WRI INDIA

Date: 15th June 2026

To

The Secretary,
Central Electricity Regulatory Commission (CERC)
6th, 7th & 8th Floors, Tower B, World Trade Centre,
Nauroji Nagar, New Delhi- 110029

Subject: Comments on the Staff Paper on 'Capacity Market for Electricity in India' (April 2026)

Reference: No. RA-14027(12)/1/2026-CERC Public Notices dated 29 April 2026 and 25 May 2026

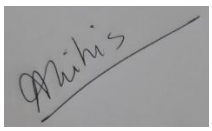
Dear Sir,

We are writing to submit our comments on the Staff Paper on 'Capacity Market for Electricity in India', published by the Central Electricity Regulatory Commission and comments were solicited through public notices dated 29 April 2026 and 25 May 2026.

Kindly find our comments and suggestions enclosed with this letter. We request the Commission to accept our submission on record and allow us to make further submissions in this matter, if necessary.

Thanking you

Sincerely,



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Comments on the CERC Staff Paper on "Capacity Markets for Electricity in India"

At the outset, we would like to submit that the proposed staff paper is a timely step in the right direction. As India moves forward with the energy transition, maintaining system reliability under rising shares of intermittent, variable, and weather-dependent demand & supply requires not just resource adequacy in terms of installed capacity, but also flexibility and on-demand energy availability at fair and economical rates. The capacity market can play an important role in this regard.

However, the proposed paper is currently a high-level options document rather than a detailed plan for implementation. Much more clarity on the conceptual aspects, data and empirical analysis that substantiates the feasibility and efficacy of the proposed options, and a clear practical implementation roadmap are essential for moving forward. Unless this essential background work is completed and placed in the public domain, the proposed options cannot be meaningfully evaluated or implemented in a time-bound, dispute-free manner. Our comments below elaborate on this core submission.

Insufficient clarity regarding which generators are eligible for which options:

1. The paper does not explicitly clarify whether a generator already enjoying assured fixed-cost recovery (a Section 62 cost-plus plant, or a competitively bid PPA that guarantees full fixed costs on availability) may also participate in the proposed market options. It neither allows nor bars them explicitly, thus leaving this crucial issue to interpretation. The basic premise of the paper is that existing (long-term) PPAs *"are inherently capacity contracts"* that guarantee recovery of full fixed costs based on availability. The new market options are explicitly framed as a "departure" from this. So conceptually, a generator with an existing assured-recovery PPA already has what the proposed capacity market is meant to offer and therefore need not participate in it.

    - **(Option A) Capacity Market for RA/Capacity Obligation** is oriented to fresh contracting under the new model (bid on capacity charge, 15-year term, forgo guaranteed full recovery, bid into DAM/RTM). Capacity already committed under an existing PPA isn't free to be re-offered,

but the paper doesn't clarify whether such a generator's untied capacity could bid or what happens at PPA expiry. Under Option 3 ("Residual RA Obligation"), discoms first meet RA through existing contracts, and only the shortfall goes to the central auction, but the paper does not clarify how or if an already-contracted, assured-recovery capacity can be recognised toward such obligation.

- **(Option B) Reserve Capacity Market**: Existing generators feature only through spare/open capacity. Section 32 imagines RA capacity providers offering headroom into reserves. However, capacity already fully committed under a long-term PPA cannot be available for this, so only the untied margin, if available, can be considered eligible.

- **(Option C) Secondary Short-Term Capacity Market:** This is the one place where existing PPA capacity clearly fits, as it's expressly a market "for existing capacities," for trading surplus contracted capacity, with discoms (the PPA holders) and gencos with surplus on the supply side. But again, it's the surplus traded by whoever holds the contract. The deeper gap in the scheme, namely, that a capacity market exists to pay the "missing money" of capacity that isn't already assured cost recovery, remains unaddressed. If the idea is that this additional income will offset any loss on the variable cost side, then that seems too optimistic.

2. A high-variable-cost, long-term PPA asset's problem isn't the fixed costs; it's that when the asset runs, it needs the energy price to rise at least to its variable cost to break even on each unit. A binding price cap of Rs 10/unit caps the highest price the energy market can ever send. So, for any asset whose variable cost exceeds Rs 10/unit (much more expensive RLNG/spot-LNG gas, some imported coal units), the market, by design, cannot clear at a price that covers its marginal cost. The capacity charge covers annual fixed cost; it does nothing for the variable-cost shortfall in precisely the hours during which the asset is needed/dispatched. That shortfall is a second, distinct slice of missing money that the proposal doesn't address.

3. A generator with regulatory certainty of full fixed-cost recovery has no missing (fixed-cost) money, so letting it also collect a capacity payment would be a double recovery of fixed costs. The paper raises the "double payment" problem, but only from the buyer's side (paying a capacity charge and the energy MCP for the same MW). The generator-side double cost recovery isn't

addressed in paragraph 23 or anywhere else. So, there's an acknowledgement of the problem, but not an adequate solution/work around. Hence, it is important to replace the qualitative "it is generally argued" treatment with an India-specific demonstration, quantifying the expected price-suppression benefit against the capacity charge under stated CONE/Net-CONE and price-cap assumptions, and explicitly addressing the generator-side double recovery issue. Internationally, the double recovery problem is handled by explicit recognition. For example, PJM lets such resources be designated "self-supplied / self-scheduled," and California counts bilateral capacity toward the RA target with only the deficit procured centrally. These and other international practices that address this problem need to be studied more carefully.

Thus, it is submitted that the central issue of whether an assured-cost-recovery generator (long-term PPA under Section 62 or 63) is (a) barred, (b) counted as self-supply toward the obligation, or (c) permitted to bid and earn an additional capacity charge needs to be clearly and explicitly addressed.

Need for a stronger empirical and analytical foundation

As highlighted earlier, the capacity market addresses only the fixed-cost missing money problem. A price cap set below an asset's variable cost creates variable-cost missing money in exactly the hours it runs, and the proposed design cannot remedy this problem. There can be three ways to make such an asset whole, and none of them is the capacity charge itself: (a) lift or revise the price cap so that the energy price can reach the asset's VC; (b) an explicit out-of-market energy uplift for the variable cost shortfall, such as what the 2025 gas-from-DSM/AS-pool did; or (c) administrative scarcity pricing.

Which of these is needed, if any, is an empirical question, and that's where some background analysis would strengthen the paper.

To support a claim that a capacity market can pull these assets in under a price-cap, the following analysis is required at the very least:

- A variable-cost map of the candidate fleet, i.e., the variable cost (Rs/MWh) of the idle/stranded units that one hopes to attract, broken down by fuel (APM gas, RLNG, spot LNG, imported coal, old subcritical coal, etc.), and the share sitting below vs. above the present Rs 10/unit cap. This alone can show which assets the market can even theoretically leverage.

- A price-duration / scarcity-hour analysis under the price-cap constraint, to see how many hours a year the energy price hits the Rs 10/unit cap, and for an asset

with VC = X, in how many hours the MCP ≥ X (profitable dispatch) vs. MCP < X (idle or loss). For VC > 10, the answer is structurally zero.

- A net-revenue ("missing money") break-up for a representative high-VC plant, splitting total shortfall into the fixed-cost slice a capacity charge can cover and the variable-cost slice that it cannot, and checking whether the capacity-charge bid cap (set at Net-CONE + 10% in the reserve design) is large enough to cover the total.

- Out-of-market uplift quantification: if the design relies on dispatching high-VC / stranded assets and compensating the VC shortfall outside the capped market, the size of that uplift, who pays for it, and how it's reconciled with the paper's claim that the mechanism avoids double payment need to be clarified and empirically demonstrated. Similarly, the possibility of a high-VC asset being forced to clear as a price taker in stress hours, including the 1.5x penalty risk, needs to be tested to determine whether it is economically feasible in the first place.

- Availability, fuel supply and locational checks, such as whether the target assets, say, gas fleet/PSP or hydro plants, can physically deliver in the stress hour (considering gas supply, water availability, ramp and/or transmission constraints, etc.), need to be verified, since a capacity charge is wasted on an asset that cannot be dispatched when needed.

- VOLL/LOLP grounding: the case for paying these assets to stay available rests on values assumed for VOLL. It's important to note here that there is no uniformity or agreement on the values to be considered for this parameter amongst states/discoms. Nevertheless, even with the assumed VOLL ~Rs 180/unit against a Rs 10/unit cap, the analysis should quantify the welfare loss from capping so far below VOLL, which is the economic justification for cap revision in the first place.

Without addressing the above issues with the supporting data and empirical analysis being shared in the public domain, it is not possible to meaningfully comment on the efficacy of the proposed options.

To summarise, the Staff Paper is right in highlighting the need for a capacity market to ensure resource adequacy and supply reliability amidst a growing share of variable generation and demand. The proposal will, however, be robust only if the eligibility criteria are clarified, the underlying parameters (CONE, Net-CONE, VOLL, LOLP) and templates for the information, such as RA-plan and assumptions, contract information, tariffs, etc., that will feed the auctions are duly established and published.

Transparently addressing the above-mentioned issues would ensure that the capacity market is rolled out on a technically strong and analytically sound basis, and would result in a fair, economical and efficient price discovery for the much-needed capacity to ensure resource adequacy and maintain healthy reserves. It would also minimise the potential disputes and litigation amongst various stakeholders post the market roll-out.

Further, for a smooth operation of such a market, the Commission will need to also define and institutionalise due monitoring governance processes that will build credibility and public trust. This would require, among other things, timely and transparent market monitoring, clear guidance and procedure on dispute resolution, regular third-party audits of all relevant systems, publishing and archiving all relevant data, and so on. International best practices in this regard also can be very instructive and need to be studied and adopted if useful.

We are grateful for this opportunity to share our views on the matter and hope that the Commission finds them useful. We request the Commission to accept our submission on record and to allow us to make further submissions in this matter, if needed.

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