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May 27, 2026

Sh. Harpreet Singh Pruthi
Secretary
Central Electricity Regulatory Commission

Subject: FICCI Submission - CERC Staff Paper on Capacity Market for Electricity in India

Dear Sir

We would like to sincerely appreciate the initiative taken by the Central Electricity Regulatory Commission in issuing the Staff Paper on Capacity Markets for Electricity in India, aimed at strengthening India's long term grid reliability framework.

FICCI welcomes the proposal of introducing Capacity Markets as outlined in the CERC Staff Paper, providing therein the options that collectively will contribute toward security and reliability of power supply.

Based on the inputs received from our members, we have divided our submission into two parts - one proposing a Technical Construct, drawing lessons from international experience and taking the Staff Paper as a base document; and the other providing Legal and Regulatory Perspectives on how the market framework may be made compliance-ready with appropriate rules and regulations, with the specific proposals therein shown in italics.

Both the Notes being submitted are aligned with the market designs enumerated in the Staff Paper and have been prepared with the objective of making the suggested market framework function effectively.

We look forward to the opportunity of engaging further on the subject and discussing the matter in person to continue the deliberations.

Thanking you,

With best regards,

Arpan Gupta
Director & Head
Mines, Metals, Cement
Power, Coal, Renewable Energy
Hydrocarbons & Civil Nuclear

FICCI Comments on CERC Staff Paper on Capacity Market for Electricity in India

(Technical Construct)

Date – May 27, 2026

Submitted to: Central Electricity Regulatory Commission (CERC)

I. Scope and Context

The CERC Staff Paper (April 2026) is a timely initiative. It draws on international experience from Germany, Great Britain, PJM (USA), and California, and addresses three mechanisms: (A) the Resource Adequacy (RA) Obligation Capacity Market, (B) the Reserve Capacity Market, and (C) the Secondary Short-Term Capacity Market. These comments address five themes:

- The fundamental incompatibility of the proposed Net-CONE pricing methodology with India's current energy market depth;
- The need to formally integrate existing long-term PPAs into a rigorous RA compliance framework before introducing a new capacity auction;
- Required modifications to Options 1, 2, and 3 under Section A;
- Strengthening the Reserve Capacity Market (Section B); and
- Enabling conditions for the secondary capacity market (Section C) to function without diluting existing PPA obligations.

A critical reference point is PJM's May 2026 White Paper (enclosed), 'Powering Reliability Through Market Design,' which undertakes a holistic review of its capacity market after nearly two decades, acknowledging that market conditions have fundamentally changed. Two of PJM's foundational principles are directly applicable to India's design choices:

- Whether resource adequacy as a common good is preserved and costs are explicitly passed through to consumers under regulatory mandate; and
- Whether the CONE study reliably answers what a new generator needs to recover to make investment viable — the number that determines whether investors will commit capital.

These guardrails must frame India's capacity market design. Equally important is PJM's diagnosis of the 'credibility trap' — where high scarcity prices trigger political intervention, investors discount the revenue signal, and capital stays on the sidelines. India must consciously avoid designing conditions for this trap to replicate.

II. Market Context and Core Diagnostic

India's market structure differs fundamentally from PJM, GB, or California — each of which operates a deep liquid energy market where capacity payments function as a marginal 'missing money' top-up. The relevant parameters are:

Market Parameter	Current Status
Long-term PPA share of energy sales	~87% via bilateral contracts (SERC-approved)

Market Parameter	Current Status
DAM + RTM share	~8% — shallow; susceptible to gaming and price spikes
Price Cap in Power Exchanges	Artificially suppresses revenue signals for new investment
Reserves adequacy	Critical shortage during solar hours; NLDC relies on Section 11 emergency procurement
Ancillary services market	SRAS/TRAS functional but volumes thin; reserve price signals weak

The underlying problem is not the system-wide 'missing money' of the PJM type. The real issues are: (a) reserve adequacy gaps during system stress; (b) residual RA shortfall not covered by existing PPAs; and (c) the absence of a liquid secondary market for surplus contracted capacity. This distinction is foundational — it changes both the choice of mechanism and the sequencing of reform.

The Net-CONE Conundrum

The CERC Paper proposes capacity auctions designed around Net-CONE — Cost of New Entry net of expected energy market revenue — as used in PJM and GB. This approach is mathematically reliable when the energy market is deep enough to produce stable, predictable clearing prices that represent the genuine opportunity cost of dispatch for all generators.

Neither condition holds in India. With only ~8% of energy transacted through DAM/RTM, clearing prices are driven by marginal surplus/deficit conditions, not by systematic competition among all generators. A generator whose PPA mandates scheduling by its contracting Discom does not participate in DAM/RTM price formation. Consequently, the 'expected energy market revenue' component of Net-CONE cannot be reliably computed.

Applying Net-CONE in these conditions risks replicating precisely the credibility trap that PJM is now trying to escape: short-term spot signals cannot anchor investor expectations, the market sends ambiguous investment signals, consumer unrest and political intervention becomes likely, and capital either leaves or demands a large risk premium.

Recommendation 1:

Commission a dedicated India-specific CONE study (CEA/NLDC), disaggregated by technology type (coal subcritical/supercritical, gas CC, hydro and pumped hydro, BESS). Apply the energy market revenue credit against CONE only when DAM/RTM traded volume exceeds 25% of total scheduled energy on a rolling 12-month basis, with a prescribed review cycle.

III. Section A — RA Obligation Capacity Market

A. Prerequisite: PPA-RA Credit Registry

India already has an implicit capacity market through long-term PPAs: the Paper itself acknowledges that Indian PPAs are inherently capacity contracts with fixed-cost recovery linked to availability, and that contracting buyers hold scheduling rights. The Paper's Options 1, 2, and 3 all assume a new capacity auction as the primary RA vehicle — but existing PPAs already serve this function for the bulk of Discom loads.

Before introducing any new capacity auction, CERC should formally establish a PPA-RA Credit Registry — a regulatory database maintained by NLDC that maps each PPA's contracted capacity to the contracting Discom's RA obligation:

- Each Discom's RA obligation is computed by SERC based on peak demand plus a defined reserve margin (15–20%).

- PPA contracts are credited against this obligation at contracted capacity, derated for availability and performance during notified system-stress hours — not merely for average availability.
- Only the net residual shortfall triggers procurement through the new capacity mechanism.
- PPAs expiring within the RA planning horizon are flagged for upcoming shortfall.

This directly mirrors the California CAISO Capacity Procurement Mechanism model and avoids the double-payment risk explicitly flagged in Para 23 of the Paper.

Recommendation 2:

Insert a new Section A0 establishing the PPA-RA Credit Registry before considering Options 1–3. **Only the residual RA shortfall after crediting existing PPAs should trigger new procurement**. Capacity must be payable for performance during notified system-stress hours, not merely for declared availability.

B. Options — Near-Term Vehicle and Long-Term Target

The three Options differ primarily in the degree to which scheduling rights are transferred to the energy market. The appropriate choice depends on DAM maturity. At ~5% DAM share today, a phased approach is essential:

Option	Assessment and Role
Option 3 (Residual RA, NLDC as central agency)	Immediate near-term vehicle (Years 1–5). Mirrors CAISO CPM. Least dependent on energy market depth. NLDC should be the designated central agency — it already has market interface, scheduling authority, and data and compute infrastructure.
Option 1 (Energy market dispatch, scheduling rights transferred)	Correct long-term target. Premature at current DAM share. Should be triggered by DAM liquidity milestones, not by a calendar date.
Option 2 (Two-part tariff with bilateral contract settlement)	Intermediate step only. The bilateral contract settlement (contract price minus MCP) adds financial complexity that many Discoms lack the treasury sophistication to manage. Should include a defined sunset clause tied to DAM liquidity thresholds.

The transition between Options should be explicitly phased by DAM market share:

Phase / Threshold	Mechanism
Phase 1 (Years 1–3): DAM below 25%	Discoms retain scheduling rights. Generators offer into DAM as price-takers only during NLDC-notified stress hours.
Phase 2 (Years 3–6): DAM at 25–40%	Scheduling rights until T-4 hours before delivery; mandatory DAM participation thereafter.
Phase 3 (Years 6+): DAM above 40%	Full energy market dispatch per Option 1.

Contract tenures must be differentiated by technology. A uniform 15-year tenure, as the Paper proposes, is inadequate for investment recovery in long-lived capital assets:

Technology	Recommended Contract Tenure
Dispatchable thermal and pumped hydro	20–25 years (consistent with project financing norms)
RE + storage	15–20 years
Existing surplus capacity (secondary market)	1–3 years

On the demand curve: the Paper's suggestion (Option 1, Option 3) to draw the contracting Discom's demand curve 'slightly above the price cap' to prevent free-riding is understandable as a transitional device but must be time-limited. The Paper itself acknowledges this 'may not be the optimal approach' and 'could raise concerns about inflating the MCP for all market participants.' It should be replaced by proper performance penalties and physical curtailment capability as the Connect-and-Manage framework matures.

Recommendation 3:

Adopt Option 3 (NLDC as central agency) as the primary near-term RA vehicle (Years 1–5), with Option 1 as the medium-term target triggered by DAM liquidity milestones. Phase the transition in three stages as specified above. Differentiate contract tenures by technology. NLDC/CEA to monitor liquidity thresholds annually and report to CERC. Operationalise Option 2's bilateral contract settlement through Regulatory Sandboxing before mandatory adoption.

IV. Section B — Reserve Capacity Market

The Reserve Capacity Market is the most urgently needed of the three mechanisms and the least dependent on energy market deepening. India's reserves deficit during solar hours — when thermal generation is at minimum turn-down and no spinning reserve is available — is a direct grid security threat. The Paper itself documents the urgency: in 2025, gas capacity of 1,744 MW was procured under Section 11 (Rs. 2,208 Cr. for approximately seven months), funded from the DSM/AS Pool. This is an expensive, non-transparent, and non-competitive substitute for a structured advance procurement mechanism.

The Paper's Reserve Capacity Market design is broadly supported. The following refinements are proposed:

- Eligibility for SRAS/TRAS should explicitly include battery storage systems and demand response aggregators from the first auction cycle. The CERC Ancillary Services Regulations should be updated accordingly.
- The holding charge for Scenario 2 (capacity requisitioned but not dispatched) should be defined as 50–70% of the discovered capacity charge — reflecting opportunity cost — rather than being left to CERC's discretion post facto. Regulatory certainty reduces litigation risk.
- A quarterly update mechanism should allow NLDC to trigger incremental procurement if the annually procured volume falls below 80% of allocated reserve requirement due to plant deratings, retirements, or non-compliance.
- Cost recovery must be made explicit: capacity charges for reserve procurement should be a regulated pass-through in SERC tariff orders, with explicit linkage to NLDC's shortfall allocation per DSM Regulations 2024 Regulation 9(7). Without this linkage, the financial chain breaks at the Discom level.

Recommendation 4:

Implement the Reserve Capacity Market as Phase 1 of the overall capacity market programme — ahead of RA Capacity Market auctions. Conduct an immediate pilot auction for 4,000–5,000 MW covering gas peakers, pumped hydro, and BESS. Define the Scenario 2 holding charge as 50–70% of the capacity charge in the Regulations. SERC Tariff Orders should treat reserve capacity charges as a priority pass-through.

V. Section C — Secondary Short-Term Capacity Market

The Secondary Short-Term Capacity Market is conceptually sound: it creates a platform for Discoms with surplus contracted capacity to sell that surplus, and for deficit Discoms to procure short-term cover without entering new long-term PPAs. Option 2 (two-part bids: capacity charge + energy charge) is preferred over Option 1 because the two-part structure provides better incentives for capacity providers to maintain plant readiness.

Three specific safeguards are essential:

- Surplus computation integrity: Any capacity offered in the secondary market must be net of the selling Discom's worst-case peak demand with a safety margin — not merely average peak demand. The Paper does not specify this guardrail.
- Gate closure clarity: The Paper proposes that contracted buyers have first right of scheduling 'until the start of the day-ahead market' — this should be specified as T-4 hours before the scheduled delivery block, consistent with existing DAM gate closure norms.
- Minimum participation thresholds: The auction should proceed only with at least 500 MW on the supply side and 200 MW on the demand side. Below these thresholds, thin-market price signals are misleading and NLDC should facilitate bilateral negotiations instead.

Recommendation 5:

Adopt Option 2 for the short-term capacity market. Specify gate closure at T-4 hours. Set minimum volume thresholds for auction activation. Pilot in one Region as proof-of-concept before national rollout. Require surplus computation to be based on worst-case peak demand, not average demand.

VI. Cross-Cutting Issues

Discom Financial Viability — A Pre-requisite

The capacity market will succeed if Discoms are creditworthy buyers. Several Discoms currently carry AT&C losses exceeding 20% and ACS-ARR gaps that prevent investment-grade credit ratings. This is a structural prerequisite for all three solutions to function. Unless addressed upfront, the financial chain will break at the Discom level regardless of how well the auction mechanism is designed.

- SERC Tariff Orders should explicitly recognise capacity charges from CERC-approved auctions as a priority cost pass-through to consumers, ahead of other regulatory adjustments.
- For Discoms, participation in capacity auctions should be conditioned on payment guarantees equivalent to the Payment Security Mechanism as governed under LPS Rules.
- Likewise, the penalty structure (1.5x capacity charge for non-performance) should include a backstop provision allowing NLDC to invoke payment guarantees under LPS Rules to prevent cascading defaults.

Price Cap in DAM and RTM — An Anomaly

Artificial price capping in power exchanges is incompatible with a well-functioning capacity market. The PJM White Paper devotes substantial analysis to this mechanism: suppressed energy prices inflate the 'missing

money' gap, place an unsustainable burden on the capacity market to attract investment, and ultimately require progressively higher capacity payments to compensate for the revenue that generators cannot earn in the energy market.

Any capacity market reform must be accompanied by a credible, time-bound pathway to remove artificial price caps and allow energy market prices to reflect scarcity. This is not merely a market design preference — it is a prerequisite for the capacity market to function without continuously expanding its scope and cost.

Recommendation 6:

CERC should coordinate with MoP to: (a) issue an advisory to SERCs requiring that capacity charges from CERC-approved auctions be treated as a priority pass-through in tariff determination; (b) establish payment guarantee requirements for Discoms as a condition of auction participation; and (c) initiate a time-bound roadmap to remove artificial price caps in power exchanges.

VII. International Experience — Applicability to India

Jurisdiction / Feature	Applicability to India
PJM RPM: Three-year forward Base Residual Auction	Not directly applicable. India's construction timelines and financing norms require 20+ year visibility. The T-3 primary auction (Option 3 of RA Obligation Capacity Market) is directionally right but needs longer-term complementary frameworks.
PJM May 2026: Credibility trap and 'missing money' diagnosis	Highly relevant. India must avoid replicating PJM's error of relying on short-term spot signals to anchor investment. Existing PPAs already provide the long-term hedge — the new capacity market must not undermine this.
GB: T-4 and T-1 auctions; descending-clock format	T-3 primary + T-1 adjustment structure recommended for India (Option 3 of RA Obligation Capacity Market). The GB 95%/5% split can be adapted as 85% primary / 15% adjustment for India. Descending-clock format is preferred but should await a pool of 10–12 regular participants; sealed-bid format initially.
Germany: Strategic reserve (out-of-market)	Direct model for India's Reserve Capacity Market. Contracted reserve plants should not participate in energy markets during their contracted reserve window — consistent with CERC's proposed design.
California CAISO CPM: Backstop procurement	Direct model for Option 3 of RA Obligation Capacity Market (Residual RA). NLDC as central agency mirrors CAISO's backstop role. Key lesson: bilateral Discom RA contracting works only with SERC support and demonstrated Discom financial health.
GB/Ireland: 15-year new-build contracts	India should differentiate by technology: 20–25 years for coal/gas/pumped hydro; 15–20 years for RE+storage. Uniform tenure across technologies is inefficient.

VIII. Summary of Recommendations

The following recommendations are proposed in order of implementation priority. CERC should designate NLDC/CEA as the monitoring body responsible for tracking DAM liquidity thresholds and triggering phase transitions between Options, with an annual public review cycle.

Priority	Recommendation
Immediate	Establish PPA-RA Credit Registry (NLDC) mapping existing PPAs to Discom RA obligations. Only the residual shortfall triggers new procurement. Capacity to be payable for performance during stress hours, not merely declared availability.
Immediate	Pilot Reserve Capacity Market (4,000–5,000 MW: gas peakers, pumped hydro, BESS) as Phase 1 of the capacity market programme — ahead of RA auctions.
Within 12 months	Commission India-specific CONE study disaggregated by technology. Apply Net-CONE only when DAM/RTM exceeds 25% of total scheduled energy.
Years 1–5	Implement Option 3 of RA Obligation Capacity Market (NLDC as central agency) as primary RA vehicle, with three-phase transition to Option 1 tied to DAM liquidity milestones. NLDC/CEA to monitor and report annually to CERC.
Structural	Differentiate contract tenures: 20–25 years for thermal/pumped hydro; 15–20 years for RE+storage. Uniform 15-year tenure inadequate for long-lived capital assets.
Governance	Ensure SERC coordination to treat capacity charges as a priority pass-through.
Regulatory	Initiate a time-bound roadmap to remove artificial price caps in power exchanges — incompatible with a functioning capacity market and escalates the missing money problem.
Design	Introduce technology-agnostic eligibility: battery storage, pumped hydro, and demand response aggregators to be eligible from the first auction cycle.

These comments are submitted to assist CERC in designing a capacity market that safeguards both investor and consumer interests, optimises existing contracted capacities, and treats reliability as a shared public good.

FICCI COMMENTS ON CAPACITY MARKET FOR ELECTRICITY IN INDIA

(Legal & Regulatory Inputs)

Date – May 27, 2026

Submitted to: Central Electricity Regulatory Commission (CERC)

The provision/clause specific comments on the CERC Staff Paper are set out below:

S.N.	STAFF PAPER	COMMENTS
Capacity Market for RA/Capacity Obligation		
1	**<u>Proposal A:</u>** **(A) Capacity Market for RA / Capacity Obligation** 26. The Resource Adequacy (RA) framework requires each State/Discom to procure capacity sufficient to meet demand at all times reliably. It is expected that the discoms shall procure generation resources using a least-cost optimization model. As per current practice, the discoms invite bids using a two-part tariff structure: fixed cost, plus variable cost, and the bidder quoting the lowest total cost	***Re. Option 1*** • The Staff paper under, Option 1, seeks to align the Indian model of power procurement with international counterparts where capacity is contracted as a product separate and distinct from energy. Resultantly, the procurer under such PPAs does not possess any scheduling rights over the contracted capacity. Instead, the dispatch of power is decided by the market. Both, generator and discom bid on a day-ahead and real-time basis and the energy is received at the Market Clearing Price. This ensures that Merit Order is followed and prevents scenarios

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	(fixed cost, plus variable cost) is awarded the contract to set up the generation project. The bidder is eligible to recover fixed costs based on the declaration of availability, and the energy charge is recovered in accordance with the discom's schedule, on a day-ahead/real-time basis. Such contracts do not go through the market, as scheduling/dispatch rights for such generating stations rest with the buying discom. 27. The proposal in the paper is a departure from the current practice of contracting to capacity contracting design as outlined below:- ***<u>RA Obligation Capacity Market (Option 1):</u>*** • The discom may invite bids based solely on the capacity charge. • The discom may draw the demand curve on a Net-CONE basis. The bidders' quotes for capacity	where a generator is sitting idle on account of its contracted procurer failing to schedule power despite there being other procurers that are in a power deficit situation. • Further, the Staff Paper recognises that in the future, even the RE projects will offer capacity in the capacity market by firming up generation with Energy Storage Systems. As India's energy mix evolves and RE-with-storage configurations mature, such an approach would enable these projects to participate on a level playing field alongside conventional thermal capacity. • The Staff Paper further recognises a bid cap, which is the maximum amount a procurer can bid in the day ahead and real time markets. *However, the Staff Paper has not specified the said amount or the parameters governing the same. This creates uncertainty for both procurers and generators. Accordingly, this clause may be clarified by Ld. CERC.* • Additionally, to guarantee the discoms' right over their contracted capacity, the Staff Paper has provided that the contracting discoms may be allowed to bid slightly above the bid

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	remuneration may be arranged in ascending order, and the intersection of the demand and supply curves would yield the market-clearing price for capacity. • The contract could be for a period of 15 years. During this period, the discom shall pay the capacity charge / remuneration as discovered in the capacity market. • On a day-ahead and real-time basis, both the generator and the discom shall bid into the Day Ahead/Real Time market. • To guarantee the discoms' right over the contracted capacity, the demand curve of the contracting discoms for such contracted capacity could be drawn slightly above the price cap. It is reiterated that this may not be the optimal approach and could also raise concerns about inflating the Market Clearing Price (MCP).	cap. However, as correctly recognised by Ld. CERC itself, artificially inflating the demand curve above the price cap in such a manner will distort the day-ahead market clearing price, thereby affecting all other market participants (open access consumers, industrial buyers, non-contracting discoms) for the benefit of the contracting discom. • The Staff Paper further provides that in order to prevent gaming, capacity providers, i.e., generators may be mandated to ensure that they participate and are cleared in the market during stress hours when the demand is at its peak. Failure to do so would impose a liability amounting to 1.5 times the capacity charge on such generators. *However, the Staff Paper has not recognised that there may be scenarios when the generator is unable to participate in the market on account of force majeure events. Therefore, it is imperative that an exception is carved out for such situations where a capacity provider is unable to generate due to no fault of his own.*

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	This is being recommended to address the free-rider concern until all discoms fulfill the RA requirements. Further, it is felt that the requirement that capacity holders bid as price takers during peak/stress hours (as stipulated in subsequent paragraphs) might counterbalance the likely adverse effect of the demand curve above the price cap. • Once the market is cleared, the discom/generator shall pay/get the Market Clearing Price (MCP) from the market. • Ensuring adequate capacity in the market is likely to keep the MCP under control. At the same time, drawing the demand curve of the contracting buyer at a price slightly above the price cap will ensure the buyer receives an equivalent quantity of energy. This approach addresses the free-rider problem and concerns	• *Further, the Staff Paper does not specify (a) the methodology for identifying stress hours, (b) the advance notice period, (c) the maximum number of stress hours per year, or (d) the appeal mechanism for incorrect notifications. This creates operational uncertainty for capacity providers. Accordingly, the framework should specify all four elements before the same is implemented.* • *The 1.5 times penalty multiplier appears to apply per failure, with no cap on annual aggregate exposure. Over a 15-year contract, repeated non-performance during stress-hour could result in disproportionate penalty exposure. Accordingly, the Staff Paper may provide an annual aggregate cap on penalty along with explicit force majeure and change-in-law carve-outs.* • *The Staff Paper provides for a uniform 15-year contract for both new and existing capacities despite the fact that existing capacities have sunk capital costs and do not require a long-term contract to remain in operation. New capacities, by contrast, require long-term certainty to support investment. Therefore, the proposed framework should adopt a tiered approach, with longer*

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	about double payment while ensuring efficient dispatch of generation resources. • To prevent gaming, the capacity providers could be mandated to ensure they participate and are cleared in the market during the peak/stress hours, to be notified by the NLDC. They (the capacity providers) could bid as price takers during such peak/stress hours. Failure to clear will make the capacity holders liable for penalty @ 1.5 times the capacity charge discovered. • It is expected that in the future, even the RE projects will offer capacity in the capacity market by firming up generation with Energy Storage System (ESS). Hence, a technology-agnostic capacity market is recommended. **<u>RA Obligation Capacity Market (Option 2):</u>**	*contracts reserved for newly built projects and shorter contracts for existing capacities.* ***Re. Option 2*** • The Staff Paper in the second option has retained the currently prevalent two-part tariff structure. Indian discoms have decades of experience with the same and generators have well-established cost models built around this structure. Adopting a familiar bid structure reduces transition risk and supports broader participation. *Accordingly, although Option 1 may be conceptually feasible, Option 2 is operationally feasible in the near term.* • Under the second option, the discom retains the ability to plan its day around its contracted capacity, as it has scheduling rights until the day ahead market opens, but the actual dispatch decision flows through the day-ahead market, allowing the cheapest available generation across the grid to serve demand. This is a step toward Market Based Economic Dispatch without

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	• The other option is for the discom to invite a bid based on the total cost (capacity charge and variable charge), as is done currently. However, day-ahead and real-time scheduling and dispatch could be as follows: (a) The Discom will have scheduling rights but not dispatch rights over the capacity on a day-ahead and a real-time basis. In other words, the discom will have the right to schedule from the contracted generator until the window for the day-ahead market opens. However, the dispatch from the generating station shall be through the market. (b) On day-ahead/real-time, both the generator and the buyer will bid into the market. To ensure the discom is guaranteed a supply of the contracted capacity, the	dismantling the bilateral contract structure that currently dominates Indian power procurement. • The bilateral settlement of the difference between MCP and contract price achieves the right economic outcome. The discom effectively pays the contracted price and the generator effectively receives the contracted price, regardless of MCP, while ensuring physical delivery flows through the market. • *The same concern raised under Option 1, with respect to above-cap bid, applies here. The above-cap bid distorts the day-ahead market and is itself acknowledged in the Staff Paper as not being optimal.* • *Additionally, the force majeure concerns raised under Option 1 apply equally to Option 2. The Staff Paper does not provide for excused non-performance due to force majeure, change in law or fuel supply failure. These categories are recognised in the Standard Bidding Guidelines under Section 63 of the Electricity*

S.N.	STAFF PAPER	COMMENTS
	discom's price bid for the capacity equivalent to the contracted/scheduled capacity will be set above the price cap. • Once the market is cleared, the MCP is paid by the discom to the market and received by the generator from the market. • Outside the market, the discom and the generator will undertake the bilateral contract settlement, based on the difference between the MCP and the contracted price (total cost) discovered in the bid. • In this way, efficient dispatch of generation, adequate capacity availability for the market, and security of supply for the discom are ensured. • In this design as well, it is suggested that the capacity providers be mandated to ensure they	*Act, 2003, and in standard PPA templates. They should be expressly carved out from the penalty regime under Option 2.* • *Similar to Option 1, the 1.5 times penalty applies per failure with no specified annual aggregate cap. Over the period of the contract, repeated stress-hour misses could result in penalty exposure several times the cumulative capacity revenue, making the contract unviable.* ***Re. Option 3*** • The Staff Paper under Option 3 explicitly aligns with the framework already established under the Ministry of Power's Resource Adequacy Guidelines, 2023 ("**MoP RA Guidelines, 2023**"), which require each distribution licensee to undertake a Long-term Distribution Resource Adequacy Plan and to demonstrate 100% tie-up for the first year and 90% for the second year. Option 3 builds on this by adding a centralised mechanism for residual shortfalls and this is a coherent extension of the existing policy framework.

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	participate and are cleared in the market during the peak/stress hours, to be notified by the NLDC. They (the capacity providers) could bid as price takers during such peak/stress hours. Failure to clear will make the capacity holders liable for penalty @ 1.5 times the capacity charge discovered. **<u>Residual RA Obligation Capacity Market (Option 3):</u>** • All buying entities are mandated to ensure their resource adequacy as per the approval of SERC. • A central agency designated by the Ministry of Power may carry out a centralized auction for 'Residual RA Obligation Capacity Market' where the discoms having RA shortfall may participate for procurement of the shortfall RA capacity.	• Further, Option 3 addresses a real coordination issue when multiple discoms are simultaneously short of RA capacity, individual bilateral procurement may result in fragmented auctions, sub-optimal pricing, and unmet demand. A centralised auction pools demand, attracts more bidders, achieves better price discovery, and ensures the residual gap is filled. The MoP RA Guidelines, 2023 under Clause 3.10, already contemplate this: "In case of shortfall, NLDC shall either communicate the shortfall to the SERC/JERC for compliance or facilitate a national-level auction for the balance capacity with participation from distribution licensees with capacity shortfall." Option 3 operationalises this provision. • *The Staff Paper does not specify which entity will be the central agency or how will the same be selected.* • *Similar to Options 1 and 2, no bid cap is specified for Option 3. The same creates uncertainty for bidders and lenders. The framework should specify the bid cap and also carve out force majeure*

S.N.	STAFF PAPER	COMMENTS
	• The central agency may draw the demand curve based on the Net-CONE principle. • The bid may be based solely on the capacity charge. • Once the bidding is completed, the discoms participating in the bid shall enter into contracts with the central agency for the RA shortfall capacity, and shall be liable for payment of proportionate capacity charge discovered in the auction. The central agency shall enter into contract with the capacity providers who are cleared in the auction. • The contract could be for a period of 10-15 years. • For short-term shortfall (1-3 years), capacity may be procured through the secondary market (discussed in the subsequent section). Discoms/entities/Sellers having excess capacity	*exceptions exempting the capacity providers from mandatory performance during peak hours.* • *The Staff Paper does not specify the timeline or advance notice period for conducting the auction prior to the relevant delivery year. In order to ensure adequate planning, financing, contracting, and implementation timelines, the framework should provide for a forward auction horizon of at least three years prior to the commencement of the delivery period.* • *Similar to Option 1 and 2, the 1.5 times penalty applies per failure with no specified annual aggregate cap. Over the period of the contract, repeated stress-hour misses could result in penalty exposure several times the cumulative capacity revenue, making the contract unviable.*

S.N.	STAFF PAPER	COMMENTS
	can sell it in the short-term secondary capacity market. • The buying entities shall not have scheduling rights. • On a day-ahead and real-time basis, both the generator and the buying entity shall bid into the Day Ahead/Real Time market. • Once the market is cleared, the buyer/generator shall pay/get the Market Clearing Price (MCP) from the market. • To prevent gaming, the capacity providers could be mandated to ensure they participate and are cleared in the market during the peak/stress hours, to be notified by the NLDC. They (the capacity providers) could bid as price takers during such peak/stress hours. Failure to clear will make the capacity holders liable for a	

S.N.	STAFF PAPER	COMMENTS
	penalty @ 1.5 times the capacity charge discovered.	
	Reserve Capacity Market	
2	**<u>Proposal B:</u>** **(B) Reserve Capacity Market** 28. International experience reveals that in most power systems, reserves are procured closer to real-time, mainly on a day-ahead and real-time basis. However, Germany has the practice of advance procurement of strategic reserves. The practice of procurement of reserves closer to the time of delivery is considered optimal and is prevalent in power systems with adequacy of resources and reserves ensured through mandates such as the resource adequacy requirement (as in the US, except ERCOT) and the mandate of all-load meet (no load shedding) requirements in other geographies not	• *The proposed Reserve Capacity Market may be supported only as an interim/transitional mechanism to address the present inadequacy of reserves in the system. As recognised in the Staff Paper itself, the long-term solution lies in effective implementation of the Resource Adequacy framework by the States and Discoms.* • *Accordingly, the framework should expressly clarify that the responsibility to maintain adequate reserves rests primarily with the States/Discoms. Centralised procurement by NLDC/RLDC should only operate as a regulatory backstop in exceptional situations where States fail to maintain the allocated reserves.* ***Re. Assessment of Reserve Capacity requirement*** • *The methodology for assessing reserve deficiency must be transparent, objective, and developed through consultation. The framework should clearly specify:* *(a) the methodology for computing reserve requirements;*

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	having a resource adequacy requirement. Given these mandates, load-serving entities ensure that sufficient resources are available to meet demand at all times. Reserve requirements are, therefore, met by the capacities already available in the power system, and such requirements can, thus, be reliably met by procuring specific reserves for specific types of Ancillary Services closer to the time of delivery. 29. In India, the Ancillary Services Regulations also provide for the procurement of reserves, Secondary Reserves, Ancillary Services (SRAS), and Tertiary Reserve and Ancillary Services (TRAS) on both Day-Ahead and Realtime basis. However, unlike in other power systems, India does not yet have mandatory resource adequacy, nor do the discoms have the required level of resources, including reserve requirements, available in their portfolio of contracts. This results in insufficient reserves in the	*(b) the timeline and periodicity of assessments;* *(c) the process for communicating identified deficiencies to States; and* *(d) an opportunity for States to remedy such deficiencies before centralized procurement is initiated.* *These procedural safeguards are essential, given that a reserve shortfall determination directly imposes financial liability on the concerned State. While advance procurement may be necessary during the transition period, annual procurement cycles could reduce operational flexibility and may not adequately reflect evolving demand patterns and renewable integration trajectories. Therefore, Ld. CERC may consider staggered or shorter-duration procurement windows, at least initially, to enable periodic reassessment of reserve requirements based on actual system conditions, demand growth, renewable penetration levels, and progress in resource adequacy implementation.* ***Re. Auction Design***

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	system, thereby posing a threat to grid security. The situation becomes critical, especially during solar hours, when net load demand dips substantially and all thermal generation operates at its minimum turn-down level, leaving no reserve available in the system. 30. The Ministry of Power (MoP) Rules set out the requirement for resource adequacy in all States. The Central Electricity Authority (CEA) has also issued Resource Adequacy plans for States. The IEGC also provides the framework for resource adequacy. 31. Once the States adopt the Resource Adequacy framework in the true spirit, there will be sufficient capacity within the system for the system operator to procure reserves closer to real time. However, this will take time, and during the transition, measures must be implemented to ensure the adequacy of reserves as a safeguard against grid failure. The	• Aligning eligibility with the existing CERC Ancillary Services Regulations provides regulatory consistency and avoids creation of parallel qualification standards. However, *the eligibility criteria should also expressly recognise participation of emerging technologies such as BESS, Pumped Storage Projects ("PSPs") and Renewable Energy with storage configurations to ensure technology-neutral participation.* • *Conducting auctions once every year may not provide sufficient flexibility in a rapidly evolving power market where demand forecasts, fuel availability and renewable penetration can change significantly within shorter periods. The framework may additionally consider supplementary or mid-term auctions to address demand forecast deviations.* • Adoption of the Net CONE methodology is broadly aligned with international practices. However, *the methodology for determination of Net CONE should be transparent, periodically reviewed and subject to stakeholder consultation.* Since Net CONE determination would directly affect bid caps and market

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	provision in the grid code that mandates the NLDC to procure reserves centrally in the event of the States' failure to procure adequate reserves is a step in this direction and may need to be implemented in the true spirit, in the larger interest of grid security. In fact, every year the Ministry of Power issues directions under Section 11 of the Electricity Act, 2003, and facilitates advance procurement of resources for use by the NLDC to meet contingencies during high-demand periods. For instance, in 2025, capacity (gas-based capacity) worth 1744 MW was procured to meet the high demand contingency from 16th March, 2025 to 15th October, 2025, and the cost (Rs. 2208 Crore) was defrayed from the Deviation Settlement Mechanism (DSM) and Ancillary Services (AS) Pool Account. 32. As such, recommendations in this paper are for advance procurement of reserve to take care of the	outcomes, an appropriate regulatory oversight mechanism may be required. • Arranging bids in ascending order is consistent with competitive market principles and promotes efficient price discovery. • A pay-as-cleared mechanism promotes competitive bidding and is consistent with established electricity market practices. However, *the framework should also incorporate appropriate market surveillance and oversight mechanism and specify suitable mitigation measures against excessive price volatility.* ***Re. Dispatch Principles*** • Granting NLDC the first right of scheduling and dispatch is appropriate from a grid security and system reliability perspective. However, *the framework should clearly define the timelines for advance notice, recall instructions and release of capacity to avoid uncertainty for generators.* • *The Staff Paper should specify minimum notice periods for scheduling and dispatch.*

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	transition until adequate resources and reserve are available in the power system through the resource adequacy framework. It is expected that advance procurement of reserve, as suggested in this paper, would help the optimal utilization of existing resources wherever available and also help create new reserve capacity. It is not expected that new capacities will be created solely to provide reserve and ancillary services. The expectation is that if there is a framework for advance procurement of reserve and ancillary services, new generation capacities that are likely to be contracted under the RA obligation in the future would be encouraged to maintain some spare capacity that they could offer in the reserve markets. It is expected that the framework of Reserve Capacity Market could open up opportunities for capacity creation as follows: (1) the capacity providers participating in the RA/capacity obligation market could have some	• Allowing capacity providers flexibility to participate across reserve and energy markets promotes market efficiency and improves asset utilisation. • Payment of both capacity charge and quoted offer price appropriately compensates the generator for availability as well as actual dispatch. • Permitting participation in DAM/RTM when reserve capacity is not requisitioned enhances market efficiency and reduces the risk of idle contracted capacity. Notably, *the framework should clearly specify the conditions and timelines under which capacity stands released for participation in the energy market.* • *While the proposed structure attempts to balance reserve adequacy and market flexibility, the framework would require detailed operational protocols relating to scheduling hierarchy, deviation settlement, and settlement methodology before implementation*. ***Re. Cost Allocation***

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	open capacity for Reserve Capacity Market; (ii) the wind/solar generators could engage an aggregator to set up energy storage system (ESS) with capacity that not only balances their forecasting errors but also participates in the Reserve Capacity Market; (iii) the CTU/transmission licensee could set up ESS as a grid element and such ESS could cater to RE forecasting error and also participate in the Reserve Capacity Market. 33. Based on the philosophy as outlined above, the Reserve Capacity Market is proposed as under: - 34. **<u>Reserve Capacity Market Design Context</u>**: The IEGC, 2023 requires States to maintain reserves, and also provides that, in the event of a State's failure to maintain the required reserves, the NLDC/RLDC shall procure such reserves on behalf of the State and allocate the cost to the deficient State. The relevant provisions are extracted below:	• Recovery of capacity charges from reserve-deficient States aligns financial responsibility with entities contributing to system inadequacy and may incentivise States to maintain adequate reserves. • Linking cost allocation to the IEGC provides regulatory consistency. Notably, *the framework should clarify whether reserve deficiency would be assessed on the basis of advance planning, real-time operational conditions, or a combination of both, as the methodology adopted would materially impact the allocation of costs and liabilities amongst States.* • Utilisation of the DSM & AS Pool may provide an existing settlement mechanism for operationalisation of reserve procurement. However, *detailed settlement and reconciliation procedures would be necessary to avoid payment disputes.* ***Re. Penalty*** • *The framework should expressly provide exemptions or relief mechanisms for force majeure events and grid-related constraints. In the absence of such safeguards, the penalty*

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	Regulation 30(11) (t) *(t) If a State falls short of maintaining secondary reserve capacity as allocated to it in terms of sub-clauses (o) or (p) of this clause, whichever is lower, the NLDC through RLDC shall procure such Secondary reserve capacity on behalf of the State under advance intimation to the concerned State and allocate the cost of procurement of such capacity to that State based on the methodology as per the detailed procedure to be issued by the NLDC after approval of the Commission.*	*structure may disproportionately increase commercial risk and discourage participation.*
Secondary Short-Term Capacity Market (for existing capacities)		
3	**Proposal C:** **(C) Secondary Short-Term Capacity Market (for existing capacities)**	• Proposal C addresses a structural gap in the Indian power market. The existing short-term segments (DAM, RTM) trade only energy. This means that a discom with surplus contracted capacity for a 1-3 month period has no efficient mechanism to

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	38. At present, closer to the time of delivery, the markets, viz., the Day-Ahead and Real-Time Markets, are energy-only markets. Even in the Term Ahead Markets, the contracts are energy-only. These markets do not guarantee capacity availability. As a result, there are times when demand far outstrips supply and prices reach the ceiling. At such times, paradoxically, there could be some capacities available in the system but not visible in the market because of silo based contracting and scheduling. At other times as well (i.e., in periods other than high-demand periods), there may be surplus and deficit capacity zones in the country. Therefore, there is a need to introduce short-term capacity markets for trading existing contracts to supplement the energy market. The idea is to create a market platform that enables capacity holders to exchange capacity rather than energy alone.	make that capacity available to a discom with a corresponding deficit. The capacity remains locked in the original bilateral PPA. Introducing a short-term capacity market closes this gap and unlocks idle capacity for productive use. ***Re: Option 1*** • The quarterly auction cycle with both one-month and three-month contract options allows discoms to address temporary capacity shortfalls (single-month spikes during festival demand or summer peaks) and structural short-term needs (quarterly seasonal patterns) through the same market. The auction frequency is high enough to be responsive to changing conditions but not so high as to create administrative issues. • *The same concern raised under Proposal A and B, with respect to above-cap bid, applies here. The above-cap bid distorts the day-ahead market and is itself acknowledged in the Staff Paper as not being optimal. Additionally, as observed under Proposals A and B, CERC in Proposal C should also specify the bid cap or the*

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	39. While there are parallels of this kind of market elsewhere in the world, the situation in India is unique, as discoms are accustomed to scheduling rights in exchange for fixed costs. Unlike the current framework of capacity contracting, international experience indicates that capacity markets generally guarantee only partial payment of the capacity charge to capacity holders, leaving them to recover the balance from the energy-only market. The following options for short-term capacity market are suggested: **<u>Short-term Capacity Market (Option 1)</u>** • The capacity auction could be conducted in the market platform, every three months for three months (including monthly contracts).	*parameters governing the same, creating uncertainty for all parties.* • *Further, allowing discoms with surplus contracted capacity to participate as sellers creates several legal and regulatory complications that CERC does not address. Specifically: (a) does sale by the discom of capacity contracted under an existing PPA require approval from the original generator under the PPA; (b) does the sale require SERC approval, and if so, on what timeline; (c) how is the revenue from such sales accounted for in the discom's revenue requirement before the SERC; and (d) what is the position if the underlying PPA generator has not consented to onward sale by the discom. These issues need to be resolved before the market is operational, failing which sellers will face regulatory and contractual uncertainty.* • *Mandatory participation during stress hours raises particular difficulties in the short-term context. A capacity provider entering into a 1-month contract is exposed to penalty risk for every stress hour during that month. The methodology for stress hour*

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	• The auction could be based on double-sided bidding. The bidding could be for capacity, with a single part bid for the capacity charge. • Supply side: eligible entities shall include discoms with surplus contracted capacity; generating companies with surplus capacity, and traders. • Demand side: eligible entities shall include discoms with deficit capacity, suppliers/capacity providers with capacity obligation to supply. • Price Discovery for 'Capacity charge' could be based on a uniform price step auction (Rs./MW). Once the bidding is completed, capacity contracts shall be formalized for duration of one month/ three months, as the case may be. • Scheduling and Dispatch: Such capacities shall be scheduled and dispatched on day ahead basis.	*identification is not specified, the maximum number of stress hours is not capped, and force majeure carve-outs are not provided. Over the duration of a one-month contract, repeated stress-hour failures could result in penalty exposure far exceeding the total contract value. The framework should provide (a) a clear methodology for stress hour identification in advance, (b) an aggregate cap on penalty exposure per contract, and (c) explicit force majeure and excused non-performance provisions.* ***Re. Option 2*** • The two-part bid structure mirrors traditional Indian PPA structures and reduces transition risk. Indian discoms and generators have decades of experience with two-part tariffs. Adopting a familiar bid structure in the short-term market supports broader participation. *While Option 1 is theoretically cleaner, Option 2 is operationally more achievable in the near future.* • Retaining the buyer's scheduling right until the day ahead market opens ensures that the buyer can plan its operations

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	Both the buyers and the sellers shall go through the day ahead market for the capacity contracted. • To guarantee the discoms' right over the contracted capacity, the demand curve of the contracting discoms for such contracted capacity could be drawn slightly above the price cap. • Once the market is cleared, the discom/generator shall pay/get the Market Clearing Price (MCP) from the market. • Ensuring adequate capacity in the market is likely to keep the MCP under control. At the same time, drawing the demand curve of the contracting buyer at a price slightly above the price cap will ensure the buyer receives an equivalent quantity of energy. This approach addresses the free-rider problem and concerns	around the contracted capacity, but the capacity is not locked out of the broader market if the buyer chooses not to schedule. This allows the seller to monetise unused capacity in the day-ahead market when the buyer does not need it, preventing the capacity from sitting idle. It is structurally similar to Option 2 of Proposal A, providing consistency across the framework. • *The penalty under Option 2 is calculated as 1.5 times the total cost (capacity + energy charge), which is materially higher than the 1.5 times capacity charge penalty under Option 1. For a typical two-part bid, total cost will be several times higher than the capacity charge alone (because energy charge reflects fuel and variable O&M for the operating hours, not just the capacity). This creates an asymmetric penalty structure where Option 2 capacity providers are penalised more heavily than Option 1 providers for what is essentially the same conduct. The penalty should be re-calibrated to apply only to the capacity component, consistent with Option 1, and capped at a reasonable proportion of the contract value.*

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	about double payment while ensuring efficient dispatch of generation resources. • To prevent gaming, the capacity providers could be mandated to ensure they participate and are cleared in the market during the peak/stress hours, to be notified by the NLDC. They (the capacity providers) could bid as price takers during such peak/stress periods. Failure to clear will make the capacity holders liable for penalty @ 1.5 times the capacity charge discovered. **Short-term Capacity Market (Option 2)** • Capacity auction in the market could be conducted every three months for three months ahead (including monthly contracts). • The auction could be based on double-sided bidding for capacity, with two two-part bids for "capacity charge + energy charge".	

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	• Supply side: eligible entities shall include discoms with surplus capacity, generating companies with surplus capacity, and traders. • Demand side: eligible entities shall include discoms with deficit capacity, suppliers/capacity providers with a capacity obligation to supply. • Price Discovery could be based on a uniform price step auction. • Scheduling and dispatch and cost recovery: Contracted buyers to have the first right of scheduling until the start of the day-ahead market, failing which the capacity providers can sell their energy into the energy market. The buyers shall be liable to pay the capacity charge as discovered in the auction, in either case, whether or not the buyer exercises the option to schedule.	

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	• In the event the capacity holder participates in the market, it has to ensure that it clears in the peak/stress hours defined by the NLDC. Failure to clear will make the capacity holders liable for a penalty @ 1.5 times the total cost discovered.	

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Additional Comment on CERC Staff Paper on Capacity Market

- The Central Electricity Regulatory Commission (CERC) has issued the *Staff Paper on Capacity Market for Electricity in India* with the objective of ensuring resource adequacy and maintaining reliable power supply in the face of increasing renewable energy penetration.

- As per Para 2 of aforesaid Staff Paper, wherein International Experience defines the Capacity Market and its' objectives as –

  A Capacity Market is an additional market created alongside the existing 'energy market', where only capacity is traded and explicitly remunerated. In a market with a capacity mechanism, while the energy market remains the main instrument for short-term resource optimisation, long-term resource adequacy is incentivised by some form of capacity payment to

  i. *address a situation when energy-only markets do not attract "adequate" investment for setting up new capacities, for any reason;*
  ii. *correct the poorly designed ancillary service market;*
  iii. *solve the problem of "missing money" (lack of sufficient dispatch over time to cover fixed costs); or*
  iv. *manage intermittent renewable energy generation.*

In the **Indian context, objectives (ii) and (iv) are particularly relevant** and should form the core basis for introducing a Capacity Market aimed at ensuring adequate and reliable capacity availability.

- At present, significant renewable energy curtailment is being witnessed across various regions of the country. While the proposed Capacity Market can play an important role in addressing future grid flexibility requirements, especially considering that **large-scale deployment of Battery Energy Storage Systems (BESS) will take time**, the market design must adequately reflect the realities of the existing generation fleet.

- In this regard, enhancing the operational flexibility of existing Thermal Power Plants (TPPs) represents the most immediate and practical solution for maintaining grid resilience**. Thermal generators have already demonstrated considerable flexibility by reducing their Minimum Technical Load (MTL) from 85% to 55%.**

- However, operation at **lower loading levels and provision of enhanced flexibility services** *require substantial retrofitting, technological upgrades, and operational modifications at thermal power stations*. Generators cannot reasonably be expected to undertake such investments or operate at sub-optimal loading levels without a clear compensation framework and adequate cost recovery mechanisms.

- Therefore, a more pragmatic approach would be to **incorporate a dedicated flexibility component within the proposed long-term Capacity Market framework**. Existing *TPPs may be **allowed to voluntarily participate** by offering additional flexibility services, including operation below the current 55% loading threshold*. Discoms may procure such flexible capacity below the 55% threshold to support grid balancing and facilitate greater renewable energy integration. The capital expenditure associated with retrofitting and flexibility enhancement may then be recovered through long-term capacity payments.

- Such an approach would simultaneously **strengthen resource adequacy, enhance grid reliability, facilitate renewable energy integration, and ensure more efficient utilization of existing generation assets**. Without adequately recognizing the role of the existing thermal fleet and providing appropriate incentives for flexibility enhancement, it may be difficult to develop a fully functional capacity market in India based solely on untied or future merchant capacity additions.