED need to be addressed. A capacity market, in principle, is intended to remunerate dependable capacity separately from energy and to ensure availability during periods of system stress. In contrast, the central feature of Option 2 is the routing of contracted capacity through the energy market for dispatch and settlement. The proposed framework therefore appears to be a restructured version of Market Based Economic Dispatch (MBED), rather than a distinct capacity market design. Labelling it as a capacity market may create conceptual ambiguity and may also dilute the focus of the present consultation.
- **RA Obligation Capacity Market (Option 3):** The Staff Paper proposes a residual RA obligation capacity market through a central agency for discoms having RA shortfall, with contract duration of 10–15 years[8]. Separately, the paper also proposes a secondary short-term capacity market for short-term shortfall of 1–3 years. This effectively creates two separate markets for addressing residual RA obligations of discoms — one long-term primary market and another secondary/short-term market.

  The need for such separation may need reconsideration. A discom may not necessarily tie up its entire residual capacity requirement through long-term contracts, not because of lack of planning, but because it may intentionally keep some space for uncertainty in demand growth, renewable energy procurement, storage availability, open access migration and future resource adequacy adjustments. A long-term residual RA contract of 10–15 years may reduce the ability of discoms to rebalance their portfolio in response to changes in demand, renewable purchase obligations, technology costs, and market conditions.

[8]Suggested Citation: Singh A. (ed.). (2021), Opinion on MoP Discussion paper on "Market Based Economic Dispatch (MBED)", 2021 Power Chronicle (Vol. 04, Issue 01, pp.12-16), Energy Analytics Lab (EAL), Indian Institute of Technology Kanpur. https://eal.iitk.ac.in/assets/docs/Volume04Issue01.pdf

The proposed long-term residual RA market may also alter the risk allocation between generators and discoms. If generators are able to tie up capacity through long-term residual RA contracts, they may be insulated from the risk of competition from surplus or excess capacity already held by discoms. In contrast, the liability of future portfolio rebalancing would remain largely with the discoms and, ultimately, consumers. This may lead to a situation where suppliers are protected through long-term capacity remuneration while discoms bear the risk of demand uncertainty, resource-mix transition, and stranded capacity.

Such an approach may not be fully aligned with the competitive spirit of the Electricity Act, 2003. The purpose of introducing a capacity market should not be to provide long-term risk insulation to generators, but to ensure that adequate and dependable capacity is available to meet system reliability requirements at least cost. **If residual RA requirements are uncertain and subject to frequent revision, the market design should enable efficient rebalancing rather than lock discoms into long-duration commitments.**

It is therefore suggested that the proposed primary residual RA obligation capacity market and the secondary short-term capacity market may be merged into a single common capacity market for residual RA needs. The contract duration in such a market may preferably be limited to 1–3 years. This would allow discoms to meet residual RA obligations while retaining flexibility to adjust their procurement portfolio over time.

A common market would also improve liquidity, avoid segmentation between long-term and short-term capacity products, reduce regulatory complexity, and better align capacity procurement with evolving system requirements.

- **Reserve capacity market- Granularity for estimation of reserve capacity requirement:** The estimation of reserve requirement is to be done on coincidental peak basis rather than the non-coincidental peak basis[9] as is suggested in the proposed staff paper. While procuring reserves estimated on non-coincidental demand pattern, the total reserve to be procured across the country would be significantly higher and impose additional costs on the distribution licensee and hence the final consumers. Given the complementarity of the demand and generation resources across discoms, the estimation of reserve should reflect the economics of reserve requirement and procurement thereof.
- **Reserve capacity market - Combined market for short-term capacity and reserve capacity market:** The proposed market for reserve capacity would break up the liquidity, enhance investors/generators risk and also reduce competition for its procurement. A combined capacity market for rebalancing short-term capacity obligation of the discoms and reserve capacity is suggested as opposed to separate segment of proposed capacity market for reserves. Furthermore, the capacity auction to be carried out every three months with contract duration for three months (including monthly contracts) same as that of the proposed short-term capacity market. The advantages of such combined market would be –
  1. It would ensure competitiveness
  2. Offer bigger market for generators/ those with excess capacity
  3. It will reduce the risk of participation and discovered price across different market segments, hence improve the confidence of the market participants
- **Procedure of estimation of reserve capacity:** The current procedure adopted by NLDC for reserve estimation arrives at a single number for ensuing year. It is proposed that the reserve estimation should be updated every quarter. This would also align with the timelines of combined auction process of short-term capacity and reserve capacity. This will also improve the robustness of the estimate and also reduce the associated error in estimation of reserve. **Since the demand as well as supply position remain dynamic, adoption of this procedure would not only improve the reliability of estimate but also make it economical for the distribution utilities to meet their capacity obligations.**
- **Effective real-time Capacity Monitoring and Market Monitoring:** Real-time capacity monitoring is essential to

[9] Though not explicitly mentioned but this can be inferred so.

ensure that no available capacity is withheld by market participants, and its dispatch can be ensured when required. Such monitoring should also confirm the availability of the required network access for dispatch of this capacity. Robust capacity monitoring will help ensure that contractual obligations of market participants, including long-term PPAs, are fulfilled and that no contracts are violated. All capacity above 1 MW should be monitorable. To begin with, all capacity above 10 MW connected to a single interconnection point should be monitored in real time basis through unique identifier. The data so acquired would be important information for market participants especially the distribution licensees and hence be publicly accessible. The same should also be accessible for enabling further research and analytical tools.

- **Effective Market Monitoring:** The power market dynamics is entangled through various products across energy, capacity, reserve and other ancillary services market product. Lack of an effective market monitoring framework, which remains long-delayed, would continue to cast its shadow on efficient market outcome. The current market monitoring framework remains limited to market reporting rather than pro-active market monitoring. The international experience provides a great deal of examples for the need and effectiveness of a robust market monitoring framework. The Centre for Energy Regulation (CER) at IIT Kanpur developed a market monitoring dashboard called Power sector Regulatory Oversight and Market Performance Tracking (PROMPT) for CERC under a project funded by the FCDO, UK. This provides a starting point for further expanding the scope and depth and frequency of market assessment and analytics enabling regulators and policy makers a hand on the market nerve while strengthening trust of the market participants.

- **Appropriateness of Net-CONE:** The proposed use of Net-CONE to set the capacity demand curve is primarily based on the international experience, where context differs from that in the Indian context. PJM, ISO-NE, NYISO, and the UK all use some version of CONE/Net-CONE in capacity-market parameter setting. Capacity-market demand curves in the main U.S. northeast markets are commonly described as relying on three elements: the capacity requirement, Net-CONE, and the shape of the curve. But the proposal departs from good practice in three ways –

  i. International markets define Net-CONE through a formal administrative process, with reference resource assumptions, cost assumptions, revenue-offset assumptions, and periodic review. The proposal does not specify any details thereof

  ii. International capacity markets usually distinguish between existing resources and new resources through offer rules, mitigation, de-rating, and sometimes different contract durations. They do not simply assume that one Net-CONE value will work equally well for all resource types and vintages.

  iii. Net-CONE is normally linked to a system reliability standard and target capacity requirement. For example, the UK auction parameters explicitly publish the reliability standard, target capacity, Net CONE, price cap, and demand-curve quantities together. In the proposal, the demand curve appears to be discussed more as a Discom procurement curve, which is less aligned with international practice. Furthermore, the Indian power sector still lacks a formal reliability standard whose cost effectiveness matches with the underlying system costs and economic realities.

  The proposals should clarify the use of Net-CONE for drawing the capacity demand curve. A Net-CONE-based demand curve is meaningful only if the reference resource, cost assumptions, expected energy/ancillary service revenue offsets, and review methodology are clearly specified. International capacity markets use Net-CONE as an administrative parameter linked to a defined reliability standard and target capacity requirement, usually with a clearly identified reference technology. The present proposal does not clarify whether the reference technology would be new coal, gas, storage, RE-plus-storage, pumped hydro, or another resource. This is important because the resulting capacity price and investment signal would differ significantly across technologies

  A formal study should be undertaken to evaluated efficacy of CONE/Net-CONE or other alternatives in the Indian context with its own sectoral, system and market peculiarities. This should also examine the methodological approach to derive demand curve, the benchmark costs and reliability standards for the integrated Indian market. Robust benchmarking of net cost of new entry is necessary to strengthen regulatory oversight in a capacity market framework. It is suggested that separate benchmarking studies be conducted by the CERC/ NLDC before applying it to the capacity market.

Power Lexicon

CERC Staff Paper on "Capacity Market for Electricity in India", 2026

Capacity Market	An additional market alongside the existing energy market where only capacity is traded and explicitly remunerated. While the energy market handles short-term resource optimization, the capacity market provides capacity payments to • Address inadequate investment in new capacity. • Address deficiencies in ancillary service markets. • Solve the "missing money" problem (insufficient revenue to cover fixed costs). • Manage intermittent renewable energy generation.
Capacity Obligation	Capacity Obligation is a decentralized approach to resource adequacy. Instead of a central authority buying all the capacity, Load Serving Entities (LSEs) and large consumers are imposed to secure a specific amount of future generation capacity. This ensures the grid has enough power during peak demand periods. Obligations can be met through – • Ownership of plant, • Contracting capacity with generators, or • By purchasing tradable capacity certificates. If enough capacity is not contracted, the supplier or the consumer will pay a **capacity shortfall penalty.** The capacity price is determined through auctions. Entities holding excess capacity can sell their exchangeable obligations to others in a secondary market. The primary goal of the framework is to encourage long-term investments in backup generation and demand-response capabilities without relying solely on real-time energy price spikes.
Short-term Capacity Market	**Short-term Capacity Market** is a market mechanism that enables the **trading of electricity generation capacity** for short durations, typically through periodic auctions for **monthly or three-month contracts.** It allows entities with surplus capacity, such as generating companies, Discoms, and traders to offer capacity to entities facing capacity shortages. The market determines the capacity price through **double sided bidding.** The contracted capacity is scheduled and dispatched on day-ahead basis. The mechanism is designed to improve resource adequacy, ensure the availability of generation capacity during peak demand periods, promote efficient utilisation of existing generation resources and enhance the reliability of power supply.
Strategic Reserve	A specific capacity kept aside (and outside the regular energy market) purely for emergencies, activated only during extreme system stress, with payment discovered through competitive tendering. System operators operate this to ensure the system remains safe and secure during stress and contingencies.
Net CONE (Net Cost of New Entry)	Net CONE is the **cost of a new generating resource after deducting the expected revenue it is likely to earn from the energy market.** It represents the portion of a

	generator's fixed costs that cannot be recovered through energy sales and therefore serves as the benchmark for capacity remuneration in a capacity market. It is used as the basis for designing the demand curve in capacity auctions to ensure adequate investment in generation capacity while avoiding overcompensation, with the **Reserve Capacity Market** using a demand curve based on **Net-CONE plus 10%** to establish the bid cap.
Reserve Capacity Market	A proposed advance-procurement mechanism (yearly auctions, one-year contracts) for Secondary and Tertiary Reserves, priced on a Net-CONE + 10% basis, with NLDC holding first right of scheduling/dispatch.
Price Discovery Mechanisms	**Pay-as-Clear –** Price discovery mechanism used in capacity auctions in which **all successful bidders receive the same Market Clearing Price (MCP), regardless of their individual bid prices**. The auction clearing price is determined at the intersection of the demand and supply curves, providing uniform capacity remuneration to all resources that clear the auction and promoting efficient competition and transparent price discovery. **Pay-as Bid –** Pricing mechanism in which each successful bidder is paid the exact price it submitted in its bid rather than a uniform Market Clearing Price (MCP). Under this approach, capacity providers receive remuneration based on their individual accepted bid prices, allowing payments to vary across successful bidders instead of using a common clearing price.
Commitment/ Holding Charge	A newly proposed charge (an opportunity-cost payment) to compensate a capacity provider when NLDC schedules it but doesn't actually dispatch it.

Draft CERC "(Power Market) (Second Amendment) Regulation, 2026"

Market Coupling	Market Coupling is a mechanism for price discovery in electricity markets, applicable to the Day-Ahead Market (DAM), Real-Time Market (RTM), and other market segments as may be notified by the Commission. Under this mechanism, all Power Exchanges collect bids from market participants in a uniform format and forward them to **the Market Coupling Operator (MCO),** who aggregates the bids across all exchanges and determines a **unified market clearing price.**
Market Coupling Operator (MCO)	The Market Coupling Operator is the entity designated to operate and manage Market Coupling. Under the draft Regulation, Grid India is designated to function as the MCO, for which it shall form a separate dedicated cell. Key Responsibilities – • Bid Aggregation • Price Discovery The MCO is responsible for receiving anonymous and validated bids transmitted by all Power Exchanges through secured channels, aggregating these bids across exchanges for each market segment, and conducting price discovery to ensure economic efficiency. The detailed responsibilities of the MCO, including operational timelines, bid processing, and charges, are to be governed by the Power Market Coupling Procedure formulated by Grid India with the approval of the Commission.

Mechanism For Treatment of connectivity granted under the GNA Regulation based on the LoA where the PPA has not been signed within a Period of 12 Months from date of issuance of the LoA

REIA	REIA stands for Renewable Energy Implementing Agency. REIAs act as intermediary procurers under TBCB framework. Their primary responsibilities includes: • Conducting auctions – Running the bidding process for news clean energy projects. • Signing agreements – Executing back-to-back PSAs with developers and PPAs with Discoms or consumers. • Aggregating power – Purchasing electricity from multiple RE developers. • Securing payments – Ensuring financial security for RE generators. Historically, there have been only four REIAs: SECI, NTPC, NHPC and SJVN. However, the Ministry of Power has issued operational guidelines allowing eligible private sector companies to also serve as REIAs to help scale up India's RE capacity.
Letter of Award (LoA)	A Letter of Award is a document issued by REIA that serves as one of the recognised routes under the GNA Regulations through which a REGS may seek connectivity to the inter-State Transmission System. Connectivity granted on the basis of an LoA is premised on the expectation that the LoA will culminate in the signing of a PPA and a PSA, leading to the eventual commissioning of the project. Under this Order, an LoA on the basis of which connectivity has been granted but where a PPA has not been signed within twelve months of its issuance triggers the applicability of the three-option mechanism. Once an entity exits the LoA route under Option-I or substitutes the original LoA under Option-II, that LoA becomes an invalid document for the purpose of obtaining any fresh connectivity or for converting connectivity from the Land or Land Bank Guarantee route to the LoA route.
Central Transmission Utility of India Limited (CTUIL)	CTUIL is the Nodal Agency responsible for the administration of connectivity granted under the GNA Regulations. In the context of this Order, CTUIL is directed - • to publish the list of entities covered under the proposed mechanism within three days of issuance of the final order. • to scrutinise applications and documents submitted by entities. • to issue revised grants of connectivity, whether in-principle or final, within stipulated timelines. CTUIL is also designated as the Nodal Agency for calling, conducting, and awarding connectivity through open auction of surrendered connectivity capacity, which it may carry out either directly or through notified Bid Process Coordinators or REIAs. Additionally, CTUIL is responsible for returning Connectivity Bank Guarantees to surrendering entities upon receipt of bid amounts from successful auction bidders, and for collecting and furnishing to the Commission the status of connectivity granted on the LoA route where PPAs remain unsigned.

6th Regulatory Certification Program (RCP) on "Power Sector Regulation: Theory and Practice"

The Centre for Energy Regulation (CER), in collaboration with the Energy Analytics Lab (EAL), successfully conducted the Regulatory Certification Program on "Power Sector Regulation: Theory and Practice" from 30th May to 21st June 2026. The program was organized under the aegis of the Office of Outreach Activities, IIT Kanpur, with the objective of providing participants with an in-depth understanding of power sector regulation in practice, grounded in fundamental economic principles.

The program was delivered by distinguished resource persons, including Mr. Ghanshyam Prasad (Chairperson, CEA), Mr. Arun Goyal (Former Member, CERC), Mr. S. C. Shrivastava (Former Chief (Engineering), CERC), Prof. Tooraj Jamasb (Director, CSEI), Mr. Buddy A. Ranganadhan (Senior Advocate, Supreme Court of India), Dr. Srini Parthasarathy (Partner and Head of Efficiency Practice, Oxera), Ms. Shilpa Agarwal (Joint Chief (Engineering), CERC), Mr. Vivek Mishra (Partner and Practice Lead, cKinetics), Mr. Himanshu Chawla (Head – Regulatory and Research, PFI), Dr. Raj Addepalli (Consultant, Texas, USA), Mr. Bijoy Kumar Sahoo (Former Project Executive Officer (PEO), CER, IIT Kanpur) and Prof. Anoop Singh (Founder & Coordinator, CER & EAL, IIT Kanpur).

The online valedictory ceremony was graced by Mr. T. K. Jose, IAS (Retd.), Chairman, Kerala State Electricity Regulatory Commission (KSERC), as the Chief Guest. He congratulated the participants on successfully completing the program, following which certificates were awarded to all successful participants.

The editor thanks Power Chronicle team for their contribution in supporting the data analysis, copy editing and coordinating final production of this issue. The editor also acknowledges the support of the IT Team, led by Garima Bajpai and Rahul Shah.

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Other Initiatives

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