15th June 2026

Mr. Harpreet Singh Pruthi
Secretary
Central Electricity Regulatory Commission,
World Trade Center, Tower-B,
Nauroji Nagar, New Delhi -110029

Subject: Comments on Staff Paper "Capacity Market for Electricity in India"

Dear Mr. Pruthi,

This is with reference to the Staff Paper dated 29th April, 2026 on **"Capacity Market for Electricity in India"**

I have gone through it and record some of my comments on the same. Additional suggestions are also provided for consideration of the Commission.

I would be pleased to address any clarification, if required.

Thanking you,

Yours sincerely,

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Comments on

Staff Paper on Capacity Market for Electricity in India

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1. **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.

2. **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, wherein each discom individually conducts a separate 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 market due to differing contract structures, and uneven regulatory treatment across states. Before introducing such a mechanism, the existing Section 63 procurement framework and corresponding guidelines also 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.

3. **Long-erm 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 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.

4. **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 under Option 1. Therefore, the proposal appears to reduce the rights of the contracting buyer without clearly demonstrating the incremental benefit over the existing procurement framework.

5. **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 (under Option 1 & 2), 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.

6. **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.

7. **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. 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.

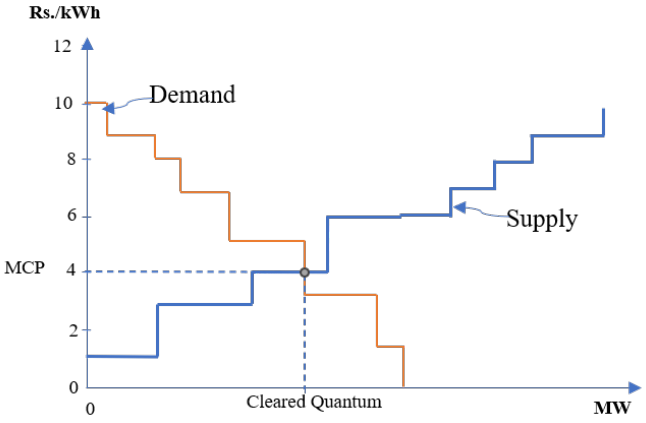
It is therefore suggested that the **framework should clearly specify resource-availability and dispatchability obligations for different technologies. Such obligations may include demonstration of fuel tie-up, coal stock, gas supply arrangement, hydro availability, storage state-of-charge requirement, 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.

8. **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 though capacity market?
- How will the energy be allocated when the energy market is 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?

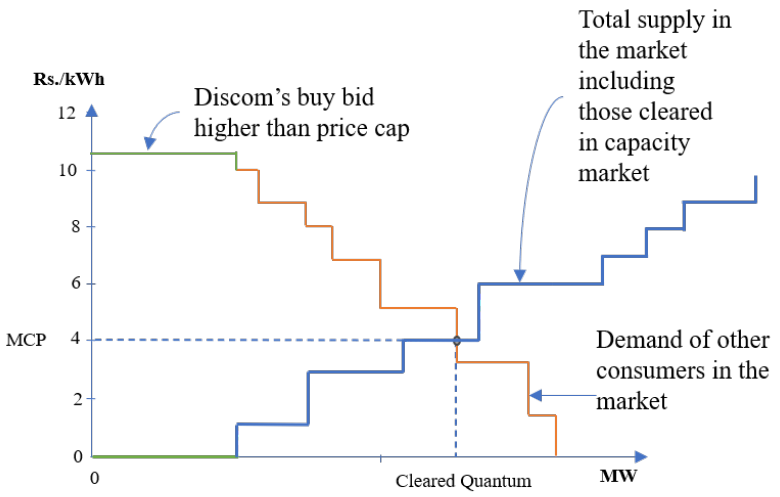
Without answering the above questions, the present proposal will lead to inefficient market outcome and inflate the price discovery during non-stress hours. Thus, it is also suggested that contracted generators be mandated to offer their capacity as price takers in all time blocks. Following illustration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

9. **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.

10. **RA Obligation Capacity Market (Option 2):** The proposed RA Obligation Capacity Market (Option 2) may need to be reconsidered in terms of its basic characterisation. 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 (MBED) framework rather than a capacity market. Thus, all the issues related to the initially proposed MBED need to be addressed[1]. 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.

11. **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. 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

[1] Power Chronicle Volume 04, Issue 01, EAL Opinion on MoP Discussion Paper on Market Based Economic Dispatch. https://eal.iitk.ac.in/assets/docs/Volume04Issue01.pdf

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.

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 be dispensed with and the secondary short-term capacity market may be proposed as 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.

12. **Reserve capacity market - Granularity for estimation of reserve capacity requirement:** The estimation of reserve requirement should be done on coincidental peak basis rather than the non-coincidental peak basis[2] 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.

13. **Reserve capacity market - Combined market for short-term capacity and reserve capacity**

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

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

The scheduling and dispatch for the capacity obligation and reserve capacity will remain separate. The former would be scheduled through market while the later would be scheduled and depatched by the system operator.

14. **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.**

15. **Effective real-time Capacity Monitoring and Market Monitoring:** Real-time capacity monitoring is essential to 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.

16. **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.

17. **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, systema 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.